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Appendix A

Gas Research Institute

Technical Issues Related to the Potential Use of Selective Catalytic Reduction (SCR) to Reduce NOx Emissions from Natural Gas-Fired Lean Burn Engines

Technical Issues Related to the Potential Use of Selective Catalytic Reduction (SCR) to Reduce NOx Emissions from Natural Gas-Fired Lean Burn Engines

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Prepared for:
Gas Research Institute

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I. INTRODUCTION

On October 27, 1998 (63 FR 57356), EPA promulgated the Agency's rulemaking to call for 22 eastern states and the District of Columbia to revise their State Implementation Plans (SIP) to address the regional transport of ozone (the SIP Call). EPA also proposed a Federal Implementation Plan (FIP) that would be implemented if any state failed to submit an adequate SIP revision in response to the EPA SIP Call (63 FR 56394).

In a technical support document for both rulemakings (A-96-56, VI-B-13), EPA stated that emissions of nitrogen oxides (NOx) from large lean-burn reciprocating internal combustion engines can be reduced by 90 percent, cost-effectively, using Selective Catalytic Reduction (SCR):

> The control level for spark ignited lean burn engines that meets the $2,000/ton criteria . . . is a limit of 125 ppmv NOx at 15% O_2. This represents selective catalytic reduction (SCR) control . . . providing a 90 percent reduction in NOx emissions.

The Agency stated in the SIP Call rulemaking that 90 percent control with SCR was adopted based on information presented in the Alternative Control Techniques Document -- NOx Emissions from Stationary Reciprocating Internal Combustion Engines (EPA-453/R-93-032) (ACT document):

> For [reciprocating internal combustion engines], EPA determined based on the relevant ACT document, that post-combustion controls are available that would achieve a 90 percent reduction from uncontrolled levels . . . . (63 FR 57418)

EPA used 90 percent control for large reciprocating internal combustion engines to calculate the state NOx budgets for the SIP Call and the FIP. In

the FIP, EPA also proposed an emission limitation of 125 ppmv for natural gas-fired lean-burn engines based on 90 percent control of NOx using SCR.

The Gas Research Institute (GRI) presents in this white paper an assessment of the technical issues related to the potential use of SCR to reduce NOx emissions from natural gas-fired lean-burn engines and the reasonableness of the EPA's estimate of a 90 percent reduction of NOx emissions from lean-burn engines using SCR. GRI intends to continue investigating NOx control techniques for natural gas lean-burn engines and NOx emissions monitoring techniques. This white paper includes information on SCR that could be assembled prior to the November 30 deadline for comments on the proposed FIP.

Overview of SCR Technology

SCR was developed to reduce NOx emissions from fossil fuel-fired boilers. In the early-to-mid 1980s, SCR was applied to cogeneration gas turbine engines and reciprocating internal combustion engines.

NOx reduction with SCR is based on the reaction of ammonia and NOx to form nitrogen and water. SCR uses a catalyst to promote the ammonia and NOx reaction. In the absence of a catalyst, the reducing reactions occur in the range of 1000°C. As the temperature is increased above the 1000°C range, the ammonia oxidizes to NO, thereby increasing the NOx emissions and as the temperature is decreased below the optimum range, unreacted ammonia is emitted from the system. When a catalyst is added, the ammonia and NOx react at temperatures significantly lower than those obtained without the catalyst.

The essential components of the SCR system are:

SCR catalyst
Exhaust ducting and SCR housing
Ammonia system

Control system and continuous emissions monitors (CEMs)

Traditional SCR catalysts are base metal catalysts composed of vanadium pentoxide, titanium dioxide, or tungsten trioxide. The temperature range for the base metal SCR catalysts for NOx conversions greater than 80 percent is about 300 to 425°C. During the 1980s zeolite SCR catalysts were developed. These catalysts have a wider temperature operating range and offer more resistance to sulfur poisoning, which has been a problem with some of the other SCR catalysts. The SCR process requires about two to three times the catalyst size of that required for oxidation exhaust catalysts (such as used for CO control), since SCR space velocities are low compared to those required for other post-combustion catalytic controls. Typically, 2 to 3 catalyst stages are required in the SCR system.

SCR requires on-site storage of ammonia and an ammonia delivery system. The ammonia system includes the ammonia storage tank, the ammonia flow regulation system, and the ammonia injectors. Heaters are required to vaporize the ammonia. The type of vaporization system used depends on the type of ammonia used -- anhydrous or aqueous -- and on the ambient temperature range experienced at the site. In order for SCR to work, the ammonia must be fully vaporized and evenly dispersed across the face of the catalyst.

The ammonia control system generally includes NOx CEMs upstream and downstream of the SCR catalyst. The ammonia flow rate required is based on a preset ammonia to NOx ratio and determined from a measurement of the inlet SCR NOx concentration and from determination of the exhaust flow rate of the engine. System performance is checked by measuring the outlet SCR NOx concentration.

The exhaust gas samples are conditioned (e.g., dried and filtered) and are pumped to the NOx analyzer. Typically, the NOx analyzer is cycled between

the inlet and outlet of the SCR unit. Generally this type of system requires a response time of approximately five minutes to obtain an accurate, stable reading of the NOx concentrations.

Basis for EPA's Conclusion that SCR is Effective

EPA used information found in the ACT document as the basis for use of 90 percent NOx reduction in the SIP Call and FIP rulemakings. In the technical support document for stationary internal combustion engines (A-96-56, VI-B-13), EPA stated that 90 percent effectiveness for the use of SCR on natural gas-fired lean burn engines was adopted based on the "achievable NOx reduction" presented in Table 2-5 of the ACT document. Table 2-5 is reproduced below.

TABLE 2-5. EXPECTED RANGE OF NO_x EMISSION REDUCTIONS AND CONTROLLED EMISSION LEVELS FOR CONTROL TECHNIQUES APPLIED TO

LEAN-BURN SI ENGINES (NATURAL GAS FUEL)

Control technique	Average uncontrolled NO_x emission level[a]		Achievable NO_x reduction, %	Expected controlled NO_x emission levels	
	g/hp-hr	Ppmv		g/hp-hr	ppmv
AF	16.8	1,230	5 - 30	11.8 - 16.0	860 - 1,170
IR	16.8	1,230	0 - 20	13.4 - 16.8	980 - 1,260
AF + IR	16.8	1,230	20 - 40	10.1 - 13.4	740 - 980
SCR	16.8	1,230	90[b]	1.7	125
L-E	16.8	1,230	87	2.0[c]	150

[a]The uncontrolled emission rate shown is a representative average for lean-burn SI engines. The actual uncontrolled emission rate will vary from engine to engine.
[b]Guaranteed NO_x reduction available from most catalyst vendors.
[c]Guaranteed controlled NO_x emission level available from engine manufacturers.

Footnote "b" to Table 2-5 indicates that the basis for the 90 percent reduction for SCR is based on the "guaranteed NOx reduction available from most catalyst vendors." Section 2 the ACT does not include a detailed discussion of the information provided by the vendors to support the claims for 90 percent reduction or the long-term performance for SCR. Section 5.2.4.4 of the ACT provides further discussion of the achievable emission reduction using SCR. In that section, the ACT states that emission reductions of 80 to 90+ percent is possible using SCR on engines in baseload applications:

> Based on the available information and the emission test data presented in Tables 5-8 and A-5, it is estimated that the achievable NOx emission reduction for SCR in gas-fired applications is 80 to 90+ percent for baseload applications, with an NH_3 slip level of 10 ppmv or less.

The ACT states that 90 percent NOx reduction was used in Chapter 6 to calculate controlled NOx emission levels and cost effectiveness. However, the ACT also states that inadequate information was available to determine achievable continuous NOx reductions and ammonia slip levels for SCR in variable load applications:

> The available data are not sufficient to assess the achievable continuous NOx reductions and ammonia slip levels for SCR used in variable load applications.

As indicated in Section V of this paper, variable load applications present unique difficulties for SCR that have not yet been adequately addressed to allow widespread application of SCR for engines in load-following applications, such as natural gas compression.

In the ACT there is emissions test information for 6 reciprocating internal combustion engines, 3 Clark engines, 2 Cooper Bessemer engines, and 1 Tecogen engine. The engines range in size from 291 to 800 horsepower. All the engines are smaller than the engine horsepower EPA adopted in the FIP (2400 hp). A total of 34 emission test results are provided in the ACT that report NOx emission reductions. Two emission test results report zero NOx emission reductions. The emission results presented were drawn from emission tests conducted in California from 1986 - 1992. Two Clark engines and the Tecogen engine were still in service at the time the ACT document was published. The other three SCR units had been removed from service or the engines had been replaced with electric units. The ACT document stated that emissions test data for existing installations with SCR ranged from 65 to 95 percent reduction.

According to the technical support document, EPA calculated the expected controlled NOx emission level as 1.7 g/hp-hr (125 ppmv) based on an average uncontrolled NOx emission level of 16.8 g/hp-hr (1230 ppmv) and 90 percent reduction of NOx using SCR. However, the emissions data in the ACT document suggests that the percent NOx reduction achieved by engines varies. No explanation is provided in the ACT document for the variability of the SCR effectiveness. No information is provided on the operating conditions of the engines when tested. Also, no information is provided on ammonia emissions (i.e., ammonia slip) from the units. The range of effectiveness reported for the 6 engines is presented in the table below.

Engine No.	Manufacturer	Model	Horsepower	Number of Tests	Range of NOx Control Reported (%)
45	Clark	HRA-6	660	5	84-91
47	Clark	HRA-6	660	5	82-88
139	Cooper Bessemer	GMV	660	1*	50
248	Cooper Bessemer	GMV-8	800	9*	87-93
309	Clark	HRA-32	350	12	65-84
357	Tecogen	CM-200	291	2	95-97

*One additional test was conducted, where zero emission reduction was reported. No explanation is provided in the report for those results.

Only one engine, the Tecogen, reported levels greater than 90 percent for all tests conducted. This small engine is designed to be used for cogeneration. Two other engines (Nos. 45 and 248) reported levels at or above 90 percent for at least one test, but levels less than 90 percent for other tests. The other engines did not include any test results at or above 90 percent NOx reduction.

The emissions data included in the ACT document for natural gas-fired lean-burn engines demonstrate that the effectiveness of SCR systems are variable.

The ACT document does not discuss or explain the variable emissions results and does not identify the factors that would contribute to this variability. Only the small cogeneration engine consistently reported emission reductions greater than 90 percent. The other engines did not consistently achieve emission reductions at or above 90 percent. As indicated in the ACT document, the 90 percent reduction presented by EPA in the SIP and FIP was based on information presented in Table 2-5. However, information presented in Section 5.2.4.4 indicates that EPA was not able to determine an achievable NOx reduction level for the use of SCR in load-following applications.

SCR Installations on Lean-Burn Engines

There is limited operating experience to date with the use of SCR on reciprocating internal combustion engines. At the time the ACT document was published, EPA identified a total of 23 engines (including 3 engines using digester gas) with lean-burn engines in the United States based on information provided by catalyst vendors and approximately 40 installations of SCR overseas. The ACT document also noted that there is little experience with SCR in variable load applications due to ammonia injection control limitations.

At present, no natural gas-fired lean burn engines were identified in the EPA RACT/BACT/LAER clearinghouse with SCR controls (Query of 15.004, post 1991). RACT/BACT/LAER determinations for lean burn engines have relied on low emissions combustion (LEC) technology, other combustion modification (such as high energy ignition systems), or parametric controls (such as retarded timing and air to fuel ratio adjustment). A total of 18 diesel engines with SCR controls (PA-0096 and PA-0097) were identified in the clearinghouse. The SCR controls for the diesel engines reduce NOx emissions by 80 percent.

For the natural gas transmission industry, there are no known SCR installations on lean burn engines in pipeline service. Two lean burn engines at a natural gas storage facility in California have SCR. These engines have been mothballed due to the operations and maintenance problems related to the use of SCR with the variable loads experienced in the natural gas storage operation. The engines are not used presently. Therefore, there are no engines in pipeline service within the United States at this time that have SCR installed. The two engines in California where SCR was installed have been mothballed and are not currently in use.

In 1996, the natural gas transmission industry conducted a survey to gather information on the reciprocating engines and turbines in natural gas transmission service. The transmission companies provided information on over 5,000 reciprocating internal combustion engines. As a part of the survey, information was provided on over 800 reciprocating internal combustion engines with some form of NOx emission controls in place. The survey results indicate that the natural gas transmission industry has installed technology that relies on combustion modification or parametric controls to reduce NOx emissions from lean-burn engines, rather than post-combustion controls, such as SCR. Only 2 of the 599 lean-burn engines with NOx controls have SCR installed (the California units). For natural gas transmission, SCR is the NOx control technique that has been used least to reduce emissions from lean-burn engines. Low emissions combustion (LEC) or other combustion or parametric control techniques have been used most often to reduce NOx emissions from lean-burn engines. In contrast, for rich-burn engines, post-combustion catalytic control (non-selective catalytic reduction -- NSCR) is the NOx control technique that has been used most often to reduce NOx emissions. The transmission industry survey indicates that 100 of 201 rich-burn engines with NOx controls have NSCR installed. The results of the industry survey are presented below.

Lean Burn Engines

Type of Control	In SIP Call States	Not in SIP Call States	Total Units
Low Emissions Combustion	245	139	384
High Energy Ignition	87	21	108
Other NOx Control	49	13	62
Parametric Controls	39	4	43
SCR	0	2*	2*
Total	371	179	599

*Mothballed.

Rich Burn Engines

Type of Control	In SIP Call States	Not in SIP Call States	Total Units
NSCR	24	76	100
Pre-Stratified Charge	7	41	48
Low Emissions Combustion*	7	32	39
High Energy Ignition*	0	10	10
Parametric Controls	3	1	4
Total	41	160	201

*Possible conversion to lean-burn conversion. Data for these engines are under review.

The survey results include NOx controls that were installed by natural gas transmission companies to comply with NOx RACT and BACT requirements. No natural gas transmission company was required to install SCR as NOx RACT or BACT. Although some companies did consider SCR as a potential control option, SCR was found to be unacceptable due to the limits of the ammonia delivery system and the need for load-following horsepower to respond to pipeline conditions. (More discussion of this issue is included in the following section of this white paper.)

Therefore, while NSCR is widely applied for natural gas-fired rich-burn engines, there are very few instances where SCR has been applied to natural gas-fired lean-burn engines. State air regulatory agencies did not require

SCR to implement NOx RACT or BACT requirements. At present, there are no engines in the natural gas transmission industry that are operating with SCR. Rather, combustion modification and parametric controls have been the techniques applied to reduce NOx emissions from existing lean-burn engines.

Difficulties Operating SCR Systems

The following issues must be considered in the context of NOx control with SCR:

Variable load operation
Ammonia handling and storage
Catalyst maintenance and disposal
Engine maintenance
Continuous emissions monitoring

Variable load operation complicates the successful operation of an SCR system given:
1) variations in NOx emissions, 2) variations in exhaust gas flow and temperature, and 3) thermal cycling.

In order for SCR to work properly, with the appropriate control of NOx emissions and without excessive ammonia emissions, it is necessary that the proportions of NOx and ammonia be correct. Reciprocating internal combustion engines in natural gas transmission service are used to compress and move natural gas along the pipeline. The load and speed of the engines must respond to pipeline conditions, supply, and demand for natural gas. As a result, engines are frequently required to change load and speed conditions. These changes produce changes in the NOx emissions from the engines. For example, a load change of only 5 percent can significantly change the NOx emitted from an engine -- for some engines NOx can increase as much as 50 percent. When these changes occur, the

ammonia feed system must be adjusted to maintain the proper ratio of ammonia to NOx. In Section 5.2.4.2, the ACT notes that variable load can cause NOx concentration swings that pose problems for the SCR system. SCR systems traditionally use a feedback system that relies on a NOx or ammonia analyzer to adjust the ammonia feed system. It takes approximately 5 minutes time to extract a sample and report NOx emission levels using a NOx CEMs. Therefore, for load-following applications, a feedback system is not sufficient alone to allow the ammonia feed system to be adequately responsive to maintain NOx reductions. Some load-following engines may be able to use SCR if the systems incorporate feed-forward controls. The feed-forward controls incorporate sophisticated predictive emissions models (PEMs), which estimate NOx and adjust the ammonia feed system accordingly. A recent installation of SCR at the Buckeye Pipeline station uses PEMs as the feed-forward controls for an SCR with new Waukesha engines. For existing engines, no applications are known where PEMs have been successfully used as feed-forward controls for SCR. One reason that the feed-forward system may not have been applied to existing engines is the need to develop a sophisticated predictive emissions model to estimate NOx. For new engines, engine manufacturers have information readily available to develop the PEMs. However, for existing engines, the owner or operator would have to independently develop a PEMs that would be sophisticated enough to reliably control the ammonia feed system. The engines at the Buckeye Pipeline station also represent a load-following application with a limited range of operating conditions since the engines are used to drive liquid pumps. For natural gas transmission, the engines are used to compress gas along the pipeline and the pipeline conditions create a wider range of operating conditions for the load-following engines. The Buckeye Pipeline station experienced difficulties with catalyst masking when lube-oil residuals were deposited on the catalysts during frequent start-up tests. For natural gas transmission service, engines often experience

frequent start-ups, which may lead to catalyst masking, as experienced at Buckeye.

Variable load conditions also result in variations in exhaust gas flow and temperature conditions. The ammonia control system would need to be adjusted to respond to the changes in the exhaust mass flow rate (especially dual shaft engines). Variable exhaust gas flow rates would also affect mixing in the catalyst. The wider the range in exhaust gas flow rates velocities, the more difficult it is to design a catalyst that can reliably achieve high emission reductions (e.g., 90 percent). Reduced engine load can also decrease the exhaust gas temperature below the range for optimal NOx conversion, which would not allow the catalyst to reliably achieve high emission reductions. Section 5.2.4.2 of the ACT states that "lower exhaust temperature at reduced power output may result in a reduced NOx reduction efficiency from the catalyst." Variable load conditions also result in thermal cycling of the catalyst, which leads to reduced catalyst life. These variable load conditions are common for engines in natural gas transmission service.

As indicated in the EPA ACT document, there is little experience using SCR systems on engines in load-following applications, such as natural gas transmission. Although catalyst vendors suggest that SCR can be designed to work in load-following applications, installations of SCR systems on load-following applications have been limited. The results of the 1996 survey of natural gas transmission companies were queried to identify SCR installations. Based on that search, only two engines have SCR installed and those engines have been mothballed.

The continuous and reliable operation of an SCR system requires close monitoring of several subsystems. This includes ammonia storage, control, metering, injection, and leak detection systems. Problems can occur with the clogging of the ammonia nozzles and these have to be closely monitored and corrective action taken immediately to ensure proper injection rates and

even distribution of ammonia in the flue gas for proper mixing. In addition, most SCR systems rely on CEMs as the feedback control for the ammonia feed system. In order to ensure reliable performance, NOx CEMs, including sample conditioning, need to be properly calibrated and maintained, which requires specially trained personnel. Finally, instrumentation for ammonia injection rate needs to be calibrated frequently to ensure proper control. These activities become difficult if the station is unmanned, which is often the case in pipeline operation.

Maintenance of the SCR system requires periodic catalyst cleaning in order to restore its reactivity. Cleaning is accomplished by washing of the catalyst with water and typically requires several days downtime for removal of the catalyst, the washing and the re-installation of the catalyst. Disposal of the solution remaining from this procedure can be an issue. Contaminants from lube oil and engine wear, such as metals or silicon oxides, will affect the frequency of catalyst cleaning and can reduce catalyst effectiveness and catalyst life. To minimize contamination, specially formulated lubricating oils must be used. For four-stroke engines, the use of low-contaminant lube oil may result in increased valve wear. The vendor generally handles disposal of SCR catalysts.

Most SCR systems rely on continuous emissions monitors (CEMs) as the feedback control for the ammonia feed system. The installation, operation and maintenance of a NOx CEMs are complicated and require specially trained personnel.

Negative Environmental Impacts from SCR

SCR relies on the use of ammonia injected in the exhaust stream in the presence of a catalyst to control NOx emissions. Ammonia is a colorless gas with a pungent odor. Ammonia is poisonous if inhaled in great quantities and is irritating to the eyes, nose, and throat in lesser amounts. Ammonia is explosive when mixed with air in certain proportions (approximately one volume of ammonia to two volumes of air).

Unlike technology like combustion modifications or parametric controls (which is used on engines in natural gas transmission service), SCR is not a pollution prevention technique and uses additional resources, which in turn create safety hazards and hazardous waste disposal problems. For example, periodic cleaning of the catalyst is required to maintain catalyst effectiveness. After cleaning, the cleaning solution is considered a hazardous waste and creates disposal problems. Additionally, catalyst disposal itself can create environmental problems because the catalyst may contain heavy metals and other toxic substances.

SCR systems usually operate with an ammonia/NOx molar ratio of about 1.0. This is close to the theoretical limit required for complete NOx reduction. However, due to kinetic limitations and improper mixing between the ammonia and the flue gas, complete reduction is not achieved, leading to unreacted ammonia escaping into the atmosphere. Increasing the ammonia injection rate to overcome deleterious kinetic and mixing effects increases the probability of NOx reduction, but also increases ammonia slip emissions. To achieve high NOx reduction efficiencies consistently, SCR systems typically operate with a relative excess of ammonia, resulting in ammonia slip emissions. This issue creates a potential for an increase in ammonia emissions into the

atmosphere, which is further exacerbated by ammonia flow difficulties associated with variable load operation.

There are safety concerns associated with accidental spills of ammonia. At low concentrations, ammonia can cause health effects and can be a nuisance due to its objectionable odor. At high concentrations, it is a toxic compound and a fire hazard. Safety hazards can occur if the ammonia is spilled or there are leaks from ammonia storage vessels. Safety hazards can be reduced if aqueous ammonia or urea is used. However, because water becomes saturated at about 25 percent ammonia by weight, aqueous ammonia tanks must be four times larger than anhydrous ammonia tanks for the same application. Consequently, the cost of storage tanks and transportation costs for aqueous ammonia will be greater than if anhydrous ammonia were used. If a concentrated aqueous solution of urea is used, the urea tank must be heated to avoid re-crystallization of the urea. The corrosive nature of ammonia leads to failure of piping and other components. Additionally suspended rust particles often clog filters and ammonia injection nozzles requiring more frequent cleaning or replacement of equipment.

Storing and using ammonia in quantities above the thresholds specified in the RMP rule may create situations where the facility has to comply with the provisions of 40 CFR part 68 as well.

Conclusions

As presented in this paper, 90 percent reduction of NOx emissions from lean-burn reciprocating internal combustion engines using SCR is not demonstrated in practice. Although catalyst vendors indicated to EPA that 90 percent reduction typically would be achievable for gas-fired applications, the emissions data presented in the ACT document suggests that NOx reduction varies for engines with SCR. Also, the ACT states that insufficient data were available to estimate achievable NOx

reduction levels for the use of SCR in variable load applications, such as natural gas transmission. Since engine operation can significantly affect parameters that affect SCR performance (such as NOx emission levels, exhaust gas flow and exhaust gas temperature), SCR systems would need to be evaluated over the full range of engine operations to determine achievable NOx control levels. Load-following applications, such as natural gas compression, present unique difficulties for SCR systems, which were not fully addressed by EPA in determining the applicability of SCR or the 90 percent effectiveness. Also, EPA's assessment of the cost-effectiveness of SCR did not include costs that would be incurred for variable load applications, including costs to develop a forward-feed PEM and costs that result from vendors "over-engineering" the SCR system to try to offset reduced NOx control efficiencies.

SCR has been installed on reciprocating internal combustion engines in very few instances. Of the 599 lean-burn engines with NOx controls that were included in a survey of natural gas transmission companies, only two engines in the United States have SCR installed and those engines have been mothballed due to difficulties operating the SCR units in a load-following application. Instead, because of the problems associated with using SCR in variable load applications, NOx emissions from lean-burn engines in pipeline service have been controlled using combustion modification or parametric controls.

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RE: U.S. Steel, a Unit of USX Corporation - Comments to Proposed Regulations Interstate Ozone Transport Reduction [25 PA Code Chapter 145]

Dear Sir or Madam:

U.S. Steel Group (USS), a unit of USX Corporation, is pleased to submit the following comments to the Environmental Quality Board's (EQB) proposed adoption of 25 PA Code Chapter 145 (relating to interstate ozone transport reduction).

1. General Comment

The proposed NOx trading program has been modeled after the SO_2 trading program both at the State and federal levels. The SO_2 trading program was developed in order for **utility units** to meet the acid rain requirements of Title IV of the 1990 Clean Air Act Amendments. In essence, the NOx trading program is geared toward utility units. Little consideration has been made for industrial sources in the proposed rulemaking, although the proposed rule covers **all units** that generate electricity greater than or equal to 15 MWe or that have maximum heat inputs greater than or equal to 250 MMBtu/hr.

This rule, having been developed with utility units in mind, should be developed **only for utility units.**

2. §145.4 Applicability

Issue #1
In the preamble to the final rule, EPA stated that "no additional control measures were assumed for source categories with relatively small NOx emissions (e.g., iron and steel mills...)." [63 FR 57403; 10/27/98]

Comment #1
USS requests that the Department considers sources in iron and steel mills **exempt** from control requirements and **exempt** from trading as proposed by EPA. EPA believed the administrative costs to develop regulations for these industries (iron and steel...) would be prohibitive and would result in an inefficient use of State's resources. [63 FR 57416; 10/27/98]

Issue #2
No provision has been made in this proposed regulation to exclude sources that utilize byproduct fuels that do not result in excessive NOx emissions. It was not EPA's intent and hopefully not the state's intent to regulate these sources, to require the installation of NOx control technologies, and to participate in NOx trading.

Comment #2
USS operates several boilers that would meet the applicability requirements in the proposed rule. However, these boilers fire byproduct fuels such as blast furnace gas and coke-oven gas, which have lower NOx emission factors than other traditional fossil fuels. USS believes that combustion of byproduct fuels such as blast furnace gas and coke-oven gas should be considered as a NOx control technology for the purpose of the NOx budget program. No additional controls should be required for these sources.

Issue #3
No provision has been made in this proposed regulation to exclude NOx control and trading requirements from small point sources. It was not EPA's intent and hopefully not the state's intent to regulate these sources, to require the installation of NOx control technologies, and to participate in NOx trading.

Comment #3
In the preamble to the final federal rule, EPA defined small point sources as "(1) electricity generating boilers and turbines serving a generator 25 MWe or less, and (2) other point sources with a heat input of 250 MMBtu/hr or less and which emit less than one ton of NOx per average summer day." [63 FR 57402; 10/27/98]

EPA is allowing NOx budget units that serve a generator less than 25 MWe to be exempt from the NOx trading program and control requirements. Pennsylvania has lowered this cutoff point to 15 MWe. EPA assumed no reductions from units less than 25 MWe in establishing State NOx budgets. **USS requests that Pennsylvania use a level of 25 MWe to match the federal program.** USS believes that it would be of little value to include these small sources in the NOx trading program.

Also, EPA's rule language at § 96.4(b) allows for exemptions through federally enforceable restrictions such as limits on a unit's operating hours, fuel type (gas or oil), etc. **The Pennsylvania rule does not allow for such exemptions.** USS requests that these exemptions be included in the final regulation.

3. EGU's vs. non-EGU's

Issue
No provision has been made in the proposed regulation for those units that generate electricity but **do not sell** electricity.

Comment
In "Responses to Questions on the Final Rule for the NOx SIP Call, Volume I, January 1999," the EPA clarifies that an Electrical Generating Unit (EGU) is one that sells electricity whereas a Non-Electrical Generating Unit (non-EGU) does not. An EGU is then subject to a more restrictive emission limit than a non-EGU.

If this rule should apply to USS, USS is uncertain how to classify its affected units – as EGU or non-EGU. It is unclear if U.S. Steel's "NOx Budget Unit" allowances will be based on 0.15 lb/MMBtu [§145.4(1)] or 0.17 lb/MMBtu [§145.4(2)]. It is also unclear what control period should be used to calculate the unit's maximum heat input rates which forms the basis for calculation of NOx allowances.

The Department should clarify this issue. It does not appear to matter to the Department whether the electricity is consumed in-house or sold. It only matters that the electricity is generated.

4. §145.2 Definitions

Issue
The definition of "boiler" in §145.2 is unclear. The definition of boilers in the proposed regulation includes fossil or other fuel-fired combustion device including process heaters used to produce heat and to transfer heat to recirculating water, steam or other medium. Does this include both direct-fired and indirect-fired units?

Comment
According to this definition, a coke oven underfiring system with a maximum rated heat input capacity of 250 MMBtu/hr or more can be construed as a boiler because it is a fossil or other fuel-fired combustion device.

USS believes that it was not the intent of the EPA to include coke ovens in these regulations. NOx controls for coke ovens have not been demonstrated in the U.S. According to the DRAFT EPA guidance document, "Alternative Control Techniques (ACT) Document – NOx Emissions from Iron and Steel Mills" dated March 1993, coke battery NOx controls in the U.S. have not been found. The draft ACT Document does supply some evidence of the use of SCR on a coke oven in Japan. However, the Japanese have acknowledged that "there are many limitations and difficulties associated with applying these controls and some may be applicable only to new ovens."

The ACT Document and other USS data indicate that coke battery NOx generation is a strong function of the heating system design. Other factors that also impact NOx formation include facility age, fuel gas composition, combustion air ratios, battery operating rate, battery flue temperature and heating system maintenance. NOx controls for coke ovens were evaluated for RACT in 1994. No conclusive evidence was found supporting a NOx control technology at that time. Since 1994, EPA has not evaluated the technical and economic feasibility for installation of NOx controls on coke ovens.

Thus, EPA and the State have no basis for including coke ovens in the §145 proposed regulations. The definition of "boiler" should be revised to clarify that coke ovens and other similar process sources are excluded units and thus, not subject to this proposed rule.

SUMMARY

In its final regulation, USS requests the Department consider that:

- Only utility units should be regulated by this rule;
- Sources in iron and steel mills should be exempt from control and trading requirements;
- Sources that combust byproduct fuels should not be regulated;
- Sources that participate in the NOx trading program be equal to or greater than 25 MWe;
- Clarification of terms needs to be done, especially for EGU vs. non-EGU units; and
- Coke ovens (and other similar process sources) not even be considered as units in this regulation.

If you have any questions or require additional information, please contact William S. Kubiak, Manager Environmental Affairs, Air Compliance at 412-433-5915 or e-mail address wskubiak@uss.com.

Sincerely,

William S. Kubiak

cc: N. Hirko
T. Woodwell
Facility Air Quality Managers

TRIGEN

TRIGEN-PHILADELPHIA ENERGY CORPORATION
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(215) 875-6900 FAX (215) 875-6910

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REVIEW COMMISSION

HERMAN A. SCHOPMAN
Vice President of Operations

April 8, 1999

Mr. J. Wick Havens
Chief, Division of Air Resourses Management
Bureau of Air Quality
12th Floor
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P.O. Box 8468
Harrisburg, PA 17105-8468

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Dear Mr. Havens

Trigen is pleased to provide our comments on the proposed approach of NOx allowance allocation and trading regulations. Trigen believes that Pennsylvania Department of Environment Protection (DEP) has an opportunity to establish a NOx trading program that will encourage improvement of efficiency and thus reduce NOx emissions in Pennsylvania since less fuel will be burned to accomplish the same task. This will result in air quality improvements while meeting the energy needs of Pennsylvania's residents and businesses.

Trigen strongly believes that NOx allowance allocations should be based on total useful energy output rather than the amount of fuel burned. Massachusetts has developed an output-based allowance allocation system. EPA has been moving toward using output based standards. For example, last year EPA changed the New Source Performance Standards (NSPS) for utility boilers from heat input-based standards to energy output based standards. EPA working in conjunction with states and industries are in the process of developing guidelines for an output-based NOx allocation system.

Unfortunately, the regulations as proposed by DEP do not take an output-based approach. Trigen understand that because DEP has to submit the revised SIP to EPA by September 30, 1999, it may not be realistic to develop an output-based NOx allocation system at this time. In the absence of an output-based allocation system, Trigen believes that DEP should take an efficiency set-aside approach. This approach will reward improvements in efficiency and, thereby, reduce NOx emissions. In early March, EPA issued a guidance document encouraging states to set 5% to 15% of total trading budget aside for energy efficiency projects. We believe that DEP should adopt EPA's set aside recommendations for energy efficient projects. Other states, such as New York, Massachusetts, and Missouri, have taken such an approach.

Trigen appreciates the opportunity to provide input on these important regulations. Trigen will provide more specific written comments to DEP prior to the due date of May 10, 1999.

Sincerely,

Cc: Dean Van Orden, Pennsylvania Department of Environmental Protection
Steve Smith, Trigen
Jim Qin, Trigen
Mark Hall, Trigen

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

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May 6, 1999

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Mr. J. Wick Havens, Chief
Division of Air Resources Management
Environmental Quality Board
15th Floor Rachel Carson State Office Building
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Harrisburg, PA 17105-8477

Dear Mr. Havens,

Thank you for giving EPA the opportunity to comment on Pennsylvania's proposed Chapter 145, Interstate Pollution Transport Reduction rule. EPA appreciates the care you have taken to include the provisions of the Model Rule, 40 CFR Part 96, to allow for a smoothly operating trading program. However, EPA has some comments regarding the proposed rule. Our comments center on a few remaining issues where the rule language may not give EPA authority to carry out all the functions needed to run the interstate trading program, and areas of potential conflict with other programs. Please enter the enclosed comments into the official public record for this rule, which closes on May 10, 1999.

Thank you for the opportunity to comment on your proposed rule. If you have any questions or wish to discuss these comments, please contact me or Cristina Fernandez at (215) 814-2178.

Sincerely,

Marcia L. Spink

Marcia L. Spink, Associate Director
Office of Air Programs
Air Protection Division

Enclosure

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Enclosure

U.S. EPA Region III & U.S. EPA Acid Rain Division Comments on Chapter 145, Interstate Pollution Transport Reduction

§ 145.1 Purpose.

It would help to have a statement explicitly authorizing the Administrator to assist you. Some possible language that could be adopted from §96.1:

> The Commonwealth authorizes the Administrator to assist the Commonwealth in implementing the NOx Budget Trading Program by carrying out the functions set forth for the Administrator in this subchapter.

§ 145.2 Definitions.

The definition of "emissions" should read, "Air contaminants exhausted from a unit or a source into the atmosphere, *as determined* in accordance with this subchapter."

The definition of "Maximum potential NO_X emission rate" should read, "...or the minimum carbon dioxide concentration (in percent CO_2) *under all operating conditions of the unit except for unit start up, shutdown, and upsets.*"

If you intend for this definition to be different from the one in §96.2, consider that a source affected under the Acid Rain Program could potentially have one maximum potential NO_X emission rate under the Acid Rain Program and a different maximum potential NO_X emission rate for your rule in your SIP. This could be confusing for the source, as well as difficult to report in an electronic quarterly report.

There appears to be a typographical error in the definition of "NOx allowances held" or "hold NOx allowances." Did you mean to say, "The NOx allowances recorded ~~in accordance with~~ or submitted for recordation, *in accordance with* this subchapter, in a NOx Allowance Tracking System account."?

The definition of "NO_X budget administrator" does not say who the Department has designated. We suggest you designate the U.S. EPA, or the Administrator of the U.S. EPA to give us authority to assist you.

There appears to be a typographical error in the definition of "authorized account representative."

Did you mean to say, "*NOx authorized account representative*–For a NOx Budget source or NOx Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all NOx Budget units at the source, in accordance with *this subchapter*,...."?

NO_X Budget Trading Program–as written, this definition could limit other states, since their emission reduction programs are not "in accordance with this subchapter." We suggest the following revision:

> NOx Budget Trading Program—A multi-state nitrogen oxides air pollution control and emission reduction program established in accordance with this subchapter *or 40 CFR 51.121*, as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor.

Same issue in the definition of "State" of limiting other States. We suggest the following revision: "One of the 48 contiguous States and the District of Columbia that adopts a NO_x Budget Trading Program pursuant to this Subchapter *or 40 CFR 51.121* ."

§ 145.6 Standard requirements.

This does not include the language from §96.6(c)(8) about automatic permit amendments. Is this covered by § 145.23(b)? Is this how you are handling automatic permit amendments?

This does not include the language from §96.6(f)(1) and (2). Is this because other State laws and rules already provide for this liability?

(e)(1)(ii) Apparent typographical error. "All emissions monitoring information, in accordance with §§ 145.70 through 145.76*; provided that* to the extent that §§ 145.70 through 145.76 provides for a 3-year period for recordkeeping, the 3-year period shall apply."

§ 145.10 Authorization and responsibilities of the NO_X authorized account representative.
§ 145.11 Alternate NO_X authorized account representative.
§ 145.12. Changing the NOx authorized account representative and the alternate NOx authorized account representative; changes in the owners and operators.

§§ 145.10(c), (d), 145.11(b), and 145.12(a), (b)

In each of these paragraphs, there is a reference to " receipt by the Department and the NOx Budget Administrator." This could be a timing issue, because it is likely that you will not receive something on the same date as EPA. Which date becomes the effective date? Also, it will be difficult for us and for you to track when both the Department and EPA have received a submission.

If you want to eliminate the timing problem, but you still want to receive copies of the account certificate of representation, you could refer to receipt by the Administrator or the NO_X Budget

Administrator (but not the Department) in this language. You then could add a sentence, requiring the NO_X authorized account representative to send a copy of the account certificate of representation to the Department. Alternatively, you could check the Acid Rain Division webpage, where account information is publicly available.

§ 145.21 NOx Budget permit applications.

There is no language here about "duty to reapply" (§96.21(c)). Do you feel your permits or your Title V permitting rules cover this already?

§ 145.25 NO_X Budget permit revisions.

See comment above for § 145.6, Standard requirements about automatic permit amendments. Does this require permit revisions for allowance transfers? If so that is a major problem. There is no problem if §145.23(b) obviates the need for permit revisions for allowance transfers.

§ 145.40 State trading program budget.

(a) and (b) "tons per *season*"–the defined term is "control period."
It seems like you are allocating fewer allowances than you have available in your State budget.

§ 145.42. NOx allowance allocations.

(d)(3) and (e) How is "allowable emission rate" defined?

(d) There needs to be some time limit on state action on set-aside requests since allocations for a given control period must be made *before* the allowance transfer deadline too that control period. The addition of more allowances after the compliance process begins would be disruptive.

§ 145.50. NOx Allowance Tracking System accounts.

(a) Typographical error to be fixed (also in part 96): " (a) "... the Administrator will establish one compliance account for each NOx Budget unit and one overdraft account for each source with ~~one~~ *two* or more NOx Budget units. Allocations of NOx allowances pursuant to subpart E of this part or §96.88 and deductions or transfers of NOx allowances pursuant to §96.31, §96.54, §96.56, subpart G of this part, or subpart I of this part will be recorded in the compliance accounts or overdraft accounts in accordance with this subpart.

§ 145.54. Compliance.

(e)(2) Apparent typographical error in reference: "Notwithstanding subparagraph *(b)(2)*(I), the NO_x Budget Administrator will deduct...."

§ 145.70. General Monitoring Requirements.

(b)(2)(iv) This is a requirement for units "that report on a control season basis under §145.74(d)...." However, the referenced language requires annual reporting for all NO_X budget units and does not allow control season basis reporting. If you intend for all your sources to report on an annual basis, then you should delete this paragraph.

Similarly, you will need to delete the phrase "and that report on an annual basis under §145.74(d)" in §145.70(b)(2)(iii). Also delete "except as provided for in 40 CFR §75.74." in §145.70(b)(4)(ii) and (iii), since the referenced provision deals with partial year reporting.

§ 145.71. Initial certification and recertification procedures.

(b)(3)(iii) This section allows for valid data from provisionally certified monitoring systems "for a period not to exceed 120 days...." However, the corresponding language (§96.71(b)(3)(iii)) in the last sentence about "issuing a notice of disapproval within 120 days of receipt of the complete certification application by the permitting authority" is not there. What happens to the validity of the data if the Department takes more than 120 days to approve the source's certification application? There is a gap in the rule that does not address that situation.

(b)(3)(iv) and (iv)(A) There is a similar issue here, where the 120 day limit on issuing the notice of approval or disapproval is not there. However, you still provide for an "automatic" certification approval if the Department does not issue a notice of disapproval. At what point would the owner or operator know for sure that the monitors really are certified, and will not be "decertified"?

We understand that the Department has concerns with committing to issuing certification disapprovals within 120 days of receipt of the application. However, Acid Rain affected sources will already follow these provisions; it may be confusing for them (and for you and EPA) to have a NO_X CEMS automatically certified under the Acid Rain Program, but not under the NO_X Budget Program. In addition, the audit decertification procedures exist in order to allow an agency to correct or replace a monitor that never should have been certified after the 120 day review period has passed. We recommend that you adopt the language in part 96 establishing the 120-day period for approval or disapproval.

§ 145.74. Recordkeeping and reporting.

(d)(3)(iii) This paragraph just applies to sources reporting only during the control period. Delete it.

§ 145.80. Applicability for opt-in sources.

This section no longer refers to a unit that is in your state. You cannot authorize a unit in another state to become a NO_X Budget opt-in source. We suggest revising the language as follows:

A unit that is *in Pennsylvania, is* not a NO_x Budget unit under § 145.4, vents all of its emissions to a stack, and is operating, may qualify, under this section and §§ 145.81 through 145.88, to become a NO_x Budget opt-in source.

§ 145.83. Applying for NOx Budget opt-in permit.

There is no language here about "duty to reapply" (§96.83(b)). Do you feel your permits or your Title V permitting rules cover this already?

§ 145.90. Emission reduction credit provisions.

(c)Did you intend for the language in this paragraph to say, "A NO_x Budget unit may transfer NO_x ERCs to a *new or modified* NO_x Budget unit if the new or modified NO_x Budget unit's ozone season...."?

(d)(2) "The NO_x allowance tracking system account for NO_x Budget units which generated ERCs transferred to non-NO_x Budget units, including prior to the date of publication in the Pennsylvania Bulletin, *shall have a corresponding number of NO_x allowances retired* that reflect the transfer of emissions regulated under §§ 145.1 through 145.88 and this section to the non-NO_x Budget units. *The amount of annual NO_x allowances deducted* shall be equivalent to that portion of the non-NO_x Budget unit's NO_x control period allowable emissions which were provided for by the NO_x ERCs from the NO_x Budget unit."

This addresses a reasonable concern about transfers from shutdown sources to new or modified sources. However, under current procedures, the Administrator would not know that allowances need to deducted for this reason. Therefore, you will need to implement this yourselves. You could do that by having authorized account representatives request EPA tp transfer NO_X allowances.

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TRANSCONTINENTAL GAS PIPE LINE CORPORATION'S ONE PAGE SUMMARY OF ITS WRITTEN COMMENTS ON THE INTERSTATE OZONE TRANSPORT REDUCTION PROPOSED RULEMAKING

Transcontinental Gas Pipe Line Corporation ("Transco") has submitted detailed written comments on the Environmental Quality Board's ("Board") Interstate Ozone Transport Reduction proposal published in the Pennsylvania Bulletin on March 6, 1999. Transco's written comments focus primarily on the proposed new Chapter 145, Subchapter B, relating to NOx emission limitations for certain stationary reciprocating internal combustion engines.

Transco supports state flexibility in approving control measures to achieve the emission reductions required by the Environmental Protection Agency's ("EPA") NOx SIP Call. Unfortunately, the Board, in proposing the new Subchapter B, has relied solely upon the EPA's proposed Federal Implementation Plan ("FIP") published in the Federal Register on October 21, 1998. However, EPA appears to have changed its position on regulating internal combustion engines. On May 6, 1999 (after Transco's written comments were prepared), EPA posted on its Technology Transfer Network revisions to the NOx SIP Call and the associated emission budget inventories. EPA now intends to include in the emissions budget inventory only those internal combustion engines with 1995 emissions greater than one ton of NOx per day. Transco supports the EPA's May 6, 1999 revisions to the NOx SIP Call and the associated emissions inventories.

In the proposed FIP, EPA erroneously included internal combustion engines with a rated capacity greater than 2400 bhp instead of engines with emissions greater than one ton per day of NOx. Indeed, this is the same threshold included in the Board's proposed rule. EPA conceeds that the proposed NOx FIP emission limitation represents the use of selective catalytic reduction control ("SCR"). However, as discussed in Transco's written comments, SCR control is not presently technically or economically feasible on variable load engines. Indeed, Transco's engines, which are used to compress and move natural gas along an interstate natural gas pipeline, are variable load.

Transco has suggested for the Board's consideration alternative language in its detailed written comments, including the use of averaging to achieve equivalent emission reductions.

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713/215-2000

May 7, 1999

James M. Seif, Chairman
Environmental Quality Board
15th Floor
Rachel Carson State Office Building
P.O. Box 8477
Harrisburg, PA 17105-8477

Re: Comments on Interstate Ozone Transport Reduction Proposal 29 Pa. Bull. 1319 (Mar. 6, 1999)

Dear Chairman Seif:

Transcontinental Gas Pipe Line Corporation ("Transco") is pleased to submit the following written comments on the Pennsylvania Environmental Quality Board's ("EQB") Interstate Ozone Transport Reduction proposed regulation published in the Pennsylvania Bulletin. See 29 Pa. Bull. 1319 (Mar. 6, 1999). Transco's comments focus primarily on the proposed new Chapter 145, Subchapter B, relating to NOx emission limitations for certain stationary reciprocating internal combustion engines. Transco understands that the Pennsylvania Department of Environmental Protection ("PaDEP") Bureau of Air Quality relied upon the Environmental Protection Agency's ("EPA") proposed Federal Implementation Plan ("NOx FIP") published on October 21, 1998 as the technical and economic basis for the new proposed emission limitations.[1]

Transco supports state flexibility instead of a one-size-fits-all federally imposed program. Transco recognizes the severe time constraints imposed on the EQB by the EPA's NOx SIP Call. However, EPA, in the proposed NOx FIP erroneously required a control level for lean-burn engines of 125 ppmv NOx at 15 percent O2 for engines that are 2400 hp or larger. EPA has conceded this emission limitation represents Selective Catalytic Reduction ("SCR") control. See 63 Fed. Reg. at 56416. SCR control is not presently technically or economically feasible on variable load engines, such as the engines owned and operated by Transco. Transco requests EQB amend the proposed regulation and delete subchapter B in its entirety, or in the alternative, only include engines that are 2400 hp or larger with actual NOx emissions during the 1995 ozone season greater than one ton per day. Finally, Transco suggests an intra-company averaging and/or trading mechanism for certain internal combustion engines be included in the final rule.

---

[1] The NOx FIP, which has not been finalized by EPA or subject to judicial review, will only become effective in those states that fail to submit approvable SIPs in response to EPA's NOx SIP Call. The NOx SIP Call allows states flexibility to choose control measures other than EPA-assumed controls to meet numerical budgets.

Transco is an interstate natural gas transmission company. Transco's 1900-mile pipe line system transports natural gas from production areas in the Gulf Coast region to customers along the eastern seaboard. Its principal markets encompass eleven southeast and Atlantic seaboard states. Transco delivers approximately 62% of all natural gas consumed in major metropolitan areas in New York, New Jersey and Pennsylvania.

On a system-wide basis, over one million horsepower is utilized to compress and move the gas along its main lines and laterals to its market area customers. The compression of natural gas is made possible through the application of internal combustion reciprocating engines (lean-burn and rich-burn), gas and steam turbines and electric motors. Over forty compressor stations are located along the interstate pipeline system at intervals of forty to one hundred miles. In Pennsylvania, Transco operates six compressor stations, including two along its main line, which transport the major portion of gas being delivered to the northeast market areas; and four along its Leidy Line, which is a storage lateral originating from Raritan, New Jersey, and extending west to Wharton, PA.

Many of the engines at Transco's compressor stations were required to develop and implement on a case-by-case basis Reasonably Available Control Technologies ("RACT"). In its top-down RACT analysis, Transco determined that SCR was not technically or economically feasible for its variable load engines. To satisfy RACT requirements, Transco installed low emission combustion ("LEC") on the majority of its engines in Pennsylvania.

Transco submits that additional emission limitations on these engines are not technically and economically feasible. The EQB proposal states, without reference to any source, that "for internal combustion engines, it is estimated that these sources will incur control costs between $500 and $2000 per ton which the EPA has determined to be highly cost effective for this source category." See 29 Pa. Bull. at 1321. Clearly, the EPA NOx FIP is in error and PaDEP's reliance on EPA's NOx FIP without independent verification and analysis is unreasonable, arbitrary and capricious. For the reasons set forth below, PaDEP should not rely upon the pending, proposed NOx FIP.

1. THE 2400 BHP CUTOFF IS ARBITRARY UNLESS LIMITED TO ENGINES WITH GREATER THAN ONE TON PER DAY ACTUAL NOx EMISSIONS DURING 1995

a. EPA has failed to use a consistent methodology to designate "large" units in the non-EGU inventory

In the NOx FIP, EPA claims to have used the same methodology as that used in the NOx SIP Call to designate "large" non-EGU units. The NOx SIP Call, 63 Fed. Reg. 57356, 57416 (Oct. 27, 1998), explicitly set forth the five-step process to be followed to distinguish Large sources from Small sources. Under the EPA's algorithm, heat capacity is first determined either by inventory data (step 1) or a default procedure (step 2). Sources with heat inputs of greater than 250 MMBtu/hr are designated as

Large sources and have assumed emission reductions (step 3). Emission reductions based upon tonnage per day are assumed only if heat capacity data are unavailable by inventory or default data (step 4). All other sources are considered Small (step 5). Under this algorithm, all sources with known heat inputs of 250 MMBtu/hr or less (either by inventory or default data) are to be considered small. EPA now indicates that this explicit algorithm is not to be followed. Now, in the NOx FIP, EPA says the dividing line between Large and Small non-EGU sources is to be 2400 horsepower. But the published inventory is not consistent with this interpretation nor the 250 MMBtu/hour or even the one ton/day. In the final inventory, 1,887 units in the non-EGU inventory with no capacity information are designated as "large" even though the unit's average summer day emissions are less than one ton per day. Transco's trade association has submitted comments to EPA requesting revisions to the regulated source category.

PaDEP's reliance on EPA's proposed NOx FIP as the basis to limit NOx emissions from internal combustion engines similarly fails to hold up under close analysis. The proposed 2400 horsepower cutoff for reciprocating internal combustion engines is inconsistent with the Ozone Transportation Assessment Group ("OTAG") recommended horsepower cutoffs and inconsistent with the size cutoffs used by EPA in calculation of the NOx SIP Call budgets. For non-utility point sources, OTAG recommended that "Large" sources include reciprocating internal combustion engines equal to or larger than 8,000 horsepower. In the final NOx SIP Call inventory, EPA indicated that they chose to use capacity indicators primarily to set cutoff levels. If the source was greater than 250 MMBtu, additional emission reductions were included to calculate the state NOx budgets. Also, the proposed 2400 horsepower cutoff for reciprocating internal combustion engines is inconsistent with the OTAG recommended emissions cutoff for "Large" sources. For non-utility point sources, OTAG recommended that "Large" sources include sources with 2 tons NOx emissions per average summer day or more. The 2400 horsepower cutoff is based on EPA's assumption that sources with NOx emissions of greater than or equal to one ton per day should be controlled.

While EPA indicated that an applicability threshold of 2400 hp was selected because engines of that size have the potential to emit at least one ton per day of NOx, the applicability criterion does not recognize the fact that not all engines ≥ 2400 hp emit at least one ton per day of NOx. Many 2400 hp engines emit less than 1 ton per day of NOx. The applicability threshold of 2400 hp was selected based on EPA's use of emission factors for lean-burn and rich-burn engines found in the ACT document, 16.8 and 15.8 g/hp-hr respectively. Transco's trade association commented to EPA that if EPA intends to regulate only "Large" reciprocating internal combustion engines, EPA should revise the applicability criterion to be consistent with the state budgets and EPA actions in the NOx SIP Call rulemaking. PaDEP has not identified how it determined the size cutoff for these engines, except to rely entirely on EPA's proposed NOx FIP.

b. The applicability criterion does not recognize units that have already been controlled for NOx

The proposed 2400 horsepower cutoff would cause additional NOx controls for many more reciprocating engines than those designated "Large" in the NOx SIP Call budgets. As proposed, the NOx FIP and the EQB proposal would impose emission limitations and emissions monitoring requirements on all engines equal to or greater than 2400 hp, regardless of the unit's actual emissions. This would result in the imposition of emission limitations and emissions monitoring requirements on engines that were designated "Small" in the state budgets and designated "Small" using the methodology described by EPA in the NOx SIP Call.

The purpose of the NOx FIP should be to implement a program of control that would meet the promulgated NOx budgets, not to expand the program of control to other sources. EQB and EPA, if it intends to impose a FIP upon Pennsylvania or any other OTAG state, must apply a consistent methodology for determining the size of a unit. Transco recommends that EQB and if necessary, EPA consistently apply the size designation methodology used in the NOx SIP Call.

EPA states that the NOx FIP proposal is intended to achieve the NOx emissions reductions required by the NOx SIP Call (and EQB states in the preamble that this rule will meet the NOx SIP Call) and the EPA's rulemaking docket contains information and analyses that are relied upon in the NOx FIP proposal. Although EPA has included by reference the entire NOx SIP Call docket, the proposed NOx FIP states that the only portions that form the basis for the FIP rulemaking are those that address feasibility and cost effectiveness of control measures and the projection of emissions reductions that various control measures would achieve. Nevertheless, EPA's proposed NOx FIP goes beyond these areas because it does not apply the same methodology described in the NOx SIP Call to designating "Large" non-EGU Units in the final inventory.

The EQB proposal does not distinguish between engines that have installed LEC technology and uncontrolled engines. The proposed threshold for regulating engines with greater than 2400 horsepower should include only those engines with actual emissions during the 1995 ozone season above one ton per day.

2. SCR IS NOT RELIABLE, COST EFFECTIVE CONTROL TECHNOLOGY

a. EPA ignored information in the ACT document that indicates SCR is not a reliable control technique to achieve 90 percent reduction of NOx from lean-burn engines in variable load applications.

According to the Technical Support Document (TSD) for Stationary Internal Combustion Engines (VI-B-13), EPA adopted SCR and 90 percent reduction as the control technique for lean-burn engines based on information provided in Table 2-5 of

the Alternative Control Techniques Document -- NOx Emissions from Stationary Reciprocating Internal Combustion Engines (EPA-453/R-93-032) (ACT document):

> The control level for spark ignited lean-burn engines that meets the $2,000/ton criteria above, is a limit of 125 ppmv NOx at 15% O_2. This represents selective catalytic reduction (SCR) control. SCR provides the greatest NOx reduction of all technologies considered in the ACT document for lean-burn engines and is capable of providing a 90 percent reduction in NOx emissions. This emission limitation corresponds to the 'Expected controlled NOx emission levels' (SCR) from Table 2-5 of the ACT document.

Table 2-5 does indicate a 90 percent reduction in NOx emissions for SCR and a footnote indicates this percent reduction is the "guaranteed NOx reduction available from most catalyst vendors." Section 5.2.4.4 of the ACT states that emission reductions of 80 to 90+ percent are possible using SCR on lean-burn engines that are used in baseload applications:

> Based on the available information and the emission test data presented in Tables 5-8 and A-5, it is estimated that the achievable NOx emission reduction for SCR in gas-fired applications is 80 to 90+ percent for baseload applications, with an NH3 slip level of 10 ppmv or less.

However, Section 5.2.4.4 of the ACT states that inadequate information was available to determine achievable continuous NOx reductions and ammonia slip levels for SCR in **variable load applications**:

> The available data are not sufficient to assess the achievable continuous NOx reductions and ammonia slip levels for SCR used in variable load applications.

Section 2.2.2.4 of the ACT notes that "there is also little experience with SCR in variable load applications due to ammonia injection control limitations." In addition, Section 5.2.4.4 states that variable load applications may pose problems for the SCR system:

> The duty cycle of the engine should also be considered in determining the applicability of SCR. Exhaust temperature and NOx emission levels depend upon engine power output, and variable load applications may cause exhaust temperature and NOx concentration swings that pose problems for the SCR system. The lower exhaust temperature at reduced power output may result in a reduced NOx reduction efficiency from the catalyst.

When the additional information presented in the ACT document is considered, along with information presented in the comments provided below, it is clear that PaDEP should not rely upon EPA's erroneous identification of SCR as the NOx control technique for lean-burn engines in variable load applications. SCR is not feasible for

variable load applications and a 90 percent reduction of NOx is not achievable using SCR on engines in variable load applications.

b. SCR is not feasible for variable load applications, such as natural gas compression.

The natural gas transmission industry has evaluated NOx emissions controls for hundreds of engines under NOx RACT and found that SCR is not a reliable control technique for engines in natural gas compression service (a variable load application). State regulators have agreed -- in no case is SCR required as NOx RACT for engines in transmission service. Instead, NOx emissions reductions have been achieved using low emissions combustion ("LEC"), combustion modifications or parametric controls ("PC"). These technologies are proven for natural gas-fired lean-burn engines, while SCR is not.

Reciprocating internal combustion engines in natural gas compression service are used to compress and move natural gas along the pipeline. An engine must respond to pipeline conditions, supply, and demand for natural gas. As a result, engines are frequently required to change load and speed conditions. This variable load operation complicates the successful operation of an SCR system given: 1) variations in NOx emissions, 2) variations in exhaust gas flow and temperature, and 3) thermal cycling.

1. Variations in NOx Emissions.
   In order for SCR to work properly, with the appropriate control of NOx emissions and without excessive ammonia emissions, it is necessary that the proportions of NOx and ammonia be correct. Changes in load and speed produce changes in the NOx emissions from the engines. For example, a load change of only five percent can significantly change the NOx emitted from an engine. When these changes occur, the ammonia feed system must be adjusted to maintain the proper ratio of ammonia to NOx. In Section 5.2.4.2, the ACT notes that variable load can cause NOx concentration swings that pose problems for the SCR system. SCR systems traditionally use a feedback system that relies on a NOx or ammonia analyzer to adjust the ammonia feed system. It takes approximately five minutes time to extract a sample and report NOx emission levels using a NOx CEMs. A recent installation of SCR at the Buckeye Pipeline station relies on a predictive emissions model ("PEMs") as the feed-forward control for ammonia feed. The engines are not equipped with CEMs. Transco's trade association understands that EPA and the South Coast Air Management District are reviewing this installation to determine if it is cost-effective. At the Buckeye station, the engines were purchased new and the manufacturer designed the PEMs to control the ammonia feed system. In addition, the engines are used to drive liquid pumps and the variations in load and speed for the engines are limited by the range of operation of the pumps. In contrast, engines on a natural gas pipeline must respond to the conditions of the natural gas within the pipeline -- a much

wider range of operation than is required for liquid pumps like those at the Buckeye station. There are no known applications where PEMs have been successfully used as feed-forward controls for existing reciprocating internal combustion engines.

2. Variations in Exhaust Gas Flow and Temperature.
   Variable load conditions also result in variations in exhaust gas flow and temperature conditions. The ammonia control system would need to be adjusted to respond to the changes in the exhaust mass flow rate. Variable exhaust gas flow rates would also affect mixing in the catalyst. The wider the range in exhaust gas flow rates, the more difficult it is to design a catalyst that can reliably achieve high emission reductions (e.g., 90 percent). Reduced engine load can also decrease the exhaust gas temperature below the range for optimal NOx conversion, which would not allow the catalyst to reliably achieve high emission reductions. Section 5.2.4.2 of the ACT states that "lower exhaust temperature at reduced power output may result in a reduced NOx reduction efficiency from the catalyst."

3. Thermal Cycling
   Variable load conditions also result in thermal cycling of the catalyst -- as the engine exhaust temperature changes. This thermal cycling leads to reduced catalyst life.

The complications introduced by variable load operation have not been sufficiently resolved to ensure reliable operation of SCR on engines in variable load applications, such as natural gas compression. EPA concluded that SCR was a feasible control technology (that achieves 90 percent reduction of NOx) based on a limited review of information presented in the ACT document. EPA is reconsidering its limited review and will likely issue guidance to states correcting the erroneous proposal. PaDEP should not rely upon EPA's limited review of the ACT document.

c. SCR will not reliably achieve 90 percent reduction of NOx for variable load applications.

The TSD indicates that EPA adopted SCR and 90 percent reduction based on vendor quotes presented in Table 2-5 of the ACT document. However, as presented in the comments above, EPA ignored other information in the ACT document that indicates SCR is not a reliable control technology to achieve 90 percent reduction of NOx for variable load applications.

d. The available data are not sufficient to assess the achievable continuous NOx reductions and ammonia slip levels for SCR used in variable load applications.

Variable load applications present unique difficulties for SCR that have not yet been adequately addressed to allow widespread application of SCR for engines in load-following applications, such as natural gas compression.

In the ACT document, emission test data for six engines with SCR are presented. Results for over 30 emission tests for the six small engines are provided in the ACT document. All the engines tested are smaller than the proposed size cutoff of 2400 horsepower (hp) proposed by EPA in the NOx FIP. The emissions data suggest that the percent NOx reduction achieved with SCR varies. Although the variability is not discussed in the ACT document, it is likely that the variability is due to changes in the engine's operation. The range of effectiveness for the six engines is presented in the table below.

Engine No.	Manufacturer	Model	Horsepower	Number of Tests	Range of NOx Control Reported (%)
45	Clark	HRA-6	660	5	84-91
47	Clark	HRA-6	660	5	82-88
139	Cooper Bessemer	GMV	660	1*	50
248	Cooper Bessemer	GMV-8	800	9*	87-93
309	Clark	HRA-32	350	12	65-84
357	Tecogen	CM-200	291	2	95-97

*One additional test was conducted, where zero emission reduction was reported. No explanation is provided in the report for those results.

The only engine that achieved levels greater than 90 percent for all tests conducted was a small engine designed for cogeneration (the Tecogen). The Tecogen would be installed in a baseload application -- not a load-following application. Two other engines reported levels at or above 90 percent for at least one test, but levels less than 90 percent for other tests. The other engines did not include any test results at or above 90 percent NOx reduction.

EPA adopted SCR and 90 percent reduction based on limited information presented in Table 2-5 of the ACT. However, information presented in Section 5.2.4.4 of the ACT indicates that EPA was not able to determine an achievable NOx reduction level for the use of SCR in load-following applications. Therefore, EPA should not use, and PaDEP should not require, SCR and 90 percent reduction for lean-burn engines in the NOx FIP or in the EQB's proposal.

e. **SCR is not a demonstrated NOx control technology for reciprocating internal combustion engines in variable load applications.**

The ACT document states that "there is also little experience with SCR in variable load applications due to ammonia injection control limitations." As indicated above, the natural gas transmission industry has evaluated NOx emissions controls for hundreds of engines under NOx RACT and found that SCR is not a reliable control technique for engines in natural gas compression service (a variable load application).

According to a review of SCR conducted by the Gas Research Institute ("GRI") (attached to these comments as Appendix A), SCR has been installed on reciprocating engines in very few instances. No natural gas-fired lean-burn engines were identified by GRI in the EPA RACT/BACT/LAER Clearinghouse with SCR controls (based on a query of post-1991 determinations for natural gas-fired internal combustion -- 15.004). RACT/BACT/LAER determinations for lean-burn engines relied on LEC technology, other combustion modification (such as high energy ignition systems), or parametric controls (such as retarded timing and air to fuel ratio adjustment). A total of 18 diesel engines with SCR controls (PA-0096 and PA-0097) were identified in the clearinghouse. The SCR controls for the diesel engines reduce NOx emissions by 80 percent.

The GRI study also cites the fact that results from a 1996 survey of North American interstate natural gas transmission companies indicate that of the 599 lean-burn engines with NOx controls, only two engines in the United States have SCR installed. Those two engines since have been mothballed due to difficulties operating the SCR units in a load-following application. NOx emissions from lean-burn engines in pipeline service have been controlled using combustion modifications or parametric controls because of the problems associated with using SCR in the variable load application.

The information presented above indicates that SCR is not demonstrated in practice for load-following applications. The information presented in the ACT document is not a sufficient basis for EPA to conclude that SCR is feasible (with 90 percent reduction) for all existing engines that would be subject to control requirements under the FIP proposal or the SIP Call. EPA should not base its proposed NOx FIP or state budgets for the FIP and SIP Call on the use of SCR for lean-burn engines. Similarly, PaDEP should not rely upon EPA's erroneous proposed FIP.

3. **EPA's cost-effectiveness analysis for the use of SCR relies on 90 percent reduction of NOx, which is not feasible for load-following applications.**

The TSD indicates that EPA relied on Figure 2-6 of the ACT to evaluate the cost-effectiveness of SCR:

As illustrated in Figure 2-6 of the ACT...The cost-effectiveness is about $800/ton for a 2200 hp engine operated 8,000 hours per year. Therefore, SCR meets the criteria of less than $2,000/ton of NOx reduction.

The cost-effectiveness results presented in the ACT document rely on 90 percent reduction of NOx. As indicated in the comments above, SCR has not been shown to reliably reduce NOx emissions by 90 percent in load-following applications. The ACT document states that although 90 percent is used for the cost-effectiveness calculations in that document, EPA had insufficient information to determine "achievable continuous NOx reductions and ammonia slip levels for SCR used in variable load applications." Variable load operation presents unique difficulties, including variations in NOx emissions, variations in exhaust gas flow and temperature, and thermal cycling, that have not been adequately addressed in the EPA cost analysis.
Therefore, EPA and EQB should not conclude that SCR is cost-effective for all engines that would be subject to the NOx FIP or NOx SIP Call, since clearly EPA and EQB have not established the effectiveness or feasibility of SCR for load-following applications. EPA should work with industry stakeholders to assess the cost-effectiveness of NOx control techniques for reciprocating internal combustion engines.

4. Projection of Emission Reductions that Various Control Measures Would Achieve.

EPA calculated the state budgets for the proposed FIP and the SIP Call based on the Agency's assessment that SCR can achieve 90 percent NOx reduction from lean-burn reciprocating internal combustion engines. As indicated in the comments above, EPA concluded in the ACT document that, while SCR could achieve 80 to 90 percent NOx reductions for engines in baseload applications, there was insufficient information to assess achievable NOx reductions for SCR on engines in variable load applications. 90 percent reduction of NOx using SCR is not proven in practice for lean-burn reciprocating engines in loadfollowing applications.

EPA should reevaluate the emission reductions for lean-burn engines based on NOx controls that are proven and are shown to be cost-effective for lean-burn reciprocating internal combustion engines.

The emission levels for lean-burn engines cannot be achieved at a cost of $2,000 per ton of NOx. Based on the ACT document, EPA incorrectly concluded that SCR for lean-burn engines could be implemented on a 2200 hp lean-burn engine for about $800 per ton of NOx. Industry data suggests that these costs are not correct.

While Transco supports the 30-day rolling average, EPA should specify that emission limits are at 100% speed and 100% torque. The attached GRI (Appendix A) report on the effectiveness of SCR applied to pipeline compressor engines also concludes that SCR is infeasible for pipeline compressor engines. The report documents that research data collected on internal combustion engines utilizing SCR is biased towards small engines in

baseload applications rather than the type of units. The industry has only identified two compressor units that have been tested with SCR. These compressor units have subsequently been removed from service due to poor performance. The report further concludes, as did the original ACT document that SCR is not designed for load following applications. Finally the test data from the ACT document shows that the average performance of the tested engines was significantly below 90% emission reduction.

5. Control Cost Effectiveness and Economic Impact Analysis

Transco's trade association has examined the Regulatory Impact Analysis for the NOx SIP Call, proposed NOx FIP, and Section 126 Petitions, the Non-Electricity Generating Unit Economic Impact Analysis for the NOx SIP Call and Ozone Transport Rulemaking - NonElectricity Generating Unit Cost Analysis. These documents contain cost analysis for control options for Large Stationary IC engines. The trade association strongly believes that errors in the basic underlying assumptions that support these analysis have severely distorted the conclusions reached regarding the control cost effectiveness of Large Stationary IC engine and the resultant economic impact on the natural gas transmission industry.

First, the emission inventory for IC engines category is significantly flawed regarding the number of sources and their corresponding level of emissions. <u>This directly affects all subsequent economic analysis</u> using this inventory.

Second, EPA's cost analysis for all control options depend on tons of NOx removed as a percentage of uncontrolled emissions. If uncontrolled emissions are significantly overstated, which we believe they are in the EPA analysis, then cost effectiveness is likewise equally overstated. As stated above the ACT uses 16.8 g/hp-hr while AP-42 is 11 g/hp-hr. This difference alone could lead to underestimating cost by 50 percent.

Third, cost effectiveness is also affected by percentage of source utilization during the ozone season. Transco's trade association members operate a number of IC engines at natural gas storage fields. Although source utilization varies widely, average summer time values for IC engines with potential to exceed one ton a day are typically in the range 50% or less. Thus cost effectiveness calculations for this sector could be underestimated by a factor of two from those used in EPA's cost analysis which was 91%. This fact point is confirmed by EPA's contractor Pechan-Avanti Group on page 57 in the September 17, 1998 report entitled Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis: There are uncertainties in the cost per ton values for IC engines because we do not know which engines are lean burn versus rich burn (lean burn is assumed), **nor operating practices (hours of operation and load).** All of these factors affect control cost." Following on page 61: "For the non-trading source analysis, the cost effectiveness of controls applied to IC engines **are a key factor in the cost analysis."**

Finally, the cost for annual emissions monitoring are also significantly underestimated. In a study recently completed for the natural gas industry, the annual cost for CEM on a single IC engine is estimated as $ 107,000 per year. This is about two and one half times the $ 43,353 per year reported in the Regulatory Impact Analysis Report.

In summary, after the corrections noted above are made, EPA's conclusion that SCR NOx emission controls for IC engines is highly cost effective, i.e. under $ 2000 per ton, is in error. Significantly, EQB's reliance on EPA's cost analysis is also in error.

Transco's Suggested Language

Transco has demonstrated that EPA's proposed level of NOx reduction for internal combustion engines greater than 2400 hp is not technically or economically feasible. Therefore, EQB should not look to those engines as a significant source of the further reductions of NOx emissions required to comply with the NOx SIP Call. If PaDEP requires additional NOx reductions to meet the NOx SIP Call, then the regulated engines should be limited to Large engines, or those with emissions greater than one ton of NOx per summer day. Suggested regulatory language is set forth below:

Section 145.101 Applicability

(a) An owner or operator of a lean or rich burn stationary internal combustion engine that had average daily NOx emissions of one ton or more during the five month period May 1, through September 30, 1995.

(b) - (d) remain the same

Section 145.102 Definitions

Definitions remain the same

Section 145.103 Standard Requirements

(a) After May 1, 2003, an owner or operator of a unit subject to the standards of this subchapter may not operate the unit May 1--September 30 of 2003, and any subsequent year unless the owner or operator has retrofitted that engine with low emission combustion technology.

(b) In lieu of low emission combustion technology retrofit on engines subject to this subchapter, an owner or operator may propose an Alternative Emission Control Program that achieves equivalent emission reductions. Equivalent emission reductions will produce an equal number of NOx reductions when applied to sources operating as they were during 1995.

(c) An owner or operator of a unit subject to this subchapter, shall demonstrate compliance with the requirements of subsection (b) using methods of compliance demonstration approved by the Department and EPA.

(d) An owner or operator of a unit subject to subsection (b), as applicable, shall comply with the following:

1. No later than January 1, 2002, submit to the Department a plan for achieving initial compliance with the requirements of subsections (b) and (c) or an Alternative Emission Control Plan.

2. No later than May 1, 2003, monitor operations and emissions and perform recordkeeping and reporting for the period from May 1 through September 30 of the previous year.

3. By March 31, 2004, and by March 31 of each following year submit to the Department a report documenting compliance with the requirement of subsection (b) for the period of May 1 through September 30 of the previous year.

Transco appreciates the opportunity to comment on this proposed rule, and looks forward to working with PaDEP in the future. If you have any questions or need clarification, please feel free to contact me at (713) 215-4562.

Sincerely,

Mary Beth Whitfield

Mary Beth Whitfield
Senior Environmental Scientist
Air Quality Compliance

Appendix A

Gas Research Institute

Technical Issues Related to the Potential Use of Selective Catalytic Reduction (SCR) to Reduce NOx Emissions from Natural Gas-Fired Lean Burn Engines

Technical Issues Related to the Potential Use of Selective Catalytic Reduction (SCR) to Reduce NOx Emissions from Natural Gas-Fired Lean Burn Engines

Prepared by:
Coerr Environmental Corporation and
Radian International, LLC

Prepared for:
Gas Research Institute

November 9, 1998

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I. INTRODUCTION

On October 27, 1998 (63 FR 57356), EPA promulgated the Agency's rulemaking to call for 22 eastern states and the District of Columbia to revise their State Implementation Plans (SIP) to address the regional transport of ozone (the SIP Call). EPA also proposed a Federal Implementation Plan (FIP) that would be implemented if any state failed to submit an adequate SIP revision in response to the EPA SIP Call (63 FR 56394).

In a technical support document for both rulemakings (A-96-56, VI-B-13), EPA stated that emissions of nitrogen oxides (NOx) from large lean-burn reciprocating internal combustion engines can be reduced by 90 percent, cost-effectively, using Selective Catalytic Reduction (SCR):

> The control level for spark ignited lean burn engines that meets the $2,000/ton criteria . . . is a limit of 125 ppmv NOx at 15% O_2. This represents selective catalytic reduction (SCR) control . . . providing a 90 percent reduction in NOx emissions.

The Agency stated in the SIP Call rulemaking that 90 percent control with SCR was adopted based on information presented in the Alternative Control Techniques Document -- NOx Emissions from Stationary Reciprocating Internal Combustion Engines (EPA-453/R-93-032) (ACT document):

> For [reciprocating internal combustion engines], EPA determined based on the relevant ACT document, that post-combustion controls are available that would achieve a 90 percent reduction from uncontrolled levels . . . . (63 FR 57418)

EPA used 90 percent control for large reciprocating internal combustion engines to calculate the state NOx budgets for the SIP Call and the FIP. In

the FIP, EPA also proposed an emission limitation of 125 ppmv for natural gas-fired lean-burn engines based on 90 percent control of NOx using SCR.

The Gas Research Institute (GRI) presents in this white paper an assessment of the technical issues related to the potential use of SCR to reduce NOx emissions from natural gas-fired lean-burn engines and the reasonableness of the EPA's estimate of a 90 percent reduction of NOx emissions from lean-burn engines using SCR. GRI intends to continue investigating NOx control techniques for natural gas lean-burn engines and NOx emissions monitoring techniques. This white paper includes information on SCR that could be assembled prior to the November 30 deadline for comments on the proposed FIP.

Overview of SCR Technology

SCR was developed to reduce NOx emissions from fossil fuel-fired boilers. In the early-to-mid 1980s, SCR was applied to cogeneration gas turbine engines and reciprocating internal combustion engines.

NOx reduction with SCR is based on the reaction of ammonia and NOx to form nitrogen and water. SCR uses a catalyst to promote the ammonia and NOx reaction. In the absence of a catalyst, the reducing reactions occur in the range of 1000°C. As the temperature is increased above the 1000°C range, the ammonia oxidizes to NO, thereby increasing the NOx emissions and as the temperature is decreased below the optimum range, unreacted ammonia is emitted from the system. When a catalyst is added, the ammonia and NOx react at temperatures significantly lower than those obtained without the catalyst.

The essential components of the SCR system are:

SCR catalyst
Exhaust ducting and SCR housing
Ammonia system

Control system and continuous emissions monitors (CEMs)

Traditional SCR catalysts are base metal catalysts composed of vanadium pentoxide, titanium dioxide, or tungsten trioxide. The temperature range for the base metal SCR catalysts for NOx conversions greater than 80 percent is about 300 to 425°C. During the 1980s zeolite SCR catalysts were developed. These catalysts have a wider temperature operating range and offer more resistance to sulfur poisoning, which has been a problem with some of the other SCR catalysts. The SCR process requires about two to three times the catalyst size of that required for oxidation exhaust catalysts (such as used for CO control), since SCR space velocities are low compared to those required for other post-combustion catalytic controls. Typically, 2 to 3 catalyst stages are required in the SCR system.

SCR requires on-site storage of ammonia and an ammonia delivery system. The ammonia system includes the ammonia storage tank, the ammonia flow regulation system, and the ammonia injectors. Heaters are required to vaporize the ammonia. The type of vaporization system used depends on the type of ammonia used -- anhydrous or aqueous -- and on the ambient temperature range experienced at the site. In order for SCR to work, the ammonia must be fully vaporized and evenly dispersed across the face of the catalyst.

The ammonia control system generally includes NOx CEMs upstream and downstream of the SCR catalyst. The ammonia flow rate required is based on a preset ammonia to NOx ratio and determined from a measurement of the inlet SCR NOx concentration and from determination of the exhaust flow rate of the engine. System performance is checked by measuring the outlet SCR NOx concentration.

The exhaust gas samples are conditioned (e.g., dried and filtered) and are pumped to the NOx analyzer. Typically, the NOx analyzer is cycled between

the inlet and outlet of the SCR unit. Generally this type of system requires a response time of approximately five minutes to obtain an accurate, stable reading of the NOx concentrations.

Basis for EPA's Conclusion that SCR is Effective

EPA used information found in the ACT document as the basis for use of 90 percent NOx reduction in the SIP Call and FIP rulemakings. In the technical support document for stationary internal combustion engines (A-96-56, VI-B-13), EPA stated that 90 percent effectiveness for the use of SCR on natural gas-fired lean burn engines was adopted based on the "achievable NOx reduction" presented in Table 2-5 of the ACT document. Table 2-5 is reproduced below.

TABLE 2-5. EXPECTED RANGE OF NO_x EMISSION REDUCTIONS AND CONTROLLED EMISSION LEVELS FOR CONTROL TECHNIQUES APPLIED TO

LEAN-BURN SI ENGINES (NATURAL GAS FUEL)

Control technique	Average uncontrolled NO_x emission level[a]		Achievable NO_x reduction, %	Expected controlled NO_x emission levels	
	g/hp-hr	Ppmv		g/hp-hr	ppmv
AF	16.8	1,230	5 - 30	11.8 - 16.0	860 - 1,170
IR	16.8	1,230	0 - 20	13.4 - 16.8	980 - 1,260
AF + IR	16.8	1,230	20 - 40	10.1 - 13.4	740 - 980
SCR	16.8	1,230	90[b]	1.7	125
L-E	16.8	1,230	87	2.0[c]	150

[a]The uncontrolled emission rate shown is a representative average for lean-burn SI engines. The actual uncontrolled emission rate will vary from engine to engine.
[b]Guaranteed NO_x reduction available from most catalyst vendors.
[c]Guaranteed controlled NO_x emission level available from engine manufacturers.

Footnote "b" to Table 2-5 indicates that the basis for the 90 percent reduction for SCR is based on the "guaranteed NOx reduction available from most catalyst vendors." Section 2 the ACT does not include a detailed discussion of the information provided by the vendors to support the claims for 90 percent reduction or the long-term performance for SCR. Section 5.2.4.4 of the ACT provides further discussion of the achievable emission reduction using SCR. In that section, the ACT states that emission reductions of 80 to 90+ percent is possible using SCR on engines in baseload applications:

> Based on the available information and the emission test data presented in Tables 5-8 and A-5, it is estimated that the achievable NOx emission reduction for SCR in gas-fired applications is 80 to 90+ percent for baseload applications, with an NH_3 slip level of 10 ppmv or less.

The ACT states that 90 percent NOx reduction was used in Chapter 6 to calculate controlled NOx emission levels and cost effectiveness. However, the ACT also states that inadequate information was available to determine achievable continuous NOx reductions and ammonia slip levels for SCR in variable load applications:

> The available data are not sufficient to assess the achievable continuous NOx reductions and ammonia slip levels for SCR used in variable load applications.

As indicated in Section V of this paper, variable load applications present unique difficulties for SCR that have not yet been adequately addressed to allow widespread application of SCR for engines in load-following applications, such as natural gas compression.

In the ACT there is emissions test information for 6 reciprocating internal combustion engines, 3 Clark engines, 2 Cooper Bessemer engines, and 1 Tecogen engine. The engines range in size from 291 to 800 horsepower. All the engines are smaller than the engine horsepower EPA adopted in the FIP (2400 hp). A total of 34 emission test results are provided in the ACT that report NOx emission reductions. Two emission test results report zero NOx emission reductions. The emission results presented were drawn from emission tests conducted in California from 1986 - 1992. Two Clark engines and the Tecogen engine were still in service at the time the ACT document was published. The other three SCR units had been removed from service or the engines had been replaced with electric units. The ACT document stated that emissions test data for existing installations with SCR ranged from 65 to 95 percent reduction.

According to the technical support document, EPA calculated the expected controlled NOx emission level as 1.7 g/hp-hr (125 ppmv) based on an average uncontrolled NOx emission level of 16.8 g/hp-hr (1230 ppmv) and 90 percent reduction of NOx using SCR. However, the emissions data in the ACT document suggests that the percent NOx reduction achieved by engines varies. No explanation is provided in the ACT document for the variability of the SCR effectiveness. No information is provided on the operating conditions of the engines when tested. Also, no information is provided on ammonia emissions (i.e., ammonia slip) from the units. The range of effectiveness reported for the 6 engines is presented in the table below.

Engine No.	Manufacturer	Model	Horsepower	Number of Tests	Range of NOx Control Reported (%)
45	Clark	HRA-6	660	5	84-91
47	Clark	HRA-6	660	5	82-88
139	Cooper Bessemer	GMV	660	1*	50
248	Cooper Bessemer	GMV-8	800	9*	87-93
309	Clark	HRA-32	350	12	65-84
357	Tecogen	CM-200	291	2	95-97

*One additional test was conducted, where zero emission reduction was reported. No explanation is provided in the report for those results.

Only one engine, the Tecogen, reported levels greater than 90 percent for all tests conducted. This small engine is designed to be used for cogeneration. Two other engines (Nos. 45 and 248) reported levels at or above 90 percent for at least one test, but levels less than 90 percent for other tests. The other engines did not include any test results at or above 90 percent NOx reduction.

The emissions data included in the ACT document for natural gas-fired lean-burn engines demonstrate that the effectiveness of SCR systems are variable.

The ACT document does not discuss or explain the variable emissions results and does not identify the factors that would contribute to this variability. Only the small cogeneration engine consistently reported emission reductions greater than 90 percent. The other engines did not consistently achieve emission reductions at or above 90 percent. As indicated in the ACT document, the 90 percent reduction presented by EPA in the SIP and FIP was based on information presented in Table 2-5. However, information presented in Section 5.2.4.4 indicates that EPA was not able to determine an achievable NOx reduction level for the use of SCR in load-following applications.

SCR Installations on Lean-Burn Engines

There is limited operating experience to date with the use of SCR on reciprocating internal combustion engines. At the time the ACT document was published, EPA identified a total of 23 engines (including 3 engines using digester gas) with lean-burn engines in the United States based on information provided by catalyst vendors and approximately 40 installations of SCR overseas. The ACT document also noted that there is little experience with SCR in variable load applications due to ammonia injection control limitations.

At present, no natural gas-fired lean burn engines were identified in the EPA RACT/BACT/LAER clearinghouse with SCR controls (Query of 15.004, post 1991). RACT/BACT/LAER determinations for lean burn engines have relied on low emissions combustion (LEC) technology, other combustion modification (such as high energy ignition systems), or parametric controls (such as retarded timing and air to fuel ratio adjustment). A total of 18 diesel engines with SCR controls (PA-0096 and PA-0097) were identified in the clearinghouse. The SCR controls for the diesel engines reduce NOx emissions by 80 percent.

For the natural gas transmission industry, there are no known SCR installations on lean burn engines in pipeline service. Two lean burn engines at a natural gas storage facility in California have SCR. These engines have been mothballed due to the operations and maintenance problems related to the use of SCR with the variable loads experienced in the natural gas storage operation. The engines are not used presently. Therefore, there are no engines in pipeline service within the United States at this time that have SCR installed. The two engines in California where SCR was installed have been mothballed and are not currently in use.

In 1996, the natural gas transmission industry conducted a survey to gather information on the reciprocating engines and turbines in natural gas transmission service. The transmission companies provided information on over 5,000 reciprocating internal combustion engines. As a part of the survey, information was provided on over 800 reciprocating internal combustion engines with some form of NOx emission controls in place. The survey results indicate that the natural gas transmission industry has installed technology that relies on combustion modification or parametric controls to reduce NOx emissions from lean-burn engines, rather than post-combustion controls, such as SCR. Only 2 of the 599 lean-burn engines with NOx controls have SCR installed (the California units). For natural gas transmission, SCR is the NOx control technique that has been used least to reduce emissions from lean-burn engines. Low emissions combustion (LEC) or other combustion or parametric control techniques have been used most often to reduce NOx emissions from lean-burn engines. In contrast, for rich-burn engines, post-combustion catalytic control (non-selective catalytic reduction -- NSCR) is the NOx control technique that has been used most often to reduce NOx emissions. The transmission industry survey indicates that 100 of 201 rich-burn engines with NOx controls have NSCR installed. The results of the industry survey are presented below.

Lean Burn Engines

Type of Control	In SIP Call States	Not in SIP Call States	Total Units
Low Emissions Combustion	245	139	384
High Energy Ignition	87	21	108
Other NOx Control	49	13	62
Parametric Controls	39	4	43
SCR	0	2*	2*
Total	371	179	599

*Mothballed.

Rich Burn Engines

Type of Control	In SIP Call States	Not in SIP Call States	Total Units
NSCR	24	76	100
Pre-Stratified Charge	7	41	48
Low Emissions Combustion*	7	32	39
High Energy Ignition*	0	10	10
Parametric Controls	3	1	4
Total	41	160	201

*Possible conversion to lean-burn conversion. Data for these engines are under review.

The survey results include NOx controls that were installed by natural gas transmission companies to comply with NOx RACT and BACT requirements. No natural gas transmission company was required to install SCR as NOx RACT or BACT. Although some companies did consider SCR as a potential control option, SCR was found to be unacceptable due to the limits of the ammonia delivery system and the need for load-following horsepower to respond to pipeline conditions. (More discussion of this issue is included in the following section of this white paper.)

Therefore, while NSCR is widely applied for natural gas-fired rich-burn engines, there are very few instances where SCR has been applied to natural gas-fired lean-burn engines. State air regulatory agencies did not require

SCR to implement NOx RACT or BACT requirements. At present, there are no engines in the natural gas transmission industry that are operating with SCR. Rather, combustion modification and parametric controls have been the techniques applied to reduce NOx emissions from existing lean-burn engines.

Difficulties Operating SCR Systems

The following issues must be considered in the context of NOx control with SCR:

Variable load operation
Ammonia handling and storage
Catalyst maintenance and disposal
Engine maintenance
Continuous emissions monitoring

Variable load operation complicates the successful operation of an SCR system given:
1) variations in NOx emissions, 2) variations in exhaust gas flow and temperature, and 3) thermal cycling.

In order for SCR to work properly, with the appropriate control of NOx emissions and without excessive ammonia emissions, it is necessary that the proportions of NOx and ammonia be correct. Reciprocating internal combustion engines in natural gas transmission service are used to compress and move natural gas along the pipeline. The load and speed of the engines must respond to pipeline conditions, supply, and demand for natural gas. As a result, engines are frequently required to change load and speed conditions. These changes produce changes in the NOx emissions from the engines. For example, a load change of only 5 percent can significantly change the NOx emitted from an engine -- for some engines NOx can increase as much as 50 percent. When these changes occur, the

ammonia feed system must be adjusted to maintain the proper ratio of ammonia to NOx. In Section 5.2.4.2, the ACT notes that variable load can cause NOx concentration swings that pose problems for the SCR system. SCR systems traditionally use a feedback system that relies on a NOx or ammonia analyzer to adjust the ammonia feed system. It takes approximately 5 minutes time to extract a sample and report NOx emission levels using a NOx CEMs. Therefore, for load-following applications, a feedback system is not sufficient alone to allow the ammonia feed system to be adequately responsive to maintain NOx reductions. Some load-following engines may be able to use SCR if the systems incorporate feed-forward controls. The feed-forward controls incorporate sophisticated predictive emissions models (PEMs), which estimate NOx and adjust the ammonia feed system accordingly. A recent installation of SCR at the Buckeye Pipeline station uses PEMs as the feed-forward controls for an SCR with new Waukesha engines. For existing engines, no applications are known where PEMs have been successfully used as feed-forward controls for SCR. One reason that the feed-forward system may not have been applied to existing engines is the need to develop a sophisticated predictive emissions model to estimate NOx. For new engines, engine manufacturers have information readily available to develop the PEMs. However, for existing engines, the owner or operator would have to independently develop a PEMs that would be sophisticated enough to reliably control the ammonia feed system. The engines at the Buckeye Pipeline station also represent a load-following application with a limited range of operating conditions since the engines are used to drive liquid pumps. For natural gas transmission, the engines are used to compress gas along the pipeline and the pipeline conditions create a wider range of operating conditions for the load-following engines. The Buckeye Pipeline station experienced difficulties with catalyst masking when lube-oil residuals were deposited on the catalysts during frequent start-up tests. For natural gas transmission service, engines often experience

frequent start-ups, which may lead to catalyst masking, as experienced at Buckeye.

Variable load conditions also result in variations in exhaust gas flow and temperature conditions. The ammonia control system would need to be adjusted to respond to the changes in the exhaust mass flow rate (especially dual shaft engines). Variable exhaust gas flow rates would also affect mixing in the catalyst. The wider the range in exhaust gas flow rates velocities, the more difficult it is to design a catalyst that can reliably achieve high emission reductions (e.g., 90 percent). Reduced engine load can also decrease the exhaust gas temperature below the range for optimal NOx conversion, which would not allow the catalyst to reliably achieve high emission reductions. Section 5.2.4.2 of the ACT states that "lower exhaust temperature at reduced power output may result in a reduced NOx reduction efficiency from the catalyst." Variable load conditions also result in thermal cycling of the catalyst, which leads to reduced catalyst life. These variable load conditions are common for engines in natural gas transmission service.

As indicated in the EPA ACT document, there is little experience using SCR systems on engines in load-following applications, such as natural gas transmission. Although catalyst vendors suggest that SCR can be designed to work in load-following applications, installations of SCR systems on load-following applications have been limited. The results of the 1996 survey of natural gas transmission companies were queried to identify SCR installations. Based on that search, only two engines have SCR installed and those engines have been mothballed.

The continuous and reliable operation of an SCR system requires close monitoring of several subsystems. This includes ammonia storage, control, metering, injection, and leak detection systems. Problems can occur with the clogging of the ammonia nozzles and these have to be closely monitored and corrective action taken immediately to ensure proper injection rates and

even distribution of ammonia in the flue gas for proper mixing. In addition, most SCR systems rely on CEMs as the feedback control for the ammonia feed system. In order to ensure reliable performance, NOx CEMs, including sample conditioning, need to be properly calibrated and maintained, which requires specially trained personnel. Finally, instrumentation for ammonia injection rate needs to be calibrated frequently to ensure proper control. These activities become difficult if the station is unmanned, which is often the case in pipeline operation.

Maintenance of the SCR system requires periodic catalyst cleaning in order to restore its reactivity. Cleaning is accomplished by washing of the catalyst with water and typically requires several days downtime for removal of the catalyst, the washing and the re-installation of the catalyst. Disposal of the solution remaining from this procedure can be an issue. Contaminants from lube oil and engine wear, such as metals or silicon oxides, will affect the frequency of catalyst cleaning and can reduce catalyst effectiveness and catalyst life. To minimize contamination, specially formulated lubricating oils must be used. For four-stroke engines, the use of low-contaminant lube oil may result in increased valve wear. The vendor generally handles disposal of SCR catalysts.

Most SCR systems rely on continuous emissions monitors (CEMs) as the feedback control for the ammonia feed system. The installation, operation and maintenance of a NOx CEMs are complicated and require specially trained personnel.

Negative Environmental Impacts from SCR

SCR relies on the use of ammonia injected in the exhaust stream in the presence of a catalyst to control NOx emissions. Ammonia is a colorless gas with a pungent odor. Ammonia is poisonous if inhaled in great quantities and is irritating to the eyes, nose, and throat in lesser amounts. Ammonia is explosive when mixed with air in certain proportions (approximately one volume of ammonia to two volumes of air).

Unlike technology like combustion modifications or parametric controls (which is used on engines in natural gas transmission service), SCR is not a pollution prevention technique and uses additional resources, which in turn create safety hazards and hazardous waste disposal problems. For example, periodic cleaning of the catalyst is required to maintain catalyst effectiveness. After cleaning, the cleaning solution is considered a hazardous waste and creates disposal problems. Additionally, catalyst disposal itself can create environmental problems because the catalyst may contain heavy metals and other toxic substances.

SCR systems usually operate with an ammonia/NOx molar ratio of about 1.0. This is close to the theoretical limit required for complete NOx reduction. However, due to kinetic limitations and improper mixing between the ammonia and the flue gas, complete reduction is not achieved, leading to unreacted ammonia escaping into the atmosphere. Increasing the ammonia injection rate to overcome deleterious kinetic and mixing effects increases the probability of NOx reduction, but also increases ammonia slip emissions. To achieve high NOx reduction efficiencies consistently, SCR systems typically operate with a relative excess of ammonia, resulting in ammonia slip emissions. This issue creates a potential for an increase in ammonia emissions into the

atmosphere, which is further exacerbated by ammonia flow difficulties associated with variable load operation.

There are safety concerns associated with accidental spills of ammonia. At low concentrations, ammonia can cause health effects and can be a nuisance due to its objectionable odor. At high concentrations, it is a toxic compound and a fire hazard. Safety hazards can occur if the ammonia is spilled or there are leaks from ammonia storage vessels. Safety hazards can be reduced if aqueous ammonia or urea is used. However, because water becomes saturated at about 25 percent ammonia by weight, aqueous ammonia tanks must be four times larger than anhydrous ammonia tanks for the same application. Consequently, the cost of storage tanks and transportation costs for aqueous ammonia will be greater than if anhydrous ammonia were used. If a concentrated aqueous solution of urea is used, the urea tank must be heated to avoid re-crystallization of the urea. The corrosive nature of ammonia leads to failure of piping and other components. Additionally suspended rust particles often clog filters and ammonia injection nozzles requiring more frequent cleaning or replacement of equipment.

Storing and using ammonia in quantities above the thresholds specified in the RMP rule may create situations where the facility has to comply with the provisions of 40 CFR part 68 as well.

Conclusions

As presented in this paper, 90 percent reduction of NOx emissions from lean-burn reciprocating internal combustion engines using SCR is not demonstrated in practice. Although catalyst vendors indicated to EPA that 90 percent reduction typically would be achievable for gas-fired applications, the emissions data presented in the ACT document suggests that NOx reduction varies for engines with SCR. Also, the ACT states that insufficient data were available to estimate achievable NOx

reduction levels for the use of SCR in variable load applications, such as natural gas transmission. Since engine operation can significantly affect parameters that affect SCR performance (such as NOx emission levels, exhaust gas flow and exhaust gas temperature), SCR systems would need to be evaluated over the full range of engine operations to determine achievable NOx control levels. Load-following applications, such as natural gas compression, present unique difficulties for SCR systems, which were not fully addressed by EPA in determining the applicability of SCR or the 90 percent effectiveness. Also, EPA's assessment of the cost-effectiveness of SCR did not include costs that would be incurred for variable load applications, including costs to develop a forward-feed PEM and costs that result from vendors "over-engineering" the SCR system to try to offset reduced NOx control efficiencies.

SCR has been installed on reciprocating internal combustion engines in very few instances. Of the 599 lean-burn engines with NOx controls that were included in a survey of natural gas transmission companies, only two engines in the United States have SCR installed and those engines have been mothballed due to difficulties operating the SCR units in a load-following application. Instead, because of the problems associated with using SCR in variable load applications, NOx emissions from lean-burn engines in pipeline service have been controlled using combustion modification or parametric controls.

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May 10, 1999

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Mr. James Seif
Chairperson, Environmental Quality Board
Rachel Carson State Office Building, 15th Floor
P.O. Box 8477
Harrisburg, PA 17105-8477

Re: Comments on the Draft Rule for Nitrogen Oxides Trading Program [25 PA. Code Chs. 123 and 145]

Dear Chairperson Seif:

Trigen Energy Corporation (Trigen) is pleased to provide comments on the proposed approach of NOx allowance allocation and trading regulations. Trigen has facilities in Philadelphia and is actively developing new projects in the Commonwealth of Pennsylvania. Trigen believes that the Environmental Quality Board (Board) has a rare opportunity to establish a NOx trading program that will encourage efficiency and thus reduce NOx emissions in Pennsylvania, since less fuel will be burned to accomplish the same task. This will result in benefits to the public through improvements in air quality, while promoting a healthy economy by meeting the energy needs of Pennsylvania's residents and businesses. In the following commentary, Trigen outlines three specific recommendations for reworking the proposed NOx Budget Trading Program.

1. Adoption of Energy Efficiency And Renewable Energy Set-Aside Provisions

The proposed rule does not set aside NOx allowances for energy efficiency projects. Trigen believes that the Board is sending the wrong message to the general public if energy efficiency projects are not rewarded. We believe that the Board should take an energy efficiency set-aside approach to NOx allowance allocations. This approach will provide an incentive to energy producers to pursue technologies which improve efficiency and, thereby, reduce NOx emissions. If efficient technologies are not encouraged, this rulemaking will have an adverse effect on the Commonwealth by perpetuating obsolete, high emission energy generation. Currently, many large stationary NOx sources utilize wasteful, outdated technologies that result in at best, perhaps 33% of heat input being converted into useful energy. Electric-only power technologies that convert upwards of 60% of heat input into useful energy are being installed around the country. Combined heat and power production, also called cogeneration, takes energy production to the next level, by squeezing as much as 90% of useful energy out of input fuel. In fact, the U.S. Department of Energy issued a challenge of doubling the U.S. Combined Heat and Power (CHP) capacity by 2010. In early March, U.S. EPA also recognized the energy efficiency value of CHP projects in its guidance document,

"Establishing an Energy Efficiency and Renewable Energy Set-Aside in the NOx Budget Trading Program". U.S. EPA encourages States to set-aside between 5 to 15 percent of the total NOx trading budget to reward energy efficiency and renewable energy projects. Other States have already taken such an approach and more are sure to follow. For example, both New York and Maryland have decided to set aside 3% of their total NOx trading budgets for energy efficiency projects. Trigen encourages the Board to adopt EPA's recommendations and set-aside at least 5% to 10% for energy efficiency and renewable energy projects. A combination of new source and energy efficiency set-asides will stimulate economic growth in the region by attracting new, low-pollution industrial and energy-generating facilities to the Commonwealth. In order to foster this growth and technological progress, it is imperative for Pennsylvania to look toward the future and make provisions for cleaner and better technology.

2. Allocation of Allowances Based on 0.15 lb/MMBtu

The Board requested comments on the approach of using the lower of the EPA model rule emission limitation or any more restrictive allowable emission rate to used in calculating NOx allowances. Specifically, EPA's NOx model trading rule allocates allowances to all sources based on a rate of 0.15 lb/MMBtu. The Board proposed to allocate NOx allowances to budget units based on the lower of either 0.15 lb/MMBtu or the unit's allowable emission rate. Trigen believes the Board would be making a serious error in judgment by failing the follow EPA's recommendation to treat all sources equally. Identical treatment of all sources is essential for an effective cap and trade program and allows market forces (not command and control) to *efficiently* allocate allowances.

In its present form, the proposed rulemaking will result in newer, more efficient sources (e.g., Trigen's Grays Ferry Cogeneration Plant in Philadelphia) subsidizing operations and the finance of emission controls undertaken by less efficient, existing sources. The reasons for this are twofold. First, newer, more efficient facilities can use less fuel to produce the same amount of energy output. Therefore, an input based approach in and of itself is already biased against newer, efficient facilities. These newer facilities, thus, will not only receive fewer allocations simply for burning less fuel, but also for maintaining lower allowable emissions rates. For instance, Trigen's Grays Ferry operation uses an expensive state-of-the-art NOx control technology to control NOx emissions. Trigen has already invested significant capital to achieve the lowest NOx emissions in the industry and ought to be rewarded, not penalized. Grays Ferry, and other highly efficient operations, should receive allowances at a fixed rate of 0.15 lb/MMBtu, and on par with all other facilities, regardless of allowable emissions. It is imperative that the Board exhibit fairness in the initial allocations. The argument is a simple one, and is based on intuitive economics: The more the initial allocation diverges from the most cost-effective allocation, the greater potential for inefficient operations to exercise power over the market. As such, an older, inefficient source can reduce its NOx emissions much more inexpensively than a newer, efficient source, and can, thereby, gain an unfair advantage by accruing additional allowances to use or sell. Utilizing the same

rate to allocate allowances for all sources is the only acceptable and equitable method for distributing allowances. This is consistent with Governor Ridge's petition with EPA to establish a cap and trade program to provide for the most cost effective emission reductions.

3. Prepare For Future Allocations Based On An Output-Based Standard

Trigen steadfastly believes that NOx allowance allocations should be based on total useful energy output rather than the amount of fuel burned. Less efficient units should not receive more NOx allowances simply because they burn more fuel. Massachusetts has developed an output-based allowance allocation system and EPA has been moving toward using output based standards. For example, last year EPA changed the New Source Performance Standards (NSPS) for utility steam generating boilers from heat input-based standards to energy output based standards.

Unfortunately, the regulations as proposed by the Board do not take an output-based approach. Trigen understands that because the Board has to submit the revised SIP to EPA by September 30, 1999, it may not be realistic to develop an output-based NOx allocation system at this time. In the absence of an output-based allocation system, Trigen encourages the Board to begin preparation to adopt an output-based standard following the initial allocation period (i.e., following the 2005 ozone season). In the meantime, an output-based standard workgroup, led by EPA with the active participation of states, industry, and other stakeholders, is in the process of developing guidelines for an output-based NOx allocation system. This guidance document will be available shortly. It is important for the Board to maintain some flexibility in its current rulemaking and allow for, what appears to be, an inevitable move toward an output-based approach in the future.

Trigen appreciates the opportunity to provide input on these important regulations and is optimistic that our recommendations will be put into practice.

Sincerely,

Trigen Energy Corporation

Jim Qin, PhD, P.E.
Manager, EHS Programs

Cc: Herman Schopman, Vice-President, Trigen-Philadelphia
Steve Smith, President, Trigen-Philadelphia
Steve Lomax, EHS Analyst, Trigen-Energy Corporation
Mark Hall, Director of Government Affairs, Trigen-Energy Corporation

May 10, 1999 (submitted via e-mail)

Mr. James Seif
Chairperson, Environmental Quality Board
Re: Summary of Comments on the Draft Rule for Nitrogen Oxides Trading Program

Dear Chairperson Seif:

Trigen Energy Corporation (Trigen) is pleased to provide this one-page summary of our detailed comments on the proposed NOx allowance allocation and trading regulations. Trigen has facilities in Philadelphia and is developing new projects in the Commonwealth of Pennsylvania. Trigen believes that the Environmental Quality Board (Board) has a rare opportunity to establish a NOx trading program that will encourage *efficiency* and thus reduce NOx emissions. Trigen outlines three recommendations for reworking the proposed NOx Budget Trading Program.

1. Adoption of Energy Efficiency And Renewable Energy Set-Aside Provisions
The proposed rule does not set aside NOx allowances for energy efficiency projects. Trigen believes that the Board is sending the wrong message to the general public if energy efficiency projects are not rewarded. This approach will provide an incentive to energy producers to pursue technologies which improve efficiency and, thereby, reduce NOx emissions. If efficient technologies are not encouraged, this rulemaking will have an adverse effect on the Commonwealth by perpetuating obsolete, high emission energy generation. Currently, many large stationary NOx sources utilize wasteful, outdated technologies that result in at best, perhaps 33% of heat input being converted into useful energy. Electric-only power technologies that convert upwards of 60% of heat input into useful energy are being installed around the country. Combined heat and power production (or, cogeneration) squeezes as much as 90% of useful energy out of input fuel. In fact, the U.S. Dept. of Energy issued a challenge to double the U.S. Combined Heat and Power (CHP) capacity by 2010. U.S. EPA encourages States to set-aside 5-15% of the total NOx trading budget to reward energy efficiency and renewable energy projects. Both New York and Maryland have set aside 3% of their total NOx trading budgets for energy efficiency projects. Trigen encourages the Board to adopt EPA's recommendations and set-aside at least 5% to 10% for energy efficiency and renewable energy projects.

2. Allocation of Allowances Based on 0.15 lb/MMBtu
EPA's NOx model trading rule allocates allowances to all sources based on a rate of 0.15 lb/MMBtu. The Board proposed to allocate NOx allowances to budget units based on the lower of either 0.15 lb/MMBtu or the unit's allowable emission rate. Identical treatment of all sources is essential for an effective cap and trade program and allows market forces (not command and control) to *efficiently* allocate allowances. The proposed rulemaking will result in newer, more efficient sources subsidizing operations and the finance of emission controls undertaken by less efficient, existing sources. Newer, more efficient facilities can use less fuel to produce the same amount of energy output. Therefore, an input based approach, in and of itself, is biased against newer, efficient facilities. These newer facilities will not only receive fewer allocations simply for burning less fuel, but also for maintaining lower allowable emissions rates. For instance, Trigen's Grays Ferry operation uses state-of-the-art NOx control technology. Trigen has already invested significant capital to achieve the lowest NOx emissions in the industry and ought to be rewarded, not penalized. Grays Ferry, and other highly efficient operations, should receive allowances at a fixed rate of 0.15 lb/MMBtu, and on par with all other facilities, regardless of allowable emissions. The argument is a simple one, and is based on intuitive economics: The more the initial allocation diverges from the most cost-effective allocation, the greater potential for inefficient operations to exercise power over the market. As such, an older, inefficient source can reduce its NOx emissions much more inexpensively than a newer, efficient source, and can, thereby, gain an unfair advantage by accruing additional allowances to use or sell. Utilizing the same rate to allocate allowances for all sources is the only acceptable and equitable method for distributing allowances.

3. Prepare For Future Allocations Based On An Output-Based Standard
Trigen believes that NOx allowance allocations should be based on total useful energy output rather than the amount of fuel burned. Less efficient units should not receive more NOx allowances simply because they burn more fuel. Massachusetts developed an output-based allowance allocation system and EPA is now promoting output based standards. Trigen encourages the Board to to adopt an output-based standard following the initial allocation period and to maintain flexibility in its current rulemaking to allow for an inevitable move toward an output-based approach.

Sincerely,
Trigen Energy Corporation, c/o Jim Qin, PhD, P.E., Manager, EHS Programs

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TOSCO
Trainer Refinery
4101 Post Rd
Trainer, Pa 19061

May 6, 1999

Environmental Quality Board
15th Floor, Rachel Carson State Office Building
P.O. Box 8477
Harrisburg, Pa. 17105-8477

RE: Comments concerning the proposed new Chapter 145
To 25 PA code (relating to interstate ozone transport reduction)

Ladies and Gentlemen:

Tosco Refining Company has reviewed the proposed new Chapter 145 to 25 PA Code, entitled Interstate Pollution Transport Reduction, as published in the *Pennsylvania Bulletin, Volume 29, Number 10*. We would like to take this opportunity to provide comments concerning this proposed regulation.

Comment 1--General

The discussion in *Section E. Summary of the Regulatory Revisions* on page 1321 indicates that the proposed Chapter 145 does not contain the exemption included in the federal rule allowing certain facilities to limit emissions to avoid being subject to the rule. The results of EPA's modeling indicates that 22 states and the District of Columbia significantly contribute to the nonattainment of the NAAQS for ozone in other states, and therefore have been required to modify their State Implementation Plans (SIPs). Each of the 22 states and the District of Columbia will be establishing state NOx Budget programs. These programs will undoubtedly be based on the Federal rule, allowing the exemption of facilities that limit emissions. Therefore, it is burdensome to restrict facilities located in Pennsylvania.

Comment 2 -- Section 145.42 (a)(1)(i) (NOx allowance allocations)

Sources defined in section 145.4(2) (nonelectric generating units) should be allowed to calculate allowances based on the average of the two (2) highest amounts for the control periods during three (3) successive years just as the electric generating facilities. Tosco Refining Company did not operate the Trainer Refinery prior to 1996. During 1995, at least one (1) of the subject units was shutdown for a portion of the control period while operated by the former owner. In addition, the accuracy of the firing rates prior to 1996 cannot be ascertained, as they are not consistent with the operating rates under the current ownership. The facility was shutdown in 1996 under the current ownership; the data should not be included in the allowance calculation. Therefore, we propose that the allowances be based on the average of the two (2) highest heat input rates for the control periods of 1997, 1998 and 1999.

Comment 3 -- Section 145.42 (c)(1) (NOx allowance allocations)

The Department's proposal to base allowances on "an amount equaling 0.17 lb/mmBTU or allowable emission level, **whichever is lower,...**" is a financial burden for facilities that have reduced NOx emissions through "overcontrol" in anticipation of the NOx Allowance Requirements of Chapter 123. For example, where RACT analyses illustrated that the cost effective control technology was "low NOx" burners, sources voluntarily installed " Ultra-low NOx " burners with the understanding that the overcontrolled emissions could be used to offset emissions from other sources in the program. This is consistent with the philosophy of the trading program. Many facilities will lose the capability of offsetting emissions internally and the trading aspects of the regulation will be virtually eliminated. Therefore, the Department should be consistent with the EPA model program, which bases allowances on an emission rate of 0.17 lb/mmBTU.

We appreciate the opportunity to comment on the proposed regulation. If you have any questions or comments, please contact the undersigned at 610-364-8102.

Sincerely,
Tosco Refining Company
Trainer Refinery

John J. Deemer
Environmental Engineer

Philadelphia Refinery

Sun Company, Inc.
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P. O. Box 8477
Harrisburg, Pa. 17105-8477

Re: 25 PA Code Chapter 145 Proposal at Pa. Bulletin,
Vol. 29, No. 10, 3/6/99, Interstate Ozone Transport Reduction

Dear Sirs:

Sunoco, Inc., (R&M) operates two petroleum refineries in Pennsylvania that are affected by the subject proposal and are the main concerns for the comments hereby submitted. This includes the Marcus Hook and the Philadelphia Refineries. The refinery sources that are affected by this proposal are the same as currently under the existing NOx allowance rule at 25 PA 123. This includes eight conventional steam boilers that supply refinery heat but no electricity, one co-generation unit that produces both process steam and electricity, and two process heaters that provide heat to hydrocarbon streams in the refinery. All of these units meet the definition of a "boiler" in the proposed 25 PA 145 regulation. Sunoco also operates two pollution control devices called CO boilers that we believe do not meet the definition of "boiler" and for which we request a distinct exemption for reasons that are presented in this comment package.

Sunoco is a member of the Penna. Chamber of Business and Industry and supports the comments to be submitted by that organization.

Very Truly Yours,

Gary C. Furlong
Managing Environmental Consultant – Air

Attachments

cc:

T. Huynh
Philadelphia Air Management Services
321 University Avenue
Philadelphia, Pa. 19104-4543

COMMENTS OF SUNOCO, Inc. (R&M)
TO THE PROPOSED NOX ALLOWANCE PROGRAM PROPOSED AT
PA BULLETIN, VOL. 29, No. 10, 3/6/99,
INTERSTATE OZONE TRANSPORT REDUCTION

1. Sunoco, Inc. hereby submits data to clarify what units are applicable under the proposal and the baseline firing rates and NOx emissions: This is presented in the following tabulations:

In the following tables these abbreviations apply:

GP = The Girard Point Processing Area of the Philadelphia Refinery
PB = The Point Breeze Processing Area of the Philadelphia Refinery
MH = The Marcus Hook, Pa. Refinery

Text Table 1, Non-EGU Units

Source & Location	Type	Point I.D. in Current 25 PA 123 Rule	Full Year 1995 Heat Input MM Btu	Full Year 1995 NOx tons	May-Sept. 1995 Heat Input MM Btu	May-Sept. 1995 NOx tons
GP-No. 37 Boiler	Boiler For Stteam Heat	02-2,3	1006003	202.8	432884	87.2
GP-No. 38 Boiler	Boiler For Steam Heat	02-4,5	1707940	145.8	729093	146.9
GP-No. 39 Boiler	Boiler For Steam Heat	02-6,7	2241409	451.7	923018	186
GP-No. 40 Boiler	Boiler For Steam Heat	02-8,9	2593348	522.7	1113261	224.4
GP-F-1 Heater	Process Heater	002-2,3,4	2586769	386.6	1130205	161.1
PB- 311 Heater	Process Heater	19/20	1236890	56.8	616322	28.3
MH-No. 7 Boiler	Boiler For Steam Heat	089	1995149	388.2	895106	161.8

Text Table 2, EGU Unit

Source & Location	Type	Point I.D. in Current 25 PA 123 Rule	1995/1996 Average Heat Input MM Btu	1995/1996 Average NOx tons	May-Sept. 1995/1996 Avg. Heat Input MM Btu	May-Sept. 1995/1996 Avg. NOx tons
MH-Co-Generator	EGU	090	3150947	303.3	1232889	137.4
			Highest two year average of 1995/96/97			

this item continued next page

Sunoco certifies that the above data is that which has been submitted to the State and to the City of Philadelphia in past emission inventories. We found it nearly impossible to reconstruct the sources that EPA used in its proposed SIP budget, even after receiving the database (EPA did not publish it except via internet access that had to be specifically asked for) and did not comment completely to EPA or to DEP after the EPA proposal (the exception is our chemical operation at Frankford, Pa. who made comment to Phila. Air Management Services). We were told after inquiry at EPA that they did not in any event intend to name all possible sources, only the "biggest' ones, in their inventory. Many of our refining sources could not be identified in EPA's data base. Facilities should not be penalized for failing to respond to the EPA There should be a proper notice from PADEP for identification of all affected sources that is part of the final PA rule.

2. Sunoco supports the concept of unit opt-in discussed at Section 145.80-88 with the exception of paragraph 145.84(2) which seems to require a season of monitored operation prior to permit approval. Provision also should be made for opt-in units that intend to opt-in because of an expanded heat input capacity above 250 MM Btu/hr.

The importance of opt-in to facilities such as refineries is that a number of units exist that are designed and operated just below the heat input level that triggers inclusion in the rule. Refineries and similar process facilities often pursue throughput expansion projects that require marginal increases in heat input at boilers and process heaters. Should a facility expand the heat input capacity of a unit above 250 MM Btu/hr, it becomes subject to the NOx allowance rule immediately upon operating the increase. If the modified facility cannot receive a NOx budget opt-in permit until it has passed through an ozone season test period it will suffer the economic loss of not having the benefit of the heat input increase. This is a penalty that is not imposed for an existing unit. Provision must be made for opt-in units that intend to opt-in because of an increased heat input design above the 250 MM Btu/hr trigger level of the regular rule. So long as an opt-in unit installs and certifies its monitoring equipment ahead of the time of its expansion it should be allowed to operate at a rate above 250 MM immediately when that change is allowed under its 25 PA 127 Plan Approval.

For the record, to show that this is a real concern at non-utility facilities, the following table shows units that Sunoco is considering for future marginal heat input increase rates that would make them subject to the NOx budget rule. The importance of the opt-in procedure itself is that a facility can opt-in the unit and receive NOx allowances for at least its' prior operation basis. Were it to expand above 250 MM Btu/he without prior opt-in, the proposed regulation is unclear as to its status. If the expanded unit is deemed a new unit at that point, but there are no new unit set-aside allowances available at the time, a considerable economic penalty would be inherent for the purchase of total capacity operating allowances.

Re: Corrected Page on Sunoco, Inc. comments to Proposed 25 PA 145 Rule.

Corrected 5/10/99

Text Table 3, Possible Sunoco Opt-in Candidates
(All examples located at Marcus Hook Refinery)

Source & Location	Type	Point I.D. in Current Emission Inventory	Full Year 1995 Heat Input MM Btu	Full Year 1995 NOx tons	May-Sept. 1995 Heat Input MM Btu	Mat-Sept. 1995 NOx tons
H-3006	Process Heater	99	1871568	122.7	831480	53.3
H-03	Process Heater	60	1977373	159.2	811143	64.1
Boiler #6	Boiler for Steam Heat	88	2000179	395.2	785712	164.7

3. Pollution control devices that fire fossil fuel and otherwise seem to fall under the applicability of this proposal should be exempt. Specifically refinery CO boilers used to control the release of CO gas to the atmosphere from Fluid Catalytic Cracking process units should be exempt from this rule.

Such an exemption already exists administratively under the present 25 PA 123 rule. Attached to this comment packet is a copy of the exemption request and the response from PADEP. We respectfully request that this exemption be incorporated in the new 25 PA 145 rule. All of the reasons for exemption put forth in our request letter of February 3, 1998 still stand. EPA has given guidance that States may include or exclude sources as they see fit.

4. There should be no special restrictions on banked allowances as a result of the 25 PA 145 rule coming into place and the 25 PA 123 rule being displaced.

The Board requested comment on this in the proposal preamble as item No. 1. Allowances banked under the existing program should be transferable to the new program because the sources regulated are the same and the control mechanism is the same. In addition, outside State allowances must be made available to Pennsylvania sources without restriction, just as other states will hope to be able to buy Pennsylvania credits. An open market is supposedly a hallmark of the EPA model rule.

Operators of existing sources such as Sunoco are concerned that there are already enough pressures toward the reduction of available allowances such that a shortage is imminent. For instance, the set-aside for new unit construction will take allowances away from existing sources to the sum of nearly 40% after 10 years.

5. New sources should receive allowances only for their needs.

The Board requested comment on the issue of new source allotments at item 2 in the preamble. Very large utility sources that repower a given site can soon account for a large bank of marketable allowances if they are issued allowances equal to the displaced source. These allowances come out of the pool for existing sources. Small existing sources such as refineries and chemical plants are already concerned about the future for allowance availability. This is economically unfair.

6. Permitting must be kept as simple and timely as possible. The proposal includes too many hurdles and time delays in receiving a NOx allowance permit.

The Board asked for comment at item 4 in the preamble. We object to several particulars in the proposal. First, at 145.5(c)(2) the re-start of a shutdown source is asked to apply 18 months in advance of anticipated startup. In today's economy it is difficult to anticipate the need for a retired unit that far in advance. This can be a real economic disadvantage to a Pennsylvania industry. The issuance of a NOx allowance permit should be only contingent on meeting the requirements of monitoring without undue administrative delay.

Pennsylvania Department of Environmental Protection
Rachel Carson State Office Building
P.O. Box 8468
Harrisburg, PA 17105-8468
October 16, 1998

Bureau of Air Quality 717-787-4310

Eric V. Schneider
Environmental Manager
Sun Philadelphia Refinery
Sun Company, Inc.
3144 Passyunk Avenue
Philadelphia, PA 19147-5299

Dear Mr. Schneider:

Thank you for your letter of February 3, 1998 concerning the applicability of the NOx allowance regulation to the CO boiler at the refinery. I apologize for the delay in responding to your letter.

The Department discussed this issue with the Ozone Transport Commission (OTC) member states. It is the consensus of the states that the CO boiler should not be included in the NOx allowance program envisioned by the OTC Memorandum of Understanding.

Please let me know if I can be of further help.

Sincerely,

Dean E Van Orden

Dean E. Van Orden, Chief
Stationary Source Section
Division of Air Resource Management

February 3, 1998

Mr. Dean Van Orden
Penna. Dept. of Environmental Protection
12 th Floor, Rachel Carson Building
400 Market St.
Harrisburg Pa. 17105-8468

Re: Pollution Control Device Status Under the NOx Allowance Rule

Dear Mr. Van Orden:

First, we wish to complement you and your department for the well organized workshop that was conducted on December 5, 1997. In particular we appreciated how floor questions were entertained and answered. It should be a model for any future workshops, especially during the developmental stages of regulations.

To the issue at hand, we at Sun still have a concern that pollution control devices have not been exempted from the NOx allowance regulatory process. We believe it is inappropriate to include such devices and we request that this issue be put on the agenda at a future meeting of the OTC. The particular device that is of concern to Sun is fluid catalytic cracker (FCC) regenerator gas incinerators (that convert CO to CO2). We do not believe it was intended that pollution control devices be regulated; unfortunately, the regulatory language provides no route for exemption. One of Sun's three existing Pennsylvania FCC units has an affected pollution control device according to the existing regulatory language. We propose that it is a bad precedent to regulate pollution control devices, and in addition there are technical and economic reasons why it is not fair to do so. Control devices are not in the same category as steam and power producing facilities (which we believe were the intended target of NOx regulation), and any number of unintended consequences can result from their regulation. Following is a discussion of detail pertinent to explaining why FCC unit CO incinerators (called a CO boiler) should be in a class of exempt pollution control devices.

<u>The design purpose and operation of FCC incinerators and waste heat recovery units.</u>
Please refer to the attached simplified process schematic. FCC units are equipment that handle a very fine particle silica-based catalyst. Catalyst at high temperature is combined with heavy hydrocarbon feed in a reaction vessel and a cracking reaction occurs that results in coke deposition on the catalyst particles. After the coke bearing catalyst is separated from product

gases it is conveyed to a second vessel for regeneration by combusting the coke. Regeneration is effected by introducing a controlled flow of air to the catalyst in a fluidized bed such that the solid coke is oxidized to either CO2 (complete combustion units) or CO2/CO mixture (partial combustion units). The regenerated catalyst flows back to the reactor, and the process continues. The regenerator off-gases at about 1300 deg F are conveyed in large pipes to pollution control and heat/material recovery devices. The first most common device is an electrostatic precipitator where fine catalyst particles are recovered for recycle or disposal. The second most common device is a steam-producing boiler device called either a heat recovery unit (for full combustion regenerators) or a CO boiler (for partial combustion regenerators). FCC's can be designed such that either full or partial coke combustion can be effected in the regenerator, so for the purpose of further discussion we will call the final steam-producing device a WHB/COB (waste heat boiler/CO boiler).

Discussion of WHB/COB operation in the mode of regenerator full combustion.
Per the definition of "heat input" at 25 PA 121.1 Sun understands that sensible heat in the gases from an FCC regenerator would not be counted in any mode of regenerator operation as heat input to a WHB/COB. Thus at an FCC unit designed solely for full combustion the WHB/COB would not be an affected source if all of its' steam production were from regenerator sensible heat. If the boiler were designed to fire auxiliary fossil fuel it would have to fire at least 250 MM btu/hr of fossil fuel to be an affected source. A WHB/COB associated with a full combustion regenerator is not a pollution control device for CO, it is primarily a heat recovery device with a possible auxiliary firing capability. NOx from the stack of such a source can be controlled only to the extent that auxiliary fuel firing can be tuned for low NOx; however, there is no practical control for the varying amounts of NOx that exit the regenerator. Regenerator NOx depends on regenerator design, how it is operated, and how much nitrogen is in the feed to the process unit (not a controllable variable). In addition, full combustion units employ combustion promoter catalyst that increases NOx formation. NOx catalytic/non-catalytic reduction units are an unproven technology in this application.

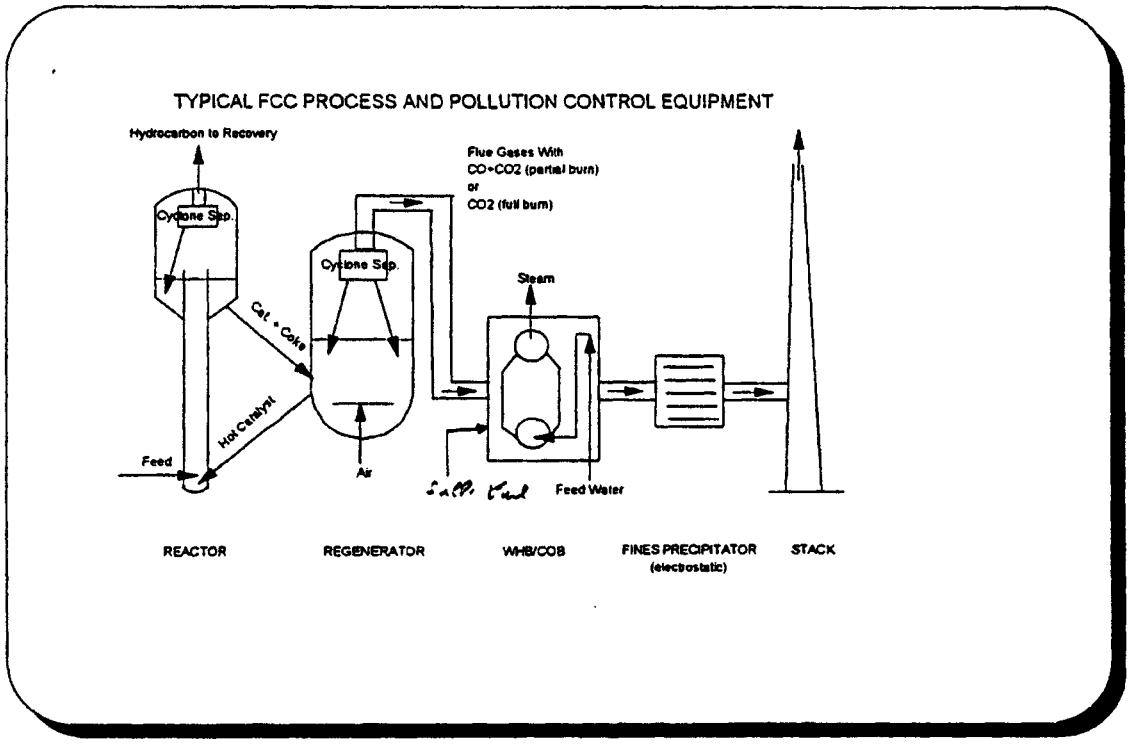
Discussion of WHB/COB operation (i.e., CO boiler operation) in the mode of regenerator partial combustion
For FCC regenerator partial combustion the regenerator effluent gas contains CO gas. A certain amount of fossil fuel must be used in the CO boiler to promote full CO combustion, and in addition extra fossil fuel ability may be designed-in to the unit for supplemental steam production. It is our understanding from the current rule that affected status would be based on a heat input calculation as follows: sum only the fossil fuel fired (ignore sensible heat imported from the catalyst regenerator) and the heat release of CO gas (non-fossil fuel) to see if the unit is fired at greater than 250 MM btu/hr. If the unit is above 250 MM btu/hr but the fossil fuel heat input portion is less than 51%, the unit is not affected by the rule.

A CO boiler is a pollution control device for removing CO from the stack. As such this unit is a slave to the process operation. NOx from auxiliary fuel may be reducible by tuning technology, but NOx from the regenerator is not controllable for most of the same reasons as discussed under full burn operation above. NOx catalytic/non-catalytic reduction technologies are also not feasible in this application in the USA. Domestic FCC units are operated over about 5 years

between turnarounds and cannot tolerate the economic penalty of an annual turnaround as practiced in Japan where SCR is employed. Economics are especially poor for an existing facility because of space restrictions and detrimental effects on the overall process unit operability.

Summary

We propose that pollution control devices be removed from applicability of the NOx allowance rule. A CO boiler operated after a partial combustion catalyst regenerator is primarily a pollution control device. Its physical design is primarily aimed at complete CO combustion. The boiler cannot be responsibly operated without converting the CO gas to CO2, and thus is a slave to the operation of the FCC regenerator. While supplemental fossil fuel may be fired in this operating mode, this is not a preferred mode since supplemental firing may reduce the reliability of the unit, and FCC units are today expected to operate over a 4 to 6 year span without shutdown for maintenance. NOx control is not feasible at these control devices in the same manner as for a conventional fired heat or power producer. Should the facility that operates a CO boiler prefer to meet its' NOx allowance by physical control, it could not do so. The overwhelming majority of affected combustion units are utility and commercial units whose sole purpose is the production of heat and/or electric power and whose design configurations permit a choice of NOx control from a common menu.



If you have any questtions please do not hesitate to call me at (215) 339-2091, or call Mr. Gary Furlong at (215) 339-2634

Very Truly Yours,

Eric V. Schneider
Environmental Manager, Sun Philadelphia Refinery

cc: Mr. Thomas Huynh (Phila. Air Management Services)
Mr. James Salvagio (DEP)

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May 7, 1999

Commonwealth of Pennsylvania
Department of Environmental Protection
Environmental Quality Board
Rachel Carson State Office Building, 15th Floor
P.O. Box 8477
Harrisburg, PA 17105-8477

Re: Review Comments for Proposed 25 Pa Code Chapter 145 - NO_x Budget Trading Program

Dear Sir or Madam:

Enclosed please find Merck & Co., Inc. (Merck's) written comments on the proposed 25 PA Code Chapter 145 NO_x Budget Trading Program regulation appearing in the March 6, 1999 Pennsylvania Bulletin. These comments are being submitted electronically.

Merck has carefully reviewed the proposed regulation and trusts that these comments will be given due consideration by the board in the final rulemaking process. Should there be any questions concerning these comments, please contact me at 215.652.9897.

Sonya Wiggins Stovall
Site Environmental Engineering

cc: Steven C. Wittmer, Merck & Co.

MERCK & CO., INC. – WEST POINT, PA

WRITTEN COMMENTS FOR THE PROPOSED 25 PA CODE CHAPTER 145 - NO_X BUDGET TRADING PROGRAM

PREAMBLE

COMMENT #1: In Section F. entitled Benefits, Cost and Compliance, DEP addresses control costs for utility sources but does not address the expected cost impact on industrial sources. Also, the stated control costs for regulated internal combustion engines do not reflect an actual range of expected cost in \$/ton NO_x controlled. MERCK has evaluated the NO_x control cost for units at the West Point facility and expect that costs over \$30,000/ton will be incurred to comply with the proposed emission limits.

COMMENT #2: Pursuant to Area No. 1 for which the Board specifically requested comment, MERCK believes that DEP should authorize the transition of all banked allowances under the current Chapter 123 NO_x Budget Program regardless of the State from which they were created. MERCK agrees that the compliance supplement pool be utilized as the means for this transition. The current Chapter 123 program and the proposed Chapter 145 program are both intended for interstate trading purposes. Any rollover of allowances from one program to the other should not be limited to only Pennsylvania allowances.

COMMENT #3: Pursuant to Area No. 2 for which the Board specifically requested comment, MERCK recommends that DEP adopt the allocation approach as outlined in 40 CFR §96 for the following reasons:

- The approach proposed by DEP provides no benefit for facilities to reduce allowable emission rates below 0.15 lb/MMBtu. MERCK believes this is contrary to the intent of the SIP call.

- The approach proposed by EPA favors the installation of add-on control equipment over reconstructing or repowering existing facilities as a compliance approach. These facilities would be restricted by a permit limit reflecting BAT or LAER; whereas, sources installing control equipment would generate allowances for sale on the open market. MERCK does not believe that one compliance approach should be more beneficial than the other.

- MERCK does not believe Pennsylvania has cause to be concerned about attaining the ozone standard since the statewide budgets for EGUs and Non-EGUs were developed by EPA consistent with the allocation approach in 40 CFR §96. The modeling analysis conducted by EPA to substantiate the need for further NOx reductions via the SIP call was also based on these budgets.

COMMENT #4: Pursuant to Area No. 3 for which the Board specifically requested comment, MERCK agrees with DEP's inclusion of units rated at 15 MW or greater into the budget program.

COMMENT #5: Pursuant to Area No. 4 for which the Board specifically requested comment, MERCK supports the decision to integrate the trading program permitting with the current Chapter 127 permitting program. Additional comments related to the execution of this integration approach are included in this attachment.

§ 145.2. DEFINITIONS

COMMENT #6: MERCK proposes that the following terms be added in the definition section:

Electric Generating Unit (EGU) – Any unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than or equal to 15 MWe and meets at least one of the following conditions:

1. The unit is currently reporting under Title IV.

2. The unit serves a generator reporting to the Energy Information Administration (EIA) using Form 860.

3. The unit serves a generator that reported to EIA using Form 867 in 1995, excluding units that are not listed as sources that sell power under contract to the electric grid using the electric generation forecasts of the North American Electric Reliability Council.

Non-Electric Generating Unit (Non-EGU) – Any unit not meeting the definition of an EGU with a maximum design heat input greater than or equal to 250 mmBtu/hr.

COMMENT #7: The intent of the term "natural" person as it is used in the definition of the NO_x authorized account representative is unclear. MERCK proposes the following change to this definition (shown in **bold**):

NO_x authorized account representative - For a NO_x Budget source or NO_x Budget unit at the source, the ~~natural~~ person who is authorized by the owners and operators of the source and all NO_x Budget units at the source, in accordance with, to represent and legally bind each owner and operator in matters pertaining to the NO_x Budget Trading Program or, for a general account, the ~~natural~~ person who is authorized, in accordance with this subchapter, to transfer or otherwise dispose of NO_x allowances held in the general account.

COMMENT #8: The definition of a *Continuous Emission Monitoring System (CEMS)* implies

that a flow monitor is a component part of any CEMS. Monitoring options exist that do not require the use of flow monitoring devices. MERCK proposes adding language similar to that provided for the continuous moisture monitor and diluent gas monitor as follows:

(1) Flow Monitor **when the monitoring is required by this subchapter**;

§ 145.4. APPLICABILITY.

COMMENT #9: MERCK proposes the following modifications to ensure consistency with the EPA State budget determinations. EPA has determined statewide budgets for EGUs and Non-EGUs; however the budget trading program is not consistent in defining these units similar to the guidance used to compile the budget. The following changes to the applicability provisions are suggested in **bold**:

> (1) Any unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than or equal to 15 MWe **and meets the definition of an EGU in §145.2**; or
>
> (2) Any unit that is not a unit under paragraph (1) and that has a maximum design heat input greater than or equal to 250 mmBtu/hr.

MERCK believes this clarification is important considering that the Cogen II Gas Turbine at the West Point facility is currently included in the State NO_x budgets for both EGUs and Non-EGUs. MERCK requests that DEP adjust the state inventory budgets as provided in §145 to ensure that all industrial gas turbines meeting the Non-EGU definition are included in the appropriate budget category and regulated consistently . Currently, all other industrial gas turbines are included only in the Non-EGU budget, including following units and facilities:

FACILITY	POINT ID	UNIT DESCRIPTION
TEXAS EASTERN GAS PIPELINE CO	032	Single Cycle Gas Turbine
SUN REFINING & MARKETING CO.	090	Combined Cycle Gas Turbine
MERCK SHARP & DOHME	039	Combined Cycle Gas Turbine
PROCTER & GAMBLE	035	Combined Cycle Gas Turbine

COMMENT #10: DEP did not initially address provisions to exempt Low Mass Emission Units from the budget program contrary to 40 CFR §96 which provided specific regulatory language for exempting units emitting 25 ton per control period or less. DEP has subsequently provided proposed language to supplement § 145.4. The following bulleted comments apply to this draft language:

- § 145.4(3)(i) specifies that units must have "emitted 25 tons of NO_x or less during each control period beginning with the control period of 1995" to qualify as a Low Mass

Emissions Unit (LMEU). This does allow r units that may have emitted greater than 25 tons during control periods after 1995 but chose to control emissions below 25 tons by installing a control device or by making other process changes to take advantage of the LMEU. MERCK suggests that this condition be eliminated and that DEP focus on the emission limits for the 2003 control periods and beyond.

- § 145.4(3)(ii) specifies that the permit limitation for low mass emissions units "equal the maximum actual NOx emissions during a control period selected from the preceding two control periods." The purpose of specifying this method for determining the permit limitation is to prevent facilities with actual emissions well below 25 tons from obtaining a permit limit at 25 tons thus requiring DEP to deduct 25 tons from the state-wide budget. The DEP proposal is too restrictive since it is based upon only two years of actual emissions. MERCK proposes that permit limits for low mass emission units be established in the following manner:

  - ✓ Base the maximum actual emission rate on the most representative year over a 5 year period or average the two highest years over the last 5 year period similar to the PSD baseline determination procedure.

  - ✓ Apply a factor to allow for natural fluctuations in capacity and/or growth. It is suggested that this factor be between 10-15% of the emission rate determined from the above criteria.

- § 145.4(3)(v) references criteria for units to lose their LMEU exemption. The regulatory reference is § 145.4(3)(iii); however, this citation does not contain any provisions for the loss of the exemption. MERCK suggests that this language be provided for completeness of the rule

§ 145.6. STANDARD REQUIREMENTS.

COMMENT #11: MERCK proposes that DEP transfer all the Standard Requirements for units and facilities that overlap with the existing Chapter 123 program to the new program provided that this would not preclude Pennsylvania's participation in the interstate trading program. MERCK does not support any changes to the regulations that preclude Pennsylvania's participation in the interstate trading program. Potential overlap requirements include, but are not limited to, the following:

- ✓ Permit Conditions and Numbers (modified as required for §145)
- ✓ Account Representatives and Alternate Account Representatives
- ✓ Account Numbers
- ✓ Monitoring Plans
- ✓ Account Certificate of Representation

Addressing the overlap in requirements would greatly reduce the paperwork and administrative requirements related to the transition to the §145 program.

COMMENT #12: MERCK believes that the penalty provisions in §145.6(d) are overly onerous and should contain explicit references defining the exact nature and cost method for determining the fine. MERCK suggests that DEP define the types of violations and adopt procedures to penalize violations based on their severity. As an example, under the proposed rule, a facility that exceeded an allowance due to a calibration error in their NO_x CEMS that was not realized until the facility performed a RATA after the control season would be penalized the same as a facility that knowingly exceeded it's allowance. MERCK recommends that these violations be penalized differently and that each ton of emissions should not constitute a separate violation.

§ 145.20. GENERAL NO_X BUDGET TRADING PROGRAM PERMIT REQUIREMENTS.

COMMENT #13: MERCK suggests that DEP clarify the wording when describing the "NO_x Budget Permit". For sources with facility-wide permits this will be the NO_x Budget Portion of the Title V or Non-Title V operating permit. Subsection (a) of this section implies that each facility would hold a separate NO_x Budget Permit. Also, upon receiving plan approval, the conditions of the plan approval would be effective until the appropriate administrative changes are made to the Title V or Non-Title V facility permit. MERCK proposes that DEP add clarifying language to this section as follows.

> (a) Each NO_x Budget source must have a NO_x Budget permit **or a complete and separable section within the facility's Title V, Synthetic Minor Title V or State Minor Source operating permit.**
>
> > (1) For NO_x Budget sources required to have a title V operating permit, the NO_x Budget portion of the title V permit shall be administered in accordance with Chapter 127, subchapter G.
> >
> > (2) For NO_x Budget sources required to have a non-title V permit, the NO_x Budget portion of the non-title V permit shall be administered in accordance with Chapter 127, subchapters A, B and F.
>
> ~~(b) Each NO_x Budget permit shall include all applicable NO_x Budget Trading Program requirements and shall be a complete and segregable portion of the permit under paragraph (a) of this section.~~

§ 145.31. THE DEPARTMENT'S ACTION ON COMPLIANCE CERTIFICATIONS.

COMMENT #14: MERCK suggests that language be added to 145.31(a) to limit the time frame in which the Department or the Administrator can make adjustments to certifications or other submissions as follows:

The Department or the Administrator may review and conduct independent audits concerning any compliance certification or any other submission under the NOx Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions **within a control period, up to 3 months after the compliance deadline for each control period.**

§ 145.40. STATE TRADING PROGRAM BUDGET.

COMMENT #14: MERCK requests that the state NO_x budgets be modified based on updated information submitted to EPA under the "Request for Modification of Data" period provided per 40 CFR §96. The budgets should account for all units subject to the program and EGUs and Non-EGUs should be separated appropriately as proposed based upon the definitions presented in this comment package.

§ 145.42. NO_x ALLOWANCE ALLOCATIONS.

COMMENT #15: "New" units are not clearly defined. Units installed after May 1 1995 would not have representative data on which to base their allocations for the 2003-2005 control period. These units would therefore be considered "new" units as inferred by §145.42(d). MERCK suggests that "new" units be explicitly defined in the rule.

COMMENT #16: MERCK recommends that DEP adopt the allocation approach as outlined in 40 CFR §96 for all units (i.e., existing and new) for the following reasons:

- The approach proposed by DEP provides no benefit for facilities to reduce allowable emission rates below 0.15 lbs./MMBtu. MERCK believes this is contrary to the intent of the SIP call.

- The approach proposed by EPA favors the installation of add-on control equipment over reconstructing or re-powering existing facilities as a compliance approach. These facilities would be restricted by a permit limit reflecting BAT or LAER; whereas, sources installing control equipment would generate allowances for sale on the open market. MERCK does not believe that one compliance approach should be more beneficial than the other.

- MERCK does not believe Pennsylvania has cause to be concerned about attaining the ozone standard since the state-wide budgets for EGUs and Non-EGUs were developed by EPA consistent with the allocation approach in 40 CFR §96. The modeling analysis conducted by EPA to substantiate the need for further NOx reductions via the SIP call was also based on these budgets.

COMMENT #17: Currently, the initial budget allocations for the 2003-2005 control period is

determined based on the actual 1995-1997 heat input (specifically the two highest of the three years) for EGUs and on the actual 1995 heat input for non-EGUs. MERCK suggests that both budgets be calculated based upon the same inventory year period.

COMMENT #18: §145.42(d)(5) states that DEP will allocate allowances by the plan approval issue date. MERCK believes this approach is not equitable for the following reasons:

- Sources required to satisfy more stringent permitting requirements (e.g., BACT, LAER) will be required to go through a public hearing which would result in delays in the plan approval process.

- Sources required to satisfy more stringent permitting requirements will be required to install more expensive and more stringent emission control technology. Thus, new sources investing in low NO_x control technology would most likely obtain allowances after less well controlled sources emitting at higher levels. This seems to conflict with the intent of the rule which should provide more benefit to those sources equipped with the most effective NO_x control technology.

- Other states may adopt a permitting program that would make it easier for new sources to obtain allowances thereby making it more attractive to construct the source outside of Pennsylvania.

MERCK proposes that DEP revise this condition to read as follows:

> (5) The Department will review, and allocate NO_x allowances pursuant to, each NO_x allowance allocation request under paragraph (2) in the order that a plan approval **application completeness determination has been** issued.

The revised condition will ensure that delays in the plan approval process beyond the control of the regulated entity will not effect the availability of allowances.

COMMENT #19: §145.42(d)(5)(i) states that the Department will begin determining allowances at the time the NO_x allocation request is received. This seems to be inconsistent with the language in §145.42(d)(5) which infers that the Department won't begin processing the request until plan approval is granted. MERCK suggests that this language be clarified throughout this section.

§ 145.54. COMPLIANCE.

COMMENT #20: MERCK proposes that §145.54(b)(2) be modified to clarify exactly which section subparagraphs (i) and (ii) reference. The suggested modification is as follows:

> (2) NO_x allowances will be deducted first under subparagraph **(b)(1)**(i) and then under subparagraph **(b)(1)**(ii):

COMMENT #21: MERCK proposes that DEP eliminate any reference to specific control period years in section (c)(9). The proposed modification is as follows:

> (9) NO_x allowances banked under Section 123.110 (relating to source compliance requirements) ~~for years 2000 through 2002~~ shall be deemed to have met the requirements of paragraphs (a) and (c). The NO_x authorized account representative must submit the application as required by paragraph (c) to the Department.

§ 145.55. BANKING.

COMMENT #22: MERCK proposes that the control periods for which sources are eligible to apply for early reduction credits under section (c) be expanded to include the any control period after & including 1999, but before 2002.

§ 145.70. GENERAL MONITORING REQUIREMENTS.

COMMENT #23: MERCK requests that DEP take steps necessary to obtain EPA approval of the current §123 monitoring requirements for use in the §145 program. In the preamble to 40 CFR §96, EPA stated that the compliance monitoring provisions from the OTC rule were used as a basis for the development of the monitoring provisions in the SIP call budget program. However, differences between the two programs exist, primarily for units not subject to 40 CFR §75 through the Acid Rain program and low mass emissions units. It is the Non-EGU units that will incur the greatest financial penalty should the current monitoring systems not be approved for use under the proposed budget program provided that such changes do not preclude Pennsylvania's participation in the interstate trading program. While MERCK recommends that the existing monitoring provisions be approved for use in the §145 program, MERCK does not support the implementation of any monitoring provisions that would preclude Pennsylvania's participation in the interstate trading program.

COMMENT #24: The requirements for installation, certification, and data accounting in section (1)(i) imply that a flow monitor is part of the required systems for monitoring. The application of a flow monitor is dependant upon the monitoring option selected and is not a mandatory component of all monitoring systems. MERCK proposes the following annotation to §145.70(1)(i):

> (i) Install all monitoring systems required under this subchapter for monitoring NO_x mass. This includes all systems required to monitor NO_x emission rate, NO_x concentration, heat input, and flow, **as necessary,** in accordance with 40 CFR §§ 75.72 and 75.76.

COMMENT #25: MERCK suggests that the Department clarify section (2)(iii) and (2)(iv) of

this section to specify a "shakedown" period for troubleshooting and debugging any required CEMS. Reporting and recording of data will not be required until after the system shakedown is completed by the deadlines specified in section (2). Allowance deductions for compliance pursuant to §145.54(b) will not be made until after the system shakedown is completed by the deadlines specified in section (2).

COMMENT #26: MERCK suggests that the provisions of section (3)(ii) be re-worded to clarify that the data collected during the initial CEMS certification process not be reported for compliance purposes and only as a means to troubleshoot EDR systems prior to initial certification. No meaningful data will be generated prior to certification of the CEMS.

§ 145.74. RECORDKEEPING AND REPORTING.

COMMENT #27: MERCK suggests that DEP clarify the intent of the meaning of the word "annual" in section (d)(1). MERCK proposes that the sentence be modified as follows to consider the option to report only for the control period:

> (1) All NO_x budget units must meet the annual **or control period** reporting requirements of this subchapter. The NO_x authorized account representative shall submit a quarterly report for each calendar quarter beginning with:

COMMENT #28: MERCK proposes modifying the language in (d)(1)(iii) to clarify when the reporting period begins. Reporting of data prior to CEMS certification should not be required and is not consistent with §145.70(2) which states that the facility must record and report data on or after the CEMS certification deadline. MERCK proposes the following annotation:

> (iii) For a unit that commences operation after May 1, 2002, the calendar quarter in which the unit commences operation. Data shall be reported from the date and hour corresponding to when the unit commenced operation **with a certified CEMs**.

§ 145.75. PETITIONS.

COMMENT #29: Pursuant to section (a)(1), MERCK requests that DEP take steps necessary to obtain EPA approval of the current §123 monitoring requirements for use in the §145 program. It is also suggested that approved alternatives be listed or referenced by the regulation.

§ 145.86. OPT-IN SOURCE WITHDRAWAL FROM NO_X BUDGET TRADING PROGRAM.

COMMENT #30: MERCK requests that the excess emissions penalty of deduction of 3 times the amount of excess emissions from the overdraft account be consistent for budget units and opt-in budget units. Currently only budget units are subject to this penalty and opt-in units

are only required a 1:1 deduction pursuant to section (b)(2).

SUBCHAPTER B. EMISSIONS OF NO_X FROM STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES.

§ 145.101. APPLICABILITY.

COMMENT #31: Potential to emit for emergency standby units is calculated at 500 hours per year based on the EPA memorandum entitled "*Calculating Potential to Emit (PTE) for Emergency Generators*" issued 6 September 1995 by John S. Sietz, Director, Office of Air Quality Planning and Standards. A permit limit is not required for this PTE to be federally enforceable under Title V and it is suggested that DEP remove the requirement for these units to obtain a permit limit for the 500 hour restriction. Also, it does not make sense to pro-rate the 500 hour per year limitation by 5/12 for the ozone season. These units are defined as "emergency" units and the potential for their use during the ozone season will not be a linear function of total operating hours. In fact, it is likely that these units will primarily be operated during the summer months in response to outages due to severe weather (e.g., thunderstorms, tornadoes, etc.) more common during the months. MERCK proposes the following changes:

> (d) Emergency standby electric generation units having the sole purpose of providing emergency electric service to the facility where it is located and which is ~~permitted~~ only to be utilized in the event of a ~~catastrophic~~ failure of the primary electrical power source for the facility and which has a permit limitation of a maximum cumulative operation of ~~208~~ **500** hours per control period are exempt from the requirements of this subchapter.

COMMENT #32: In addition to exempting emergency standby units, it is recommended that DEP consider providing an exemption that would exempt not only standby units, but also peaking units. Peaking units are operated during the peak season (June 1st – September 30th) to also meet the electric demand of industrial plants to help offset premium electric costs incurred during the peak season. These units are only operated to **meet plant demand**, not to sell electricity to the grid. It is not cost effective to install control equipment on such units considering they are typically used at 10% capacity or less. Control costs will exceed $30,000/ton for these units based on discussions with control vendors. MERCK proposes that section (e) be added as follows:

> **(e) Peaking standby electric generation units having the sole purpose of providing peaking electric service and which have a permitted capacity factor of 10%, or less, are exempt from the requirements of this subchapter.**

§ 145.102. DEFINITIONS.

COMMENT #33: The term *Permitted Capacity Factor* is defined but not referenced in the

regulation.

§ 145.103. STANDARD REQUIREMENTS.

COMMENT #34: Revise wording in section (b) as noted:

(b) Each emission limit expressed in paragraphs (a)(1) through (4) of this section ~~may~~ **shall** be multiplied by X, where X equals the engine efficiency (E) divided by a reference efficiency of 30 percent. Engine efficiency (E) shall be determined using one of the methods specified in paragraph (b)(1) or (2) of this section, whichever provides a higher value. However, engine efficiency (E) shall not be less than 30 percent. An engine with an efficiency lower than 30 percent shall be assigned an efficiency of 30 percent.

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ENVIRONMENTAL QUALITY BOARD

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Environmental Quality Board
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Proposed Revisions to 25 PA Code Chapter 123 and New Chapter 145

Interstate Ozone Transport Reduction
Implementation Regulations

Duquesne Light Company Comments

Dear Environmental Quality Board Members:

Introduction

Duquesne Light Company is the investor owned electric utility that serves over 575,000 customers, with service territory in Allegheny and Beaver Counties located in Western Pennsylvania. Duquesne has a direct interest in the proposed regulation since its facilities will incur significant costs to achieve additional NOx reductions from its generating stations as a result of the regulation. Accordingly, we appreciate the opportunity to submit the following comments.

Duquesne's fossil-fired plants have already reduced their NOx emissions by 55 percent from 1990 levels in accordance with the requirements of the Ozone Transport Commission's NOx Memorandum of Understanding. The expense incurred to install and operate the control equipment to achieve these emission reductions constitute a significant economic disadvantage for our Company at a time when power markets are being opened to competition. The NOx SIP Call Rule will require emission reductions of approximately 85 percent. Implementing this rule will subject our Company to an intolerable competitive disadvantage if other states do not adopt essentially identical emission reduction requirements on the same schedule.

In January of this year, Pennsylvania began to implement one of the most significant laws in the history of our state electric utility industry – the Pennsylvania Electric Generation Customer Choice and Competition Act. Duquesne believes that Governor Ridge and all the supporters of the historic legislation intended for Pennsylvania's economy to benefit from competitive power markets. But, if Pennsylvania electric generators lose market share as a result of more stringent environmental requirements, Pennsylvania's economy may be weakened by electric competition as energy dollars flow to other producing states. Accordingly, Duquesne urges the EQB, and all Pennsylvania policy-makers, to do all they can to minimize the economic impact of these proposed regulations, and to ensure a level playing field for the Commonwealth's affected sources.

The Regulatory Development Process Has Focused Only on Implementation Issues

The EPA §110 SIP Call is one of the largest national and state level regulatory control programs ever promulgated. Yet the PA DEP in its presentation of the proposed rule to AQTAC, said the Department will not discuss any of the policy issues, economic impacts or national regulatory considerations. It is troubling in the extreme that the Department would seek to avoid discussions about the economic impact of this rule on Pennsylvania's economy, particularly as we enter this historic period of open competition in the electric generation industry. The 1992 APCA requires substantive review and evaluation of control strategies which are adopted in State Implementation Plans. ACTAC is the established body for such discussion. In limiting discussion to implementation issues, the Environmental Quality Board should not assume that the SIP Call itself has been approved and endorsed by AQTAC and that the very serious policy issues it raises have been discussed and addressed. They have not. In addition, proceeding directly to the adoption of control strategies, as DEP proposes, ignores the APCA SIP review provisions and precludes any evaluation of the emission reduction requirements effects on industry and commerce.

Specific Comments on Proposed Chapter 123 Revisions and New Chapter 145 Regulations

Issue: §145.40 thru 145.42 – Connected Heat Input Values for Duquesne's Brunot Island, Cheswick, Elrama and Phillips Power Stations – On February 19, 1999 Duquesne submitted to EPA requested heat input revisions for the above stations. Although EPA has not formally responded to Duquesne, it is our understanding that EPA has not made the requested heat input corrections.

Recommendation: The Department should adopt the heat input values submitted to EPA (copies also forwarded to the Department). As an alternative, the Department should recognize the revisions requested for Cheswick and Elrama and also confirm that Brunot Island and Phillips Power Stations will not be subject to the §110 SIP Call

until reactivated and be eligible at that time for allowance allocations under proposed §145.42(b) and (d) New Source Set Aside Provisions.

Issue: §145.4(2) - Unit Applicability Below 25 MW - The proposed applicability criterion is more restrictive than federal requirements because the proposal would apply to units that serve generators greater than or equal to 15 megawatts.

Recommendation: Duquesne recommends the following language revision for Section 145.4(2):

"A unit that, any time on or after January 1, 1995, serves a generator with a unit summer net capacity greater than or equal to 25 Mwe". This is consistent with the AQTAC recommendation of April 23, 1999.

Discussion: EPA's SIP call sets an applicability level of 25 megawatts for electric generation units. Pennsylvania's program should be consistent with the federal program in this regard to avoid the risk of placing Pennsylvania generators at a competitive disadvantage with respect to generators in other states. Using the federal applicability level will allow Pennsylvania to meet EPA SIP call requirements and to join in a regional emission trading program with states that elect to conform to the federal model rule. Using the federal applicability criterion was endorsed by the Department's Air Technical Advisory Committee at its April 22, 1999 meeting.

The rating basis for the applicability criterion should be specified in the rule to add clarity. Unit performance capability varies with ambient temperature. Electric generation supply planning commonly utilizes different unit net capability ratings for winter and for summer. Because the proposed rule applies only during the summer ozone season, which extends from May 1 through September 30, the summer net unit capability should be specified in the rule.

Issue: §145.42 Single Year Allocation Methodology - A single year allocation based on a unit's heat input four years prior to the year for which the allocation is being calculated would not reflect normal utilization of a unit and could result in an abnormally high or low allocation year for an individual unit.

Recommendation: - Section 145.42 should be revised to reflect a three-year allocation using the same methodology proposed for the initial allocation period (2003-2005). For example the control period 2006-2008 allocation would be based on the best two of three unit utilization years from 2000-2002.

Discussion: - We support the Department's proposed methodology to use the average of the two highest amounts of the unit's heat input for the control periods in 1995, 1996 and 1997 for calculating the NOx allowance allocations for the initial 2003-2005

allocation period. However, we do not support the Department's proposed methodology to use the unit's heat input from the single control period in the year that is four years prior to the year of subsequent allocation periods beginning 2006 and thereafter. For instance, heat input for 2002 would be used to calculate the 2006 allocation. Instead, we recommend the Department use the average of the two highest utilization years for the three years that begin six years before the first year of the subsequent three-year allocation period. For example, the best two years of three unit utilization years for 2000, 2001, and 2002 would be used to calculate the 2006-2008 allocation. The two-out-of-three period method would prevent an abnormal single period utilization, either high or low, from skewing the future period allocation. The three-year allocation would allow for longer range planning on the part of the electric generation facilities and would reduce the administrative burden on the Department for recalculating the allocation every year. Such a revision is well within the State Implementation Plan (SIP) approval guidelines contained in the EPA's NOx SIP call rule.

Issue: §145.42 (b)(1) Overall NOx Allowance Allocation Methodology - The method of NOx allocation outlined in this Section deviates from the §96.42 of the federal rule by providing an additional condition in allocation of NOx allowances to sources. Specifically, §142.42 allocates NOx allowance as follows: "...in an amount equaling 0.15 lb/mmBtu or allowable emission level, whichever is lower, multiplied by the heat input..."(emphasis added).

Recommendation: - The proposed language should be changed to become consistent with the language in the federal rule by dropping the underscored text above in the issue statement.

Discussion: - The adoption of the language in the federal rule is advantageous for several reasons. First, it simplifies the language by giving all sources, irrespective of type or emission rate, allowances calculated by the same methodology. This eliminates game playing by special interests to carve out specific provisions that would benefit them disproportionately over other sources and provides a level playing field.

Issue: §145.55(c) - Carry Forward Banking Limitations - Limiting the number of banked allowances carried forward from 2002 to 2003 would be environmentally counterproductive because such limitation would provide an economic disincentive for making early emission reductions.

Recommendation: - The final rule should not provide any restrictions on the number of banked allowances carried forward from 2002 to 2003. To eliminate the unnecessary restrictions in the proposed rule, subsection 145.55 (c) should be deleted.

Discussion: Limiting credit for early NOx reductions will provide no benefit to the environment. The proposed rule limits the number of banked allowances in Pennsylvania that can be carried forward into 2003 to 13,716 tons. The 13,716 ton proposed limit is based on the "compliance supplement pool" (CSP) number assigned to Pennsylvania by EPA. There is no environmental basis for imposing such a restriction. In fact, the restriction on carry forward of banked allowances would be environmentally counterproductive because it would discourage early reduction by introducing economic uncertainty into the compliance planning process – particularly for those sources most adversely affected by the costs of NOx reductions.

The OTR program currently has a mechanism for banking early reductions, and has progressive flow control provisions intended to address concerns about high annual emissions that might result from an accumulation of a large number of banked emission allowances. The CSP limitations is an unnecessary and counterproductive complication for states such as Pennsylvania that are already participating in the OTR program.

Issue: § 145.70 General Monitoring Requirements - The monitoring requirements in the proposed Chapter 145 are different from those in the existing Chapter 123. These changes will result in the surrender of allowances for emissions which never occur. They also will require sources compliant with Chapter 123 to expend significant additional monies for software and hardware with no commensurate increase in the accuracy of the data.

Recommendation: - The proposed regulations should incorporate the monitoring requirements of existing 25 PA Chapter 123.108 of the Department's regulations. These requirements were incorporated from the Ozone Transport Commission (OTC) "NO_x Model Rule." The "Model Rule" was developed by a stakeholder group consisting of state regulators, U.S. EPA, environmental groups and industry representatives to implement the "OTCs NO_x Memorandum of Understanding."

Discussion: - The monitoring requirements of this section are significantly different from those required by Chapter 123. The proposed Chapter 145 relies on the new 40 CFR 75.19. The specific difficulties with that section are for establishing unit-specific default NO_x emission rates for low mass emitter units.

In Part 2, (G) of the "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program" ("Guidance Document") incorporated into 25 PA Chapter 123 by Pennsylvania Department of Environmental Protection (PaDEP) and also used by the other OTC states, oil and gas fired peaking units (in the case of electric generators these are simple-cycle combustion turbines) are permitted to use a tested NO_x default rate coupled with long-term fuel flow measurement methods to achieve cost effective compliance with OTC NO_x monitoring and reporting requirements. Further deviation from the specifications of the OTC Guidance Document also creates problems for sources that are using CEMS to meet 40 CFR Part

60 on PA 25 Chapter 139 monitoring requirements. These sources have invested significantly in upgrading data acquisition and handling system hardware and software to comply with the Chapter 123 requirements. Deviation from Chapter 123 monitoring requirements under the proposed Chapter 145 means these sources will need to make additional expenditures to satisfy the new requirements. This has been identified as a "cost of doing business," however, it is an unnecessary cost as it does not improve the representativeness of the emissions data.

Consequently, it is strongly recommended that the proposed Chapter 145 use the monitoring requirements specified in Chapter 123. Use of these monitoring requirements solves all of the problems associated with the monitoring provisions of the proposed Chapter 145.

Issue: "SUBCHAPTER B. EMISSIONS OF NO_X FROM STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES" - The major potential impact of proposed Subchapter B to the electric generation industry is its treatment of diesel generators.

Recommendation: - In its proposed March 6, 1999 regulation, DEP added new language to the Applicability section of Subchapter B at §145.101(d) which we believe was intended to provide an exemption for diesel generators. However, we are concerned that in its current form, it may not allow sufficient flexibility to exempt companies' diesel generators.

Duquesne believes that the only eligibility constraint for gaining an exemption from the subchapter under §145.101(d) should be on the number of operating hours allowed. The proposed exemption language should be revised as follows:

> *(d) A diesel generator which has a permit limitation of a maximum cumulative operation of 208 hours per control period is exempt from the requirements of this subchapter.*

An exemption, such as the one above, provides the desired environmental protection (by capping operating hours) while simultaneously providing appropriate flexibility in the use of diesel generators to allow for the multiple real and potential scenarios in which they may be utilized.

Discussion: - Duquesne strongly believes that diesel generators should be exempt from the requirements of Subchapter B and the NOx SIP Call program based on the following considerations:

Diesel generators are very small (e.g. usually in a range between 1 and 4 megawatts). They are utilized primarily to provide a source of electric power to power plants during times of real <u>or potential</u> loss of the normal electric supply used to operate the plant and its equipment.

Diesel generators located at fossil generating plants may also directly, or indirectly by covering auxiliary boiler load, supply electric power to the grid during periods of real or potential power grid failure. It should be noted that with regard to diesel generators located at nuclear power plants that the Nuclear Regulatory Commission (NRC) prohibits their use for any purposes other than providing standby power.

Regardless of their specific use, diesel generators operate at very low capacity factors (generally well under 5%). Many diesel generators are also permit restricted to a 5%, or other very low, capacity factor as part of their NOx RACT permits.

Post-combustion NOx emission controls for diesel generators would be extremely costly in comparison to emission controls at other sources. Costs to control diesel generators would be measured in the 10s of thousands of dollars per ton removed - far in excess of the cost of any other EPA NOx control requirements.

Subchapter B also sets prescriptive NOx emission concentration levels and does not allow for NOx allowance trading to satisfy the regulatory requirements. Unless diesel generators are exempted, the result will be a gross mis-allocation of capital dollars to some of the least cost effective, lowest aggregate NOx ton emission sources.

We thank you for the opportunity to submit the above comments.

Sincerely,

RWOrchowski

R. W. Orchowski
Manager of Environmental Affairs

ENVIRONMENTAL QUALITY BOARD

Proposed Revisions to 25 PA Code Chapters 123 and new Chapter 145
Interstate Ozone Transport Reduction Implementation Regulations
Summary of Duquesne Light Company Comments
Submitted May 10, 1999

Implementing this rule will subject all Pennsylvania electric generators to an intolerably competitive disadvantage if other states do not adopt essentially identical requirements on the same schedule. The EQB should insure that Pennsylvania does not get out in front of this Program if other states cited in the SIP Call do not follow-through with their rulemakings.

The 1992 Amendments to the PA Air Pollution Control Act requires substantive review and discussion of control strategies adopted in State Implementation Plans. The PA DEP limited discussion of this rulemaking to implementation issues only despite the enormous policy, economic and air quality implications of this rule. The EQB should be acutely aware of this serious shortfall to the regulation development process.

Issue: §145.4(2) - Unit Applicability Below 25 MW - The proposed applicability criterion is more restrictive than federal requirements (25 MW cutoff) because the PA proposal would apply to units that serve generators greater than or equal to 15 megawatts.

Recommendation: Consistent with the April 23, 1999 ACTAC recommendation, revise the applicability criterion upward to cover units that serve generators greater than or equal to 25 megawatts. Also summer net unit capability should be designated as the applicable criterion.

Issue: §145.42 Single Year Allocation Methodology - Single year allocations based on a unit's heat input four years prior to the year for which the allocation is being calculated would not reflect normal utilization of a unit and could result in an abnormally high or low unit allocation.

Recommendations: Revise Section 145.42 to reflect a three-year allocation approach using the same methodology proposed for the initial allocation period (2003-2005).

Issue: §145.42(b)(1) Overall NO_x Allocation Methodology - §145.42(b)(1), which prescribes the manner in which NO_x allowances will be allocated, deviates from the language in the federal rule.

Recommendation: Revise §145.42(b)(1) to be consistent with the federal rule language, as unanimously approved by the PA DEP Air Quality Technical Advisory Committee.

Issue: §145.44(c) - Carry Forward Banking Limitations - Limiting the number of banked allowances carried forward from 2002 to 2003 would be environmentally counterproductive because such limitation would be an economic disincentive to early emission reductions.

Recommendation: Section 145.55(c) should be deleted. The final rule should not provide any restrictions on the number of banked allowances carried forward from 2002 to 2003.

Issue: §145.70 General Monitoring Requirements - Proposed Chapter 145 monitoring requirements are significantly different from those in the existing Chapter 123. These changes will result in the surrender of allowances for emissions which never occur and also require sources currently compliant with Chapter 123 to expend significant additional monies for software and hardware with no commensurate increase in the accuracy of the data.

Recommendation: The proposed regulations should incorporate the existing monitoring requirements of 25 PA Chapter 123.108, which were incorporated from the Ozone Transport Commission (OTC) "NO_x Model Rule".

Issue: Subchapter B Diesel Generator Exemption - Subchapter B sets prescriptive emission limits for internal combustion engines that would require extremely costly emission control technology for negligible NO_x emissions. The subchapter should provide an appropriate exemption for low utilization diesel generators.

Recommendation: §145.101(d) should be revised to focus simply on operating hours, per each diesel generator using the following suggested language: §145.101(d) *A diesel generator which has a maximum cumulative operation of 208 hours per control period is exempt from the requirements of this subchapter.*