NITROGEN OXIDE STACK SAMPLING
AT THE U. S. DOE OAK RIDGE
Y-12 STEAM PLANT

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ABSTRACT

On November 7, 1997, the EPA proposed a Nitrogen Oxides State Implementation Plan Call (NO_x SIP Call) for 22 states in the eastern United States which included the state of Tennessee. This initial proposal was followed by proposed statewide NO_x budgets in the May 11, 1998, Supplemental Notice of Proposed Rulemaking. In the development of the NO_x SIP Call, EPA performed a number of air quality analyses and determined that NO_x emissions from Tennessee should be reduced. Industrial boilers, turbines, stationary internal combustion engines, and cement manufacturing are the only non-electric generating unit sources for which reductions are assumed in the budget calculation. Emission reductions are required if specific source heat input capacity is greater than 250 million Btu per hour.

The U.S. Department of Energy (DOE) Oak Ridge Y-12 Steam Plant consists of four Wickes pulverized coal fired boilers each rated at a maximum heat input capacity of 298 million Btu per hour, and will therefore be impacted by these regulatory actions. Each boiler is equipped with two pulverizing mills. Coal or natural gas or a combination of these two fuels may be fired. This paper provides the results of NO_x emission stack testing conducted June 15-21, 1999, on the Y-12 Steam Plant Boilers 1 and 2. Measurements of oxygen (O_2), carbon monoxide (CO), carbon dioxide (CO_2), and stack gas flow were also performed. Information gained from these stack tests will be used to determine NO_x emission control strategies for the steam plant for compliance with future emission requirements resulting from the NO_x SIP Call.

INTRODUCTION

In August 1997, eight northeastern states filed petitions under the Clean Air Act (CAA) Section 126 seeking to control NO_x emission sources upwind of their respective states. CAA Section 126 allows states to petition EPA to make a finding that a major source or group of sources is significantly interfering with a state's ability to attain or to maintain ambient air quality standards.

The eight Section 126 petitions claimed that specific upwind NO_x sources were contributing to ozone non-attainment or maintenance problems in the petitioning states. In response to the petitions, EPA issued November 7, 1997, and May 11, 1998 initial proposals and an October 27, 1998, final rule requiring 22 states (including Tennessee) and the District of Columbia (DC) to modify their existing State Implementation Plans (SIPs) to better control NO_x emissions (hereafter referred to as the "NO_x SIP Call").[1-3]

The final rule established a NO_x emission trading program which sets a NO_x emission budget for each affected state, with states free to choose the NO_x control measures to adopt in order to achieve their respective budget. States were given a deadline of September 30, 1999, for submittal of revised SIPs. The NO_x trading program would apply to any fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system in the source categories named in the petitions that fits one of the following categories: (1) units that, on or after January 1, 1995, produce electricity for sale with a name-plate capacity greater than 25 MW (large electricity-generating units or EGUs); or (2) units with maximum design heat input capacity greater than 250 million Btu/hr that, on or after January 1, 1995, do not serve an electric generator (large non-EGUs). NO_x emission reductions required for these two categories of sources are specified as: 0.15 lb/MMBtu for EGUs as a group and 60% reduction for non-EGUs as a group, using uncontrolled 1995 actual NO_x emissions adjusted for growth to the year 2007 as baseline. The final rule also requires that all units covered by the NO_x Budget Trading Program must comply with 40 CFR 75 NO_x emission monitoring requirements, and that units burning coal or solid fuels are required to use both NO_x CEMs and flow CEMs. The final rule specifies that NO_x controls must be in place by May 1, 2003 and that States must achieve their allotted NO_x emission budgets by September 30, 2007.

Two more recent rulemakings of the U.S. Court of Appeals for the D.C. Circuit have affected certain elements of EPA's rulemaking under Section 126. On May 14, 1999, the court ruled the 8-hour national ambient air quality standard (NAAQS) for ozone to be unenforceable. The 8-hour ozone standard formed part of the underlying technical basis for certain of EPA's determinations on the Section 126 petitions. And, on May 25, 1999, the court granted a motion to stay the SIP submission deadlines established under the NO_x SIP Call. In light of those rulings, EPA proposed in June to separate the time line for action on the Section 126 petitions from the due dates in the NO_x SIP Call. EPA also proposed to stay its actions on the portions of the Section 126 petitions based on projected non-compliance with the 8-hour ozone standard. At this point, the deadlines established in the October 27, 1998 final rule are on hold pending resolution of these issues.

Since the U.S. DOE Y-12 Plant Steam Plant is located in an affected state (Tennessee) and is a fossil fuel-fired stationary boiler with a maximum design heat input capacity greater than 250 MMBtu/hr, it meets the definition of an affected unit under the final rule (large non-EGU). The Tennessee Air Control Board has adopted rules to implement the NO_x SIP Call (in manner required by EPA). The rules are in the Tennessee Attorney General's Office undergoing a legal review. The Board has instructed the Department to hold the rules after the Attorney General review and not to file them with the Secretary of State until the Board specifically authorizes their filing. The rules propose a 232 ton per ozone season (May-September) NO_x limit for the Y-12 Steam Plant, which represents an approximate 40 percent reduction when compared to the 1995

ozone season baseline estimated emissions. NO_x emission stack testing was conducted June 15-21, 1999 on the Y-12 Steam Plant Boilers 1 and 2 to provide actual NO_x emissions data so Y-12 Plant personnel could develop a strategy to comply with the new rules. Specifically, the test results are needed to provide an early indication of whether or not add-on emission controls (e.g., low NO_x burners) will be needed to achieve compliance with the proposed 232 ton NO_x seasonal limit. As the Y-12 Steam Plant personnel continue to scope options for attaining compliance with the rule, the plans are to have the stack test results evaluated by an outside vendor to assess compliance options (to make a determination whether or not add-on controls should be pursued further or eliminated from consideration).

The following sections provide the methodologies utilized and results of this stack testing, which was performed by Lockheed Martin Energy Systems, Inc., Analytical Chemistry Organization personnel using equipment rented from Clean Air Engineering (CAE, Palatine, Illinois).

PLANT AND SAMPLING LOCATION DESCRIPTION

Process Description and Operation

The Oak Ridge Y-12 9401-3 Steam Plant consists of four Wickes pulverized coal fired boilers rated at 250,000 lb/hr of 250-psig steam. Each boiler is equipped with two pulverizing mills. Coal or natural gas or combination may be fired. Steam generated is used primarily for building environmental control.

Control Equipment Description

The flue gas from each boiler is ducted through an air preheater. Flue gas then passes through a Joy Manufacturing reverse air baghouse. Filtered gas is ducted from the baghouse outlet to the boiler induced draft fan and then to the stack. One stack services Boilers No. 1 and 2, and another stack services Boilers No. 3 and 4. Each baghouse outlet is equipped with a continuous opacity monitor, and there is a continuous opacity monitor in the stack.

Stack Gas Sampling Location

Sampling ports for each boiler are provided in a horizontal rectangular section of duct downstream of the baghouse outlet. Seven ports are installed in the horizontal duct 6 ft high and 4.5 ft wide. A 7x4 matrix for sample and velocity traverses has been previously used for source testing. A location for installation of a single point continuous sampling probe was determined based on a velocity traverse and selection of a point with local velocity close to the average velocity of the duct cross-section.

Process Sampling Locations

No raw material or process samples were collected for analysis. Existing monitoring equipment was used to collect process data.

SAMPLING AND ANALYTICAL PROCEDURES

Operating Conditions

Operating conditions are summarized with presentation of emission results.

Test Methods

Instrumentation and Equipment

Measurement equipment met specifications of applicable EPA reference methods.

NO_x measurements were performed with a Thermo Environmental Model 42CHL NO_x Analyzer. The measurement system for this project included an NO_2 to NO converter.

Separate Servomex 1400 O_2 Analyzers were supplied for measurement of O_2 and CO_2.

A Thermo 48 CO Analyzer was supplied for measurement of CO.

An Alfa Laval (VIA) MAK 2 sample gas conditioner was furnished to deliver a clean, dry gas sample for the extractive analyzers, with monitor results reported on a dry basis.

CAE also provided certified zero, mid-range, and high-range calibration gases in cylinders.

An EMRC Flow Monitor was rented from CAE. The flow monitor was understood to be state of the art for applications requiring continuous flow monitoring under 40 CFR 75 Acid Rain Program. Its rental for this project provided an opportunity to perform a site-specific evaluation of its performance and operation. Along with the O_2 data and fuel factors, the continuous flow data provided parameters for a continuous record of boiler heat input based on reference method measurements. The continuous flow monitor was based on stack velocity measurement using an "S" type pitot tube probe and a pressure transducer and was also equipped with a thermocouple to measure duct temperature.

EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrument Analyzer Procedure)

In Method 7E, a gas sample is continuously extracted from a stack, and a portion of the gas sample is conveyed to an instrumental chemiluminescent analyzer for determination of NO_x concentration.[4] The instrument was set up to record NO_x in a range of 0-1,000 ppm.

EPA Method 3A - Determination of Oxygen and Carbon Dioxide Concentration in Emissions from Stationary Sources (Instrument Analyzer Procedure)

In Method 3A, a gas sample is continuously extracted from a stack, and a portion of the gas sample is conveyed to an instrumental analyzer or analyzers for determination of O_2 and CO_2 concentrations.[5] An instrumental measurement range of 0-25% was set up for both O_2 and CO_2.

EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources

In Method 10, an integrated or continuous gas sample is extracted from a sampling point and

analyzed for carbon monoxide (CO) by a nondispersive infrared (NDIR) analyzer or equivalent.[6] An instrumental measurement range of 0-500 ppm was set up for CO.

Quality Assurance/Quality Control Activities

The measurements were performed in a manner to verify that measurement system performance specifications of the reference methods were met.

SUMMARY AND DISCUSSION OF TEST RESULTS

Objectives

The primary objective was to measure baseline NO_x emissions under selected operating conditions.

Field Test Changes and Problems

The equipment was rented on basis of a 10-day price agreement that included shipment time in the duration. The equipment was shipped from the vendor on Saturday, June 12 and arrived in Oak Ridge on Monday, June 14, but was delivered to the Oak Ridge National Laboratory. It was not installed and operational until Tuesday, June 15. Some troubleshooting of the continuous flow monitor was required, and it was not operational for a period after startup of the continuous gas analyzers. Some additional loss of data occurred due to power outages or ground fault interruptions that were experienced while the equipment was unattended. The equipment was disassembled and prepared for return shipment beginning on Monday, June 21, 1999.

Presentation of Results

Calculation of Results

Fuel Factor

Fuel factor may be calculated by

$$F_o = \frac{20.9 - \%O_2}{\%CO_2}$$

where:

$F_o =$ fuel factor

$\%O_2 =$ percent oxygen by volume (dry basis)

$\%CO_2 =$ percent carbon dioxide by volume (dry basis)

EPA Method 3B provides expected F_o ranges for typical fuels in Table 1.[7]

Table 1. Expected fuel factor values

Fuel Type	F_o Range
Coal:	
Anthracite or lignite	1.016-1.130
Bituminous	1.083-1.230
Oil:	
Distillate	1.260-1.413
Residual	1.210-1.370
Gas:	
Natural	1.600-1.836
Propane	1.434-1.586
Butane	1.405-1.553
Wood	1.000-1.120
Wood bark	1.003-1.130

The fuel factor calculated from oxygen and carbon dioxide measurements was used to confirm the type of fuel fired.

Average Flue Gas Velocity

Average flue gas velocity, in feet per second, may be calculated by[8]

$$v_s = 85.49 \times C_p \times \left(\sqrt{\Delta p}\right)_{avg} \times \sqrt{\frac{460 + t_{savg}}{P_s \times M_s}}$$

where:

      avg= average

      v_s= average flue gas velocity, feet per second

      C_p= pitot tube coefficient

$\Delta p=$ velocity pressure, inches water

$t_s=$ stack temperature, °F

$P_s=$ absolute flue gas pressure, inches mercury

$M_s=$ wet molecular weight of flue gas

For an "S" type pitot tube, the baseline coefficient is 0.84.

Absolute stack pressure may be calculated by

$$P_s = P_{bar} + \frac{P_g}{13.6}$$

where:

$P_{bar}=$ barometric pressure, inches Hg

$P_g=$ stack gas static pressure, inches H_2O

The static pressure was measured to be -5.8 to -5.9 in. H_2O. A constant absolute stack gas pressure of 29 in. Hg was assumed in lieu of continuous determinations.

The molecular weight of the stack gas is dependent upon additional factors.

Percent moisture is dependent upon water vapor generated by combustion of hydrogen in the fuel as well as humidity in the combustion air.

EPA Method 19 provides equations that may be combined to estimate percent moisture depending on fuel type in lieu of continuous moisture measurements.[9]

Method 19 provides two expressions for emission rate (E)

$$E = (C_d)(F_d)\left(\frac{20.9}{20.9 - \%O_{2d}}\right)$$

and

$$E = (C_w)(F_w)\left(\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2w}}\right)$$

where:

$C_d=$ pollutant concentration on dry basis

$F_d=$ F-factor, dry standard cubic feet per million Btu at 0% O_2 and 68°F

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$\%O_{2d}=$ percent oxygen by volume (dry basis)

$C_w=$ pollutant concentration on wet basis

$F_w=$ F-factor, wet standard cubic feet per million Btu at 0% O_2 and 68°F

$B_{wa}=$ fractional moisture content of air supplied for combustion

$\%O_{2w}=$ percent oxygen by volume (wet basis)

Wet and dry basis concentrations are related by

$$C_w = \frac{C_d}{1 + B_{ws}}$$

and

$$\%O_{2w} = \frac{\%O_{2d}}{1 + B_{ws}}$$

where:

$B_{ws}=$ fractional moisture content of stack gas

The two expressions for emission rate may be set equal and solved explicitly for B_{ws} if B_{wa} is known. EPA Method 19 provides for assigning a value of 0.027 for B_{wa} at any location at all times in lieu of actual data.

The result using additional factors from EPA Method 19 is

$$B_{ws} = \frac{20.9(F_w - F_d + F_d B_{wa}) - \%O_{2d}(F_w - F_d)}{20.9 F_d (1 - B_{wa})}$$

where:

$F_d=$ F-factor, dry standard cubic feet per million Btu at 0% O_2 and 68°F

$F_w=$ F-factor, wet standard cubic feet per million Btu at 0% O_2 and 68°F

Percent water vapor (%H_2O) is calculated by

$$\%H_2O = B_{ws} \times 100$$

Dry mole fraction of the stack gas (M_{fd}) may be calculated by

$$M_{fd} = 1 - \frac{\%H_2O}{100}$$

Dry molecular weight of the stack gas (M_d) may be calculated by

$$M_d = \frac{\%CO_2}{100} \times 44 + \frac{\%O_2}{100} \times 32 + \frac{\%CO + \%N_2}{100} \times 28$$

where:

%CO₂=   percent carbon dioxide by volume (dry basis)

%O₂=   percent oxygen by volume (dry basis)

%CO=   percent carbon monoxide by volume (dry basis)

%N₂=   percent nitrogen by volume (dry basis)

Wet molecular weight of the stack gas (M_s) may be calculated by

$$M_s = M_d \times M_{fd} + 18 \times \frac{\%H_2O}{100}$$

Dry Volumetric Stack Gas Flow Rate at Standard Conditions

Dry volumetric stack gas flow rate at standard conditions (Q_{sd}) in cubic feet per minute may be calculated by[8]

$$Q_{sd} = 60 \times \left(1 - \frac{\%H_2O}{100}\right) \times v_s \times A \times \frac{460 + t_{std}}{460 + t_{savg}} \times \frac{P_s}{P_{std}}$$

where:

A=   stack cross-sectional area, ft^2

t$_{std}$=   standard temperature at 68°F

P$_{std}$=   standard absolute pressure at 29.92 in. of Hg

If needed, wet volumetric stack gas flow rate at actual conditions (Q_{aw}) may be calculated by

$$Q_{aw} = 3600 \times v_s \times A$$

Approximate Heat Input Rate

EPA Method 19 provides F factors that are ratios of combustion gas volumes to heat inputs for different fuel types.[9] Table 2 summarizes F factors for various fuels.

Table 2. F factors for various fuels

Fuel Type	F_d (dscf/10⁶ Btu)	F_w (wscf/10⁶ Btu)	F_c (scf CO_2/10⁶ Btu)
Coal:			
Anthracite	10,100	10,540	1,970
Bituminous	9,780	10,640	1,800
Lignite	9,860	11,950	1,910
Oil	9,190	10,320	1,420
Gas:			
Natural	8,710	10,610	1,040
Propane	8,710	10,200	1,190
Butane	8,710	10,390	1,250
Wood	9,240		1,830
Wood bark	9,600		1,920
Municipal	9,570		1,820

Site-specific F factors may be calculated from elemental analyses and gross calorific values:

$$F_d = \frac{3.64\% \, H + 1.53\% \, C + 0.57\% \, S + 0.14\% \, N - 0.46\% \, O}{GCV} \times 10^6$$

and

$$F_w = \frac{5.57\% \, H + 1.53\% \, C + 0.57\% \, S + 0.14\% \, N - 0.46\% \, O - 0.21\% \, H_2O}{GCV} \times 10^6$$

where:

    %H=   concentration by weight of hydrogen, wt %

    %C=   concentration by weight of carbon, wt %

    %S=   concentration by weight of sulfur, wt %

%N= concentration by weight of nitrogen, wt %

%O= concentration by weight of oxygen, wt %

%H$_2$O= concentration by weight of water, wt % (omitted if %H and %O include unavailable H and O)

GCV= gross calorific value, Btu/lb

For coal, the factors in Table 2 were applied, but for natural gas, it was possible to calculate site-specific F factors from available analytical data.

Approximate heat input rate, million Btu per hour, may be calculated by

$$mmBtu/hr = 60 \times \left(\frac{Q_{sd}}{F_d}\right)\left(\frac{20.9 - \%O_2}{20.9}\right)$$

Mass Emission Rate

Mass emission rate, in pounds per hour, may be calculated from measured concentration by

$$lb/hr = \frac{60(ppm_{vd})(f_{wt})(Q_{sd})}{(385.3)(10^6)}$$

where:

ppm$_{vd}$= parts per million, by dry volume

f$_{wt}$= formula weight, 46 for NO$_x$

Emission Factor

An emission factor in pounds per ton of coal may be calculated by

$$lb/ton = (lb/hr)\frac{(Btu/lb)(2000)}{(mmBtu/hr)(10^6)}$$

A heating value of 12,500 Btu/lb was assumed for coal based on available data.

An emission factor in pounds per million cubic feet of natural gas may be calculated by

$$lb/MCF = (lb/hr)\frac{(Btu/SCF)}{(mmBtu/hr)}$$

A heating value of 1,035 Btu/SCF was applied for the natural gas based on available data.

Emissions may also be calculated in terms of pounds per million Btu by

$$lb/mmBtu = \frac{(lb/hr)}{(mmBtu/hr)}$$

Percent Excess Air

Finally, the results may be correlated to percent excess air calculated by

$$\%EA = \frac{\%O_2 - 0.5 \times \%CO}{0.264 \times \%N_2 - (\%O_2 - 0.5 \times \%CO)} \times 100$$

Specific Results

Table 3 summarizes operating conditions and NO_x emission results based on measured one-minute averages. Data from an initial operating period for Boiler No. 2 on gas were not adequately captured due to installation and troubleshooting of the monitoring equipment. The NO_x emission factors may be compared to 280 lb per 10^6 scf natural gas from Supplement D to the Fifth Edition of AP-42 or to 31 lb per ton of coal from Supplement E.[10-11]

Table 3. Summary of operating conditions and NO_x emission results

Condition	Start time End time		Heat input MMBtu/hr	NO_x lb/hr	NO_x lb/ton coal or 10^6 scf gas	NO_x lb/MMBtu	Excess air %
Boiler #2	06/16/99 17:30	Avg	115	80.2	17.1	0.70	145
coal	06/17/99 11:12	Stdev	5	7.6	1.4	0.06	14
		Min	71	47.7	13.7	0.56	78
		Max	150	93.5	19.3	0.79	283
Boiler #1	06/17/99 16:00	Avg	122	29.2	244	0.24	123
gas	06/17/99 17:33	Stdev	10	4.2	29	0.03	24
		Min	64	10.7	148	0.14	90
		Max	154	33.1	271	0.27	260
Boiler #1	06/17/99 21:01	Avg	112	85.9	18.8	0.76	155
coal	06/19/99 00:17	Stdev	6	5.9	1.1	0.04	10
		Min	100	73.5	15.3	0.62	110
		Max	139	105.7	20.4	0.83	185

Condition	Start time End time		Heat input MMBtu/hr	NO_x lb/hr	NO_x lb/ton coal or 10^6 scf gas	NO_x lb/MMBtu	Excess air %
Boiler #1 coal	06/19/99 21:01 06/20/99 04:58	Avg	112	84.4	18.4	0.75	155
		Stdev	3	2.3	0.3	0.01	5
		Min	100	77.4	17.6	0.72	141
		Max	123	90.7	19.3	0.79	175
Boiler #1 coal	06/20/99 21:01 06/21/99 00:01	Avg	110	116.1	25.8	1.05	140
		Stdev	3	4.3	0.6	0.02	7
		Min	101	106.5	24.9	1.02	122
		Max	121	133.7	28.2	1.15	158
Boiler #1 coal	06/21/99 05:22 06/21/99 08:30	Avg	119	115.5	23.8	0.97	125
		Stdev	4	4.1	0.3	0.01	7
		Min	104	101.0	22.0	0.90	111
		Max	131	128.9	24.6	1.00	152

DEVELOPMENT OF A POTENTIAL NO_x EMISSION CONTROL STRATEGY

Potential NO_x emission control strategy should consider historical heat input requirements for the facility. After selection of a baseline for future reductions, an evaluation of projected NO_x emissions based on type of fuel, heat input requirements, and emission factors can be performed. After implementation of the strategy, NO_x emissions could be measured with a continuous emissions monitoring system (CEMS) and type of fuel operation be scheduled accordingly.

Table 4 predicts that 351 tons of NO_x would be emitted during an "ozone season" (May through September) according to an operational baseline of 1995 with the fraction of the heat input requirement satisfied by natural gas (NG) as indicated and applying the latest available AP-42 emission factors**.**

Table 4. Seasonal NO$_x$ emission estimate for 1995 baseline at latest AP-42 emission factors

Month	Year	% NG	tons coal	lb/ton	MCF NG	lb/MCF	ton NO$_x$
May	1995	2.45	6687	31	4.058	280	104.2
June	1995	1.29	3904	31	1.229	280	60.7
July	1995	1.30	3569	31	1.133	280	55.5
Aug	1995	2.22	4059	31	2.227	280	63.2
Sept	1995	1.12	4321	31	1.181	280	67.1
Season			22540		9.828		351.

Table 5 predicts a seasonal emission of 294 tons if an emission factor of 26 lb/ton of coal were applied.

Table 5. Seasonal NO$_x$ emission estimate for 1995 baseline at 26 lb/ton coal

Month	Year	% NG	tons coal	lb/ton	MCF NG	lb/MCF	ton NO$_x$
May	1995	2.45	6687	26	4.058	280	87.5
June	1995	1.29	3904	26	1.229	280	50.9
July	1995	1.30	3569	26	1.133	280	46.6
Aug	1995	2.22	4059	26	2.227	280	53.1
Sept	1995	1.12	4321	26	1.181	280	56.3
Season			22540		9.828		294.

If an emission factor of 19 lb/ton of coal were applied, Table 6 indicates that the seasonal emission estimate is 216 tons and below a 232-ton seasonal limit that has been tentatively proposed.

Table 6. Seasonal NO$_x$ emission estimate for 1995 baseline at 19 lb/ton coal

Month	Year	% NG	tons coal	lb/ton	MCF NG	lb/MCF	ton NO$_x$
May	1995	2.45	6687	19	4.058	280	64.1
June	1995	1.29	3904	19	1.229	280	37.3
July	1995	1.30	3569	19	1.133	280	34.1
Aug	1995	2.22	4059	19	2.227	280	38.9
Sept	1995	1.12	4321	19	1.181	280	41.2
Season			22540		9.828		216.

Finally, for an emission factor of 31 lb/ton of coal, Table 7 illustrates that, if 44.47% of the input requirement were satisfied by natural gas, the seasonal NO$_x$ emission estimate could be lowered to 232 ton.

Table 7. Seasonal NO$_x$ emission estimate for 1995 baseline and heat input satisfied by switch to natural gas

Month	Year	% NG	tons coal	lb/ton	MCF NG	lb/MCF	ton NO$_x$
May	1995	44.47	3807	31	73.633	280	69.3
June	1995	44.47	2196	31	42.482	280	40.0
July	1995	44.47	2008	31	38.840	280	36.6
Aug	1995	44.47	2305	31	44.590	280	42.0
Sept	1995	44.47	2427	31	46.939	280	44.2
Season			12742		246.485		232.

CONCLUSIONS

1. Nitrogen oxides emission factors measured for the Y-12 9401-3 Steam Plant were potentially 16-39% lower (19-26 versus 31 lb/ton of coal) than EPA Publication AP-42 for the operating conditions under which the measurements were performed. Extrapolation to other operating periods should be performed cautiously, however, without specific understanding of other parameters such as fuel nitrogen content.

2. A potential NO_x emission control strategy could be developed based on continuous emissions monitoring systems (CEMS) data and facility heat input requirements.

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Y-12 Plant Records Services (3)