Phase II Assessment of NO_2/NOx Ratios at Fossil Fuel Power Plants

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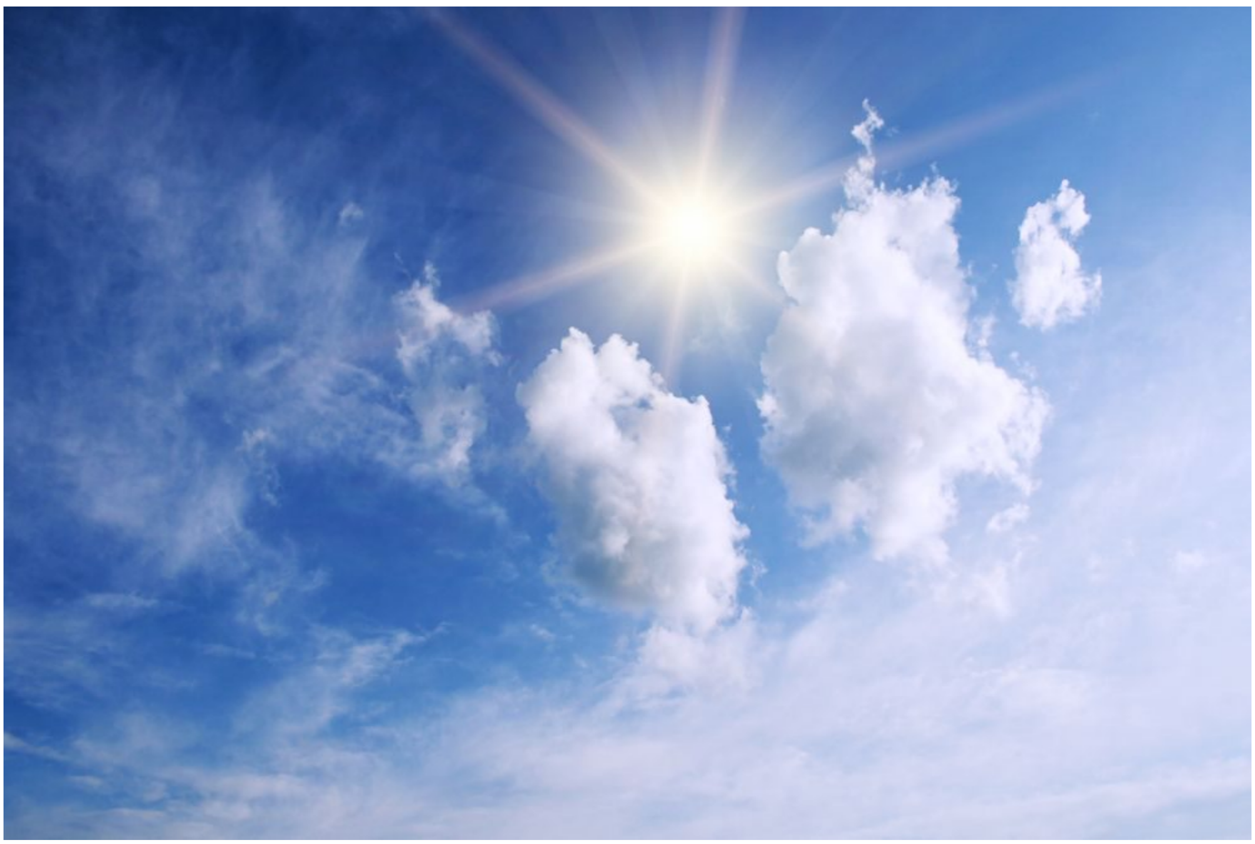

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3002017533

Technical Update, January 2020

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THE FOLLOWING ORGANIZATION, UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

Environmental Resources Management (ERM)

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ABSTRACT

As National Ambient Air Quality Standards (NAAQS) become more stringent, it is increasingly important to accurately characterize emissions from all sources of air pollution, including power generation facilities. The NAAQS for nitrogen oxides (NOx) can be the controlling standards for electrical generating units (EGUs). While the indicator for the NAAQS is specifically NO_2, most estimated and reported emissions from power generating facilities are for NOx, which include both NO_2 and nitric oxide (NO). The United States Environmental Protection Agency (U.S. EPA) has identified the AERMOD modeling system as the preferred model for demonstrating compliance with the 1-hour and annual NO_2 NAAQS in support of permit applications such as Prevention of Significant Deterioration (PSD) and other types of compliance demonstrations. Improper assumptions about the ratio of NO_2 to NOx in the stack (NO_2/NOx In-Stack Ratio or ISR) may cause AERMOD and other models which simulate the conversion of NOx to NO_2 to assess compliance with the 1-hour and annual NO_2 NAAQS to inaccurately overstate the contribution of power plant emissions to ambient NO2 concentrations. In the absence of site-specific data, the U.S. EPA currently requires the use of a default NO_2/NOx ISR of 0.5. More accurate information on the NO_2/NOx ISR will allow the models to better estimate the overall ambient NO_2 concentration, as well as the contribution that can be attributed to power plant emissions.

NO_2/NOx ISR data are important for modeling proposed NOx emissions from EGUs that need a new or modified permit, units subject of another type of compliance demonstration, and any collocated or nearby units that may need to be modeled explicitly in these applications. Improved NO_2/ NOx ISR data can also be used in photochemical models (e.g., SCICHEM, CMAQ and CAMx) to better characterize initial plume chemistry leading to the formation of ozone and secondary fine particulate matter ($PM_{2.5}$).

This project is designed to compile and analyze existing NO_2 and NOx emissions data from electric utilities for a variety of EGU types across the United States. The goal of the project is to generate a set of recommendations for NO_2/NOx ISRs that can be used in a variety of modeling exercises that will more accurately reflect actual ISRs than using the U.S. EPA default NO_2/NOx ISR of 0.5.

This report provides an update to the previous publicly-available report published in September 2019 (3002017300). The update incorporates the analysis of new data provided by EPRI members for a variety of new units and additional datasets from units previously included. The new units include 11 coal and 2 synthesis gas (or syngas, from coal gasification) boilers, 11 natural gas combined cycle turbines, 5 natural gas simple cycle turbines units (2 of which also fire fuel oil). Additional data was provided for 2 combined cycle units and 4 simple cycle combustion units that were included in the previous analysis. For most unit types the results provided in the previous analysis did not change significantly. The ISR average value for boilers changed negligibly from 0.020 to 0.019. For combined cycle units the value changed more substantially from 0.539 to 0.413. The additional combined cycle units analyzed were all in the range of 201-400 MW capacity. The average ISR value for natural gas simple cycle units changed from 0.229 to 0.227, while for fuel-oil units the value changed from 0.135 to 0.163.

The preliminary calculations of average NO_2/NO_x ISRs based on data that have been provided by EPRI member companies indicates that the U.S. EPA's default of 0.5 overstates actual monitored values for all generating unit types, fuels, and operating loads. The largest difference is for boilers. While the over estimation is not as large, use of the default ISR is also overstated for Reciprocating Internal Combustion Engines (RICE) and combustion turbines in simple cycle mode. The NO2/NOx ISRs calculated from the data sets for combined cycle turbines approaches the default ISR when averaged across all of the operating loads included in the study. However, the average ISR for combined cycle turbines when they are operated at greater than 90% load is 0.276.

This report presents a summary of the data sets that have been analyzed to date and recommendations for future work.

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PRIMARY AUDIENCE: Utilities with fossil fuel generation conducting modeling for compliance with the NO_2 National Ambient Air Quality Standards (NAAQS).

SECONDARY AUDIENCE: Stakeholders interested in using the data collected to gain insights for future air quality projections, planning, regulation and compliance.

KEY RESEARCH QUESTION

Fossil fuel electric generation units emit nitrogen oxides (NOx), which are comprised of nitrogen oxide (NO) and nitrogen dioxide (NO_2). The relevant National Ambient Air Quality Standards (NAAQS) are based on NO_2 concentrations. However, most of the NOx at the point of emissions from combustion sources is in the form of NO. Final NO_2 concentrations presenting downwind of sources result from the initial NO_2/NOx ratio of the emissions (i.e., the in-stack ratio or ISR), and chemical reactions in the atmosphere (i.e., the reaction of NO with ambient ozone to form NO_2).

EPA's Guideline on Air Quality Models (40 CFR Part 51, Appendix W) provides requirements and recommendations for modeling NO_2 impacts in accordance with the Prevention of Significant Deterioration (PSD) permit requirements to demonstrate compliance with the 1-hour and annual NO_2 standard. A three-tiered approach is used to estimate NO_2 from NOx values simulated using the AERMOD dispersion model. Of those, Tier 3 uses either the Ozone Limited Method (OLM) or Plume Volume Molar Ratio Method (PVMRM), which are detailed algorithms for determining NO_2 concentrations as a function of ozone in the domain. These methods require project specific information such as NO_2/NOx ISR and ambient ozone data at the facility of interest. In the absence of measurement data, a default in-stack NO_2/NOx ratio of 0.5 is used in these Tier 3 approaches. Use of this default ratio, as opposed to values more specific to the unit type and fuel relevant to the EGU of interest, has the potential to lead to inaccurate calculations of downwind NO_2 concentrations.

This project will contribute additional information on ISRs for potential use in regulatory modeling for different configurations of fossil fuel electricity generation units.

RESEARCH OVERVIEW

This report is an update to a previous published report (ID# 3002017300) that describes the compilation, summary and evaluation of NO_2/NO_x ISRs calculated from measurement data collected at a variety of fossil fuel units in the United States during real-world operations. The units were classified by primary mover, fuel type and unit rating or load, and included coal, oil and natural gas-fired boilers, reciprocating internal combustion engines (RICE), simple cycle turbines and combined cycle turbines. A comparison between unit configurations in this report and nationwide capacity configurations is also included. For this updated version of the report, additional data for boilers, natural gas and fuel-oil simple cycle turbines and natural gas combined cycle turbines were analyzed. The database of NO_2/NO_x ISRs collected in this study will provide electric utilities with aggregated data-based estimates which may be appropriate as inputs for optional air quality modeling runs or those required for compliance. In comparison, the currently available information in the EPA In-Stack Ratio Database is primarily on data collected from RICE. This project aims to provide information with which to improve model estimates of NO_2 downwind of combustion sources, which could result in improved estimates of EGU contributions to ambient ozone concentrations.

KEY FINDINGS

The key findings from this study included the following:

- The default EPA NO_2/NOx ISR of 0.5 for fossil fuel combustion EGUs may overstate actual monitored values for many generating unit types and fuels.
- The largest overstatement is for boilers.
- The default NO_2/NOx ISR is also larger than the values calculated in this analysis for RICE and simple cycle combustion turbines at all operating loads.
- Based on the data analyzed for combined cycle turbines, calculated ISR values from this project are similar to the default ISR when averaged across all of the operating loads included in the study. The average ISR for combined cycle turbines when they are operated at greater than 90% load is 0.276.
- Compared to countrywide coal and natural gas generating unit configurations, the database gathered for this project seems to be representative for coal generating units. However, more data could be gathered for natural gas simple cycle and combined cycle units for an updated analysis; such an analysis would benefit from more data for natural gas units of different configurations and operational conditions.

WHY THIS MATTERS

Use of the default ISR value recommended by EPA for regulatory modeling may overestimate EGU contributions to downwind pollution. Increased availability of data from representative fossil fuel EGUs will contribute to improved understanding of the range of NO_2/NOx ISRs at real-world operating power plants. It will be considered if the compiled database from this project could be used to update the EPA ISR Database (https://www3.epa.gov/scram001/no2_isr_database.htm). The goal is to reflect a range of values that is more representative of real facility operating conditions than currently exists.

HOW TO APPLY RESULTS

ISR values determined in this study may be appropriate for application to units with matching characteristics for dispersion air quality modeling. The values may also be used as inputs to other models that base their emissions estimates on a range of operating parameters.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- The information in this document, once reviewed by EPA and stakeholders, can provide valuable input to EPA's ISR database for use in air quality modeling. It will also provide guidance for future efforts, within the electric and other industries, to improve the characterization of NOx emissions.

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PROGRAM: PS203A: Air Pollutants and Toxics: Models and Assessments

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1 INTRODUCTION

The United States Environmental Protection Agency's (U.S. EPA's) Guideline on Air Quality Models (40 CFR Part 51, Appendix W) identifies the AERMOD modeling system as the preferred model for demonstrating compliance with the 1-hour and annual NO_2 NAAQS in support of permit applications such as Prevention of Significant Deterioration (PSD) and other types of compliance demonstrations. In the AERMOD modeling system, three options are available for the treatment of the conversion of oxides of nitrogen (NOx) emitted from the stack to nitrogen dioxide (NO_2) concentrations in the ambient air. The most conservative, Tier 1, assumes that all NOx emitted from the stack is NO_2 and hence there is no adjustment for the actual NO_2/NOx In-stack Ratio (ISR); the NOx concentrations calculated by the model are assumed to be equal to the ambient NO_2 impact. The second tier uses an Ambient Ratio Method (ARM2) that adjusts the calculated NOx concentration based on empirically derived upper limits determined from observed NO_2/NOx ambient ratios versus the ambient NOx concentration. However, ARM2 applies a floor to the ambient ratio of 0.5.

For cases where the Tier 2 approach in AERMOD does not demonstrate compliance, AERMOD provides two more sophisticated approaches known as Tier 3 options: Plume Volume Molar Ratio Method (PVMRM) and Ozone Limiting Method (OLM). Both PVMRM and OLM in AERMOD incorporate the ISR of NO_2 to NOx emissions on a source by source basis to simulate less conservative downwind concentrations of NO_2. The NO_2/NOx ISR is needed to accurately characterize the initial, in-stack condition for the Tier 3 NO conversion to NO_2 in ambient air. A more accurate NO_2/NOx ISR may also improve the simulation performance related to downwind concentrations of NO_2, ozone and fine particulate matter ($PM_{2.5}$) for photochemical models such as SCICHEM, CMAQ, and CAMx.

In the absence of a unit-specific NO_2/NOx ISR, the U.S. EPA requires the use of the default NO_2/NOx ISR of 0.5 for the primary source and any sources in the immediate vicinity of the primary source. This conservative value is likely to cause the model results to inaccurately reflect the primary source contributions to downwind NO_2 concentrations as well as the overall NO_2 concentration itself. Approval of alternative NO_2/NOx ISR values requires stack test data, a vendor guarantee for the source, or the use of an entry in the U.S. EPA's ISR database. Currently this database has entries only for limited unit configurations, dominated by values for reciprocating engines.

To assist utilities in determining the most applicable NO_2/NO_x ISR for their sources, this study collects and analyzes NO_2 and NO_X stack emissions data from a variety of sources across the United States. The NO_x, NO and/or NO_2 data provided have been used to calculate NO_2/NO_x ISRs for each data set. The results have been categorized by unit design (boiler, simple and combined cycle turbines, and reciprocating engines), fuel type, unit size, and unit load.

The calculated NO_2/NO_x ISRs may be used to support recommended alternative values for modeling other than a conservative default ISR value of 0.5.

Following the publication of the report ID # 3002017300 additional members submitted data to supplement the previous analysis, and some members who had submitted data for the first analysis submitted additional data for additional facilities. In particular, the number of combined cycle operations represented in the full analysis documented here is more than twice the number in the previous report (20 vs. 9). The number of facilities included in this analysis increased from 87 to 118 and the number of data sets increased from 127 to 200. This report documents the combined analysis of data collected in both phases.

2
CHARACTERIZATION OF RECEIVED DATA

Data were received on four different types of electric generating units (EGUs); boilers, combined cycle turbines, simple cycle turbines, and reciprocating internal combustion engines (RICE). Data from a total of 118 EGUs were considered in the analyses.

Table 2-1 presents a summary of the unit types represented in the data that have been included in this analysis.

Table 2-1
Electric Generating Unit Type by Owner

Owner ID	Boiler	Combined Cycle	Simple Cycle	RICE	Total
A	8	0	0	0	8
B	11	11	6	0	28
C	0	0	11	0	11
D	14	0	2	6	22
E	0	0	2	19	21
F	0	2	5	0	7
G	5	1	0	0	6
H		2	4	0	6
I	2	2	0	0	4
J	2	0	0	0	2
K	0	2	1	0	3
Total	42	20	31	25	118

Four fuel types were represented in the data: coal, synthesis gas (syngas), fuel oil, and natural gas. The oil can be further categorized into diesel, low sulfur fuel oil, and ultra-low sulfur fuel. Table 2-2 shows the distribution of fuel by type of EGU.

Table 2-2
Electric Generating Unit Type by Fuel

Fuel Type	Boiler	Combined Cycle	Simple Cycle	RICE	Total
Coal	28	0	0	0	28
Fuel Oil	14	0	5	25	44
Natural gas	0	18	26	0	44
Coal Syn Gas	0	2	0	0	2
Total	42	20	31	25	118

The data received on NO_2 and NOx stack emission measurements included both stack test data and data collected by Continuous Emission Monitoring Systems (CEMS). The data collected by CEMS can be further divided into hourly data and minute data. Data collected during a relative accuracy test audit (RATA) when the unit operating load is held steady during the testing were placed in the stack test category.

Table 2-3 presents the number of data sets that were received by the source type of each generating unit. Note that multiple data sets were submitted for some generating units so that the total number of data sets exceeds the unit count in Table 2-1.

Table 2-3
Number of Data Sets by Source and Type of Generating Unit

Unit Type	Stack Test	CEMS Hourly	CEMS Minute	Total
Boiler	83	1	4	88
RICE	44	0	0	44
Combined Cycle	16	4	3	23
Simple Cycle	22	14	9	45
Total	165	19	16	200

For this analysis, it was assumed that all data were equally valid, i.e., stack data and CEMS data were given equal weight in the subsequent averaging of the resultant NO_2/NOx ISRs. As discussed in more detail in Section 6 of this report, a detailed review of each of the data sets is recommended for future work to provide further quality checks and improve data reliability.

As noted earlier, some data are from stack tests which reported only one data point each for NO_2 and NOx, while the CEMS data provided a value for every hour or minute in the reporting period. Table 2-4 breaks down the data sets by the number of data points in each data set. As shown in the table, the largest number of data sets had only one data point.

Table 2-4
Number of Data Points in Data Set by Type of Generating Unit

Number of Data Points in Data Set	Boiler	Combined Cycle	Simple Cycle	RICE	Total
1	83	16	22	44	165
10-100	0	0	1	0	1
101-1,000	3	0	13	0	16
1,001-10,000	1	4	4	0	9
>10,000	1	3	5	0	9
Total	88	23	45	44	200

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DETERMINATION OF THE NO_2/NOx ISR

Average NO_2/NOx ISRs were calculated for each of the different types of EGU and fuel. Where possible, further subcategorization was made by the generating capacity of the unit and the operating load during the sampling. The ISRs associated with each data set were calculated separately and later averaged together with other calculated ISRs to generate average ISRs for each of the groupings described below.

3.1 Boilers

As noted in Table 2-3, most data for boilers came from stack tests; only five (5) CEMS data sets were submitted for boilers. The unit operating load when the data were being collected was not noted in most cases (69 of the 88) so all data was processed together without any differentiation by load since not all of the data sets contained load information. Table 3-1 presents the average ISR results for the boilers by size and by fuel as well as overall average ISRs for the Boiler category and the fuel and size subcategories.

Table 3-1
Average NO_2/NOx ISR for Boilers

Size (MW)	Fuel Oil			Coal			All Fuels		
	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets
1-200	0.012	14	16	0.029	5	25	0.022	19	41
201-400	NA	0	0	0.016	4	12	0.016	4	12
401-600	NA	0	0	0.009	3	9	0.009	3	9
601-800	NA	0	0	0.015	12	25	0.015	12	25
> 801	NA	0	0	0.013	4	4	0.013	4	4
All Sizes	0.012	14	16	0.019	28	75	0.018	42	91

One of the oil-fired boilers has low NOx burners whereas none of the other oil-fired boilers listed any emission controls. The unit with the low NOx burners had a much lower ISR than the others (0.005 vs. an average ISR of 0.012) but removing this unit from the average in the table did not change the average ISR for the group since there were so many data sets for oil fired boilers.

Emission controls were not listed for all coal-fired boilers. Of the units that listed controls, 15 listed Flue Gas Desulfurization (FGD). Nine of those with FGD also had SCR and the other two added Selective Non-Catalytic Reduction (SNCR) with FGD. Four additional units added Electrostatic Precipitation (ESP) to the SCR/FGD control system and one of those four listed additional control for mercury emissions. One unit combined an ESP with SNCR and both Dry Sorbent Injection and Powder Activated Carbon (PAC) for control of mercury emissions. Four units reported using low NOx burners; two using both a low NO_X burner and overfire air, one used SCR with the low NOx burner and one unit reported just low NOx burners.

Four coal-fired boilers are identified as supercritical boilers. Taken separately, the average NO_2/NOx ISR for supercritical boilers is 0.013. When these units are removed from the average for coal fired boilers in the table above, the average ISR for the other coal fired boilers remains 0.019 and the overall for all boilers remains 0.018.

The standard deviation of NO_2/NO_X ISR for each of the CEMS data sets was also calculated. Since the stack test results reported only one value, no standard deviation could be calculated for that data. To determine the standard deviation when categorizing data sets by unit size, the average of the variances was computed by taking the sum of the square of the standard deviation of each data set in the size category, and then the standard deviation for the size category was computed using the square root of the average variance. Table 3-2 summarizes the average and the standard deviations of the boiler ISRs by boiler size. Note that for data sets that have only a single reported ISR value (stack tests), no standard deviation was computed and therefore it won't be counted toward the average and the standard deviation in Table 3-2, making them different from the ones presented in Table 3-1. In particular, none of the data for the oil-fired boilers was included because they all came from stack tests.

Table 3-2
Average and Standard Deviation of NO_2/NOx ISR for Boilers Based on CEMS Data

Size (MW)	Coal			
	ISR Average	ISR Std	# Units	# Data Sets with StDev
1-201	NA	NA	0	0
201-400	0.009	0.009	2	2
401-600	0.003	0.012	1	1
601-800	0.048	0.011	1	1
> 801	0.002	0.005	1	1
All Sizes	0.011	0.010	5	5

3.2 Reciprocating Internal Combustion Engines

All data for the RICE units came from stack testing. The size of the units tested range from 1 to 12.5 MW, and they fire diesel or ultra-low sulfur diesel fuel. Since the range in size of the units was small and they all fire some type of diesel fuel, the ISRs are not categorized by size or fuel. All operating loads that were recorded are between 75 and 110%.

Table 3-3 presents a summary of the data by operating load and whether the unit was listed as employing an emissions control technique. All controlled units identified Fuel Injection Timing Retard (FITR) as the emission reduction method employed.

Table 3-3
Average NO_2/NOx ISR for RICE

Operating Load (%)	Controlled			Uncontrolled			All Units		
	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets
75-90%	0.106	2	4	0.091	2	2	0.101	4	6
90-100%	0.071	10	18	0.091	4	6	0.076	14	24
100-110%	0.086	6	12	0.088	1	2	0.086	7	14
Total	0.080	18	34	0.091	7	10	0.082	25	44

Since all data came from stack tests that reported only one value, no standard deviations of the ISR were calculated for RICE.

3.3 Combined Cycle Combustion Turbines

For the combined cycle units, all data were collected while the units were firing either natural gas or syngas. Emissions from most of the combined cycle units are controlled with SCR (13 of 20) and many reported also using an oxidation catalyst (8 of the 13). Data were collected both with stack testing and through CEMS. The CEMS data sets were fairly evenly divided between minute data (3 data sets) and hourly data (4 data sets). For the purpose of preparing average ISR data by load, when load data was not available, it was assumed that the data was collected when the unit was operating at greater than 90% load. Table 3-4 summarizes the average of the combined cycle units by operating load.

Table 3-4
Average NO_2/NOx ISR for Combined Cycle Units

Operating Load (%)	1-200 MW			201-550 MW			All Sizes		
	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets
50-75%	0.517	4	4	0.785	2	2	0.607	6	6
75-90%	0.637	6	6	0.610	2	2	0.630	8	8
90-100%	0.282	8	11	0.268	10	10	0.276	18	21
All Loads	0.428	10	13	0.391	10	10	0.413	20	23

Note that the average ISRs for the 90-100% operating loads are far less than for the other loads; the range of values in the average was also greater for this operating load than the others. The individual ISRs for the data sets ranged from 0.023 to 0.579. The difference in both the average and the ranges in the values for the 90-100% operating load versus the other loads could be related to the presence of duct firing at the higher operating loads. Most of the data sets did not provide information on whether and how much duct firing was occurring during the data collection period.

Similar to the data for the boilers, the standard deviation for the CEMS data were calculated but the stack test data was omitted because only one value was reported. Table 3-5 summarizes the average and the standard deviations of the ISRs calculated for the combined cycle units by operating load based on the CEMS data alone.

Table 3-5
Average and Standard Deviation of NO_2/NOx ISR for Combined Cycle Units Based on CEMS Data

Operating Load (%)	1-200 MW				201-550 MW				All Sizes			
	ISR Average	ISR Std	# Units	# Data Sets with StDev	ISR Average	ISR StDev	# Units	# Data Sets with StDev	ISR Average	ISR Std	# Units	# Data Sets with StDev
50-75%	0.517	0.109	4	4	0.785	0.074	2	2	0.607	0.099	6	6
75-90%	0.493	0.064	4	4	0.610	0.077	2	2	0.532	0.059	6	6
90-100%	0.480	0.061	4	4	0.305	0.095	3	3	0.405	0.078	7	7
All Loads	0.497	0.081	4	4	0.529	0.085	3	3	0.509	0.078	7	7

3.4 Simple Cycle Combustion Turbines

The data for simple cycle combustion turbines were collected via stack test and CEMS. Again, some CEMS data sets recorded minute data and other contained hourly data. In the calculation of the average ISR, all data were treated equally whether it came from stack test results or hourly or minute CEMS data. Most of the units were firing natural gas when the data were collected, but five were firing diesel fuel. Three diesel-fired units did not report using emission controls while the other two diesel fired units listed the use of water injection to control emissions. Eight gas fired units did not list any emission controls while all but one of the others listed either dry low NO_X (DLN) burner design or steam or water injection for emission control. Only one unit, a small (40 MW) natural gas fired turbine, reported having both an oxidation catalyst (OC) and SCR for emission control.

All diesel fired turbines are 52 MW or less except one large (200 MW) unit. Similarly, all except three natural gas fired turbines fall within the 110 to 210 MW range; the other three range in size from 40-54 MW. Two size categories were considered for each of the fuels. Tables 3-6 and 3-7 present the results of the ISR calculations for simple cycle turbines firing natural gas and diesel fuel, respectively.

Table 3-6
Average NO_2/NOx ISR for Natural Gas Fired Simple Cycle Units by Size and Operating Load

Operating Load (%)	40-54 MW			110~210 MW			All Sizes		
	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets
50-75%	NA	0	0	0.261	18	19	0.263	18	19
75-90%	0.245	2	2	0.231	20	21	0.236	22	23
90-100%	0.081	1	1	0.197	19	24	0.181	20	25
100-110%	0.079	1	1	NA	0	0	0.152	1	1
All Loads	0.163	3	3	0.227	26	31	0.215	29	34

Table 3-7
Average NO_2/NOx ISR for Diesel Fired Simple Cycle Units by Size and Operating Load

Operating Load (%)	<52 MW			200 MW			All Sizes		
	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets	ISR Average	# Units	# Data Sets
50-75%	NA	0	0	0.298	1	1	0.298	1	1
75-90%	NA	0	0	0.331	1	1	0.331	1	1
90-100%	0.030	2	2	NA	0	0	0.030	2	2
100-110%	0.161	2	8	NA	0	0	0.161	2	8
All Loads	0.135	4	10	0.315	2	2	0.165	6	12

Similar to the combined cycle units, the average ISR for the 90-100% operating loads was much less than for the other loads; however, in the case of the diesel units of less than 52 MW the two individual ISRs for the 90-100% operating load were very similar (0.033 and 0.028).

As with the other types of units that had data from both CEMS and stack tests, the standard deviation for the CEMS data were calculated but the stack test data were omitted because only one value was reported. All data for the smaller oil-fired units came from stack tests; data for the larger unit came from a short minute data set. Twelve data sets for the natural gas fired simple cycle turbines were from stack testing, with the remainder from hourly and minute data. Tables 3-8 and 3-9 summarize the average and standard deviations of the simple cycle units by operating load for natural gas and diesel fired units, respectively.

Table 3-8
Average and Standard Deviation of NO_2/NOx ISR for Natural Gas Fired Simple Cycle Units by Operating Load Based on CEMS Data

Operating Load (%)	40-54 MW				110-210 MW				All Sizes			
	ISR Average	ISR Std	# Units	# Data Sets with StDev	ISR Average	ISR Std	# Units	# Data Sets with StDev	ISR Averag e	ISR Std	# Units	# Data Sets with StDev
50-75%	NA	NA	0	0	0.280	0.117	16	17	0.280	0.117	16	17
75-90%	NA	NA	0	0	0.197	0.067	16	17	0.197	0.067	16	17
90-100%	0.081	0.012	1	1	0.181	0.041	15	20	0.177	0.040	16	21
100-110%	0.079	0.012	1	1	NA	NA	0	0	0.079	0.012	1	1
All Loads	0.080	0.012	1	1	0.217	0.080	16	21	0.212	0.078	17	22

Both hourly and minute data were submitted for several units for the same time periods. A comparison of the calculated NO_2/NOx ISR using the hourly and the minute data is presented in Table 3-10. Standard deviations could be calculated since each of data sets have multiple entries, so Table 3-10 also reports the propagated standard deviations.

Table 3-9
Average and Standard Deviation of NO_2/NO_x ISR for Diesel Fired Simple Cycle Units by Operating Load Based on CEMS Data

Operating Load (%)	200 MW			
	ISR Average	ISR StDev	# Units	# Data Sets with StDev
50-75%	0.298	0.021	1	1
75-90%	0.331	0.019	1	1
90-100%	NA	NA	0	0
100-110%	NA	NA	0	0
All Loads	0.315	0.020	1	1

Table 3-10
Comparison of NO_2/NO_x ISR for Minute and Hourly Data

Unit ID	Minute Data		Hourly Data	
	ISR Average	ISR Std	ISR Average	ISR Std
CT1	0.232	0.039	0.231	0.033
CT2	0.191	0.016	0.190	0.006
CT3	0.142	0.046	0.141	0.018
CT4	0.245	0.072	0.245	0.056
CT5	0.261	0.125	0.286	0.106

As shown in Table 3-10, the calculated ISR is very similar between the two different types of data sets for the first four units. These data had flags to identify periods of startup and shut down, which were used to exclude those periods from the ISR calculations. The data remaining after the flagged periods were excluded were for loads of 90% or greater. Since the CT5 data did not have periods of startup and shutdown flagged, the information on the load was used to select periods when both the hourly and minute data indicated that the unit was operating at a load of 90% or greater. The greater discrepancy between the minute and the hourly data may be due to the less precise method of identifying periods of startup and shutdown.

To avoid double counting, where both hourly and minute data were provided for the same period for the same unit, only the hourly data were considered in the analysis except for in the comparison shown in Table 3-10.

4

COMPARISON WITH COUNTRYWIDE CONFIGURATIONS

To test the representativeness of this project's ISR database, the unit configurations were compared to U.S. countrywide configurations for coal and natural gas units using data from the 2017 Energy Power Velocity Power Database (EPV)[1]. The EPV database gathers electricity generators data from the Energy Information Administration (EIA) and independent system operators. Net generation data was obtained from the generation table of the 2016 Emissions & Generation Resource Integrated Database (eGRID) from the U.S. EPA[2]. The eGRID database compiles data from the EIA and the EPA Clean Air Markets Database (CAMD). The objective is to capture up-to-date and complete information on the generation mix by fuel and prime mover type for the US power generation fleet as well as total generation to illustrate the level of representativeness of the project database.

The EPV database for coal and natural gas units contains 804 operating coal units and 4884 natural gas units. The generation table of the eGRID database contains 695 operating coal units and 5669 natural gas units. As shown in Tables 4-1 and 4-2, about 48% of the coal generating units in the EPV database have a rated capacity between 1-200 MW and 44% between 201-800 MW. On the other hand, about 87% of the natural gas units rated capacity is between 1-200 MW and 11% between 200-800 MW. The eGRID database presents a similar distribution for coal and natural gas units. Both databases show that natural gas units are typically of relatively small capacity. Coal generating units are slightly more evenly distributed by capacity, though nearly half are in the smallest capacity bin.

In terms of total generation, the eGRID database shows the largest generation fraction for the coal units between 601-800 MW (31%) followed by the units between 401-600 MW (26%) and the units of more than 800 MW (24%). This indicates that while more than 50% of the units are less than 400 MW, most of the generation is really produced by units greater than 400 MW. For the natural gas units, the eGRID database indicates that most of the generation is produced by the smaller size units, especially those between 1-200 MW.

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[1] 2017 Energy Velocity Power Database, ABB, https://search-ext.abb.com/library/Download.aspx?DocumentID=9AKK106930A8237&LanguageCode=en&DocumentPartId=A4-web&Action=Launch

[2] US EPA, The Emissions and Generation Resource Integrated Database (eGRID 2016), Office of Atmospheric Programs, Clean Air Markets Division, https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid

Table 4-1
Coal Generating Unit Distribution by Rated Capacity

Capacity (MW)	EPV Total	EPV (%)	eGRID Total	eGRID (%)	eGRID Total Generation (MW)	eGRID % Total Generation	Project Total	Project (%)
1 - 200	382	47.5	314	45.2	64,795,505	6.4	5	17.9
201 – 400	122	15.2	116	16.7	130,527,805	13.0	4	14.3
401 - 600	118	14.7	110	15.8	257,540,029	25.6	3	10.7
601 - 800	109	13.6	99	14.3	315,640,364	31.3	12	42.9
>800	73	9.1	56	8.1	238,869,452	23.7	4	14.3

Table 4-2
Natural Gas Generating Units by Rated Capacity

Capacity (MW)	EPV Total	EPV (%)	eGRID Total	eGRID (%)	eGRID Total Generation (MW)	eGRID % Total Generation	Project Total	Project (%)
1 - 200	4246	86.9	5088	89.8	818,437,554	60.2	36	81.8
201 – 400	246	5.0	488	8.6	449,310,905	33.0	6	13.6
401 - 600	163	3.3	71	1.3	72,469,446	5.3	2	4.6
601 - 800	150	3.1	14	0.3	8,277,350	0.6	0	0
>800	79	1.6	8	0.1	11,662,343	0.9	0	0

The project database contains 28 coal units and 44 natural gas units. About 43% of the coal units are larger units between 601-800 MW, followed by 18% units between 1-200 MW and 14% between 201-400 MW. Note the rated capacity distribution for coal units in the project database does not closely match that of the EPV and eGRID databases. However, the project database appears to offer a good representation of the coal units that produce more than 50% of the total generation, according to eGRID. About 82% of the project database natural gas units rated capacity is between 1-200 MW, 14% between 201-400 MW and 4% between 401-600 MW. The ISR database also offers a good representation of the natural gas units that produce more than 90% of the total generation, when compared to the eGRID database.

Most coal generating units (87.5%) in the project coal database are steam turbines. The database also contains data for 2 Integrated Gasification Combined Cycle units (IGCC), for which the syngas combusted for energy generation is obtained from coal gasification. Consequently, the ratio of steam turbines in the project database is lower than the ratio of 95.8% in the EPV coal generation and 99.1% in the eGRID databases (Table 4-3). The EPV and eGRID databases have data for 1 and 4 IGCC units, respectively. Overall, the project database is representative of the most common type of prime mover (steam turbines) for coal generation.

Table 4-3
Coal Generating Unit Distribution by Prime Mover

Prime Mover	EPV Total	EPV (%)	eGRID Total	eGRID (%)	eGRID Total Generation (MW)	eGRID % Total Generation	Project Total	Project (%)
Atmospheric Fluidized Bed	33	4.1	0	0	0	0	0	0
Steam Turbine	770	95.8	694	99.1	1,007,373,155	99.6	28	93.3
Integrated Gasification Combined Cycle	1	0.1	4	0.6	3,828,019	0.4	2	6.7

The project database contains data for simple cycle combustion turbines (59%) and combined cycle natural gas units (41%). In the EPV database about 48% of the units are combustion turbines, 14% combined cycle units, 25% internal combustion engines and 10% steam turbines. The eGRID database presents a similar distribution (though combined cycle units are more prevalent than internal combustion engines) with 39% combustion turbines, 32% combined cycle units, 18% internal combustion engines and 10% steam turbines. Most of the generation, about 82%, is produced by the combined cycle units, followed by combustion turbines (9%), and steam turbines (6%). Considering these distributions, we may conclude that the project database is more representative of the US fleet configuration than the U.S. EPA NO_2/NO_x ISR database. About 99% of the records from the U.S. EPA ISR database are from internal combustion engines.

Table 4-4
Natural Gas Generating Unit Distribution by Prime Mover

Prime Mover	EPV Total	EPV (%)	eGRID Total	eGRID (%)	eGRID Total Generation	eGRID % Total Generation	Project Total	Project (%)
Combined Cycle Turbine	669	13.7	1,798	31.7	1,109,269,827	81.2	18	40.9
Combined Cycle Single Shaft Turbine	56	1.2	54	1.0	405,631,25	3.0	0	0
Combustion Gas Turbine	2345	48.0	2,191	38.7	120,677,613	8.9	26	59.1
Compressed Air Storage	1	0.02	1	0.02	NA	NA	0	0
Fluidized Bed	3	0.06	0	0	0	0	0	0
Fuel Cell	119	2.4	66	1.2	711,512	0.1	0	0
Internal Combustion Engine	1225	25.1	1,016	17.9	3,597,911	0.3	0	0
Steam Turbine	466	9.5	543	9.6	85,345,656	6.3	0	0

The project, EPV and eGRID databases could also be compared for the type of NO_x emissions controls present. However, the associated generation data could not be obtained from eGRID due to use of different codes for generator ID and unit ID that do not always match.

For the EPV database, about 30% of the coal generating units have NO_x combustion controls (i.e. low NO_x burners, low NO_x cell burner, low NO_x burner technology with separated OFA, low NO_x burner technology with close-coupled separated OFA), 7% post-combustion NO_x controls (i.e. selective catalytic reduction, selective non-catalytic reduction and ammonia injection), 38% a combination of combustion and post-combustion NO_x controls, and 25.4% no reported controls. About 36% of the units in the project database have NO_x combustion controls, close to the EPV database, and 64% have post-combustion controls. None of the reported coal units have a combination of combustion and post-combustion controls or no reported controls (Table 4-5).

About 21% of the coal units in the EPV database were matched by emission controls with the project database units. In the project database, about 11% of the coal units have low NO_x burners and 11% low NO_x cell burners, compared to 55% and 1%, respectively, of the matching units in the EPV database. Also 7% had low NO_x burner technology with separated OFA and 7% a combination of low NO_x burners and overfire air, compared to 16% and 7%, respectively, of the matching units in the EPV database. Finally, 54% had selective catalytic reduction and 11% selective non-catalytic reduction, compared to 17% and 4%, respectively, of the matching units in the EPV database (Table 4-6).

Table 4-5
Coal Generating Unit Distribution by NO_x Emissions Controls

Emissions Controls	EPV Total	EPV (%)	Project Total	Project (%)
Combustion	239	29.7	10	35.7
Post-Combustion	54	6.7	18	64.2
Combustion and Post-Combustion	307	38.2	0	0
No Controls	204	25.4	0	0

Table 4-6
Coal Generating Unit Distribution by Matching NO_x Emissions Controls with the ISR database

Emissions Controls	EPV Total	EPV (%)	Project Total	Project (%)
Low NO_x Burners	92	55.1	3	10.7
Low NO_x Cell Burner	2	1.2	3	10.7
Low NO_x Cell Burner Technology with Separated Overtire Air	27	16.2	2	7.1
Low NO_x Burners and Overfire Air	12	7.2	2	7.1
Selective Catalytic Reduction	28	16.7	15	53.6
Selective Non-Catalytic Reduction	6	3.6	3	10.7

Nearly 42% of the natural gas simple cycle combustion turbines in the EPV database have combustion controls (i.e. low NO_x burners, water injection and steam injection), 3% have post-combustion controls (i.e. selective catalytic reduction and oxidation catalyst), 11% have a combination of combustion and post-combustion controls and 44% have no reported emissions controls. Natural gas combustion turbines in the project database have either combustion controls (low NO_x burners, water injection or steam injection) and no reported controls (or the controls were not operating while the NO_x measurements were taken, so the units were considered in the project database as not controlled) (Table 4-7). The major differences between the EPV and project databases are twofold: (1) about 50% of the project units have low NO_x burners, compared to 24% in the EPV database; and (2) 19% of the project units have no controls, compared to 45% in the EPV database (Table 4-7 and Table 4-8).

For the natural gas combined cycle units, close to 19% of units in the EPV database have combustion controls (i.e. low NO_x burners, water injection or steam injection), 1% post-combustion controls (i.e. selective catalytic reduction and/or oxidation catalyst), 56% a combination of combustion and post-combustion controls and 18% no reported controls (Table 4-7). About 62.5% of the units in the project database have a combination of combustion and post-combustion controls (i.e. selective catalytic reduction and oxidation catalyst, selective catalytic reduction and low NO_x burners or selective catalytic reduction, low NO_x burners and oxidation catalyst), a 31.3% no reported controls and a 6.3% combustion controls (i.e. selective catalytic reduction (Table 4-7 and Table 4-8).

Table 4-7
Natural Gas Generating Unit Distribution by NO_x Emissions Controls

Emissions Controls	EPV Total	EPV (%)	Project Total	Project (%)
Simple Cycle Combustion Turbines				
Combustion	981	41.8	21	80.8
Post-Combustion	74	3.2	0	0
Combustion and Post-Combustion	250	10.7	0	0
No Controls	1045	44.6	5	19.9
Combined Cycle Turbines				
Combustion	125	18.7	1	6.3
Post-Combustion	49	7.3	0	0
Combustion and Post-Combustion	377	56.4	10	62.5
No Controls	118	17.6	5	31.3

Table 4-8
Natural Gas Generating Unit Distribution by Matching NO_x Emissions Controls with the ISR Database

Emissions Controls	EPV Total	EPV (%)	Project Total	Project (%)
Simple Cycle Combustion Turbines				
Dry Low NO_x Burners	564	24.9	13	50.0
Dry Low NO_x Burners and Water Injection	242	10.7	2	7.7
Water Injection	409	18.1	4	15.4
Steam Injection	5	0.2	2	7.7
No Controls	1045	46.1	5	19.2
Combined Cycle Turbines				
Selective Catalytic Reduction	48	10.1	1	5.6
Selective Catalytic Reduction and Oxidation Catalyst	1	0.2	6	33.3
Selective Catalytic Reduction and Dry Low NO_x Burners	290	60.9	2	11.1
Selective Catalytic Reduction, Dry Low NO_x Burners and Oxidation Catalyst	19	4.0	2	11.1
No Controls	118	24.8	5	27.8

From these tables we can appreciate that, while the project database constitutes a small sample of units, it generally reflects the relative amount of generation provided by coal and gas-fired units present in the U.S. electricity generation fleet. The project database also has some notable contributions, such as ISRs calculated for several IGCC units.

Coal generating units are, in general, well represented in unit count, prime movers, capacity and NO_x emissions controls than natural gas generating units. To more closely reflect the proportions in the U.S. fleet (as portrayed by the EPV and eGRID databases), future data gathering efforts should target coal generating units with no NO_x controls and lower capacity ratings.

Data for more natural gas units would be required to more closely match the ratio of coal to natural gas units in the EPV database. It should also focus on natural gas combined cycle, steam turbines and internal combustion engine sources, including units with no NO_x emissions controls.

5
SUMMARY OF FINDINGS

The results based on the calculation of the ISR from the submitted stack test and CEMS data reveal that the U.S. EPA default of 0.5 overstates the actual monitored values for all generating unit types and fuels. The largest over estimate is for boilers where the average ISR for all sizes and fuel types is 0.018. When compared with the ISR for the oil-fired boiler with low NO_x burners, the difference is even greater; 0.005 vs. 0.5. Use of the default NO_2/NO_x ISR also overestimates the ISR for RICE and combustion turbines in simple cycle use at all operating loads. The calculated ISRs based on the data provided for combustion turbines in combined cycle use are similar to U.S. EPA's default value but still less than the default value, with a value of 0.413 when averaged over all operating loads. The average ISR for combined cycle turbines when they are operated at greater than 90% load is 0.276.

As noted earlier, the U.S. EPA NO_2/NOx ISR database already has many data points that support lower NO_2/NOx ISRs for RICE; of the 2,326 entries in the U.S. EPA ISR database[3], 2,299 are for RICE. A review of the data shows that 95.2% of entries in the U.S. EPA database have an ISR below 0.5 and 76.9% have an ISR below 0.2. The data presented in this analysis for RICE are similar to many entries in the current U.S. EPA ISR database.

There are only eleven entries for turbines in the U.S. EPA ISR database and they are all for small turbines (less than 100 MW). The five turbines in the U.S. EPA ISR database that are used for power generation are fired with fuel oil and kerosene. There are only 14 entries for boilers in the US EPA ISR database, all are located in Alaska. The two boilers in the U.S. EPA ISR database that are used for electricity generation are coal fired while the other, much smaller boilers (<30mmBTU/hr) are fired with a mixture of fish oil and diesel. This means that the current U.S. EPA ISR database does not contain information for turbines or boilers that is representative of the type of units that are included in this study.

[3] Downloaded November 8, 2018 from the EPA website (https://www3.epa.gov/scram001/no2_isr_database.htm)

6
RECOMMENDATIONS FOR FURTHER STUDY

The results of this study indicate that the calculated NO_2/NO_x ISRs for all types of units that were included in the study are less than the default NO_2/NO_x ISR required by U.S. EPA for modelling input. While the ISRs for combined cycle turbines included in this analysis are the most similar to the default value, it should be noted that this type of generating unit had fewer data sets than any other group in the study. Additionally, not all combined cycle data sets provided information on the presence of duct firing during data collection. The effect of duct firing on the ISR can be analysed in future work if information on the presence and amount of duct firing is included in the data sets.

Analysis of additional data, including data for units with different types of emissions control equipment (combustion and post-combustion controls) may also provide more clarity on the effect that different control types and configurations have on the resultant ISRs. While this report only includes data collected after the emissions control equipment, a wider suite of data was originally obtained from the utilities which included data measured before the emissions controls. Data are often collected before the emission control equipment for the purpose of providing process information to emissions and other operating control systems. However, for the purpose of determining the ISRs to be used in dispersion modeling any additional data collected should be after the controls as passing through the control device can change the ratio of NO_2 to NO_x for some types of controls and the effect is unknown for others.

Additionally, since both boilers and turbines are underrepresented in the U.S. EPA NO_2/NO_x ISR database, and the preliminary analysis indicates that the default NO_2/NO_x ISR overpredicts the ratio of NO_2 to NOx in the stack for boilers and turbines operating in simple cycle, additional data sets for boilers and turbines operating in simple cycle mode should also be pursued.

When acquiring additional data sets and additional support information for the data already provided, all information that is required for submittal to the U.S. EPA NO_2/NO_x ISR database should be included. The instructions for preparing a submittal to the U.S. EPA, as well as the format of the data entry, are included in Appendix A.

Additional information regarding the QA/QC processes applied to the data is also needed. For example, it is important to know which regulatory program the data was collected under (Part 75, Part 60, state permit only, or only for engineering purposes) and if the data has been post-processed for submission to those programs. If available, additional QA/QC support data should be provided, including RATAs, calibrations, and linearity checks. This will further facilitate a quality assurance review of the data sets and support eventual submittal to the US EPA NO_2/NO_x ISR database.

A

NO_2/NO_x ISR DATABASE SUBMITTAL INSTRUCTIONS

21 December 2018

Data entry and submission

Data should be submitted by emailing a completed template to Chris Owen (owen.chris@epa.gov). The template may be renamed to suit the filer's purpose and as many templates may be sent as necessary. However, DO NOT SEND ZIP files. All emailed files are automatically scanned by the EPA email server and .zip files are automatically deleted from incoming emails and will not be seen by the recipient.

There is a wide range of sampling scenarios that may occur (e.g., continuous monitoring, stack tests, etc.) that may result in dozens of tests for each emission unit per year. We request that each test be included as an individual entry into the database to maximize the statistical significance of the ISRs for each source type. For example, a facility may be required to perform monthly testing. At each monthly test, 3 30-min samples may be taken, resulting in 36 ISRs collected per year. Ideally, all 36 test results would be included in a submission of the ISR data.

The ISR template has 41 entry fields, 31 of which are marked as "required" and are identified with a **red** background while fields that are considered optional are identified with a **blue** background. Data that is submitted that does not include all required information will not be added to the posted database. Since the data submitted to the database does not undergo any review or QA/QC vetting by OAQPS, the required fields include sufficient information to identify the original submitter and specific tests reports, in case the appropriate reviewing authority requires additional vetting of supplied NO_2/NO_x ISRs.

Please note the following required fields are "either/or" and are indicated with an asterisk (*) in the list:

- **Source classification code** OR **Equipment class** & **Equipment description** may be submitted for a complete record. However, both are preferred if possible.
- **Contact name** OR **Contact number** may be submitted for a complete record. However, both are preferred if possible.
- NO, NO2, and NOx – two of these fields are required to compute the ISR. If a field is unknown, please leave blank (do not enter zero).

Guidance on each data field is given in the table below:

Site and facility information	Site Name	This should be where the stack and equipment are located, not company headquarters, etc.
	Facility ID	As used by the relevant permitting agency. If a facility ID has not been determined yet, please mark as "TBD"
	State (facility)	Please select from the drop-down list. This should be where the stack and equipment are located, not company headquarters, etc.
	County (facility)	Please select from the drop-down list. This should be where the stack and equipment are located, not company headquarters, etc.
	State-County FIPs code	This field will auto-populate based on the previous responses.
	EPA Region	This field will auto-populate based on the previous responses.
	Facility Description	This should provide a brief description of the overall purpose of the facility.
	Permitting Agency	Identify the appropriate reviewing authority, e.g., EPA Regional Office, State or Local agency.

	Permit Number	If a permit has already been issued, the permit number should be provided here.
Emission unit information	Source classification code*	If unknown, the "Equipment class" and "Equipment description" fields may be used for a complete record.
	Equipment class*	If unknown, the SCC field may be used for a complete record. A drop-down list is provided to help guide selection. An "other" category is included and additional details should be given in the comments.
	Equipment description*	If unknown, SCC field may be used for a complete record.
	Fuel Type	A drop-down list is provided to help guide selection. An "other" category is included and additional details should be given in the comments.
	Equipment manufacturer & model	
	Equipment manufacture date	
	Emission Unit Number	This is typically defined in the permit.
	Equipment capacity	As rated by the manufacturer. Output units should also be specified.
	Control Equipment 1	Emissions controls. A drop-down list is provided to help guide selection. An "other" category is included and additional details should be given in the comments.
	Control Equipment 2	Emissions controls. A drop-down list is provided to help guide selection. An "other" category is included and additional details should be given in the comments.
Testing and sampling information	Testing company	Company who operates the testing equipment.
	Testing method	A drop-down list is provided to help guide selection. An "other" category is included and additional details should be given in the comments. Method 7E is by far the most common.
	Analyzer make/model	
	Analyzer equip type	A drop-down list is provided to help guide selection.
	NO2 line loss corrected?	Some groups have reported that significant losses of NO2 (and thus total NOx) in the sample line, either due to dirty sample lines or condensation formed in the line when ambient temperatures are significant lower than the sample gas. Testing methods allow for calibration gases to be added at the inlet (which would test for line loss) or at the instrument (no test for line loss). When line loss is tested, the NO2 levels can be corrected to account for this loss.
	Test date	Please use a MM/DD/YYYY format.
	Load (% of capacity)	If unknown, please enter zero (0).
	Operating temp (F)	Temperature of the sample gas.
	Operation mode	A drop-down list is provided to help guide selection. An "other" category is included and additional details should be given in the comments.
	Flow rate	Flow rate of the sample gas.
	Flow Rate Units	Units for the sample gas flow rate.
	Test duration	Length of gas sampling.
	Test type	A drop-down list is provided to help guide selection. An "other" category is included and additional details should be

		given in the comments.
	Output units	Output units for NO, NO2 and NOx values.
	Avg. NO2*	It is anticipated that most instruments will report the average over the test duration. If something other than average is given, please provide details in the comments section. Only two of these values are required, but if all three are available, please provide all values.
	Avg NO*	
	Avg NOx*	
	% O2	From the sample gas. This is typically reported by the multi-gas meters used in gas sampling.
	Ratio	The ISR is computed automatically from the given NOx data.
Additional information	Reporting entity	This should be the company, department, or agency who is submitting the ISR data to OAQPS.
	Contact name	This does not have to be the name of the individual submitting the data, but should be someone who can provide details about the submitted ISR data in the event the data needs to be reviewed further.
	Contact number*	
	Contact email*	
	Completeness check	This will automatically indicate if all of the required fields have been completed. It should account for partial completion of the “either/or” fields.
	Comments	The comments field should be used anytime an “Other” option is selected from a drop-down list. Any additional unique information about the testing scenario can also be given here.

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