FROM: HQ AFCESA/CES
139 Barnes Drive
Tyndall AFB FL 32403-5319

SUBJECT: **Engineering Technical Letter (ETL) 98-2: Clean Air Act Amendments Requirements for Electric Generators and Power Plants**

1. Purpose. This ETL provides guidance to help the Base Civil Engineer (BCE) comply with the Clean Air Act Amendments (CAAA) for electric generators and power plants.

NOTE

Information included in the attached Technical Guidance Document is not intended to duplicate or supersede Federal, state, and local standards for environmental compliance. Users must comply with Federal, state, and local standards in accordance with applicable Air Force Policy Directives and Instructions.

2. Application: All United States Air Force (Air Force) installations with responsibility for new and existing generators and power plants.

2.1. Authority. This ETL is consistent with AFI 32-1062, *Electrical Power Plants and Generators*, and AFI 32-7040, *Air Quality Compliance.*

2.2. Effective Date: Immediately.

2.3. Expiration: Expires five years from date of issue.

2.4. Ultimate Recipients: Base Civil Engineers (BCEs) and others responsible for environmental compliance at Air Force installations.

3. Referenced Publication: 42 U.S. Code 401 through 7642, as amended, *Clean Air Act*.

4. Specific Requirements. The technical guidance provided in Attachment 1 should be used by the BCE to evaluate proposed projects involving electric generators and power plants to ensure compliance with CAAA requirements.

5. Point of Contact: Mr. Raymond N. Hansen, P.E., HQ AFCESA/CESE, DSN 523-6317, commercial (850) 283-6317, or INTERNET hansenr@afcesa.af.mil.

Patrick C. Daugherty, P.E.
Director of Technical Support

2 Atch
1. Technical Guidance Document
2. Distribution List

TECHNICAL GUIDANCE DOCUMENT

CLEAN AIR ACT AMENDMENTS REQUIREMENTS FOR GENERATORS AND POWER PLANTS

Contents

Paragraph		Page

Illustrations

Page

Tables

Page

A1.1. Introduction.

A1.1.1. Background. In response to the requirements of the Clean Air Act Amendments (CAAA) of 1990, the Air Force has developed specific policies and goals for air-quality control and pollution prevention at its installations, including the permitting and control of air emissions from generators and power plants. Large power production requirements are directly responsible for a significant portion of the pollutant emissions generated by Air Force installations. Generators and power plants are common sources of air pollution on Air Force bases as they supply base load electrical power, provide emergency standby electrical power, or meet peaking requirements. This technical guidance addresses the implementation of CAAA requirements for new and existing generators and power plants at Air Force installations.

A1.1.2. Purpose.

A1.1.2.1. Objectives. This technical guidance provides information essential to achieving and maintaining compliance with Federal, state, and local air quality standards applicable to generators and power plants. The document reviews and summarizes applicable Federal, state, and Air Force requirements; provides decision making criteria that will enable the Base Civil Engineer (BCE) to review proposed projects from an air quality perspective; and suggests methods to achieve compliance with requirements. This guidance is not intended to duplicate Federal, state, and local standards. Use of this information does not relieve the user from compliance with Federal, state, and local standards as required by Air Force Directives and Instructions. In cases of uncertain guidance or of conflict with Federal, state, or local standards, comply with Air Force policy and instructions.

A1.1.2.2. Impact. To evaluate adequately the impact of CAAA requirements for new construction or repairs to generators and power plants, the Air Force BCE needs information about the technological and procedural regulatory requirements of Federal, state, and local agencies; decision making criteria; and other guidance. This technical guidance will help BCEs use their electrical generating equipment to provide unhampered mission support while maintaining Air Force compliance with environmental agency requirements.

A1.1.3. Scope. This technical guidance is divided into seven major sections, including this introduction. Other sections include:

- Section A1.2 - Describes the typical generators and power plants used at Air Force installations.
- Section A1.3 - Identifies air pollutants commonly emitted from generators and power plants and methodologies for estimating actual and potential emissions.
- Section A1.4 - Reviews applicable Federal regulations and requirements, including Prevention of Significant Deterioration (PSD); New Source Review (NSR); New Source Performance Standards (NSPS); hazardous air pollutants (HAPs); acidic deposition control; and Title V operating permits. Addresses specific state and Air Force requirements.
- Section A1.5 - Discusses available emission control technologies for both external and internal combustion sources.

- Section A1.6 - Provides guidance for achieving and maintaining regulatory compliance. Outlines the steps required to obtain air quality permits. Identifies procedural requirements for record keeping, monitoring, and reporting. Suggests methods to comply with permitting, control, and monitoring requirements and presents proactive recommendations to avoid noncompliance. These recommendations can be used to develop implementation plans for compliance with CAAA requirements.
- Section A1.7 - Provides a glossary of terms used in this document and lists commonly used acronyms and abbreviations, air quality attainment status of Air Force installations, and Federal and state regulatory agencies.

A1.2. Typical Generators and Power Plants.

A1.2.1. Overview.

A1.2.1.1. Prime Movers. Electricity can be generated by coupling an electrical generator to a "prime mover". Air Force installations employ two main categories of prime movers to drive electrical generators: (1) external combustion units (fossil-fuel-fired steam generators, often referred to as boilers, and (2) internal combustion (IC) units (gas turbines and reciprocating engines). The combined prime mover-electrical generators will be referred to in this document as generators, generator units, or power plants. Most generator units used by the Air Force are IC reciprocating engines; however, a few installations use steam generators and gas turbines. Generators and power plants vary in size and can burn a variety of fuels, including natural gas, propane, fuel oil, diesel, JP-4, JP-8, gasoline, and, in limited cases, coal. Choice of fuel depends on the type of unit and the availability of the fuel. Natural gas, gasoline, and distillate-type fuels are used at most installations. The air quality implications of combustion of each of the fuel types are discussed in paragraph A1.3.

A1.2.1.2. Generators. Electrical generating units are either stationary or portable. Typical portable generators have power ratings of 200 kilowatts (kW) [150 horsepower (hp)] or less. A generator may operate continuously or intermittently depending on its application. Generators used for peaking and backup power supply usually are operated about 2 hours each month to comply with equipment warranty and maintenance requirements.

A1.2.2. External Combustion Units.

A1.2.2.1. Classification. External combustion units are classified by type of fuel. These units are fuel-fired, indirect heat exchangers (boilers) that produce steam. The steam drives turbines that generate mechanical power, and, when subsequently coupled to generators, produce electrical power. External combustion steam generators convert the chemical energy in the fuel into thermal energy (boiler), mechanical energy (turbine), and electrical energy (generator). Though coal-, oil-, and gas-fired boilers differ in design and operation, the basic processes are similar. Figure A1.1 presents a simplified diagram of a large external combustion power plant.

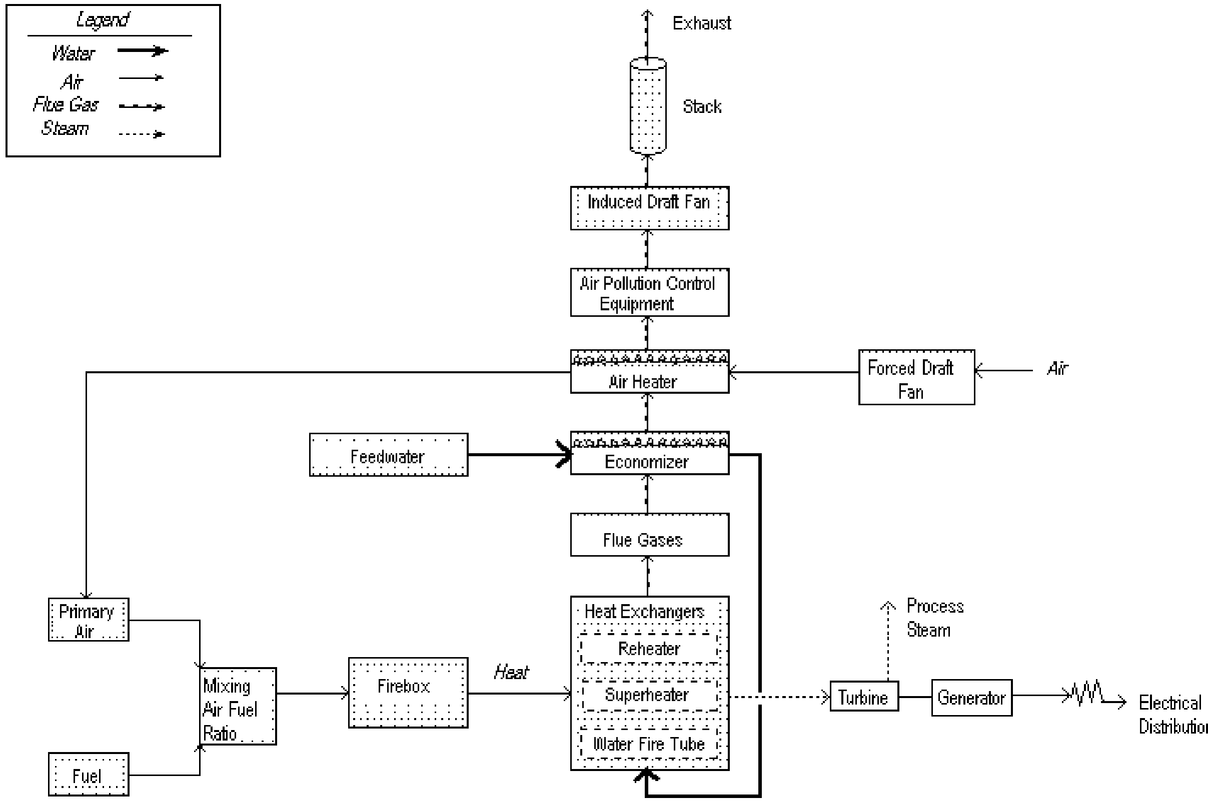


Figure A1.1. Large External Combustion Power Plant

A1.2.2.2. Categorization. Coal-fired systems are categorized by mode of operation. Fuel oil, natural gas, and liquefied petroleum gas (LPG) systems are categorized by their gross input heat rate expressed in American engineering units of million British thermal units per hour (MMBtu/hr) or metric units of megawatts (MW). External combustion unit categories by size are listed in Table A1.1.

Table A1.1. External Combustion Unit Categories by Size

	Gross Heat Rate	
Category	**MMBtu/hr**	**MW**
Utility Steam Generators	> 100	> 29.3
Industrial Steam Generators	10 to 100	2.93 to 29.3
Commercial Steam Generators	0.5 to 10	0.15 to 2.93

Note: One MW is equivalent to 3.41 MMBtu/hr.

A1.2.2.3. Coal-Fired Steam Generators. Coal is classified by its heating value and chemical composition and is broadly categorized in declining quality as anthracite, bituminous, sub-bituminous, or lignite. Typical heating values and compositions for each type of coal are presented in Table A1.2. Bituminous is by far the type most commonly used for fuel. The quality of coal burned determines its overall emission rate. Coal with higher ash content and sulfur content produces higher particulate and sulfur dioxide emissions, respectively.

Table A1.2. Typical Heating Values and Chemical Composition for Various Types of Coal

	Heating Value		Carbon	Ash	Sulfur
Type of Coal	**(Btu/lb)**	**(Mj/kg)**	**(wt %)**	**(wt %)**	**(wt %)**
Anthracite	11,800-13,000	27.4-30.2	75-90	10-20	0.6-0.8
Bituminous	10,500-14,400	24.4-33.5	50-80	5-25	0.7-4.5
Sub-bituminous	8,500-10,200	19.8-23.7	45-65	5-25	0.7-4.5
Lignite	6,300	14.6	35-50	5-12	1.0

Note: Mj/kg - megajoules per kilogram

A1.2.2.4. Fuel-Oil-Fired Steam Generators. The term “fuel oil” applies to a wide range of liquid petroleum products including crude oil, distillates, and residuals. The two major categories of fuel oil used for steam generators are distillate oils and residual oils. These oils are further distinguished by grade. Grades No. 1 and 2 are distillate oils; Nos. 5 and 6 are residuals or “bottoms” from refinery processes. Residual oils are the residue remaining after the lighter fractions of gasoline, kerosene, and distillates have been removed from crude oil. No. 6 fuel oil is sometimes referred to as Bunker C. No. 4 oil is likely to be a blend containing appreciable distillate stock even though it is classified as a residual fuel. Distillate fuel oils contain less sulfur and ash than the more viscous residual oils, but tend to be more expensive. Residual oils, however, require more elaborate process equipment to handle and burn. The heavier residual oils (Nos. 5 and 6) must be pre-heated to facilitate flow and proper atomization in burners because of higher viscosity and lower volatility. Table A1.3 presents properties of the various grades of fuel oil. Fuel oils with higher ash content and sulfur content produce higher particulate and sulfur dioxide emissions, respectively.

Table A1.3. Fuel Oil Properties

Grade	Description	Heat Content (Mj/L)	Heat Content (Btu/gal)	Ash (wt %)	Sulfur (wt %)
No. 1	Distillate	37.9	136,000	--	0.10 to 0.50
No. 2	Distillate	39.6	142,000	--	0.10 to 1.00
No. 4	Residual	40.4	145,000	0.10	0.20 to 2.00
No. 5	Residual (preheat temp. 77-104 °C (170-220 °F))	41/3	148,000	0.10	0.50 to 3.00
No. 6 (Bunker C)	Residual (preheat temp. 104-127 °C (220-260 °F))	42.1	151,000	--	0.70 to 4.00

Notes: One Btu/gal is equivalent to 0.000279 Mj/L (megajoules per liter).

A1.2.2.5. Natural-Gas-Fired Steam Generators. Natural gas, a relatively clean-burning fuel, is a mixture of hydrocarbons, consisting of a high percentage of methane (more than 80 percent) and varying amounts of ethane, propane, butane, and inserts such as nitrogen, carbon dioxide, and helium. Small amounts of sulfur are usually added to distribution lines [approximately 0.15 grains sulfur per 100 standard cubic feet (scf) to impart a detectable odor to the fuel.] Gross heating values for natural gas range from 33.5 to 44.7 megajoules per cubic meter (Mj/m^3) (900 to 1,200 Btu/scf).

Note: One Btu/scf is equivalent to 0.0372 Mj/m^3.

A1.2.2.6. LPG-Fired Steam Generators. LPG is a popular mixture used to fuel steam generator units. LPG consists of one or more of the following: propane, butane, propylene, and butylene. Advantages of LPG are its high gross heating value [approximately 112 Mj/m^3 (3,000 Btu/scf)] and ease of handling. LPG is considered a relatively clean-burning fuel.

A1.2.3. Internal Combustion (IC) Units. IC units are the type of generators most often used at Air Force installations. Stationary, industrial-sized reciprocating IC generators are the most common, although a few gas turbines are used for power generation. Fuels used in IC generator units include natural gas, gasoline, and non-gasoline petroleum distillates (NGPD) such as diesel, No. 2 fuel oil, JP-4, JP-5, and JP-8.

A1.2.3.1. Gas Turbines.

A1.2.3.1.1. The major components of a typical gas turbine are the compressor, the combustor, and the turbine. An axial compressor is used to increase pressure of the combustion air stream. An annular combustor burns fuel to heat the compressed air. An axial turbine then converts the energy in the hot compressed gases exiting the combustor to shaft work to drive the axial compressor and an electrical generator.

A1.2.3.1.2. In a simple cycle gas turbine, the exhaust gases are vented directly to the atmosphere (see Figure A1.2). Another type of gas turbine is a regenerative or combined cycle gas turbine. In a regenerative cycle unit, the heat value in the exhaust gases is recovered through either a heat exchanger to preheat the compressed air or a heat recovery steam generator (HRSG). The HRSG can either be supplementary-fired or non-fired. Figure A1.3 presents a schematic of a regenerative gas turbine equipped with a preheater.

A1.2.3.2. Reciprocating Engines. Reciprocating engines used to generate electric power are classified in three ways: the method of ignition and type of fuel used; the combustion cycle and fuel-charging method; and the power produced (engine size). Each classification has a significant impact on pollutant emissions. A summary of the classifications is presented in Table A1.4.

A1.2.3.2.1. Method of Ignition and Type of Fuel Used. All NGPD-fired generators are compression ignition (CI) engines. All reciprocating generators fueled with gasoline or natural gas are spark ignition (SI) engines. Reciprocating engines are further classified based on the air-to-fuel (A/F) ratios. All naturally aspirated and some turbocharged four-stroke cycle SI engines are categorized as rich-burn engines. All other reciprocating engines are categorized as lean-burn engines. Rich-burn engines operate with an A/F ratio near stoichiometric, or slightly fuel rich of stoichiometric, and can be adjusted to operate with an exhaust oxygen concentration of 4 percent or less. Lean-burn engines include two-stroke SI engines and all CI engines, and operate with an A/F ratio that is fuel lean of stoichiometric and cannot be adjusted to operate with an exhaust oxygen concentration of less than 4 percent. Lean-burn engines generally have an exhaust oxygen level of 12 percent or greater.

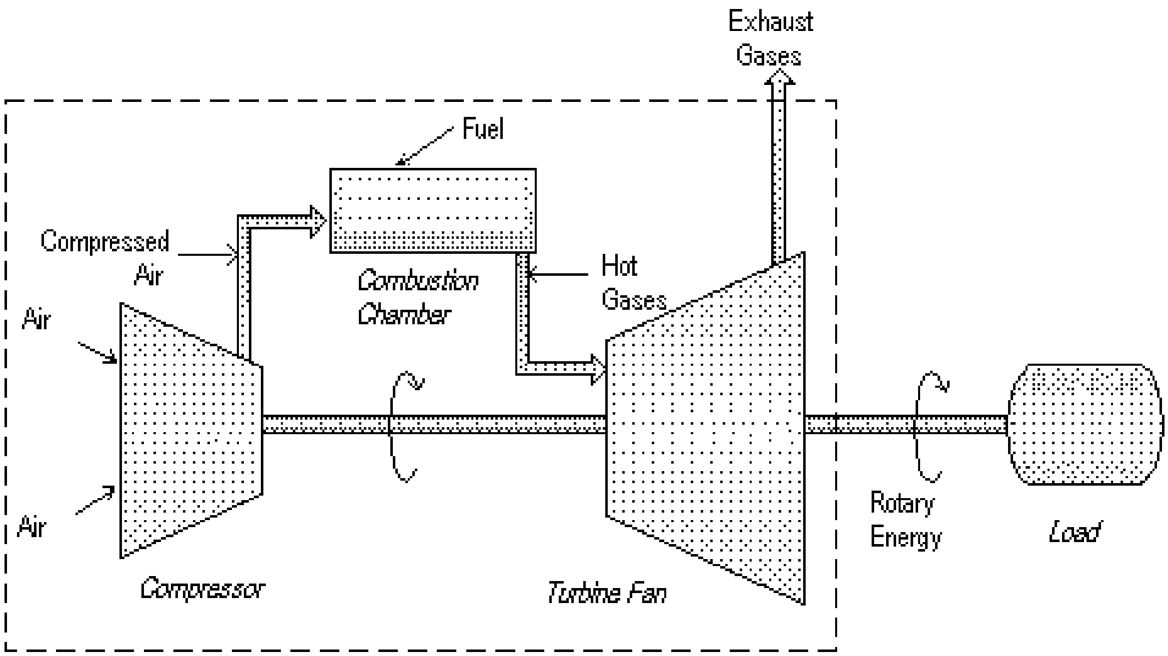


Figure A1.2. Simple Cycle Gas Turbine

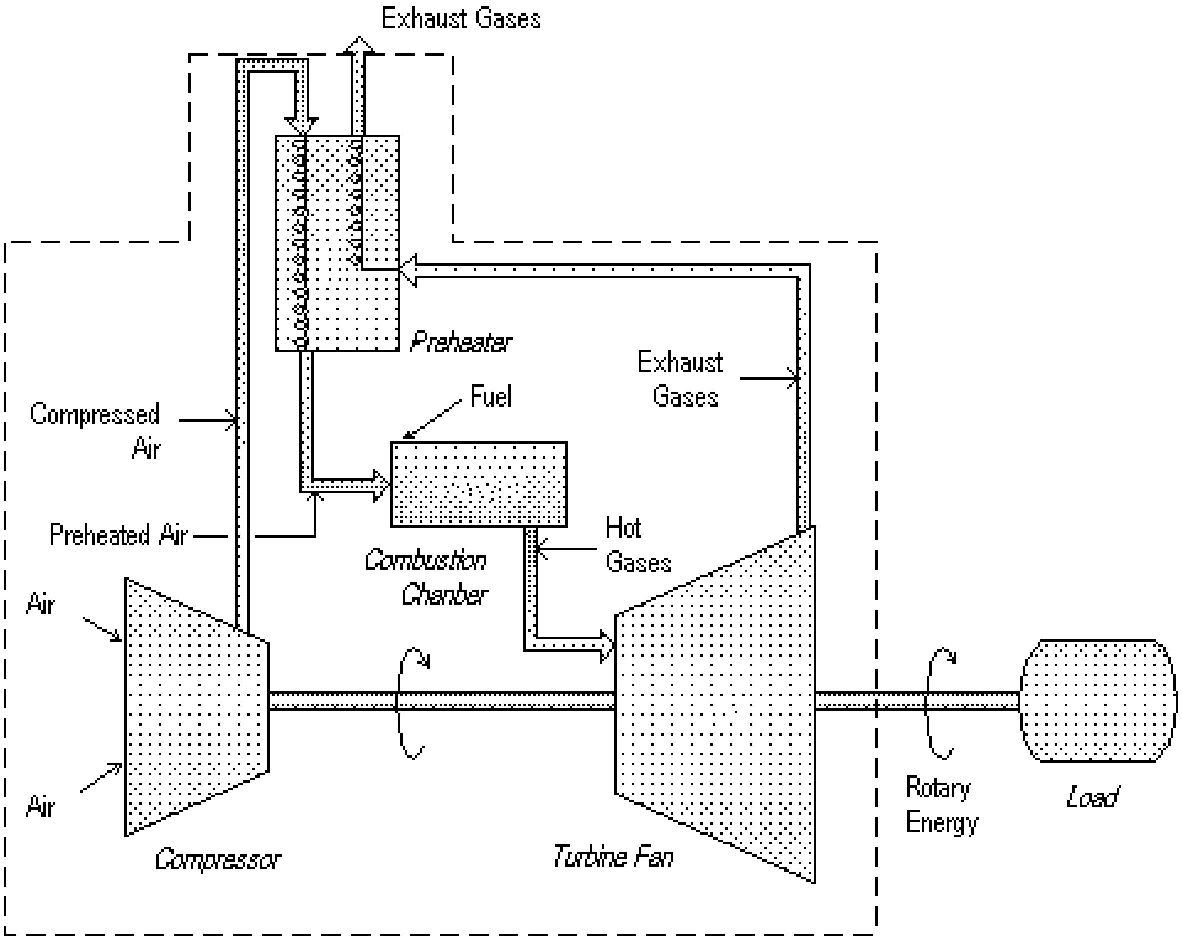


Figure A1.3. Regenerative Cycle Gas Turbine

Table A1.4. Classification of Typical Reciprocating Engines

Fuel Type	Operating Cycle	Charging Method	Engine Size	Power Output Range hp	Power Output Range kW
SI Rich-Burn					
Natural Gas	Four-Stroke Cycle	Naturally Aspirated	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
		Supercharging/ Turbocharging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
Gasoline	Four-Stroke Cycle	Naturally Aspirated	Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Supercharging/ Turbocharging	Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
SI Lean-Burn					
Natural Gas	Two-Stroke Cycle	Naturally Aspirated	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
		Supercharging/ Turbocharging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
		Blower-Scavenging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
Gasoline	Two-Stroke Cycle	Naturally Aspirated	Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Supercharging/ Turbocharging	Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Blower-Scavenging	Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35

SI = Spark Ignition

Table A1.4. Classification of Typical Reciprocating Engines (Continued)

Fuel Type	Operating Cycle	Charging Method	Engine Size	Power Output Range hp	kW
CI Lean-Burn					
Distillate Oil (diesel)	Four-Stroke Cycle	Naturally Aspirated	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Supercharging/ Turbocharging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
	Two-Stroke Cycle	Naturally Aspirated	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Supercharging/ Turbocharging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Blower-Scavenging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
Dual-Fueled (gas/oil)	Four-Stroke Cycle	Naturally Aspirated	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Supercharging/ Turbocharging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
	Two-Stroke Cycle	Naturally Aspirated	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Supercharging/ Turbocharging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35
		Blower-Scavenging	Large Bore	600 - 9,700	447 - 7,233
			Medium Bore	50 - 1,200	35 - 890
			Small Bore	3 - 50	2 -35

CI = Compression Ignition

A1.2.3.2.2. Combustion Cycle and Fuel-Charging Method.

A1.2.3.2.2.1. Four-stroke engines complete the power cycle in two engine revolutions -- one for the intake/compression stroke, and one for the power/exhaust stroke. These engines are either naturally aspirated or turbocharged to introduce air or an air-fuel mixture into the cylinders of the IC engine. Naturally aspirated engines use suction created by the piston to entrain the air charge. Turbocharged engines use a turbine to pressurize the charge.

A1.2.3.2.2.2. Two-stroke engines complete the power cycle in a single engine revolution. These engines may be turbocharged using an exhaust-powered turbine to pressurize the charge for injection into the cylinders. Other two-stroke engines either use blower scavenging with low pressure air blowers or are naturally aspirated by the piston to remove combustion products from the cylinders.

A1.2.3.2.3. Power Produced (Engine Size) Method. Industrial reciprocating generators with rated power in excess of 447 kW (600 hp) are classified as large bore engines (LBEs). One kW is equivalent to 1.34 hp. The LBEs are generally greater than 5.7 liters (350 cubic inches) per cylinder displacement and have a bore size of approximately 20 centimeters (8 inches). They typically produce more than 75 kW (100 hp) per cylinder. The smaller generator units are referred to as smaller industrial reciprocating engines (SIREs) and are generally between 2 kW and 447 kW (3 hp and 600 hp) in rated power. SIREs include not only small stationary generators, but also portable units, some of which are in service as aerospace ground equipment (AGE). SIREs generally have multiple cylinders, with outputs ranging from 2 to 11 kW (3 to 15 hp) per cylinder in the smaller units, to 7.5 to 75 kW (10 to 100 hp) per cylinder in the larger units. Bore size in the SIREs ranges from 8 to 13 centimeters (3 to 5 inches) in the smaller units to 9 to 23 centimeters (3.5 to 9 inches) in the larger IC generators.

A1.3. Air Pollutants of Concern. Fuel combustion in generators and power plants results in the emission of both criteria air pollutants and hazardous air pollutants (HAPs). Emission rates depend upon the size, type, and design of the combustion system; the fuel type, composition, and amount consumed; the operating conditions; and the level of equipment maintenance. Combustion characteristics affecting pollutant emissions include combustion temperature, oxygen concentration, residence time (at high temperature), air/fuel mixing, burner/combustion chamber geometry, operating conditions (load and engine speed), ignition timing, and humidity. Table A1.5 summarizes physical properties of several fuels.

Table A1.5. Typical Fuel Properties

	Higher Heating Value [1]	%N	%S	%Ash
Natural Gas	33.5-44.7 Mj/m^3 (900-1,200 Btu/scf)	0	<0.015	0
Distillate Oils	37.4-39.6 Mj/L (0.134-0.142 MMBtu/gal)	<0.015	<0.5	<0.01
Residual Oils	40.4-42.1 Mj/L (0.145-0.151 MMBtu/gal)	0.1-0.5	0.5-4.0	0.1-1.1
Coal	14.6-33.5 Mj/kg (6,300-14,400 Btu/lb)	0.5-2.0	0.2-4.5	5-25

[1] All water formed is condensed into liquid state.
%N = percent nitrogen
%S = percent sulfur

A1.3.1. Criteria Pollutants.

A1.3.1.1. National Ambient Air Quality Standards (NAAQS). The Environmental Protection Agency (EPA) established NAAQS for six pollutants: carbon monoxide (CO), nitrogen dioxide (NO_2), particulate matter (PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), ozone (O_3), and lead. These are commonly called "criteria pollutants." Because O_3 is difficult to measure and its formation is related to volatile organic compounds (VOCs), VOCs (which can be an ozone precursor) are regulated as its surrogate. "Noncriteria pollutants" include non-VOCs and HAPs. Fine particulate matter ($PM_{2.5}$) was included with the criteria pollutants in July 1997 because a significant fraction of total particulate matter (PM) is emitted as $PM_{2.5}$.

A1.3.1.2. Principal Pollutants. The principal criteria air pollutants of concern emitted from generators and power plants are nitrogen oxides (NOx), CO, PM, and to a lesser extent, VOCs and sulfur oxides (SOx), depending on the fuel sulfur content. VOCs are also referred to as hydrocarbons (HC), but are frequently qualified as non-methane hydrocarbons (NMHCs) to exclude methane, which is not a VOC. HAPs include organic compounds, which are a subset of NMHCs, and inorganic compounds and metals, which are a subset of PM. Table A1.6 summarizes the major and minor pollutants emitted from various types of generators and power plants.

Table A1.6. Types of Generators and Corresponding Emissions

Type of Generator or Power Plant	Major Emissions	Minor Emissions
Coal-Fired Steam Generating Unit	NOx SOx PM	CO NMHCs
Fuel-Oil-Fired Steam Generating Unit	NOx SOx PM	CO NMHCs
Natural-Gas-Fired Generating Steam Unit	NOx	CO PM SOx
Gas Turbine	NOx	CO NMHCs PM
Reciprocating Engine	NOx CO	PM SOx NMHCs

A1.3.1.3. Nitrogen Oxides (NOx).

A1.3.1.3.1. Generators and power plants are the largest contributors to NOx emissions at most Air Force installations. NOx is a composite of six oxides of nitrogen: NO, NO_2, N_2O, N_2O_3, N_2O_4, and N_2O_5. Of these, nitrogen monoxide (NO) and nitrogen dioxide (NO_2) are formed in sufficient quantities to be significant in atmospheric pollution. Most NO eventually converts to NO_2, which is the only oxide of nitrogen for which a NAAQS has been established.

A1.3.1.3.2. Nitrogen oxides are formed by several mechanisms in the combustion process and depend on combustion characteristics and fuel properties. The primary mechanism of NOx formation in most types of generator units is “thermal NOx”. Thermal NOx results from thermal oxidation or “fixation” of atmospheric nitrogen in the combustion flame. It is dependent upon the peak flame temperature, available oxygen, fuel/air mixing, gas residence time, and fuel nitrogen concentration. Increased flame temperature, oxygen availability, and/or residence time at high temperatures will increase NOx production. NO produced by incomplete oxidation of atmospheric nitrogen converts to NO_2 and other NOx compounds in the presence of oxygen downstream of the combustion chamber.

A1.3.1.3.3. Another mechanism for NOx formation in generator units is “fuel or organic NOx,” which results from the conversion of chemically-bound nitrogen in the fuel. Fuel nitrogen conversion is an important NOx-forming mechanism when either residual oil or coal are used as a fuel, since residual oils and coal have higher nitrogen contents than the other fuels. Table A1.5 lists typical fuel nitrogen contents by weight for common generator fuels.

A1.3.1.3.4. NOx Emissions from External Combustion Units.

A1.3.1.3.4.1. For coal-fired units, sources of nitrogen are the combustion air (79 percent nitrogen) and the fuel itself. Fuel nitrogen accounts for a major portion (up to 80 percent) of the total NOx emissions from coal combustion.

A1.3.1.3.4.2. For fuel oil (distillate) combustion, most NOx is produced by thermal fixation of atmospheric nitrogen, as fuel oils tend to have negligible nitrogen content. NOx emissions from tangentially-fired fuel oil boilers are generally less than those from horizontally opposed units.

A1.3.1.3.4.3. The firing practices used during boiler operation can affect NOx emission levels. The following combustion configurations can reduce NOx emissions between 5 and 60 percent:

- Low excess air (LEA) firing
- Flue gas recirculation (FGR)
- Staged combustion (SC)
- Reduced air preheat (RAP)
- Low NOx burners (LNBs)
- Load reduction

A1.3.1.3.4.4. For residual oil combustion, as much as 50 percent of total NOx emissions are produced by conversion of nitrogen present in the fuel. However, for higher nitrogen content fuels, not all of the fuel nitrogen is converted to NOx; some may be converted to ash and emitted as PM_{10}. Conversion of fuel nitrogen to NOx can range from 20 percent to 90 percent.

A1.3.1.3.4.5. NOx is the major pollutant emitted from natural-gas-fired steam generators and gas turbines. Thermal fixation of atmospheric nitrogen is the principal mechanism of NOx formation from these sources.

A1.3.1.3.5. NOx Emissions from Internal Combustion Units.

A1.3.1.3.5.1. Engine design and operating parameters, type of fuel, and ambient conditions all have an impact on NOx emissions from IC engines. For gas turbine IC engines, the rates of NOx emission depend on the firebox design; firing temperature; and classification of the gas turbine as a simple cycle or regenerative cycle turbine, twin shaft or single shaft turbine, or industrial type turbine.

A1.3.1.3.5.2. NOx emissions from gas turbines are primarily the result of thermal fixation because of the high temperatures, high pressures, and excess air environment within the gas turbine. Regenerative cycle turbines equipped with preheaters use waste heat to elevate the temperature of the turbine combustor inlet air, which increases the production rate of thermal NOx.

A1.3.1.3.5.3. An asymptotic relationship exists between NOx emissions and the firing temperature (which is directly related to the combustion temperature) of the gas turbine. Because firing temperature is directly related to the power output (load) of the gas turbine, NOx emissions increase with increasing turbine load. Increasing the compressor exit temperature and pressure while decreasing the A/F ratio improves the combustion efficiency of a gas turbine. These conditions also reduce CO and HC emissions. Gas turbine NOx emissions increase as the following design parameters increase: pressure ratio, turbine efficiency, combustor pressure, firing temperature, and turbine load. Changes in ambient humidity also significantly affect NOx formation as the water in the combustion air disassociates, thus lowering the flame temperature and reducing NOx formation.

A1.3.1.3.5.4. For reciprocating IC engines, NOx emissions are influenced by A/F ratio, charging method, ignition timing, combustion chamber valve design, engine combustion cycle, and operating load and engine speed. Thermal fixation of atmospheric nitrogen is the predominant mechanism of NOx formation, unless residual oil fuel is used in the reciprocating engine. NOx emissions increase when residual oil fuels with high fuel nitrogen content are used. Efforts to reduce NOx emissions from reciprocating IC engines, however, can affect the formation of CO and NMHC.

A1.3.1.4. Carbon Monoxide.

A1.3.1.4.1. The rate of CO emissions from generators and power plants depends on the fuel oxidation efficiency of the source. CO is an intermediate combustion product that forms when the oxidation of fuel hydrocarbons to CO_2 does not proceed to completion. CO is produced when there is a lack of available oxygen, the combustion temperature is too low, or the residence time in the combustion chamber is too short. Promoting high combustion temperatures, long residence times at high temperature, and turbulent mixing of fuel and combustion air can reduce CO emissions. Operating reciprocating IC engines with a high A/F ratio will also reduce CO emissions (see discussion of A/F adjustment effect on emissions in Paragraph A1.5.2.2.2.) Although CO emissions can be minimized by controlling the combustion process carefully, CO emissions can increase by a factor of 10 to 100 if a generator unit is improperly operated or inadequately maintained. Smaller combustion units tend to have higher CO emissions than larger combustion units because the smaller units provide less high-temperature residence time, which can result in incomplete combustion and CO formation. IC engines emit significantly more CO than external combustion units.

A1.3.1.4.2. CO emissions from turbines are relatively low (less than 0.1 lb/MMBtu) except during startup, shutdown, and partial load operation, when gas turbine efficiency is low. A trade-off exists between reducing NOx emissions and increasing CO emissions. Higher firing temperatures, longer residence times, higher A/F ratios, and additional A/F mixing in the primary combustion zone reduce CO emissions, but increase NOx emissions. Aircraft derivative turbines typically have shorter combustors than heavy-duty industrial turbines and, therefore, lower residence times and higher CO emissions.

A1.3.1.5. Hydrocarbons (HCs). Vapor phase hydrocarbon emissions result from unburned or partially burned fuel in the combustion process. NMHCs are the principal HCs of regulatory concern. HC emissions depend on the combustion efficiency of the generator unit and generally occur in small amounts. NMHC emissions result from inadequate mixing of fuel and air, incorrect A/F ratios, and/or quenching of combustion products by combustion chamber surfaces. A number of the NMHCs emitted are also listed as HAPs.

A1.3.1.6. Sulfur Dioxide (SO_2). Emissions of sulfur dioxide result from oxidation of sulfur present in the fuel used in a generator unit. SO_2 emissions are very low from generator units that use natural gas, LPG, or distillate oil because these fuels have negligible sulfur content. However, SO_2 emissions from coal- and residual-fired units may be higher because of higher fuel sulfur contents. The fuel sulfur content can average as much as 4.0 percent by weight in high sulfur No. 6 fuel oils, and 4.5 percent by weight in some high sulfur coal fuels. Because of the sulfur content in coal, coal combustion (sometimes used for large power production operations) is the largest single contributor to “acid rain” formation. Large coal-fired steam generating units are used at only a few Air Force installations.

A1.3.1.7. Particulate Matter (PM).

A1.3.1.7.1. PM in some form is probably the most common air pollutant and is defined according to its particle size. Until 1987, EPA regulated particulate matter as total suspended particulate (TSP) matter, which is the term given to PM collected by a high volume air sampler with particle size range of 0.1 to about 100 micrometers in diameter. In light of evidence that only particles smaller than 10 micrometers in diameter are harmful to health and welfare, EPA adopted standards for PM smaller than 10 micrometers (PM_{10}). In July 1997, EPA added standards for PM smaller than 2.5 micrometers ($PM_{2.5}$), since a significant fraction of total PM is emitted as $PM_{2.5}$. Particulate matter emissions are typically inclusive of component species, including HAPs, as are HC emissions.

A1.3.1.7.2. Emissions of PM from generator and power plant units are a function of fuel volatile content and ash content and are considered minor compared to emissions of NOx and CO. Because coal and residual oils have significantly higher ash content and lower volatility than other fuels, PM emissions from generators using these fuels tend to be higher than from generators that burn natural gas or distillate oil. For fuel-oil-fired units, PM emissions depend predominantly on the grade of fuel fired; low grade oils generate more particulate emissions due to their lower volatility, higher ash, and higher sulfur contents. Combustion of lighter distillate oils results in significantly lower PM formation than combustion of heavier distillate oils. Formation of PM depends in general on the completeness of combustion. Particulate emissions from distillate oil-fired units are primarily carbonaceous particles resulting from incomplete combustion of the fuel and are not well correlated to either the ash or sulfur content, whereas particulate emissions from residual oil fired units are more directly related to these parameters.

A1.3.2. Hazardous Air Pollutants (HAP).

A1.3.2.1. Air Toxics. Air toxics are defined as any air pollutants for which an NAAQS does not exist and that may reasonably be anticipated to cause cancer, developmental effects, reproductive dysfunction, neurological disorders, heritable gene mutations, or other serious or irreversible chronic or acute health effects in humans. Air toxics are also referred to as HAPs. EPA has identified and listed 189 chemicals and components as HAPs. Some of these HAPs are emitted as products of incomplete combustion (organic) while others are present in the fuel (inorganic).

A1.3.2.2. HAPs. HAPs can either be organic or inorganic non-criteria air pollutants, and exist in gaseous or particulate form. Most gaseous hazardous or toxic compounds are HCs. Conditions that favor organic-HAP emissions are identical to those that favor HC emissions. Inorganic-HAP emissions, however, are related only to the amount of trace metals in the fuel.

A1.3.2.3. Formaldehyde. The primary HAP emitted from hydrocarbon-based fuel combustion is formaldehyde, which is present in the vapor phase of the flue gas. Smaller units tend to have higher formaldehyde emissions as a result of lower combustion temperatures and less efficient combustion. The higher combustion temperatures in larger units subject formaldehyde to oxidation and decomposition. Unburned HC emissions can include other vapor phase organic compounds including aliphatic, oxygenated, and low molecular weight aromatic compounds, such as benzene, toluene, hexane, and xylenes.

A1.3.3. Emission Estimation Methodology.

A1.3.3.1. Basic Procedures. The basic emission estimating procedures are listed below in order of increasing cost and reliability of estimate:

- Engineering judgment
- Emission factors
- Engineering calculations/mass balance
- Equipment vendor data
- Single source (stack) tests
- Parametric source tests
- Continuous emission monitoring (CEM)

A1.3.3.2. Best Representation. Source-specific tests or CEM data provide the best representation of emissions from a given source. These procedures are generally preferred because the actual pollutant contribution of an existing source can be determined. However, test data are not always available, and the costs of conducting source tests or CEM are high. Source testing or CEM data cannot be used to determine emission estimates of proposed new sources.

A1.3.3.3. Emission Factors.

A1.3.3.3.1. Definition. Emission factors, the most widely used method for estimating emissions, are averages of available data of acceptable quality and are generally assumed to represent long-term average emissions for facilities in a specific source category. These representative values attempt to relate the quantity of pollutant released per unit of source activity associated with the release. As averages, emission factors are unlikely to provide accurate emission estimates for a particular source.

A1.3.3.3.2. Application and Limitation. The use of emission factors facilitates the estimation of emissions from various sources and is accepted for preparation of area wide emission inventories, applicability determinations, or screening sources for compliance. However, using emission factor estimates for source-specific permit limits or emission regulatory compliance determinations is not recommended and is usually not acceptable to the regulatory agency. More reliable emission estimation methodologies should be used for these purposes. Emission information from equipment vendors, such as performance guarantees or actual source test data from similar equipment, is a better source of information than emission factors.

A1.3.3.3.3. Summary of Emission Factors. Because of the variety of generator types employed at Air Force installations, a summary of available emission factors has been included in this document (Tables A1.7a - A1.10b) as a means to evaluate the regulatory applicability and relative air quality impact of new and existing generator units. For actual permitting and establishment of specific emission limitations for a generator unit, the Base Civil Engineer should obtain more accurate source data or use a more reliable method of emission estimation. **Note:** Emission factors are not yet developed for $PM_{2.5}$.

A1.3.3.4. Use of Emission Factors. Both actual emissions and potential-to-emit (PTE) emissions are determined through the use of emission factors. Actual emissions are calculated using actual values for annual fuel consumption or hours of operation. Potential emissions generally assume operation for 8,760 hours per year (24 hours per day, 365 days per year) unless limited by Federally-enforceable permit stipulations. An EPA policy determination allows PTE emissions for emergency generators to be calculated on the basis of 500 hours operation per year rather than 8,760. However, generators at facilities that operate under a load-sharing agreement with the local utility are not considered “emergency generators” and are not permitted to use the 500-hour-per-year assumption.

A1.3.3.5. Estimating HAP Emissions. For estimating HAP emissions, speciation factors are applied to PM and HC emissions, usually as a weight percent of the various constituents of HC and PM. Because there are no distinctions for HAPs based on particle size, the speciation factors are applied to PM or TSP emission levels rather than those for PM_{10}.

A1.3.3.6. References. Sources of additional information regarding emission factors include the following:

- *Compilation of Air Pollutant Emission Factors*, U.S. Environmental Protection Agency, January 1995
- *Calculation Methods for Criteria Air Pollutant Emission Inventories*, Armstrong Laboratory, July 1994
- *Identification of Volatile Organic Compound Species Profiles*, California Air Resources Board, August 1991 [for HAPs estimation]
- *Air Quality Utility Information System (AQUIS),* HQ AFMC/CEV
- *USAF Air Conformity Applicability Model,* Earth Tech

- Previous facility air pollutant emissions calculations, such as those done for Title V permit applications (see paragraph A1.4.1.7.)

A1.3.3.7. Tables of Emission Factors. Tables A1.7a and A1.7b present the uncontrolled emission factors for external combustion generators and power plants (fossil-fuel-fired steam generators). Tables A1.8a and A1.8b present the uncontrolled, emission factors for internal combustion generators and power plants (gas turbines and reciprocating engines). HAP emission factors for these source categories are shown in Tables A1.9a and A1.9b (external combustion) and Tables A1.10a and A1.10b (internal combustion).

Table A1.7a. Criteria Pollutant Emission Factors for External Combustion Units (Metric)

Fuel/Firing Type	Capacity (MW)	Units	Emission Factor NOx	CO	PM_{10}	VOC	SOx
Bituminous Coal							
Chain grate		kg/ton	3.75	3.00	3.00	0.03	9.5*S
Cyclone		kg/ton	16.9	0.25	0.065*A	0.06	9.5*S
Hand-fired		kg/ton	4.55	138	3.10	5.00	7.75*S
Pulverized dry bottom-tangential		kg/ton	7.20	0.25	0.575*A	0.03	9.5*S
Pulverized dry bottom- wall		kg/ton	10.9	0.25	0.575*A	0.03	9.5*S
Pulverized wet bottom		kg/ton	17.0	0.25	0.065*A	0.02	9.5*S
Spreader stoker		kg/ton	6.85	2.50	6.60	0.03	9.5*S
Traveling grate		kg/ton	3.75	3.00	3.00	0.03	9.5*S
Underfeed stoker		kg/ton	4.75	5.50	3.10	0.65	7.75*S
No. 2 Fuel Oil (distillate)							
Normal or Tangential	greater than 29.3	kg/1,000 L	2.40	8.59	0.12	0.024	2.07*S
Normal or Tangential	2.93 to 29.3	kg/1,000 L	2.40	8.59	0.12	0.024	2.07*S
Normal or Tangential	0.14 to 2.93	kg/1,000 L	2.40	8.59	0.15	0.041	2.07*S
Normal or Tangential	less than 0.14	kg/1,000 L	2.16	8.59	0.02	0.086	2.07*S
No. 4 Fuel Oil (residual)							
Normal	greater than 29.3	kg/1,000 L	8.04	0.60	0.59	0.09	2.24*S
Tangential	greater than 29.3	kg/1,000 L	5.04	0.60	0.59	0.09	2.24*S
Normal or Tangential [1]	2.93 to 29.3	kg/1,000 L	2.40	0.60	0.72	0.02	2.24*S
Normal or Tangential [1]	less than 2.93	kg/1,000 L	2.40	0.60	0.52	0.04	2.24*S
No.5 Fuel Oil (residual)							
Normal	greater than 29.3	kg/1,000 L	8.04	0.60	0.85	0.09	2.36*S
Tangential	greater than 29.3	kg/1,000 L	5.04	0.60	0.85	0.09	2.36*S
Normal or Tangential [1]	2.93 to 29.3	kg/1,000 L	6.60	0.60	1.03	0.03	2.36*S
Normal or Tangential [1]	less than 2.93	kg/1,000 L	6.60	0.60	0.74	0.14	2.36*S
No.6 Fuel Oil (residual)							
Normal	greater than 29.3	kg/1,000 L	8.04	0.60	0.79*S + 0.26	0.09	2.36*S
Tangential	greater than 29.3	kg/1,000 L	5.04	0.60	0.79*S + 0.26	0.09	2.36*S
Normal or	2.93 to 29.3	kg/1,000 L	6.60	0.60	0.96*S	0.03	2.36*S

Tangential [1]				+ 0.33		
Normal or	less than 2.93 kg/1,000 L	6.60	0.60	0.96*S	0.03	2.36*S
Tangential [1]				+ 0.33		

Table A1.7a. Criteria Pollutant Emission Factors for External Combustion Units (Metric) (Continued)

Fuel/Firing Type	Capacity (MW)	Units[2]	Emission Factor NOx	CO	PM_{10}	VOC	SOx
Natural Gas							
Normal	greater than 29.3	kg/Mm^3	7.07	0.51	0.039	0.018	0.008
Tangential	greater than 29.3	kg/Mm^3	3.54	0.51	0.039	0.018	0.008
Normal or Tangential	2.93 to 29.3	kg/Mm^3	1.80	0.48	0.18	0.036	0.008
Normal or Tangential	0.09 to 2.93	kg/Mm^3	1.29	0.27	0.15	0.068	0.008
Normal or Tangential	less than 0.09	kg/Mm^3	1.21	0.51	0.14	0.093	0.008
LPG (Butane)							
	greater than 29.3	kg/1,000 L	2.52	0.43	0.072	0.072	0.002
	less than 2.93	kg/1,000 L	1.80	0.25	0.060	0.072	0.002
LPG (Propane)							
	greater than 29.3	kg/1,000 L	2.28	0.38	0.072	0.060	0.002
	less than 2.93	kg/1,000 L	1.68	0.23	0.048	0.060	0.002

Source: Air Force Air Quality Utility Information System (AQUIS), developed by Argonne National Laboratories.

Notes: A = ash content (wt%)
S = sulfur content (wt%)

[1] If nitrogen content (wt%) is available, EF (NOx) = 12.526 * N + 2.464.

[2] kg/Mm^3 = kilograms per 1,000 cubic meters

Table A1.7b. Criteria Pollutant Emission Factors for External Combustion Units (English)

Fuel/Firing Type	Capacity (MMBtu/hr)	Units	Emission Factor NOx	CO	PM_{10}	VOC	SOx
Bituminous Coal							
Chain grate		lb/ton	7.5	6	6	0.05	38*S
Cyclone		lb/ton	33.8	0.5	0.26*A	0.11	38*S
Hand-fired		lb/ton	9.1	275	6.2	10	31*S
Pulverized dry bottom-tangential		lb/ton	14.4	0.5	2.3*A	0.06	38*S
Pulverized dry bottom-wall		lb/ton	21.7	0.5	2.3*A	0.06	38*S
Pulverized wet bottom		lb/ton	34	0.5	2.6*A	0.04	38*S
Spreader stoker		lb/ton	13.7	5	13.2	0.05	38*S
Traveling grate		lb/ton	7.5	6	6	0.05	38*S
Underfeed stoker		lb/ton	9.5	11	6.2	1.3	31*S
No. 2 Fuel Oil (distillate)							
Normal or Tangential	greater than 100	lb/1,000 gal	20	5	1	0.2	144*S
Normal or Tangential	10 to 100	lb/1,000 gal	20	5	1	0.2	144*S
Normal or Tangential	0.5 to 10	lb/1,000 gal	20	5	1.2408	0.34	144*S
Normal or Tangential	less than 0.5	lb/1,000 gal	18	5	0.186	0.713	144*S
No. 4 Fuel Oil (residual)							
Normal	greater than 100	lb/1,000 gal	67	5	4.96	0.76	155.7*S
Tangential	greater than 100	lb/1,000 gal	42	5	4.96	0.76	155.7*S
Normal or Tangential [1]	10 to 100	lb/1,000 gal	20	5	6.02	0.2	152*S
Normal or Tangential [1]	less than 10	lb/1,000 gal	20	5	4.34	0.34	152*S
No.5 Fuel Oil (residual)							
Normal	greater than 100	lb/1,000 gal	67	5	7.08	0.76	162.7*S
Tangential	greater than 100	lb/1,000 gal	42	5	7.08	0.76	162.7*S
Normal or Tangential [1]	10 to 100	lb/1,000 gal	55	5	8.604	0.28	159*S
Normal or Tangential [1]	less than 10	lb/1,000 gal	55	5	6.204	1.13	159*S

Table A1.7b. Criteria Pollutant Emission Factors for External Combustion Units (English) (Continued)

Fuel/Firing Type	Capacity (MMBtu/hr)	Units	Emission Factor NOx	CO	PM_{10}	VOC	SOx
No.6 Fuel Oil (residual)							
Normal	greater than 100	lb/1,000 gal	67	5	6.60*S + 2.18	0.76	162.7*S
Tangential	greater than 100	lb/1,000 gal	42	5	6.60*S + 2.18	0.76	162.7*S
Normal or Tangential [1]	10 to 100	lb/1,000 gal	55	5	8.03*S + 2.72	0.28	159*S
Normal or Tangential [1]	less than 10	lb/1,000 gal	55	5	8.03*S + 2.72	0.28	159*S
Natural Gas							
Normal	greater than 100	lb/10^6 cu ft	550	40	3	1.411	0.6
Tangential	greater than 100	lb/10^6 cu ft	275	40	3	1.411	0.6
Normal or Tangential	10 to 100	lb/10^6 cu ft	140	37	13.7	2.784	0.6
Normal or Tangential	0.3 to 10	lb/10^6 cu ft	100	21	12	5.28	0.6
Normal or Tangential	less than 0.3	lb/10^6 cu ft	94	40	11.18	7.26	0.6
LPG (Butane)							
	greater than 10	lb/1,000 gal	21	3.6	0.6	0.6	0.016
	less than 10	lb/1,000 gal	15	2.1	0.5	0.6	0.016
LPG (Propane)							
	greater than 10	lb/1,000 gal	19	3.2	0.6	0.5	0.018
	less than 10	lb/1,000 gal	14	1.9	0.4	0.5	0.018

Source: Air Force Air Quality Utility Information System (AQUIS), developed by Argonne National Laboratories.

[1] If nitrogen content (wt%) is available, EF (NOx) = 104.39 * N + 20.54

Notes: A = ash content (wt%)
S = sulfur content (wt%)

Table A1.8a. Criteria Pollutant Emission Factors for Internal Combustion Engines (Metric)

		Capacity		Emission Factor				
Engine Type	**Fuel**	**(MW)**	**Units[1]**	**NOx**	**CO**	**PM_{10}**	**NMHC**	**SO_2**
		greater than 3	kg/Mj	0.19	0.047	0.007	0.010	0.40
			g/kW-hr[3]	2.15	0.52	0.094	0.117	4.57*S
Turbine	Natural Gas	less than 3	kg/Mj	0.146	0.073	na	0.001	na
			g/kW-hr[4]	1.75	1.11	na	0.013	na
	NGPD		kg/Mj	0.30	0.021	0.011	0.007	0.43
			g/kW-hr[5]	3.40	0.234	0.185	0.0833	4.92*S
	Natural Gas	0.45 to 9.69	kg/Mj	1.2	0.16	na	0.047	na
	(2-stroke lean-burn)		g/kW-hr[6]	14.6	2.01	na	0.576	na
	Natural Gas	0.45 to 9.69	kg/Mj	1.0	0.69	na	0.013	na
Large Bore Engine	(4-stroke rich-burn)		g/kW-hr[7]	13.4	11.6	na	0.188	na
	NGPD	0.45 to 9.69	kg/Mj	1.3	0.35	21.3	0.043	0.121*S
			g/kW-hr[8]	14.6	3.34	0.4	0.390	$4.92*S_1$
	Dual-Fuel[2]	0.45 to 9.69	kg/Mj	1.3	0.34	21.3	0.086	$0.024*S_1 + 0.385*S_2$
			g/kW-hr[9]	10.9	4.56	na	0.802	$0.247*S_1 + 5.81*S_2$
	Natural Gas	less than 0.45	kg/Mj	2.41	0.30	0.01	0.06	0.00
Small Industrial			g/kW-hr[10]	15.8	2.15	na	0.967	na
Reciprocating	NGPD	less than 0.45	kg/Mj	1.90	0.41	0.13	0.15	0.12
Engine			g/kW-hr[11]	18.8	4.06	1.34	1.50	1.24
	Gasoline	less than 0.45	kg/Mj	0.70	27.0	0.041	1.24	0.036
			g/kW-hr[12]	6.7	267	0.438	9.12	0.359

Source: Air Force Air Quality Utility Information System (AQUIS), developed by Argonne National Laboratories.
NGPD = non-gasoline petroleum distillate (includes distillate oils, residual oils, JP-4, JP-5, and JP-8); S = sulfur content (%); S_1 = sulfur content in fuel oil (%);
S_2 = sulfur content in natural gas (%); na = not available

Table A1.8a. Notes:

1. Units are kg/Mj (heat input). g/kW-hr (power output). The difference in these factors takes into account average combustion unit efficiency.
2. Dual-fuel: 95% natural gas, 5% fuel oil
3. Large uncontrolled gas turbines, natural gas fired, AP-42, Table 3.1-1 (SCC 20100201)
4. Uncontrolled natural gas prime movers, gas turbines, AP-42, Table 3.2-1 (SCC 20200201)
5. Large uncontrolled gas turbines, fuel oil fired, AP-42, Table 3.1-1 (SCC 20100101)
6. Uncontrolled natural gas prime movers, 2-cycle lean burn, AP-42, Table 3.2-1 (SCC 20200252)
7. Uncontrolled natural gas prime movers, 4-cycle rich burn, AP-42, Table 3.2-1 (SCC 20200254)
8. Large stationary diesel engines, AP-42, Table 3.4-1 (SCC 20200401)
9. Large stationary dual-fuel engines, AP-42, Table 3.4-1 (SCC 20200402)
10. Uncontrolled natural gas prime movers, 4-cycle lean burn, AP-42, Table 3.2-1 (SCC 20200253)
11. Uncontrolled diesel industrial engines, AP-42, Table 3.3-1 (SCC 20200102)
12. Uncontrolled gasoline engines, AP-42, Table 3.3-1 (SCC 20200301)

Table A1.8b. Criteria Pollutant Emission Factors for Internal Combustion Engines (English)

Engine Type	Fuel	Capacity (MW)	Units[1]	Emission Factor				
				NOx	CO	PM_{10}	NMHC	SO_2
Gas Turbine	Natural Gas	greater than 4021	lb/MMBtu	0.44	0.11	0.01676	0.024	0.94
			lb/10^3hp-hr[3]	3.53	0.86	0.154	0.192	7.52*S
		less than 4021	lb/MMBtu	0.34	0.17	na	0.002	na
			lb/10^3hp-hr[4]	2.87	0.675	na	0.021	na
	NGPD		lb/MMBtu	0.698	0.048	0.0244	0.017	1.01
			lb/10^3hp-hr[5]	5.60	3.84	0.304	0.137	8.09*S
Large Bore Engine	Natural Gas (2-stroke lean-burn)	600 to 13,000	lb/MMBtu	2.7	0.38	na	0.11	na
			lb/10^3hp-hr[6]	24.0	3.31	na	0.948	na
	Natural Gas (4-stroke rich-burn)	600 to 13,000	lb/MMBtu	2.3	1.6	na	0.03	na
			lb/10^3hp-hr[7]	22.0	19.0	na	0.309	na
	NGPD	600 to 13,000	lb/MMBtu	3.1	0.81	0.0496	0.1	1.01*S
			lb/10^3hp-hr[8]	24.0	5.5	0.7	0.642	$8.09*S_1$
	Dual-Fuel[2]	600 to 13,000	lb/MMBtu	3.1	0.79	0.0496	0.2	$0.05*S_1+0.895*S_2$
			lb/10^3hp-hr[9]	18.0	7.5	na	1.32	$0.406*S_1+9.57*S_2$
Small Industrial Reciprocating Engine	Natural Gas	less than 600	lb/MMBtu	5.6	0.7	0.016	0.136	0.001
			lb/10^3hp-hr[10]	26.0	3.53	na	1.59	na
	NGPD	less than 600	lb/MMBtu	4.41	0.95	0.31	0.36	0.29
			lb/10^3hp-hr[11]	31.0	6.68	2.20	2.47	2.05
	Gasoline	less than 600	lb/MMBtu	1.63	62.7	0.096	2.88	0.084
			lb/10^3hp-hr[12]	11.0	439.0	0.721	15.0	0.591

Source: Air Force Air Quality Utility Information System (AQUIS), developed by Argonne National Laboratories.
NGPD = non-gasoline petroleum distillate (includes distillate oils, residual oils, JP-4, JP-5, and JP-8); S = sulfur content (%); S_1 = sulfur content in fuel oil (%); S_2 = sulfur content in natural gas (%); na = not available

Table A1.8b. Notes:

1. Units are lb/MMBtu (heat input) and lb/hp-hr (power output). The difference in these factors takes into account average combustion unit efficiency.
2. Dual-fuel: 95% natural gas, 5% fuel oil
3. Large uncontrolled gas turbines, natural gas fired, AP-42, Table 3.1-1 (SCC 20100201)
4. Uncontrolled natural gas prime movers, gas turbines, AP-42, Table 3.2-1 (SCC 20200201)
5. Large uncontrolled gas turbines, fuel oil fired, AP-42, Table 3.1-1 (SCC 20100101)
6. Uncontrolled natural gas prime movers, 2-cycle lean burn, AP-42, Table 3.2-1 (SCC 20200252)
7. Uncontrolled natural gas prime movers, 4-cycle rich burn, AP-42, Table 3.2-1 (SCC 20200254)
8. Large stationary diesel engines, AP-42, Table 3.4-1 (SCC 20200401)
9. Large stationary dual-fuel engines, AP-42, Table 3.4-1 (SCC 20200402)
10. Uncontrolled natural gas prime movers, 4-cycle lean burn, AP-42, Table 3.2-1 (SCC 20200253)
11. Uncontrolled diesel industrial engines, AP-42, Table 3.3-1 (SCC 20200102)
12. Uncontrolled gasoline engines, AP-42, Table 3.3-1 (SCC 20200301)

Table A1.9a. HAP Emission Factors for External Combustion Sources (Metric)

Firing Type	Coal Emission Factor/ (10^{-9}*HHV) (kg/ton) Chain Grate	Dry Tangential	Pulverized Dry Wall	Pulverized Wet	Spreader Stoker	Traveling Grate	Underfeed Stoker	Fuel Oil Emission Factor/ (10^{-9}*HHV) (kg/1000 L) No. 2	No. 4	No. 5	No. 6	Natural Gas Emission Factor (10^{-3}*HHV) (kg/Mm^3)
Formaldehyde	na	na	na	na	182	115	na	131	117	117	117	na
Pyrene	na	na	na	154,965	na	na	na	na	na	0.0038	na	na
Indeno(1,2,3-c,d)Pyrene	na	na	99	25,594	na	na	na	na	na	na	na	na
Benzo (g,h,i,)Perylene	na	na	na	17,145	na	na	na	na	na	na	na	na
Benzo(b)Fluoranthene	na	na	na	28,561	na	na	na	na	na	na	na	na
Fluoranthene	na	na	na	69,652	na	na	na	na	na	na	na	na
Chrysene	na	na	na	8,902	na	na	na	na	na	na	na	na
Benzo(a)Pyrene	na	na	na	7,996	na	na	na	na	na	na	na	na
Phenanthrene	na	na	na	219,671	na	na	na	na	na	0.00453	na	na
Acenaphthene	na	na	na	na	na	na	na	na	na	0.0420	na	na
Ammonia	na	na	na	na	na	na	na	na	na	na	na	1.3
Fluorene	na	na	na	na	na	na	na	na	na	0.0130	na	na
Naphthalene	na	na	na	na	na	na	na	na	na	1.72	na	na
Manganese	na	na	1322	1561	na	na	na	5.8	na	7.17	20.0	4.683
Mercury	na	na	13	13	na	na	na	1	na	na	6.88	na
Nickel	na	na	956	878	na	na	na	70.1	na	152	652.6	na
Arsenic	na	na	564	443.5	332	647.9	na	1.7	na	2.77	27.4	na
Beryllium	na	na	67	66.8	na	na	na	1.0	na	0.0882	0.18	na
Cadmium	na	na	36.6	47.0	26	51.9	na	4.5	na	2.97	4.678	na
Chromium	na	na	1574	841	1035	na	na	23.7	na	1.67	30.7	na
Vanadium	na	na	21	na	na	na	na	na	na	na	na	na
Selenium	na	na	307.7	na	na	na	na	na	na	1.56	16	na
Antimony	na	na	na	na	na	na	na	na	na	na	14	na
Cobalt	na	na	na	na	na	na	na	na	na	na	41	na
Hexavalent Chromium	na	na	na	na	na	na	na	na	na	0.346	na	na

Source: Air Force Air Quality Utility Information System (AQUIS), developed by Argonne National Laboratories.
HAP Emissions (kg) = (Emission Factor)(k)(HHV)

Table A1.9a. HAP Emission Factors for External Combustion Sources (Metric) (Continued)

Example: Formaldehyde emissions from burning 2,000,000 liters No. 2 fuel oil with a HHV of 38.4 Mj/L

EF = (131kg/Mj)(10^{-9})(38.4 Mj/L) = 5.05 x 10^{-3} kg/L

Formaldehyde Emissions (kg) = (5.05 x 10^{-3} kg/L)(2,000,000 L) = 10.0 kg

k = units conversion factor = 10^{-9}

HHV = fuel higher heating value, Mj/kg or Mj/L (see Table 3.2.)

na = not available

1.0 Btu/scf = 37.2 j/L = 0.0373 Mj/m^3

1.0 Btu/gal = 279 j/L = 0.279 Mj/m^3

1.0 Btu/lb = 2.32 kj/kg

Table A1.9b. HAP Emission Factors for External Combustion Sources (English)

Firing Type	Coal Emission Factor/(10^{-9}*HHV) (lb/ton)							Fuel Oil Emission Factor / (10^{-9}*HHV) (lb/1000 gal)				Natural Gas Emission Factor (10^{-9}*HHV) (lb/10^{6} cf)
	Chain Grate	Dry Tan-gential	Pulverized Dry Wall	Pulverized Wet	Spreader Stoker	Traveling Grate	Underfeed Stoker	No. 2	No. 4	No. 5	No. 6	
Formaldehyde	na	na	na	na	442	280	na	319	283	283	283	na
Pyrene	na	na	na	376,000	na	na	na	na	na	0.009	na	na
Indeno(1,2,3-c,d)Pyrene	na	na	240	62,100	na	na	na	na	na	na	na	na
Benzo (g,h,i,)Perylene	na	na	na	41,600	na	na	na	na	na	na	na	na
Benzo(b)Fluoranthene	na	na	na	69,300	na	na	na	na	na	na	na	na
Fluoranthene	na	na	na	169,000	na	na	na	na	na	na	na	na
Chrysene	na	na	na	21,600	na	na	na	na	na	na	na	na
Benzo(a)Pyrene	na	na	na	19,400	na	na	na	na	na	na	na	na
Phenanthrene	na	na	na	533,000	na	na	na	na	na	0.011	na	na
Acenaphthene	na	na	na	na	na	na	na	na	na	0.102	na	na
Ammonia	na	na	na	na	na	na	na	na	na	na	na	3.2
Fluorene	na	na	na	na	na	na	na	na	na	0.032	na	na
Naphthalene	na	na	na	na	na	na	na	na	na	4.18	na	na
Manganese	na	na	3208	3788	na	na	na	14	na	17.4	48.5	11.363
Mercury	na	na	32	32	na	na	na	3	na	na	16.7	na
Nickel	na	na	2320	2130	na	na	na	170	na	370	1,584	na
Arsenic	na	na	1368	1076	806	1,572	na	4.2	na	6.73	66.5	na
Beryllium	na	na	162	162	na	na	na	2.5	na	0.214	0.429	na
Cadmium	na	na	88.8	114	64	126	na	11	na	7.2	11.35	na
Chromium	na	na	3820	2040	2,512	na	na	57.5	na	4.04	74.5	na
Vanadium	na	na	51	na	na	na	na	na	na	na	na	na
Selenium	na	na	746.7	na	na	na	na	na	na	3.79	38	na
Antimony	na	na	na	na	na	na	na	na	na	na	35	na
Cobalt	na	na	na	na	na	na	na	na	na	na	99	na

Hexavalent Chromium	na	na	na	na	na	na	na	na	na	0.839	na	na

Source: Air Force Air Quality Utility Information System (AQUIS), developed by Argonne National Laboratories.

HAP Emissions (lb) = (Emission Factor)(k)(HHV)

Table A1.9b. HAP Emission Factors for External Combustion Sources (English) (Continued)

Example: Formaldehyde emissions from burning 500,000 gallons No. 2 fuel oil with a HHV of 138,000 BTU/gal.

EF = (319 lb/MMBTU)(10^{-9})(0.138 MMBTU/gal) = 4.4 x 10^{-5} lb/gal

Formaldehyde Emissions (lb) = (4.4 x 10^{-5} lb/gal)(500,000 gal) = 22.0 lb

k = units conversion factor = 10^{-9}

HHV = fuel higher heating value, BTU/lb or BTU/gal (see Table 3.2.)

na = not available

1.0 Btu/scf = 37.2 j/L = 0.0373 Mj/m^3

1.0 Btu/gal = 279 j/L = 0.279 Mj/m^3

1.0 BTU/lb = 2.32 kj/kg

Table A1.10a. HAP Emission Factors for Internal Combustion Engines (Metric)

Compound	Emission Factors (mg/Mj)				
	Turbines		SIREs		LBEs
	NGPD	Natural Gas	NGPD	Gasoline	NGPD
Organic					
Acetaldehyde	na	na	3.30E-01	na	1.08E-02
Acrolein	na	na	<3.98E-02	na	3.39E-03
Aldehydes	na	na	3.01E+01	3.01E+01	na
Benzene	na	0.0011 (g/g VOC)	4.01E-01	na	3.34E-01
1,3-Butadiene	na	na	<1.68E-05	na	na
Formaldehyde	na	0.0081 (g/g VOC)	5.08E-01	na	3.40E-02
Naphthalene	na	na	3.65E-02	na	5.59E-02
Propylene	na	na	1.11E+00	na	1.20E+00
Toluene	na	0.0004 (g/g VOC)	1.76E-01	na	1.21E-01
Xylenes	na	0.0004 (g/g VOC)	1.23E-01	na	8.31E-02
Inorganic					
Antimony	9.47E-03	na	na	na	na
Arsenic	2.11E-03	na	na	na	na
Beryllium	1.42E-04	na	na	na	na
Cadmium	1.81E-03	3.10E-03	na	na	na
Chromium	2.02E-02	1.68E-03	na	na	na
Cobalt	3.92E-03	na	na	na	na
Lead	2.50E-02	na	na	na	na
Manganese	1.46E-01	5.45E-02	na	na	na
Mercury	3.92E-04	na	na	na	na
Nickel	5.16E-01	1.88E-02	na	na	na
Phosphorus	1.29E-01	na	na	na	na
Selenium	2.28E-03	na	na	na	na

Source: Air Force Air Quality Utility Information System, developed by Argonne National Laboratories.
na = not available
SIREs = Small Industrial Reciprocating Engines
LBEs = Large Bore Engines

Table A1.10b. HAP Emission Factors for Internal Combustion Engines (English)

	Emission Factors (lb/MMBtu)				
	Turbines		SIREs		LBEs
Compound	NGPD	Natural Gas	NGPD	Gasoline	NGPD
Organic					
Acetaldehyde	na	na	7.67E-04	na	2.52E-05
Acrolein	na	na	<0.0000925	na	7.88E-06
Aldehydes	na	na	7.00E-02	0.07	na
Benzene	na	0.0011 (lb/lb VOC)	9.33E-04	na	7.76E-04
1,3-Butadiene	na	na	<0.0000391	na	na
Formaldehyde	na	0.0081 (lb/lb VOC)	1.18E-03	na	7.89E-05
Naphthalene	na	na	8.48E-05	na	1.30E-04
Propylene	na	na	2.58E-03	na	2.79E-03
Toluene	na	0.0004 (lb/lb VOC)	4.09E-04	na	2.81E-04
Xylenes	na	0.0004 (lb/lb VOC)	2.85E-04	na	1.93E-04
Inorganic					
Antimony	0.000022	na	na	na	na
Arsenic	4.90E-06	na	na	na	na
Beryllium	3.30E-07	na	na	na	na
Cadmium	4.20E-06	7.20E-06	na	na	na
Chromium	4.70E-05	3.90E-06	na	na	na
Cobalt	9.10E-06	na	na	na	na
Lead	5.80E-05	na	na	na	na
Manganese	3.40E-04	1.27E-04	na	na	na
Mercury	9.10E-07	na	na	na	na
Nickel	1.20E-03	4.37E-05	na	na	na
Phosphorus	3.00E-04	na	na	na	na
Selenium	5.30E-06	na	na	na	na

Source: Air Force Air Quality Utility Information System, developed by Argonne National Laboratories.
na = not available
SIREs = Small Industrial Reciprocating Engines
LBEs = Large Bore Engines

A1.4. Applicability of Air Quality Regulations.

A1.4.1. Federal Regulations.

A1.4.1.1. Overview.

A1.4.1.1.1. Air quality is regulated by the U.S. Environmental Protection Agency (EPA) under the Clean Air Act (CAA) of 1977. In 1990, Congress passed 11 amendments to the CAA. The primary focus of the CAA of 1977 and the CAAA of 1990 is to set, attain, and maintain NAAQS.

A1.4.1.1.2. Primary NAAQS prescribe pollution limits designed to protect the public health within an adequate margin of safety. Secondary NAAQS prescribe limits necessary to protect the public welfare from adverse effects on soil, water, crops, animals, weather, climate, and property. EPA established NAAQS for six air pollutants, commonly called criteria pollutants: NO_2, CO, O_3, SO_2, PM (PM_{10} and $PM_{2.5}$), and lead (Pb).

A1.4.1.1.3. The CAA of 1977 divided states into geographical air quality management areas, and required them to determine whether ambient concentrations of each criteria pollutant met the NAAQS (attainment areas), failed to meet the NAAQS (non-attainment areas), or were designated as unclassifiable (treated as attainment areas).

A1.4.1.1.4. NAAQS are not directly enforceable, but are to be achieved by means of State Implementation Plans (SIPs) adopted by the states. SIPs include whatever combination of emission limitations, schedules, and other measures necessary to ensure attainment and maintenance of primary and secondary NAAQS. SIPs must also include pre-construction review requirements for new major sources and major modifications consistent with the prevention of significant deterioration (PSD) and non-attainment area NSR programs. Specific regulations differ depending on the attainment status of an area; the more stringent regulations apply to non-attainment areas. An area can be designated as an "attainment area" for one or more criteria pollutants and "non-attainment" for others.

A1.4.1.1.5. Many Air Force installations are major sources of air pollution, based upon the CAAA definition of a "major source." Depending on its type and size, a generator or power plant unit could by itself be classified as a major source. The definitions of "major source" and "major modification" vary with an area's attainment status. Non-attainment areas have more restrictive definitions of "major." The various definitions are summarized in Section A1.6 of this document. (Also see EPA Policy/Guidance document, 2 August 1996, *Major Source Determination Guidance for Military Installations Under the Clean Air Act.)*

A1.4.1.1.6. The CAA allows a new major source or modification of an existing major source that may be subject to PSD or non-attainment area NSR to avoid these requirements by "netting out." Netting out means that the total increase in a pollutant from the new or modified source during any period of 5 consecutive years, including the year of increase, is offset by an equal or greater reduction of emissions of the same pollutant from other sources at the facility. Whether a source may net out of permit requirements depends on the attainment status of the region and the state regulatory requirements for the facility location, as set forth in the SIP.

A1.4.1.2. Attainment Areas.

A1.4.1.2.1. Attainment requirements are intended to prevent further significant deterioration of air quality, and apply to areas that are in compliance with the NAAQS. These areas are called attainment areas or PSD areas (see paragraph A1.7). PSD requires that SIPs include measures to prevent "significant deterioration" of areas where the air is already "clean" (attainment areas and unclassified areas). PSD creates three classifications:

- Class I – wilderness, national parks, pristine areas
- Class II – moderate growth
- Class III – heavy industrial

Increments have been adopted for PM_{10}, SO_2, and NO_2. The increments vary according to the area classification, with smaller increments allowed for lower classifications (Class I area). Increments are allowable increases in ambient concentrations over "baseline" air quality, and are based on percentages of the NAAQS, ranging from 2 to 50 percent. Other than designated Class I areas, all PSD areas are classified as Class II, but are subject to reclassification.

A1.4.1.2.2. PSD Pre-construction Review.

A1.4.1.2.2.1. PSD prohibits construction of new major sources or modifications of existing major sources in any area to which PSD applies unless a permit has been secured prior to construction or modification. Under recent guidance from EPA, Air Force installations can be divided into discrete sources by grouping of "common control" (i.e., other Federal agencies, sister branches of the military) or industrial activity based on the two-digit Standard Industrial Classification[1] (SIC) Code. Establishing separate sources within an installation effectively increases the amount of "room" each source has before modifications performed at the source will trigger PSD. Increases and decreases in emissions from modifications at the installation can be offset in order to avoid PSD review as a major modification because of increases in "significant net ."

A1.4.1.2.2.2. For Air Force installations in attainment areas, PSD preconstruction review and permitting requirements apply only to new major sources having a PTE of 250 tons per year (tpy) of any criteria pollutant, unless the source belongs to one of 28 specially listed major source categories. Most generators and power plants at Air Force installations do not fit into any of the major source categories, with the possible exception of fossil-fuel-fired electric utility steam generating units of more than 73 MW (250 MMBtu/hr) heat input. The threshold for defining a major source for this category is 100 tpy.

---

[1] SIC codes, established in the 1987 Standard Industrial Classification Manual published by the U.S. Office of Management and Budget, classify industrial facilities by their type of economic activity.

A1.4.1.2.2.3. If the modification of an existing major source increases its net emissions to exceed any value of the *de minimis* emission rates listed in Table A1.11, the modification is defined as "major" and is subject to PSD requirements. The PSD requirements do not apply to the 189 HAPs.

Table A1.11. PSD *De Minimis* Emission Rates ("Major" Modification Significant Net Increase in Emissions)

Pollutant	Emission Rate
Nitrogen Oxides	40 tons per year
Carbon monoxide	100 tons per year
Sulfur dioxide	40 tons per year
Particulate matter (TSP)	25 tons per year
PM_{10}	15 tons per year
Ozone	40 tons per year (as VOCs)

A1.4.1.2.2.4. Generator or power plant units that are new major sources or major modifications require a PSD permit, unless their emissions increase can be offset by an emissions decrease from other emission units within the same source (netting out). The application for a PSD permit must contain the following information:

- Source Impact Analysis: The allowable increase in emission from the proposed new or modified source must not cause or contribute to pollution that violates the NAAQS or the PSD increments. Air quality dispersion modeling analyses are used to demonstrate compliance. Such analyses can range in complexity from screening modeling of a single stack to refined complex terrain modeling of multiple stacks.
- Air Quality Analysis: Federal regulations provide that onsite, pre-construction meteorological and/or ambient pollutant concentration data for up to 1 year may be required. Depending on application-specific issues, data from nearby monitoring stations may be used to satisfy the requirements. Post-construction monitoring may also be imposed to demonstrate that the NAAQS or increments are not exceeded.
- Source Information: Description of the nature, location, design capacity, typical operating schedule, and associated specifications and drawings of the proposed new or modified generator are required. A detailed construction schedule and description of the planned pollution controls must be included.
- Control Technology Review: PSD requires adoption of the Best Available Control Technology (BACT) to control each pollutant subject to regulation that would have a PTE in significant amounts. Compliance with all other applicable SIP, NSPS, and NESHAPs (National Emissions Standards for Hazardous Air Pollutants) emission standards is also required.

- Air-Quality-Related Values Analysis: If a source is located within 100 kilometers of a Class I area, an analysis of the impairment to visibility, soils, and vegetation is required in consultation with the Federal land manager of that Class I area.

- Public Participation: An opportunity for a public hearing on the PSD application and notice of such a hearing must be provided as part of the review process.

A1.4.1.2.3. Best Available Control Technology (BACT). The control technology requirements that fulfill BACT are determined on a case-by-case basis. BACT must always be at least as stringent as NSPS delineated in the CAA for specific industrial source categories. EPA now requires a five step “top-down” BACT analysis procedure for PSD permits. This procedure involves the following steps:

- Identification of all emission control technology alternatives and alternative processes, including Lowest Achievable Emission Rate (LAER) alternatives.

- Elimination of any control options not technically feasible for this type of source.

- Identification of the “top” (most effective) emission control technology and ranking of any less effective controls in descending order.

- Determination of the economic, energy, and other environmental impacts of each control technology and elimination of any technology with unacceptable impacts.

- Selection of the BACT and the emission limits.

A1.4.1.2.4. Visibility and Air-Quality-Related Values.

A1.4.1.2.4.1. For Class I areas, the PSD permitting process requires that the Federal land manager of any Class I area be notified, and the EPA must be consulted as to whether the proposed facility will adversely affect air-quality-related values, including visibility in the Class I area. EPA has defined visibility impairment as any humanly perceptible change in visibility such as visual range, contrast, or coloration from the natural conditions.

A1.4.1.2.4.2. The results of dispersion modeling are generally used to assess the impact of source emissions on soils and vegetation. Compliance with NAAQS normally ensures there will be no harmful impacts to soils and vegetation. Screening procedures to analyze visual impairment range from a set of simple equations (Level I) to sophisticated visibility modeling (Level III). The Level I screening, which is highly conservative, typically is sufficient to demonstrate non-visibility impairment.

A1.4.1.2.4.3. In addition to the provisions for Class I area visibility protection under the PSD pre-construction review program, there is a separate program for preventing and remedying visibility impairment in mandatory Class I areas. The regulations adopted under this program require states with mandatory Class I areas to incorporate provisions for visibility protection into their SIPs. These provisions must include measures necessary to prevent and remedy visibility impairment. If major existing stationary sources in certain source categories (i.e., fossil-fuel-fired generating plants in excess of 73 (250 MMBtu/hr) are determined to impair visibility in Class I areas, they are required to install Best Available Retrofit Technology (BART).

A1.4.1.3. Non-attainment Areas.

A1.4.1.3.1. Non-attainment requirements apply to any areas that violate any NAAQS. Ozone non-attainment areas present the most extensive and difficult sets of non-attainment problems. Non-attainment areas also exist for CO, SO_2, Pb, and PM_{10} (see paragraph A1.7). Non-attainment areas for each criteria pollutant are subdivided by the severity of the area's air pollution problem. Areas with more severe pollution problems are given more time to achieve NAAQS, but must comply with stricter and more numerous control measures. Attainment deadlines, size of affected facilities, and strictness of minimum control measures vary with pollution severity. Table A1.12 highlights ozone, CO, and PM_{10} non-attainment areas, including major source trigger levels, emissions offset requirements, and control technology requirements.

Table A1.12. Non-attainment Areas - Major Source Trigger Levels, Emissions Offsets, and Control Requirements

Criteria Pollutant	Requirement Category	Area Designation: Marginal	Moderate	Serious	Severe	Extreme
Ozone[1]	New and Existing Major Sources	100 tpy	100 tpy	50 tpy	25 tpy	10 tpy
	Major Modifications (Significant Net Emissions Increase)[2]	40 tpy	40 tpy	25 tpy	25 tpy	any increase
	VOC & NOx Offset Ratios[3]					
	Internal (for netting)	1.0	1.0	1.3	1.3	1.3
	External	1.1	1.15	1.2	1.3	1.5
	Control Strategy					
	Existing "major" sources	RACT	RACT	RACT	RACT	RACT
	New "major" sources/modifications	LAER	LAER	LAER	LAER	LAER
CO	New and Existing Major Sources	NA[4]	100 tpy	50 tpy	NA[4]	NA[4]
	Major Modifications (Significant Net Emissions Increase)	NA[4]	100 tpy	50 tpy	NA[4]	NA[4]
	CO Offset Ratios[3]					
	Internal (for netting)	--	1.0	1.0	--	--
	External	--	1.0	1.0	--	--
	Control Strategy					
	Existing "major" sources	--	RACT	RACT	--	--
	New "major" sources/modifications	--	LAER	LAER	--	--

Table A1.12. Non-attainment Areas - Major Source Trigger Levels, Emissions Offsets, and Control Requirements (Continued)

Criteria Pollutant	Requirement Category	Area Designation: Marginal	Moderate	Serious	Severe	Extreme
PM_{10}	New and Existing Major Sources	NA[4]	100 tpy	70 tpy	NA[4]	NA[4]
	Major Modifications (Significant Net Emissions Increase)	NA[4]	15 tpy	15 tpy	NA[4]	NA[4]
	PM_{10} Offset Ratios[3]					
	Internal (for netting)	--	1.0	1.0	--	--
	External	--	1.0	1.0	--	--
	Control Strategy					
	Existing "major" sources	--	EPA to issue guidelines		--	--
	New "major" sources/modifications	--	EPA to issue guidelines		--	--

BACT = best achievable emission rate
LAER = lowest achievable emission rate
RACT = reasonable available emission rate
tpy = tons per year

[1] Regulated as VOC and NOx.
[2] Major modifications are modifications that of themselves constitute a major source, or modifications to existing major sources that represent a significant net emissions increase (as listed).
[3] Emissions Offset (Offset Ratios) - A compensating reduction in the emissions of an affected pollutant from a permitted emissions unit to provide an emission allowance for a new or modified emissions unit.
[4] CO and PM_{10} non-attainment areas are classified as either “moderate” or “serious”.

A1.4.1.3.2. Non-attainment Area New Source Review. One of the largest impacts of the non-attainment requirements on Air Force installations relates to construction of new facilities or modification of existing facilities, including generators and power plants. When emissions from a major source located in a non-attainment area are expected to increase above *de minimis* levels as a result of an expansion or modernization project, the proposal is subject to NSR prior to construction. NSR requires that a construction permit be obtained, that technology standards reflecting LAER be satisfied, and that offsets representing emission reductions from other sources be provided.

A1.4.1.3.3. Lowest Achievable Emission Rate. Major new sources and major modifications in non-attainment areas must be equipped with LAER control technology. LAER must be as stringent as the most stringent control achieved in practice on a similar application *without* regard to economic factors.

A1.4.1.3.4. Reasonably Available Control Technology (RACT).

A1.4.1.3.4.1. The CAAA require existing major sources in non-attainment areas to be equipped with RACT. RACT is the degree of emission reduction that the EPA determines is reasonably available, considering technological and economic feasibility, health, environment, and energy impacts. Although a determination of what controls constitute RACT can be made on a case-by-case review of the circumstances of each individual facility, EPA has adopted the mechanism of issuing control technique guidelines (CTGs) to provide a generic definition of RACT for specified industrial categories. The CTGs describe the types of air pollution control measures and the levels of control that they should achieve to satisfy applicable RACT requirements.

A1.4.1.3.4.2. The CAAA also require that EPA develop alternative control techniques (ACT) for sources of VOCs and NOx that emit 25 tpy or more. An ACT document (July 1993) has been prepared for stationary reciprocating engines, which have been identified as a source category that emits more than 25 tpy of NOx.

A1.4.1.4. New Source Performance Standards.

A1.4.1.4.1 Overview.

A1.4.1.4.1.1. NSPS are established for particular pollutants in industrial categories based on adequately demonstrated control technologies. The Federally-established NSPS emission standards apply to stationary sources that have been modified or built after the dates designated in the specific rule, and have been developed for numerous specific industrial facilities and operations. The standards are generally stated as emission limits, but where emission limits are not feasible, work practice standards may be specified. NSPS authority has been delegated to some states by EPA.

A1.4.1.4.1.2. Most generators used at Air Force bases are small enough to avoid NSPS requirements; however, some types of large capacity generators are subject to specific NSPS requirements. Specific NSPS might apply to the following:

- Fossil-fuel-fired steam generating units with a heat input capacity greater than 73 MW (250 MMBtu/hr)
- Industrial-commercial-institutional steam generating units with a heat input capacity between 29 MW and 73 MW (100 MMBtu/hr and 250 MMBtu/hr)
- Small industrial-commercial-institutional steam generating units with a heat input capacity between 2.9 MW and 29 MW (10 MMBtu/hr and 100 MMBtu/hr)
- Gas turbines with a heat input capacity greater than 2.9 MW (10 MMBtu/hr)

A1.4.1.4.1.3. NSPS do not require a permit, but sources must notify EPA when construction or modification begins, and again before startup. Construction of such sources may trigger other permitting requirements. Performance tests are required within 180 days after startup in order to demonstrate compliance with the standards. These tests must be conducted in accordance with EPA test methods. A summary of the applicable NSPS for generators and power plants is presented in Tables A1.13.a. and A1.13.b.

A1.4.1.4.2. Fossil-Fuel-Fired Steam Generating Units. Steam-generating units commencing construction or modification after August 17, 1971, and having a heat input greater than 73 MW (250 MM Btu/hr) are required to limit the emission of PM, NOx, and SO_2. Monitoring of these pollutants, opacity, and fuel analysis is also required [40 CFR Part 60, Subpart D].

A1.4.1.4.3. Electric Utility Steam-Generating Units. Electric utility steam-generating units commencing construction or modification after September 18, 1978, and having a heat input greater than 73 MW (250 MMBtu/hr) are required to meet technology-forced emission limits for PM, NOx, and SO_2. Flue Gas Desulfurization (FGD)–wet scrubbers–are needed for coal-fired units that burn coal with a sulfur content above approximately 1.5 percent in order to meet the SO_2 standards. To meet the particulate standards, either electrostatic precipitators (ESPs) or baghouses are generally used. ESPs tend to be more efficient for PM control in units burning high sulfur coal; baghouses appear to be the better PM technology for units burning low sulfur coal. NOx can be controlled through the use of highly efficient combustion technology. Continuous emission monitoring for NOx, SO_2, and opacity emissions is required. The oxygen or carbon dioxide content of flue gas must also be monitored [40 CFR Part 60, Subpart Da].

Table A1.13a. NSPS Requirements for Generators and Power Plants (Metric)

Source Category	Fuel Type	Pollutant	Emission Limit (ng/J)[1]	Reduction Requirement[2]	Monitoring Requirements	
					Emissions	Other
Steam Generator (> 73 MW)	Solid fossil fuel (coal, except lignite)	PM	43	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
constructed or modified		SO_2	520	[NA]	continuous	
after 8/17/71		NOx	300	[NA]	continuous	
[40 CFR Part 60,	Liquid fossil fuel	PM	43	[NA]	none	flue gas O_2 or CO_2 fuel analysis
Subpart D]	(fuel oil)	Opacity	20%; 27% 6min/hr	[NA]	continuous	
		SO_2	340	[NA]	continuous	
		NOx	130	[NA]	continuous	
	Gaseous fossil fuel	PM	43	[NA]	none	flue gas O_2 or CO_2 fuel analysis
	(natural gas)	Opacity	20%; 27% 6min/hr	[NA]	continuous	
		NOx	86	[NA]	continuous	
	Lignite Coal	NOx	260	[NA]	continuous	flue gas O_2 or CO_2, fuel analysis
	Lignite mined in ND, SD, or MT & burned in cyclone fired unit	NOx	340	[NA]	continuous	flue gas O_2 or CO_2, fuel analysis
Utility Steam Generator (> 73 MW)	Solid fossil fuel (coal, except lignite)	PM	13	99%	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	
constructed or modified after 9/18/78		SO_2	520	90% (if >0.20 lb/MM Btu)	continuous	
		NOx	260 ng/J bit.coal	65%	continuous	
[40 CFD Part 60,			210 ng/J subbit.coal	65%	continuous	
Subpart Da]	Liquid fossil fuel (fuel oil)	PM	13	70%	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	
		SO_2	340	90% (if >0.20 lb/MM Btu)	continuous	
		NOx	130	30%	continuous	

	Gaseous fossil fuel (natural gas)	PM	13	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	
		SO_2	340	90% (if > 0.20 lb/MM Btu)	continuous	
		NOx	86	25%	continuous	

Table A1.13a. NSPS Requirements for Generators and Power Plants (Metric) (Continued)

Source Category	Fuel Type	Pollutant	Emission Limit (ng/J)[1]	Reduction Requirement[2]	Monitoring Requirements: Emissions	Monitoring Requirements: Other
Industrial/Commercial Steam Generator (29 - 73 MW) constructed or modified after 6/19/84 [40 CFR Part 60, Subpart Db]	Pulverized coal	PM	22	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	520	90%	continuous	
		NOx	300	[NA]	continuous	
	Spreader stoker & fluidized bed	PM	22	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	520	90%	continuous	
		NOx	260	[NA]	continuous	
	Mass-feed stoker	PM	22	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	520	90%	continuous	
		NOx	210	[NA]	continuous	
	Distillate oil	PM	43	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	340	90%	continuous	
		NOx	43 (low heat)	[NA]	continuous	
		NOx	86 (high heat)			
	Residual oil	PM	43	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	340	90%	continuous	
		NOx	130 (low heat)	[NA]	continuous	
		NOx	170 (high heat)			
	Natural gas	PM	[NA]	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	[NA]	[NA]	continuous	
		NOx	43 (low heat)	[NA]	continuous	

NOx	86 (high heat)

Table A1.13a. NSPS Requirements for Generators and Power Plants (Metric) (Continued)

Source Category	Fuel Type	Pollutant	[1] Emission Limit(ng/J)	Reduction Requirement[2]	Monitoring Requirements: Emissions	Monitoring Requirements: Other
Small Industrial/Commercial Steam Generator (2.9 - 29 MW) constructed or modified after 6/9/89 [40 CFR Part 60, Subpart Dc]	Solid fossil fuel (coal)	PM	22	[NA]	none	fuel analysis
		Opacity	20%; 27% 6min/hr	[NA]	continuous	
		SO_2	520	90%	continuous	
	Liquid fossil fuel (fuel oil)	PM	[NA]	[NA]	none	fuel analysis
		Opacity	20%; 27% 6min/hr	[NA]	continuous	
		SO_2	215	[NA]	continuous	
Gas Turbines (>2.9 MW) constructed or modified after 10/31/1977 [40 CFR Part 60, Subpart GG]	Gaseous fuel (> 29.3 MW)	NOx	75 ppm[3]	[NA]	[NA]	fuel analysis
		SO_2	150 ppm[4]	[NA]	continuous	fuel consumption water to fuel ratio
	Gaseous fuel (2.9 to 29.3 MW)	NOx	150 ppm[3]	[NA]	[NA]	fuel analysis
		SO_2	150 ppm[4]	[NA]	continuous	fuel consumption water to fuel ratio

Exemptions: emergency gas turbines
most military gas turbines
fire fighting gas turbines
regenerative cycle gas turbines <29 MW

Conversions: ng/j = nanogram per joule = 10^{-9} g/j
1.0 lb/MMBtu = 430 ng/J
ppm = parts per million

1. Opacity limits are unitless. NSPS requires that opacity is not to exceed 20%, except for periods of excess emissions no longer than 6 minutes/hour, during which time opacity is not to exceed 27%.
2. Reduction requirement is the emissions reduction of a specific pollutant with reference to uncontrolled emissions.
3. Adjusted for heat rate and fuel-N content.
4. Fuel sulfur content not to exceed 0.8 wt%.

Table A1.13b. NSPS Requirements for Generators and Power Plants (English)

Source Category	Fuel Type	Pollutant	Emission Limit (lb/MMBtu)[1]	Reduction Requirement[2]	Monitoring Requirements: Emissions	Monitoring Requirements: Other
Steam Generator (>250 MM Btu/hr)	Solid fossil fuel (coal, except lignite)	PM	0.10	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	
constructed or modified after 8/17/71		SO_2	1.20	[NA]	continuous	
		NOx	0.70	[NA]	continuous	
[40 CFR Part 60, Subpart D]	Liquid fossil fuel (fuel oil)	PM	0.10	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	
		SO_2	0.80	[NA]	continuous	
		NOx	0.30	[NA]	continuous	
	Gaseous fossil fuel (natural gas)	PM	0.10	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		NOx	0.20	[NA]	continuous	
	Lignite Coal	NOx	0.60	[NA]	continuous	flue gas O_2 or CO_2, fuel analysis
	Lignite mined in ND, SD, or MT & burned in cyclone fired unit	NOx	0.80	[NA]	continuous	flue gas O_2 or CO_2, fuel analysis
Utility Steam Generator (>250 MM Btu/hr)	Solid fossil fuel (coal, except lignite)	PM	0.03	99%	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	
constructed or modified after 9/18/78		SO_2	1.20	90% (if >0.20 lb/MM Btu)	continuous	
		NOx	0.60 (Bit. coal)	65%	continuous	
[40 CFD Part 60, Subpart Da]	Liquid fossil fuel	PM	0.03	70%	none	flue gas O_2 or CO_2
	(fuel oil)	Opacity	20%; 27% 6min/hr	[NA]	continuous	
		SO_2	0.80	90% (if >0.20 lb/MM Btu)	continuous	
		NOx	0.30	30%	continuous	
	Gaseous fossil fuel	PM	0.03	[NA]	none	flue gas O_2 or CO_2
	(natural gas)	Opacity	20%; 27% 6min/hr	[NA]	continuous	

	SO_2	0.80	90% (if > 0.20 lb/MM Btu)	continuous
	NOx	0.20	25%	continuous

Table A1.13b. NSPS Requirements for Generators and Power Plants (English) (Continued)

Source Category	Fuel Type	Pollutant	Emission Limit (lb/MMBtu)[1]	Reduction Requirement[2]	Monitoring Requirements	
					Emissions	Other
Industrial/Commercial Steam Generator (100-250 MM Btu/hr) constructed or modified after 6/19/84 [40 CFR Part 60, Subpart Db]	Pulverized coal	PM	0.05	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	1.20	90%	continuous	
		NOx	0.70	[NA]	continuous	
	Spreader stoker & fluidized bed	PM	0.05	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6 min/hr	[NA]	continuous	fuel analysis
		SO_2	1.20	90%	continuous	
		NOx	0.60	[NA]	continuous	
	Mass-feed stoker	PM	0.05	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	1.20	90%	continuous	
		NOx	0.50	[NA]	continuous	
	Distillate oil	PM	0.10	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	0.80	90%	continuous	
		NOx	0.10 (low heat)	[NA]	continuous	
		NOx	0.2 (high heat)			
	Residual oil	PM	0.10	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	0.80	90%	continuous	
		NOx	0.30 (low heat)	[NA]	continuous	
		NOx	0.4 (high heat)			
	Natural gas	PM	[NA]	[NA]	none	flue gas O_2 or CO_2
		Opacity	20%; 27% 6min/hr	[NA]	continuous	fuel analysis
		SO_2	[NA]	[NA]	continuous	
		NOx	0.10 (low heat)	[NA]	continuous	
		NOx	0.20 (high heat)			

Table A1.13b. NSPS Requirements for Generators and Power Plants (English) (Continued)

Source Category	Fuel Type	Pollutant	Emission Limit (lb/MMBtu)[1]	Reduction Requirement[2]	Monitoring Requirements Emissions	Monitoring Requirements Other
Small Industrial/Commercial	Solid fossil fuel	PM	0.05	[NA]	none	fuel analysis
Steam Generator	(coal)	Opacity	20%; 27% 6min/hr	[NA]	continuous	
(10-100 MMBtu/hr)		SO_2	1.20	90%	continuous	
constructed or modified	Liquid fossil fuel	PM	[NA]	[NA]	none	fuel analysis
after 6/9/89	(fuel oil)	Opacity	20%; 27% 6min/hr	[NA]	continuous	
[40 CFR Part 60, Subpart Dc]		SO_2	0.50	[NA]	continuous	
Gas Turbines	Gaseous fuel	NOx	75 ppm[3]	[NA]	[NA]	fuel analysis
(>10 MMBtu/hr)	(>100 MMBtu/hr)	SO_2	150 ppm[4]	[NA]	continuous	fuel consumption
constructed or modified						water to fuel ratio
after 10/31/1977	Gaseous fuel	NOx	150 ppm[3]	[NA]	[NA]	fuel analysis
[40 CFR Part 60,	(10 to 100	SO_2	150 ppm[4]	[NA]	continuous	fuel consumption
Subpart GG]	MMBtu/hr)					water to fuel ratio

Exemptions: emergency gas turbines
most military gas turbines
fire fighting gas turbines
regenerative cycle gas turbines <100 MMBtu

Conversions: ng/j = nanogram per joule = 10^{-9} g/j
1.0 lb/MMBtu = 430 ng/J
ppm = parts per million

1. Opacity limits are unitless. NSPS requires that opacity is not to exceed 20%, except for periods of excess emissions no longer than 6 minutes/hour, during which time opacity is not to exceed 27%.
2. Reduction requirement is the emissions reduction of a specific pollutant with reference to uncontrolled emissions.
3. Adjusted for heat rate and fuel-N content.
4. Fuel sulfur content not to exceed 0.8 wt%.

A1.4.1.4.4. Industrial-Commercial-Institutional Steam Generating Units. Steam-generating plants commencing construction or modification after June 19, 1984, and having a heat input greater than 29 MW (100 MMBtu/hr) are subject to the NSPS emission limitations for PM, NOx, and SO_2. The limitations that apply depend on the type of fuel being burned [40 CFR Part 60, Subpart Db]. Continuous emissions monitoring of SO_2, NOx, and opacity are required, in addition to monitoring of flue gas O_2 (or CO_2) and fuel analysis.

A1.4.1.4.5. Small Industrial-Commercial-Institutional Steam Generating Units. Small steam generating units commencing construction or modification after June 9, 1989, and having a heat input capacity between 2.9 MW (10 MMBtu/hr) and 29 MW (100 MMBtu/hr) are required to limit SO_2 and PM emissions. The emission limitations that apply are dependent on the type of fuel being burned. Continuous monitoring of SO_2 and opacity are required, and the facility must monitor fuel analysis. Excess emission reports must be submitted for any calendar quarter in which a facility exceeds the SO_2 or opacity limits. If no limits are exceeded, then semi-annual reports must be filed affirming that no limits have been exceeded [40 CFR Part 60, Subpart Dc].

A1.4.1.4.6. Gas Turbines. Stationary gas turbines with heat inputs greater than 2.97 MW (10 MMBtu/hr) that were constructed or modified after October 3, 1977, are required to limit the emission of NOx and SO_2. Emissions and the sulfur and nitrogen content of the fuel being burned must be monitored [40 CFR Part 60, Subpart GG].

A1.4.1.5. Air Toxics.

A1.4.1.5.1. Overview. Section 112 of the CAA regulates emissions of HAPs or air toxics. EPA was authorized to identify compounds to regulate under this program and to establish emission standards for them. Prior to 1990, NESHAPs had been established for the following eight compounds: arsenic, asbestos, benzene, beryllium, mercury, radionuclides, radon-222, and vinyl chloride. Title III of the CAAA of 1990 radically revised the program, listing a total of 189 HAPs and focusing on technology-based regulation. Under the amended legislation, EPA is required to establish emission standards for the categories and subcategories of sources that emit them. These emission standards are generally known as Maximum Achievable Control Technology (MACT). Petitions to list or delist substances are determined by whether the substance may reasonably be anticipated to cause adverse effects to human health or the environment.

A1.4.1.5.2. Title III Applicability. Air toxic permitting requirements and MACT standards apply to “major sources”, those that have a PTE of 10 tpy of any HAP or 25 tpy of any combination of HAPs. Area sources are defined as stationary sources of HAPs that are not major sources. EPA must list categories and subcategories of area sources that it determines will present a threat of adverse effects to human health or the environment. Standards for area sources must represent at least Generally Available Control Technology (GACT). Generators and power plants typically emit only small quantities of HAPs. Therefore, current air toxic permitting and MACT requirements under Titles III and V, respectively, of the CAAA are unlikely to apply to these sources.

A1.4.1.5.3. Maximum Achievable Control Technology (MACT). Title III requires new and existing major sources and some minor sources to install controls within specified time periods to meet MACT for reducing HAP emissions. EPA has listed 174 industrial categories and subcategories for major and area HAP sources and issues the standards according to a 10-year statutory timetable. MACT standards for generators and power plants (industrial and commercial boilers, stationary IC engines, and stationary gas turbines) are scheduled for adoption November 15, 2000. If EPA fails to promulgate required standards by the statutory deadlines, then 18 months after the deadline (but only after the effective date of a Title V permit program), sources in any category must apply to the permitting authority to establish MACT limits on a case-by-case basis. This is known as the MACT “hammer.”

A1.4.1.6. Acidic Deposition Control. Title IV of the CAAA of 1990 is directed at reducing acid rain deposition by controlling sources of SO_2 and NOx, two causes of acid rain. The goal is to reduce nationwide SO_2 emissions by 10 million tpy below 1980 levels and to reduce NOx emissions by 2 million tpy by the year 2000. Most new and existing fossil-fuel-fired power plants in the contiguous 48 states are affected. The regulations apply only to commercial utilities with a production capacity of at least 25 MW (85 MMBtu/hr) that produce electricity for sale. Industrial plants that do not produce electricity for sale are not regulated under this rule. Therefore, it is unlikely that any Air Force installations would be directly impacted by Title IV regulations. Industrial facilities, however, may elect to be affected facilities and sell excess emission rights.

A1.4.1.7. Title V Operating Permits.

A1.4.1.7.1. Title V of the CAAA of 1990 created a nationwide operating permit system for most significant sources. The program, to be implemented primarily by the states, is subject to EPA oversight. EPA has promulgated regulations specifying the minimum elements of a state operating permit program, and all the states are in various stages of obtaining program approval. The goal of Title V is to consolidate existing requirements under a comprehensive operating permit umbrella in order to create greater certainty for permittees and more comprehensive oversight by state agencies. With the exception of permitting fees, no significant new substantive requirements were created under Title V.

A1.4.1.7.2. The following sources are covered under the Title V operating permit program:

- Sources with the potential to emit 100 tpy of any criteria pollutant
- Sources with the potential to emit 10 tpy of any one HAP or 25 tpy of any combination of HAPs
- Sources subject to NSPS (some states)
- Any source with a PSD permit or subject to PSD permitting
- Any source with an NSR permit or subject to NSR permitting in non-attainment areas
- Sources affected under the Title IV acid rain provisions

A1.4.1.7.3. Title V provides for the assessment of annual permit fees sufficient to cover all reasonable costs of the permit program. The average fees are to be at least $25/ton of each regulated pollutant. The term "regulated pollutant" does not include CO, and states are not required to include in its emissions base any emissions above 4,000 tpy CO from a source. Allowable emissions, rather than PTE estimates, are used as the annual license fee basis. However, some states allow facilities to pay annual license fees based on their actual emissions if the facility maintains sufficient monitoring data and documentation of actual operation (i.e., hours, raw material input, fuel use).

A1.4.1.7.4. Title V requires the submittal of an annual compliance certification signed by the responsible official. Sources not in compliance must submit plans and schedules showing how and when they will comply with all applicable requirements.

A1.4.1.7.5. Title V permits are issued for a maximum of 5 years and must be renewed. Because of the large volume of permits to be processed, some states have established a staggered schedule for permit submittals based on major source categories. Each state has different procedures, so contact with the state air pollution control agency is recommended in determining Title V operating permit submittals.

A1.4.1.7.6. The CAAA increased the level of public involvement in the air permitting process. Title V programs must provide adequate procedures for public comment and opportunity for judicial review of permit actions by applicants and any others who participate in the public comment period.

A1.4.1.7.7. The permitting authority (state agency) must submit a copy of each Title V permit application to EPA for review. EPA may object to the issuance of the permit if it finds a failure to comply with applicable requirements. If EPA objects, the state agency cannot issue the permit unless it is revised to satisfy the objection. Anyone may petition EPA to object to a proposed permit, based on grounds raised during the public comment period.

A1.4.1.7.8. Title V regulations allow for two shields from regulatory enforcement: an application shield and a permit shield. The application shield allows the facility to operate under its Title V application in lieu of an operating permit. To keep the shield, the facility must maintain a "complete" application with the regulatory agency. The permit shield covers all applicable regulations identified by the applicant, and compliance with the shield is deemed compliance with any requirement of the CAA. Sources are eligible for the permit shield to the extent that their permit addresses the applicable requirement (even if misconstrued); or if the state agency, in acting on the permit, has determined that the requirement is not applicable and has so stated in the permit. The permit shield is issued at the discretion of the permitting authority. If the permittee or the permitting authority fails to evaluate the applicability of a particular air quality regulation during the permitting process, the permittee is not shielded against future enforcement action for non-compliance with that specific regulation.

A1.4.1.7.9. Operational flexibility is another important provision of the Title V program. To avoid future permit modifications or re-openings, planned facility changes should be addressed in the initial Title V permitting process. Changes in the facility (installation) are permitted without a formal permit revision if permit emission limits are not exceeded and the facility is not a “modification” as defined in Title I of the CAAA. Well-defined alternative operating scenarios should be developed identifying the applicable requirements of each scenario, including monitoring, record keeping, and reporting methods.

A1.4.2. Air Force Policy. Air Force installations must adhere to both DoD and Air Force regulations, which provide instructions relating to air emissions.

A1.4.2.1. Department of Defense Regulations. DoD Instruction 4120.114, *Environmental Pollution Prevention, Control, and Abatement*, implements DoD policies provided by Executive Order 12088, *Federal Compliance With Pollution Standards*, and Office of Management and Budget Circular A-106. The instruction establishes policies for developing and submitting plans to install improvements needed to abate air emissions from DoD facilities.

A1.4.2.2. Air Force Instructions. Air Force Instruction (AFI) 32-7040, *Air Quality Compliance*, sets forth policy and procedures for controlling pollutant emissions into the air. This instruction mandates compliance with all applicable Federal, state, and local regulations concerning air quality, including SIPs. AFI 32-7040 refers responsible officials to the Air Force Research Laboratory, Airbase and Environmental Technology Division (AFRL/MLQ) (formerly Armstrong Laboratory), for assistance with monitoring, record keeping, reporting requirements, and conducting emissions inventories.

A1.4.3. State/Local Regulations.

A1.4.3.1. State Responsibility. Individual states have the primary responsibility for administering Federal air quality regulations. The extent to which an Air Force installation is regulated depends upon the state or local jurisdiction in which the installation is located. The CAA requires each state to develop, enact, and enforce air quality regulations that are at least as stringent as the Federal (EPA) regulations. However, state and local regulations can be more stringent and more comprehensive than the Federal regulations. Each state must identify state-specific air quality issues and then develop air quality regulations that address the issues. The SIP outlines the regulations established by a state to meet the NAAQS and other Federal air quality requirements.

A1.4.3.2. Use of Federal Guidelines. State and local regulations usually follow the Federal guidelines for state programs and have many similar features. Some states and local air pollution control agencies have defaulted to the EPA regulations and have enacted the Federal regulations verbatim. However, depending on the type and severity of the air pollution problems within the state or region, the individual regulations will vary. For example, photochemical oxidant (ozone) problems are widespread in southern California; thus individual Air Pollution Control Districts and Air Quality Management Districts in that state have very stringent VOC and NOx emission requirements. North Dakota, however, has no such problem and, therefore, has fewer and less stringent regulations.

A1.4.3.3. Permit Requirements. State and local regulations generally establish emission limitations for various types of sources and require permits for construction, modification, and operation of sources of air pollution. All states are required to have a construction permit program for new or modified major stationary sources. Permit requirements depend on the attainment status of the area in which the source is located. These programs include pre-construction review of the emission source, and must be in accordance with PSD or non-attainment requirements (See paragraphs A1.4.1.2 and A1.4.1.3, respectively).

A1.4.3.4. Operating Permit Program. The CAAAs require each state to develop, implement, and administer a comprehensive operating permit program for all major stationary sources. It is the Title V program described in paragraph A1.4.1.7. This program implements and ensures compliance with the requirements outlined in the individual SIP. Requirements for operating permits vary with the attainment status of the area in which the installation is located. In addition to emission limitations and permits, state and local air pollution control agencies may require performance testing and periodic or continuous emissions monitoring to ensure compliance with emission limitations.

A1.4.3.5. Following Most Stringent Regulations. Because state/local air quality regulations vary, the environmental function for an Air Force installation must be familiar with the specific air quality regulations for the state and any local regulatory agency with jurisdiction over the installation. The installation must know and follow the most stringent applicable regulations.

A1.4.3.6. Specific Generator Regulations. The following regulations specifically related to generators vary among state and local authorities:

- Although EPA issued a policy (September 6, 1995) that the PTE for emergency generators can be calculated on the basis of operation for 500 hours/year, some states still require PTE to be calculated on the basis of operation for 24 hours per day, 365 days per year (8,760 hours/year).
- States may provide a list of specific exceptions from permitting requirements. The threshold for this exemption varies across the country. An example is Colorado, which exempts *insignificant* emission units from operating permit requirements (i.e., stationary internal combustion engines that have actual emissions less than 5 tons per year (tpy) or a rated horsepower (hp) of less than 50, and emergency generators that operate less than 250 hours/year). Another example is Florida, which exempts emergency generators and general purpose internal combustion engines that consume less than 121,133 liters (32,000 gallons) diesel fuel per year on a facility wide basis.
- Regulations vary concerning generator units that serve as aerospace ground equipment AGE. Some states treat AGE as a mobile source, while others treat it as a stationary source. Utah treats a skid-mounted AGE as a stationary source and wheel-mounted AGE as a mobile source. (**Note:** Recent legal decisions indicate that AGE meeting CAA definitions of “non-road” engines [such as diesel engines above 50 hp, but not gas turbines] may no longer be classified as stationary sources by the permitting authority; however, the permitting authority may impose operational controls, such as

limits on time of operation. For additional information, contact the Command Air Quality Manager or the Air Force Legal Services Agency, Environmental Law and Litigation Division.)

A1.4.3.7. Coordination with Air Pollution Control Agency. The specific state and local air quality regulations that would apply to an individual Air Force installation are too numerous to include in this document. Many regulations, especially those associated with the Title V operating permit program, are only now being implemented. The environmental function for the installation should contact the appropriate air pollution control agency to obtain information on the existing and pending air quality regulations and permit requirements that may affect the operations and resources of the installation.

A1.4.3.8. Unique Military Mission. State and local agencies, which tend to focus on local industry, may not understand the military operations, activities, and mission of an Air Force installation. This lack of information and local industry focus may result in excessive state and local compliance requirements for the installation. Because the installation's operations are not necessarily parallel to those of local industry, the environmental function must establish good communication and liaison with the state and/or local air pollution control agency to help ensure reasonable stipulations and to maintain compliance.

A1.5. Control Technologies.

A1.5.1. Overview. Basic emission control technologies exist for most sources of air pollution associated with generators. This document describes only existing or demonstrated technologies, not emerging and innovative technologies. IC sources comprise the majority of generators at Air Force installations; control technologies associated with IC sources are presented in detail, followed by an overview of control technologies related to external combustion sources. Two basic approaches to control an air pollutant are:

- Combustion Modification - Control technologies that prevent the formation of the pollutant. These can include fuel modifications or combustor modifications.
- Flue Gas Treatment - Control technologies that treat the exhaust gas to remove or destroy the pollutant prior to its release into the atmosphere.

A1.5.2. Combustion Modifications. Combustion modification control technologies may involve the following:

- Modification of operating conditions
- Equipment retrofit
- Redesign or replacement of equipment
- Change in fuel type
- Use of fuel additives
- Fuel treatment

A1.5.2.1. External Combustion Units.

A1.5.2.1.1. Table A1.14 summarizes control technologies used primarily to reduce emissions of NOx from external combustion units. The lower combustion temperatures used in these control technologies can reduce combustion efficiency and, therefore, cause increases in CO and NMHC emissions.

A1.5.2.1.2. Emissions of CO, NMHCs, and PM_{10} result mainly from incomplete combustion. These emissions can be minimized through regular maintenance of burners and through the use of processes that promote combustion efficiency, high combustion temperatures, long residence times at those temperatures, and turbulent air/fuel mixing.

A1.5.2.1.3. Sulfur oxide emissions, which are proportional to the sulfur content of the fuel, may be reduced by switching to fuels with a lower sulfur content. The sulfur content of coal fuels can be reduced through conventional, physical coal cleaning (10 to 30 percent SO_2 reduction), or chemical cleaning and solvent refining (30 to 90 percent SO_2 reduction).

A1.5.2.2. Internal Combustion (IC) Units. A number of the combustion modifications used to control emissions from external combustion units are also available for IC units. Control measures to date have been directed mainly at limiting emissions of NOx, the primary pollutant of significance emitted from IC units (see paragraph A1.5.2.2.1.1). SO_2 control is generally not a major concern with regard to IC generator units, since most of the diesel and natural gas used for fuel have a negligible sulfur content. SO_2 control is achievable through using low sulfur fuels or wet scrubbing the engine exhaust.

A1.5.2.2.1. Gas Turbines.

A1.5.2.2.1.1. The most prevalent NOx control technique for gas turbines is the injection of water or stream directly into the combustion chamber primary zone. This technique typically reduces NOx emissions by as much as 90 percent for natural-gas-fueled units and 70 percent for distillate-fueled units. Water injection tends to be more effective than steam injection. However, the additional heat load of the water used in water/steam injection reduces efficiency by 2 to 3 percent. Other disadvantages to this technique are associated with the availability of water or steam and the system requirement for the injection of very clean water, which could necessitate an expensive water treatment plant.

Table A1.14. Combustion Modifications - External Combustion

Control Technique	Description of Technique	Fuel Type	Control Effectiveness (Reduction)	
			NOx	SO_2
Fuel Switching	Use lower sulfur fuels	coal	na	SO_2 decreases
		fuel oil	na	SO_2 decreases
		natural gas	na	SO_2 decreases
	Use lower nitrogen fuels	coal	20%	na
		fuel oil	40%	na
		natural gas	not effective	na
	Conversion to fuel oil[1]	coal	NOx decreases	SO_2 decreases
	Conversion to natural	coal	NOx decreases	SO_2 decreases
		fuel oil[1]	NOx decreases	SO_2 decreases
Low Excess Air (LEA)	Reduction of combustion air[2]	coal	20 to 40%	na
		residual oil	0 to 28%	na
		distillate oil	0 to 24%	na
		natural gas	10 to 20%	na
Staged Combustion (SC)	Reduction of underfire airflow	coal	5 to 25%	na
includes	and increase overfire air	residual oil	20 to 50%	na
[Burners Out of Service	(LEA + OFA)[3]	distillate oil	17 to 44%	na
(BOOS)]		natural gas[4]	25 to 45%	na
Flue Gas Recirculation	Recirculation of portion of flue	residual oil	15 to 30%	na

(FGR)	gas to burners	distillate oil natural gas[5]	58 to 73% 60 to 90%	na na
Flue Gas Recirculation plus Staged Combustion	Combined techniques of FGR and SC	residual oil distillate oil	25 to 53% 73 to 77%	na na

Table A1.14. Combustion Modifications - External Combustion (Continued)

Control Technique	Description of Technique	Fuel Type	Control Effectiveness (% Reduction)	
			NOx	SO_2
Load Reduction (LR)	Reduction of air and fuel flow to burners	coal[6] fuel oil[6] natural gas	15% slight NOx reduction 10 to 30%	na na na
Low NOx Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	fuel oil natural gas	20 to 50% 40 to 85%	na na
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	coal fuel oil natural gas	0 to 8% 5 to 16% 20 to 50%	na na na

na = not applicable
OFA = overfire air

Comments:
1 Effectiveness of NOx and SOx reduction depends on fuel nitrogen and sulfur content.
2 CO, HC, and PM emissions may increase.
3 One or more burners on air only, with remainder firing fuel rich.
4 Removal of 25% of burners is most effective in units with 4 or more burners.
5 Flame stability can be a problem; efficiency decreases because of power needed to recycle the flue gas.
6 NOx emissions can increase when load is reduced below 60%.

A1.5.2.2.1.2. Alternate methods are being developed to control NOx without the use of water (dry controls). These advanced combustion designs modify combustion mixing, air staging, and flame stabilization to allow operation at a much leaner Air/Fuel (A/F) ratio than existing operations. Resultant lower peak temperatures in the primary flame zone reduce the generation of NOx but, at the same time, can increase CO emissions. The dry techniques typically have not produced more than a 40-percent reduction in NOx emissions.

A1.5.2.2.2. Reciprocating Engines.

A1.5.2.2.2.1. A variety of control techniques involving combustion modifications may be applied to the different types of reciprocating engines. Most engine control techniques involve combustion modifications. An exception is selective catalytic reduction (SCR), which is a post-combustion control method. NOx reductions are primarily achieved by retarding the spark, decreasing the inlet temperature, and increasing the A/F ratio. Table A1.15. lists the control techniques for each engine type. A brief description of these techniques follows.

Table A1.15. Combustion Modification Control Techniques for Reciprocating Engines

Engine Type	Control Technique	Relative NOx Reduction
Rich-burn SI engine (natural gas)	Air/Fuel adjustment (A/F) Ignition timing retard (IR) A/F plus IR Prestratified charge (PSC) Low-emission combustion (L-E)	10 to 40 % 10 to 40 % 10 to 40 % 87 % 87 %
Lean-burn SI engine (natural gas)	Air/Fuel adjustment (A/F) Ignition timing retard (IR) A/F plus IR Low-emission combustion (L-E)	5 to 30 % 0 to 20 % 20 to 40 % 87 %
Diesel engine	Ignition timing retard (IR)	20 to 30 %
Dual-fuel engine	Ignition timing retard (IR) Low-emission combustion (L-E)	20 to 30 % 75 %

A1.5.2.2.2.2. Air/Fuel (A/F) Adjustment.

A1.5.2.2.2.2.1. The A/F adjustment technique inhibits NOx formation by reducing the oxygen available to combine with nitrogen. In rich-burn SI engines, this can be accomplished by adjusting the A/F ratio toward fuel-rich operation. A low oxygen environment contributes to incomplete combustion, which results in lower combustion temperatures and less NOx formation. Figure A1.4 shows the impact of A/F ratio on NOx, CO, and hydrocarbon (HC) formation. The disadvantages associated with A/F adjustment for rich-burn SI engines include incomplete combustion, which can result in increased CO and HC emissions, and decreased combustion efficiency, which, in turn, can result in an increase in the brake-specific fuel consumption (BSFC).

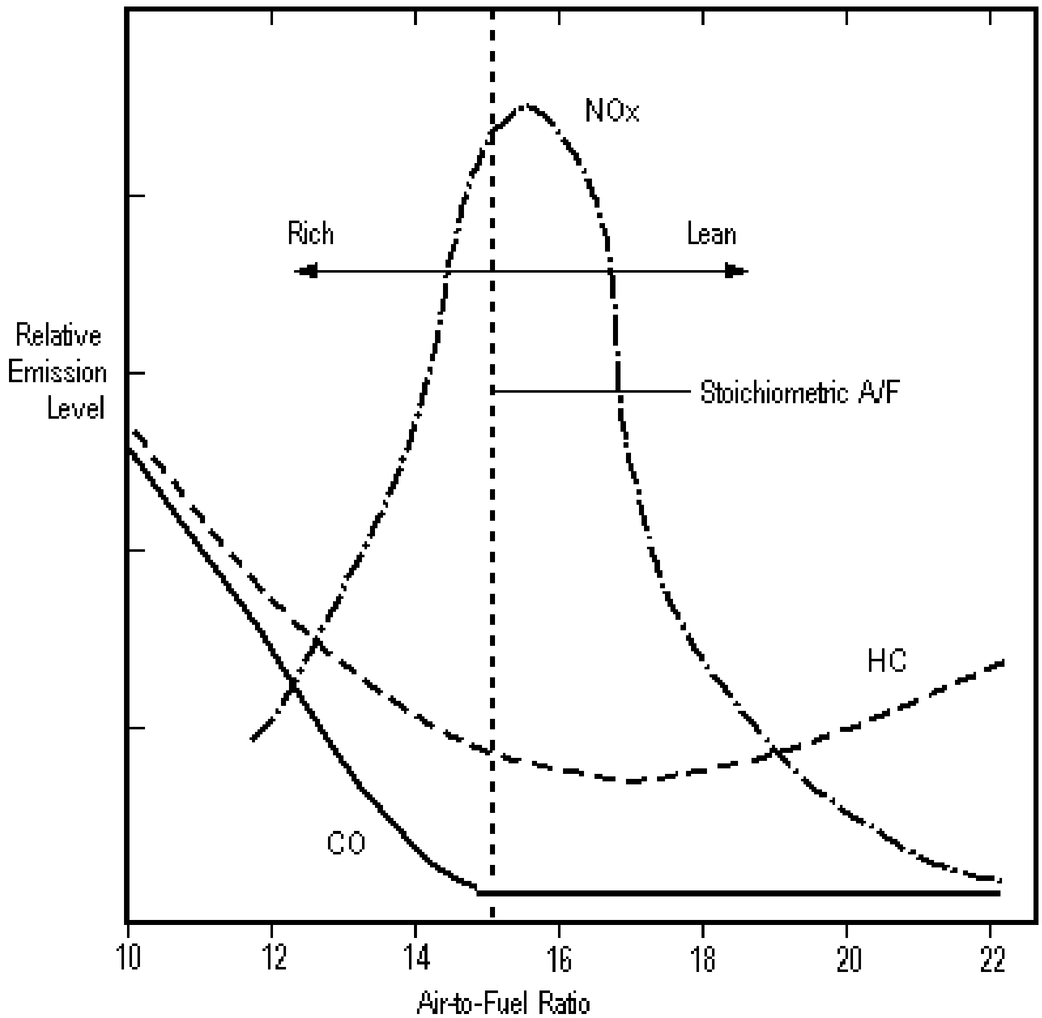


Figure A1.4. Effect of Air/Fuel Ratio on NOx, CO, and HC Emissions

A1.5.2.2.2.2.2. For lean-burn SI engines, the A/F ratio can be adjusted toward fuel-lean operation, which increases the combustion air volume and the heat capacity of the air-fuel mixture. This adjustment, in turn, lowers the combustion temperature and reduces NOx formation. High A/F ratios (lean-burn conditions) that reduce NOx and CO formation favor HC formation. Disadvantages similar to those encountered with rich-burn SI engines occur with the lean-burn SI engines.

A1.5.2.2.2.2.3. A/F adjustment applied to large bore diesel and dual-fueled engines has resulted in NOx reductions of 7 to 8 percent in diesel engines and 25 to 40 percent in dual-fired units. In conjunction with these reductions, fuel consumption penalties occur with increases of 1 to 3 percent in BSFC.

A1.5.2.2.2.3. Ignition Timing Retard (IR). This technique reduces NOx formation by delaying initiation of combustion until later in the power cycle. The delay is achieved by increasing the volume of the combustion chamber and reducing residence time of the combustion products. The levels of NOx reductions vary with each engine. Moderate IR does not appear to significantly increase CO or HC emissions; however, some fuel consumption penalties are associated with this control technique. To sustain NOx reductions, electronic ignition control systems must be used to automatically adjust the timing, thus accommodating changes in engine load or ambient conditions.

A1.5.2.2.2.4. Combined A/F Adjustment and Ignition Timing Retard. The combination of A/F adjustment and IR can achieve NOx reduction similar to that achieved by A/F adjustment alone, but with additional flexibility in operating characteristics. These include improved fuel consumption response to load changes. The combined control techniques may cause slight increases in CO and HC emissions.

A1.5.2.2.2.5. Prestratified Charge (PSC). This technique is an add-on control to four cycle, rich-burn SI engines, and facilitates the combustion of a leaner A/F ratio. NOx formation rates are reduced as a result of reduced combustion temperatures when the increased air acts as a heat sink. While vendors offer guarantees of NOx emission levels of 2 g/hp-hr (140 ppm), power reductions as high as 20 percent can occur with naturally aspirated engines. Adding a turbocharger can partially offset the power reductions. The BSFC increases for higher control effectiveness and decreases for more moderate control (4 to 7 g/hp-hr). In general, CO and HC emissions increase with the use of the PSC control technology.

A1.5.2.2.2.6. Low-Emission Combustion (L-E). Engines designed for L-E combustion (also referred to as torch ignition or jet cell combustion) can operate at much leaner A/F ratios than conventional designs. The result is improved air/fuel mixing and complete combustion. In some designs, a pre-combustion chamber or antechamber is used prior to the main combustion chamber. NOx formation is reduced as a result of lowered combustion temperatures. However, slight CO and HC emission increases occur with most engine designs. Because L-E adversely affects the engine response to load increases, it is not recommended for stand-alone power generation applications.

A1.5.2.2.2.7. Table A1.16 presents the impact on various parameters when emission control technologies are applied to diesel-fueled industrial reciprocating engines. The impact is reflected in an increase or decrease to the parameter. Some of these control technologies may also be effective for gasoline-fueled units.

Table A1.16. Diesel Emission Control Technology - Industrial Reciprocating Engines

Emission Control Technology	Effect of Control Technology on Emissions	
	Increase	**Decrease**
Fuel Modifications		
Sulfur content decrease		PM_{10}, SO_2, engine wear
Aromatic content increase	NOx, PM_{10}	
Cetane number		NOx, PM_{10}
Decrease 10% and 90% boiling point		PM_{10}
Fuel additives		NOx, PM_{10}
Water/fuel emulsions		NOx
Engine Modifications		
Ignition timing retard (IR)	PM_{10}, BSFC [1]	NOx, power
Increase fuel injection pressure	NOx, PM_{10}	
Injection rate control		NOx, PM_{10}
Rapid spill nozzles		PM_{10}
Electronic timing and metering		NOx, PM_{10}
Injector nozzle geometry		PM_{10}
Combustion chamber modifications		NOx, PM_{10}
Turbocharging	PM_{10}, power	NOx
Charge cooling		NOx
Exhaust gas recirculation	PM_{10}, power, engine wear	NOx
Oil consumption control		PM_{10}, engine wear

[1] brake-specific fuel consumption

Source: EPA Publication AP-42, 1995.

A1.5.3. Flue Gas Treatment. Flue gas treatment can be classified into two basic groups, dry processes and wet processes. They are described first for application to external combustion units and then for application to internal combustion units.

A1.5.3.1. External Combustion Units.

A1.5.3.1.1. Post-combustion Control Techniques. NOx is the principal pollutant of concern in external combustion units; however, SO_2 and PM control technologies may be required for coal- and oil-fired units, especially during upset conditions and soot blowing, or when dirty heavy oil or coal is fired.

PM emissions are generally controlled through the use of mechanical collectors, such as ESPs, multiple cyclones, and fabric filters (baghouses). Wet scrubbers, though primarily used to control sulfur oxide emissions, can be used to achieve particulate reductions up to 99 percent. Wet scrubbers typically are less efficient than ESPs or baghouses for removing particulate.

A1.5.3.1.2. Flue Gas Desulfurization (FGD) Techniques. Sulfur oxide emissions are typically controlled through the use of FGD techniques, which may be wet, dry, or semi-dry processes. These processes may be regenerable, in which the reagent is treated and reused, or non-regenerable, in which the reagent is dewatered and discarded. Wet scrubbing with lime or limestone (alkali slurries) is the method most commonly applied and it has successfully controlled SO_2 emissions from coal-fired generator units. Venturi-type scrubbers, sodium carbonate scrubbers, magnesium oxide/hydroxide (MAGOX process) scrubbers, and dual alkali scrubbers have also been applied commercially. Table A1.17 summarizes the control technologies for external combustion units that may be employed to control emissions from fossil-fuel-fired steam generators at Air Force installations.

A1.5.3.2. Internal Combustion Units. Two flue gas treatment options for NOx control have been developed for gas turbines. One is a dry process involving the reduction of NOx to nitrogen and water, and the other is a wet process involving the oxidation of NO to NO_2, followed by wet scrubbing of the NO_2.

A1.5.3.2.1. Selective Catalytic Reduction (SCR). SCR is a dry process that uses ammonia as a reducing agent to convert NOx into nitrogen and water. The ammonia also serves as a catalyst in the presence of oxygen to complete the conversion of CO and unburned hydrocarbons to CO_2 and water. The SCR process has achieved NOx reductions of 80 percent or more. Catalyst vendors typically guarantee NOx reductions of 90 percent for natural-gas-fired turbines. Depending on the catalyst used, precise limits of flue gas temperatures are necessary for optimum SCR operation. A flue gas temperature range of 315 to 426 °C (600 to 800 °F) is common.

Table A1.17. Flue Gas Treatment Technologies - External Combustion

Control Technique	Description of Technique	Fuel Type	Reduction		
			NOx	PM	SO2
Wet Scrubbing	Alkali slurries (lime/limestone)	coal	na	50 to 60%	80 to 95+%
		fuel oil	na	50 to 60%	80 to 95+%
	Sodium carbonate	coal[1]	na	50 to 60%	80 to 98%
		fuel oil	na	50 to 60%	80 to 98%
	Magnesium oxide/hydroxide (MAGOX)	coal[2]	na	50 to 60%	80 to 95+%
		fuel oil	na	50 to 60%	80 to 95+%
	Dual alkali	coal	na	50 to 60%	90 to 96%
		fuel oil	na	50 to 60%	90 to 96%
Spray Drying	Semi-dry process in which small quantities of sodium carbonate/calcium hydroxide spray contacts with flue gas	coal	na	na	70 to 90%
		fuel oil	na	na	70 to 90%
Furnace Injection	Direct injection of limestone/nahcolite into boiler	coal	na		25 to 50%
		fuel oil	na		25 to 50%
Duct Injection	Direct injection of limestone/nahcolite into duct	coal	na		25 to 50+%
		fuel oil	na		25 to 50+%
Multiple Cyclones	Mechanical collection	coal	na	90 to 95%	na
		fuel oil	na	85%	na
Electrostatic Precipitator (ESP)	Particles are captured electrically	coal	na	99.9%	na
		fuel oil	na	40 to 90%	na
Fabric Filter (Baghouse)	Filtration through fabric filters	coal	na	99.8%	na
		fuel oil	na		na

Table A1.17. Flue Gas Treatment Technologies - External Combustion (Continued)

			Reduction		
Control Technique	**Description of Technique**	**Fuel Type**	**NOx**	**PM**	**SO2**
Selective Non-Catalytic Reduction (SNR) [Ammonia/Urea Injection]	Injection of NH_3/urea into combustion flue gases	coal fuel oil natural gas	up to 40% 30 to 60% 40 to 70%	na na na	na na na
Selective Catalytic Reduction (SCR)	Catalyst promotes reaction of NH_3 with NOx	fuel oil natural gas	90% 90%	na na	na na

na = not applicable

Notes:

[1] High reagent costs; 1 to 125 MW application range.

[2] Regenerable process.

A1.5.3.2.1.1. SCR Applications. SCR has been used to control NOx emissions from reciprocating engines and has been applied with some success to lean-burn SI engines and to diesel and dual-fired engines. NOx emissions have been reduced between 65 and 95 percent for lean-burn SI engines, and 80 to 90 percent for diesel and dual-fired units. The catalysts for SCR are generally base-metals, such as vanadium pentoxide or zeolite. Special handling and disposal requirements for spent catalysts containing vanadium pentoxide are of concern in some areas where this material is considered hazardous.

A1.5.3.2.1.2. SCR Disadvantages. SCR is expensive because of the capital investment required for ammonia storage facilities, the cost of ammonia, and the add-on control equipment. Additional concerns exist regarding catalyst poisoning and fouling of the catalyst and downstream equipment by ammonium bisulfate, a reaction product. Ammonia carryover or “slipping” can occur and, in some cases, can result in a requirement to control ammonia emissions. Some difficulties have also been experienced in controlling ammonia emissions during load changes.

A1.5.3.2.2. Selective Non-Catalytic Reduction (SNR). SNR is a dry process that operates without a catalyst. Like SCR, SNR uses ammonia to reduce NOx emissions. However, for CO and HC control, the process relies on high-temperature gas phase reactions instead of using a catalyst. The SNR process operates within a narrow temperature range of approximately 954 $\pm$10 °C (1750 $\pm$50 °F). NOx reductions of 35 to 75 percent have been reported with the use of SNR. The SNR process tends to cost less than SCR and eliminates some of the catalyst-related problems. Controlling ammonia injection during upsets and significant changes in load or fuel can affect emissions.

A1.5.3.2.3. Nonselective catalytic reduction (NSCR). NSCR has been applied only to carbureted, rich-burn SI engines. NOx emission reductions of 90 to 98 percent have been reported using NSCR, which employs the same catalytic reduction technique used in automobile applications. A platinum-based metal is the predominant catalyst material employed in NSCR. The catalytic reactor simultaneously reduces NOx, CO, and HC to water, carbon dioxide, and diatomic nitrogen. NSCR requires that the engine operate at a fuel-rich A/F ratio, resulting in increased CO and HC, with some fuel consumption penalty.

A1.5.3.2.4. Wet Process. The wet process for gas turbine NOx control uses ozone or chlorine dioxide as an oxidizing agent to convert NO to NO_2, which is then absorbed in a wet scrubbing process. This process is expensive because of the cost of oxidizing agents, storage requirements for the agents, generation of waste by-products, and wastewater production.

A1.5.4. EPA Control Technology Programs.

A1.5.4.1. Regulatory Origins. Each major program under the CAA and CAAA has unique control technology requirements. Because different control programs apply to different circumstances, one or more control technology programs may apply simultaneously to a generator at an installation. Table A1.18 lists various control technology programs and their associated regulatory origin.

Table A1.18. Control Technology Programs Under the Clean Air Act

Program	Source
New Source Performance Standard (NSPS)	CAA
Best Available Control Technology (BACT)	PSD
Lowest Achievable Emission Rate (LAER)	Non-attainment Area NSR
Reasonably Available Control Technology (RACT)	Non-attainment Provisions
Maximum Achievable Control Technology (MACT)	Hazardous Air Pollutant Program
Generally Achievable Control Technology (GACT)	Hazardous Air Pollutant Program

A1.5.4.2. Levels of Control. Under the CAA are five separate control technology programs: BACT, RACT, LAER, MACT, and GACT (see Table A1.18). In addition, NSPS establishes minimum levels of control for certain pollutants that apply to specific categories of industrial sources (steam boilers and gas turbines >73 MW (250 MMBtu/hr) heat input). NSPS basically set the threshold level of control for specific source categories for which standards have been established. RACT is the next level of increasing control stringency, and is the degree of control that EPA has determined reasonably achievable considering technological and economic feasibility, and health, environment, and energy impacts. BACT is more stringent than RACT and is determined on a case-by-case basis, taking into consideration economics, environmental and energy impacts. LAER is the most stringent control technology achieved in practice on a similar application without regard to economic factors. MACT and GACT apply to the emissions of HAPs.

A1.5.4.3. Typical Agency Determinations. Table A1.19 lists examples of control technologies that have been applied to reciprocating engine generators (natural-gas-fired) in each control technology program. Determinations are made on a case-by-case basis; therefore, these listings should be considered as typical agency determinations. Engine size and design, the operating duty cycle, ambient conditions, engine maintenance, and other site-specific factors affect the suitability and effectiveness of the control technology and must be taken into consideration.

A1.5.4.4. EPA Clearinghouse. The EPA has developed a RACT/BACT/LAER Clearinghouse (RBLC) in Research Triangle Park, North Carolina, to assist in determining the control technology to be applied to various sources. The Clearinghouse maintains a database of distilled permit information and control technology determinations made nationwide. The database can be accessed by modem through EPA’s Office of Air Quality Planning and Standard’s Bulletin Board under the RBLC menu by dialing (919) 541-5742. The Clearinghouse main telephone number is (919) 541-0800.

Table A1.19. Typical Control Technology Determinations for Natural-Gas-Fired IC Engines

Level	Technology	Percent NOx Reduction	Cost/Ton of NOx
BACT	Lean-Burn	80 to 90	$300 - $400
RACT (2-stroke)	NSCR	60 to 85	$200 - $1,000
RACT (4-stroke)	PSC	70 to 85	$20 - $200
LAER	Lean-Burn plus SCR	90 to 95	$12,000 - $20,000

A1.6. Regulatory Compliance Guidance. This section provides recommendations and decision making criteria that will enable the base civil engineering community to evaluate the impact of the CAAA on the construction and operation of generators and power plants at Air Force installations. Tabular summaries of criteria and flowcharts are included to facilitate this process.

A1.6.1. Generator Project Review and Evaluation Criteria.

A1.6.1.1. Environmental Staff Involvement. The review and evaluation of a generator improvement project (new generator capacity or the modification of existing generator units) from an air quality perspective should involve the facility environmental management staff at the planning stage. Design, engineering, equipment acquisition, and permitting activities should be coordinated from project commencement to help avoid delays associated with air permitting, equipment specification and installation, or notices of violation (NOVs).

A1.6.1.2. Steps to Regulatory Compliance. The recommended steps to achieve regulatory compliance in construction or modification of generators and power plants are summarized in Table A1.20, followed by discussion of the applicability of each step.

Table A1.20. Summary of Permitting and Compliance Procedure for Generators and Power Plants

Step	Description
1	Determine that additional generator capacity or modification of existing generator units is necessary.
2	Define generator specifications.
3	Coordinate initial project with environmental management groups.
4	Determine preliminary emission estimates of proposed generator unit.
5	Conduct regulatory applicability review.
6	Determine the permitting requirements for the proposed generator.
7	Determine appropriate control technology requirements based on the NAAQS attainment status, generator type, and generator size.
8	Evaluate whether alternatives exist that would enable the project to reduce or avoid permitting, control technology requirements, or classification as a major source.
9	Hold a pre-application meeting with the appropriate permitting authority (state or local regulatory agency, or EPA). If the project is not subject to PSD or NSR, skip to step 17.
10	PSD or NSR only: Determine if ambient air quality monitoring is required.
11	PSD or NSR only: Conduct a control technology analysis.
12	PSD or NSR only: Conduct atmospheric dispersion modeling (if required).
13	PSD or NSR only: Evaluate the impact of the new generator on visibility, vegetation, and soils in PSD areas.
14	PSD or NSR only: Prepare permit application for submittal to the regulatory agency.
15	PSD or NSR only: Prepare early for the public review process, particularly if the new generator project is controversial.
16	PSD or NSR only: Review carefully the draft permit to be issued for the new generator unit as received from the regulatory agency.
17	Determine if the new generator unit will constitute a major source under Title V.
18	Schedule and attend a Title V application pre-submittal meeting with the regulatory agency.
19	Develop well-defined alternative operating scenarios that enable operational flexibility.
20	Determine monitoring requirements for each emission unit.
21	Complete the Compliance Certification for the Title V permit application.

22	Prepare and submit the permit application package to the appropriate regulatory agency.
23	After receipt of the construction and/or operating permit for the new generator unit, become familiar with all the permit conditions and limitations and implement all monitoring, record keeping, and reporting requirements.

A1.6.1.2.1. Step 1: Determine the need. The project should be initiated when the civil engineering community decides that additional generator capacity needs will require the installation of new units or modification of existing units.

A1.6.1.2.2. Step 2: Define generator specifications. Include the following data:

- Type of generator unit (steam boiler, gas turbine, reciprocating engine);
- Proposed size of the generator (power output, heat input);
- Planned fuel type (coal, residual fuel oil, petroleum distillate, gasoline, natural gas);
- Planned operational mode of the generator (continuous, peaking, emergency standby);
- Project timing and schedule (when the generator needs to be on line).

A1.6.1.2.3. Step 3: Coordinate initial project with environmental management groups. Outline the scope of the project (defined in step 2) and review the preliminary project schedule with respect to anticipated permit processing duration. Discuss potential regulatory requirements and identify preliminary data requirements for air quality permits. Establish points of contact for the project within the respective base departments.

A1.6.1.2.4. Step 4: Determine preliminary emission estimates of proposed generator unit. Calculate potential emissions of all criteria pollutants and HAPs from the proposed unit based on maximum anticipated operation (the amount of operation you wish to permit the unit for). Use the screening-level emission estimates to evaluate whether the regulatory thresholds for “major source” or “major modification” are triggered.

A1.6.1.2.5. Step 5: Conduct regulatory applicability review.

A1.6.1.2.5.1. Determine the NAAQS attainment status of the proposed site for the generator. (See paragraph A1.7.3. for a list of the attainment status designated for each Air Force installation by state.) Compare the the potential emissions calculated in Step 4 to the regulatory trigger levels to determine whether the proposed generator or its modification constitutes a new major source, a new minor source, a minor modification, or a major modification. If the Air Force installation has employed a “bubble concept” in an existing air permit, and the entire installation is considered to be a single source (or if the installation is divided into several separate sources, some of which may have employed the “bubble” concept), then potential emissions from the proposed generator must be evaluated with respect to the “net increase in emissions.” Several Air Force installations have used the bubble concept rather than separately permitting individual sources, especially where the installations have applied for or been issued a Title V operating permit or a synthetic minor non-Title V operating permit.

A1.6.1.2.5.2. Review existing or potential emissions offsets from other sources at the installation to determine if the emissions increase from the new generator can be offset by reducing permitted emissions from other sources at the installation. This may allow the proposed addition or modification to fall below the major source threshold levels.

A1.6.1.2.5.3. Use Table A1.21, a summary of generator sizes in relation to NOx emission levels, as a rule-of-thumb to determine if the emissions trigger major source requirements.

A1.6.1.2.6. Step 6: Determine the permitting requirements for the proposed generator. Figure A1.5 presents a construction permit decision tree, which will help determine the type of permit needed for the proposed generator. All air permit applications must undergo a pre-construction review by the regulatory agency. The level of pre-construction review depends on the size of the source. If the generator constitutes a new major source or a major modification, then either PSD (in attainment areas) or NSR (in non-attainment areas) will apply. Figure A1.6 outlines the steps in conducting PSD pre-construction review and NSR review. Even if PSD and/or NSR are avoided, modification of the existing Title V operating permit or the triggering of a Title V permit may be required. Figures A1.7a and A1.7b summarize the procedures necessary to acquire a Title V operating permit. Some states require facilities to obtain air construction or air operation permits prior to commencing construction and/or operation of the source, even if the proposed generator constitutes a minor source. Installations must comply with state air permitting regulations, which in many cases are more stringent than the Federal regulations.

A1.6.1.2.7. Step 7: Determine appropriate control technology requirements, based on the NAAQS attainment status, generator type, and generator size. If the proposed generator is a fossil-fuel-fired steam generator or a gas turbine with a heat input greater than 2.9 MW (10 MMBtu/hr), NSPS requirements apply. Paragraph A1.4.1.4 summarizes NSPS requirements. If the generator will be located at a major source of NOx, or will itself constitute a major source of NOx, RACT requirements apply. If the generator constitutes a major source with respect to PSD and is located in an attainment area, BACT requirements apply and will supersede RACT. If the generator constitutes a major source with respect to NSR and is located in a non-attainment area, LAER requirements apply and will supersede RACT. (See paragraph A1.5 of this document for additional information regarding available control technologies.)

Table A1.21. Potential NOx Emissions for Various Sizes of Generators[1]

Generator Type	Fuel	Average Power Output (kW)[2]				
		10 tpy	25 tpy	40 tpy	50 tpy	100 tpy
Small Industrial	NGPD	55	137	220	275	> 447
Reciprocating Engine (less than 447 kW)	Gasoline	155	387	> 447	> 447	> 447
	NGPD	< 447	< 447	< 447	< 447	709
	Natural Gas					
Large Bore Engine	(2-stroke, lean burn)	< 447	< 447	< 447	< 447	709
(447 kW - 9,700 kW)	(4-stroke, lean burn)	< 447	< 447	< 447	< 447	773
	(4-stroke, rich burn)	< 447	< 447	< 447	< 447	773
	Dual Fuel	< 447	< 447	< 447	472	945
	NGPD	304	760	1216	1520	3040
	Natural Gas					
Gas Turbine	(greater than 3 MW)	<3000	<3000	<3000	<3000	4822
	(less than 3 MW)	593	1483	2372	2965	>3000

[1] Assumes generator operation 8,760 hours/year.
[2] The generator outputs are only screening-level estimates to be used to determine if the threshold for a major source is exceeded. The generator outputs are based on emission factors in Table A1.8ba.
NGPD = Non-Gasoline Petroleum Distillate
MW = 3.41 MMBtu/hr

A1.6.1.2.8. Step 8: Conduct an internal project review to investigate possible alternatives that would enable the project to reduce or avoid pre-construction review requirements (PSD or NSR), control technology requirements, or classification as a major source.

A1.6.1.2.8.1. Evaluation and identification of possible alternatives can save time and money if they help to avoid expensive pre-construction review procedures, air permits, and stringent control technology. The average emission factors presented in this document are adequate to conduct the initial screening of generator emissions; however, more specific generator emission estimates should be determined for the permitting effort. Emission data from the vendor/manufacturer of the selected generator unit are usually available. Additional permitting or control requirements can be avoided with the use of refined emission estimates that are more characteristic of emissions from the proposed generator.

A1.6.1.2.8.2. The installation may also consider operational methods to reduce allowable emissions below PSD or NSR trigger levels. These methods could consist of accepting limits on hours of operation, fuel consumption, or power output in a construction permit or Federally-enforceable operating permit.

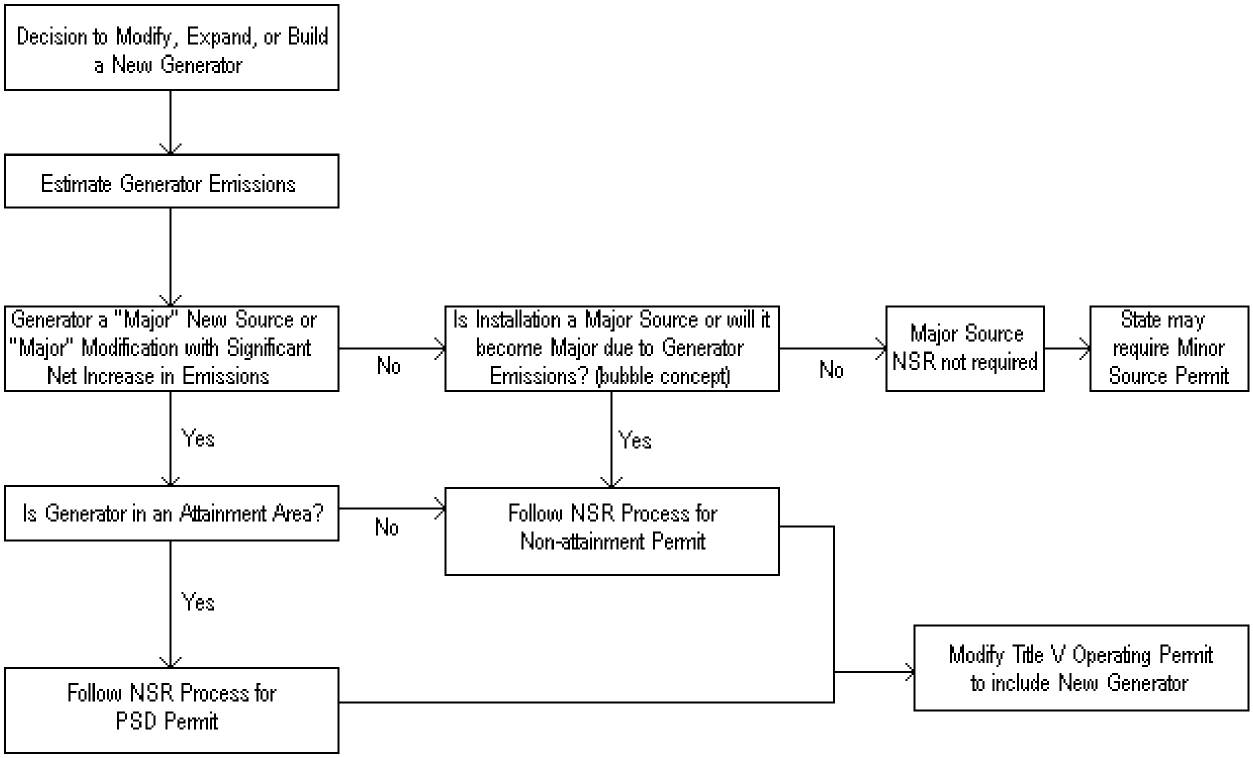


Figure A1.5. Construction Permit Decision Tree

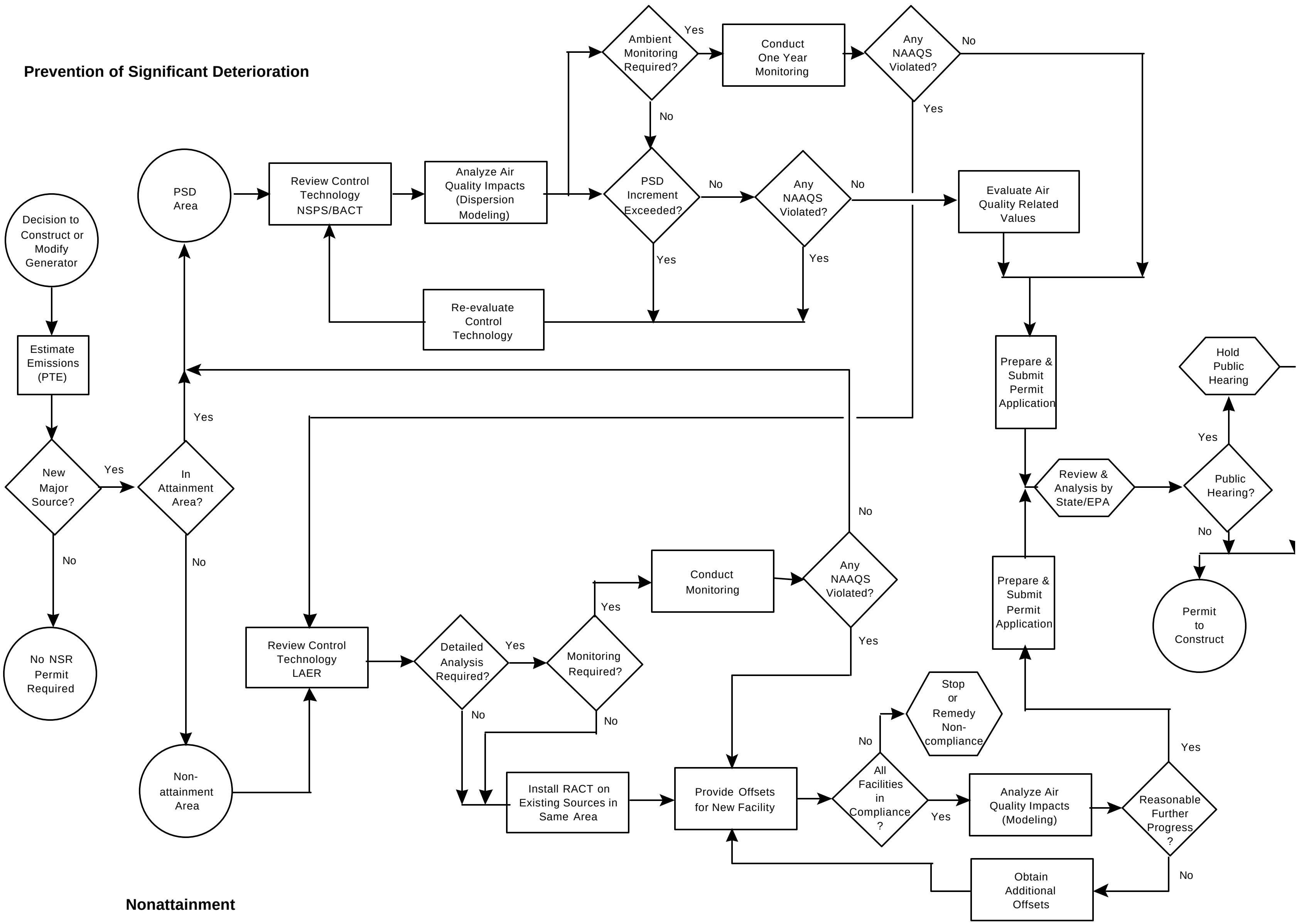
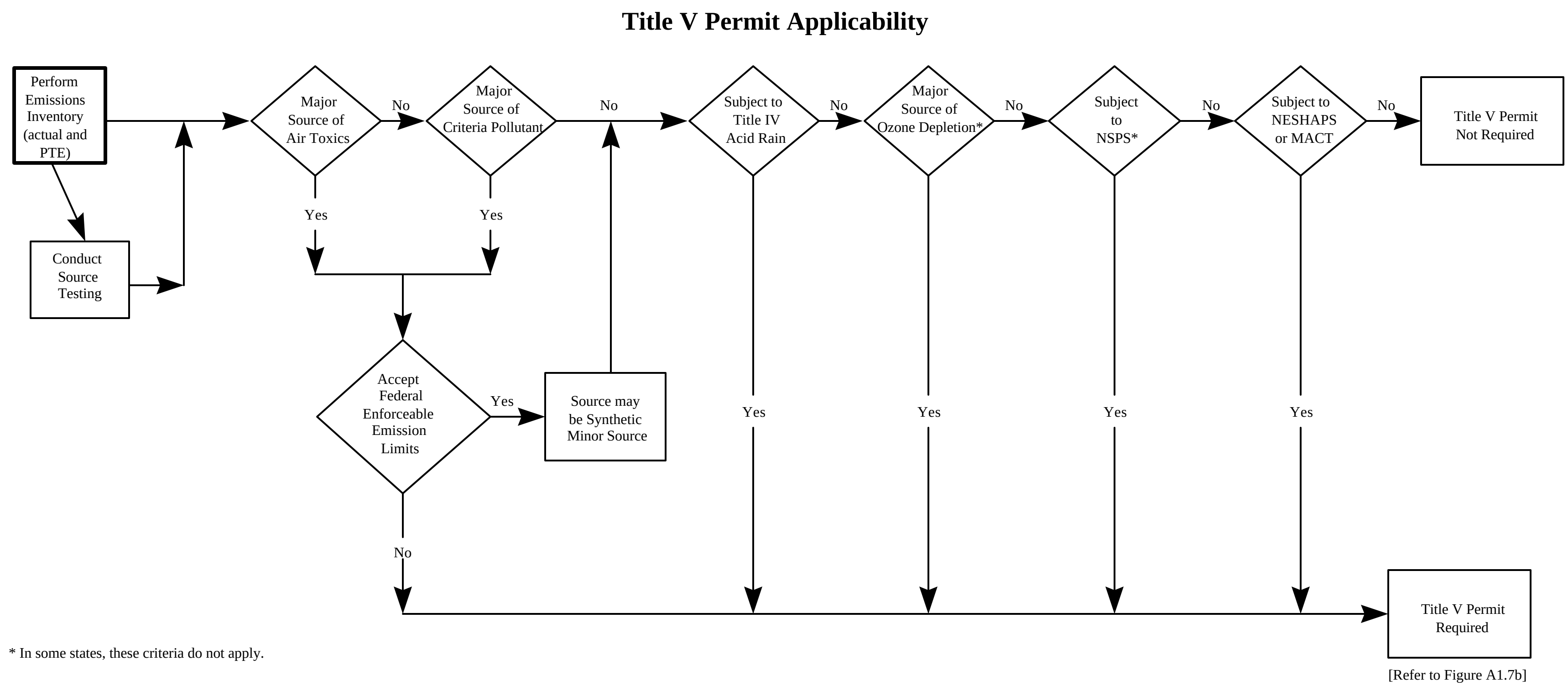


Figure A1.6. PSD and NSR Processes



Atch 1 (78 of 109)

Figure A1.7. Title V Operating Permit Process (Sheet 1 of 2)

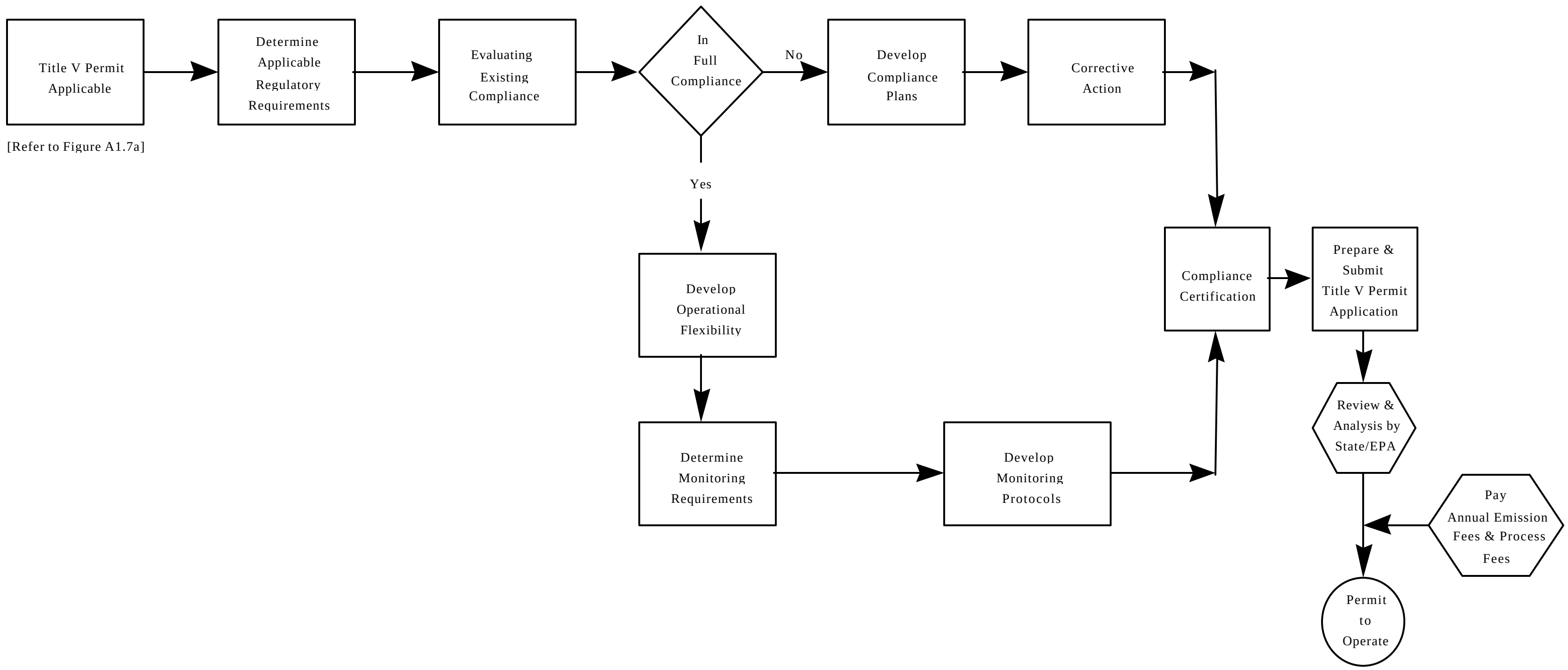


Figure A1.7. Title V Operating Permit Process (Sheet 2 of 2)

A1.6.1.2.8.3. Generator characteristics, fuel type, operating conditions, and control technology will be the basis for preparation of the permit application. Determine the following information for the proposed generator:

- Source Description
  - Process flow sheets (material flow, gas flow, and heat flow)
  - Site plan (location of proposed generator in relation to other sources)
  - Generator type (manufacturer, model)
  - Size of generator (power output, heat input, fuel consumption)
  - Generator parameters (% excess air, firing type)
  - Stack parameters (stack height, exit diameter, exit velocity, exit temperature)
  - Anticipated operating conditions (hours of operation, capacity factor, seasonal % load)

- Fuel Data
  - Type of fuel
  - Source of fuel
  - Fuel analysis (% nitrogen, % sulfur, high and low heating values)
  - Fuel storage and handling system description

- Control technology
  - Type of control (ESP, baghouse, SCR, LEA, water injection)
  - Make and model of pollution control equipment
  - Control equipment specifications
  - Control effectiveness (expected, manufacturer's guarantee)
  - Cost of control technology (cost per unit of pollutant removed, ratio of total cost to total investment)
  - Energy and fuel requirements for control equipment
  - Liquid and/or solid wastes produced from control equipment (amount generated, handling and disposal method)

A1.6.1.2.9. Step 9: Hold a pre-application meeting with the respective regulatory agency (state or EPA). Make sure that the regulatory agency has a complete, up-front understanding of the project being submitted for permitting. Hold this meeting early in the process; review and agency processing times tend to be shorter when agencies have the complete picture of a proposed project. Use the meeting with the regulatory agency to identify and address important issues early in the application process in addition to informing the agency of the project. (Refer to paragraph A1.7.4 for a listing of Federal and state air pollution control agencies.)

Note: Steps 10 through 16 apply to sources subject to either PSD or NSR pre-construction review. If the proposed generator is not a new major source or major modification to an existing source, skip steps 10 through 16.

A1.6.1.2.10. Step 10: If the proposed generator triggers PSD or non-attainment area
NSR, determine if ambient air quality monitoring is required.

A1.6.1.2.10.1. Ambient monitoring can be a long lead item for permitting, especially if a full year of ambient monitoring is required prior to submitting a PSD permit application. Less than one full year of monitoring may be possible, but EPA generally requires at least four months of data collection. Screening dispersion modeling should be employed to determine if predicted ambient impacts associated with emissions from the proposed generator are less than the *"de minimis"* monitoring concentrations established by EPA (see Table A1.22). If the predicted impacts or existing air quality in the generator's impact area are below *"de minimis"* levels, no ambient monitoring is required. However, the monitoring exemption is not automatic. In cases where an applicable PSD increment or NAAQS appears to be threatened or a Class I area may be adversely impacted, EPA may impose monitoring requirements anyway.

Table A1.22. *De Minimis* Monitoring Concentrations

Pollutant	Averaging Time	Ambient Concentration (μg/m³)
Nitrogen Dioxide	Annual	14
Carbon Monoxide	8-hour	575
Sulfur Dioxide	24-hour	13
PM_{10}	24-hour	10
TSP	24-hour	10
Ozone		(Exemptions granted when VOC emissions are less than100 tpy)

μg/m³ - micrograms per cubic meter

A1.6.1.2.10.2. In most cases, existing air quality data are available and can be used instead of time-consuming and expensive pre-construction monitoring. Sources of information could include monitoring data collected by state and local air pollution control agencies, data collected by other firms, or meteorological data collected by the National Weather Service. Existing data should meet the following criteria:

- Representative of the facilities impact area
- Collected in compliance with EPA monitoring provisions
- Current (i.e., collected in two-year period preceding permit application or updated by modeling if data are more than two years old)

A1.6.1.2.10.3. If ambient monitoring is required, regulatory agency concurrence of the monitoring network plan is strongly recommended prior to commencement. The pollutants to be monitored, monitoring methodology, number and location of monitoring stations, and quality assurance plans must be identified and must meet agency requirements.

A1.6.1.2.11. Step 11: Conduct a control technology analysis that supports and documents the selected control technology for the proposed generator. Control effectiveness, economics, energy penalties, and associated environmental impacts of the proposed generator unit should be evaluated. Compare the selected control technology with other control technology determinations for similar sources within the same area. If the results of the analysis indicate that the selected control technology is inadequate, other technologies should be considered that could meet regulatory requirements. If necessary, negotiate with the applicable regulatory agencies to avoid imposition of the more stringent control technology than required by rule.

A1.6.1.2.12. Step 12: Conduct atmospheric dispersion modeling (if required) to demonstrate that emissions from the proposed generator do not violate NAAQS, PSD increments (attainment areas), or reasonable further progress (non-attainment areas). If dispersion modeling is necessary, a "screening analysis" should be applied prior to using more sophisticated modeling. EPA established the screening analysis using very conservative, worst-case emissions and meteorological parameters to demonstrate compliance with NAAQS and PSD increments. If the screening analysis is passed, the source will not have to employ the more complex models. Compliance can sometimes be demonstrated by comparing the predicted impacts with the significant threshold or *"de minimis"* levels shown in Table A1.22.

A1.6.1.2.13. Step 13: Evaluate the impact of the new generator on visibility, vegetation, and soils in PSD areas. The results from the dispersion modeling serve as a basis for the air-quality-related values analysis. Compare the ambient concentration predictions to available scientific literature regarding sensitive vegetation and soils. To evaluate the impacts on visibility, perform a conservative screening level analysis. If the screening analysis indicates unacceptable impacts, more refined visibility modeling can be performed.

A1.6.1.2.14. Step 14: Prepare permit application for submittal to the regulatory agency. If needed, hold additional pre-application meetings with the regulatory agency to clarify the permitting requirements and to obtain agency concurrence on the procedures and methodologies used to determine impacts, control emissions, and demonstrate compliance. Cooperation and communication with the permitting agency generally helps to streamline the completeness determination, reduce the overall duration of the agency review process, and provide opportunities to resolve conflicts early in the permitting process. Be sure to use the application format and/or permit forms issued by the regulatory agency.

A1.6.1.2.15. Step 15: Prepare early for the public review process, particularly if the new generator project is controversial. Involvement of the general public in the issuance of permits is becoming more prevalent and is required by law for a number of the major permits issued by an agency. Be open and up-front when discussing the project and its related permit with the public. In most cases, a new generator unit will not be significant or controversial enough to trigger a formal public hearing on the permit application. If, however, there appears to be significant public opposition to the project, permit acquisition may be expedited and major controversy diffused by holding informational meetings with the concerned public or special interest groups and keeping these groups informed throughout the permitting process long before a permit reaches the public hearing stage. In the case of a public hearing, make careful advance preparations in order to make a credible showing at the hearing. Gathering intelligence on the concerns of the public and then being well-prepared to respond to those concerns is important to avoid “surprise” opposition.

A1.6.1.2.16. Step 16: Review carefully the draft permit to be issued for the new generator unit. Permitting agencies usually will issue a draft permit for review by the permittee before issuing the formal permit. Carefully review preliminary permit stipulations and conditions. Obtain concurrence from all groups working on the specific permit (Base Civil Engineer and environmental management groups), including the operator of the new generator unit, that compliance can be achieved for all permit stipulations, as well as all monitoring and record keeping requirements. The permit is, in essence, a contract between the agency and the Air Force and cannot be arbitrarily modified without formal permit revision. Non-compliance with permit conditions can subject the Air Force to fines and penalties. (See paragraph A1.6.2.2.)

A1.6.1.2.17. Step 17: Determine whether the new generator unit will constitute a major source under Title V. Though a new generator by itself may not be subject to PSD or NSR, its net increase in emissions can trigger the need for a Title V operating permit or a modification of the existing Title V permit. The CAAA broadly defines the sources subject to the Title V operating permit program. These include any major source under the CAA, sources requiring NSR, any source subject to the air toxics program, any source subject to the acid rain program, and other sources that EPA deems appropriate. In some states, sources regulated under NSPS are also subject to the Title V operating permits program. Sources with the PTE 100 tpy of criteria pollutants, or the PTE of 10 tpy of any one HAP, or 25 tpy of any combination of any HAPs are subject to Title V permitting requirements.

A1.6.1.2.18. Step 18: As with NSR, it is advisable to have a Title V application pre-submittal meeting with the regulatory agency.

A1.6.1.2.18.1. Pre-application meetings with the regulatory agency can be used to establish the format and level of detail required in the permit application, define insignificant or non-applicable emission units, and identify any agency concerns early in the process. Title V operating permits will serve as a “blueprint” for all future air compliance activities. The permit is issued for a minimum period of five years, after which it must be renewed. Because obtaining removal or relaxation of existing permit conditions is very difficult, it is important to ensure the Title V permit contains reasonable stipulations and emission limitations for which continuous air quality compliance can be maintained.

A1.6.1.2.18.2. A Title V operating permit application is not required for generators that do not constitute a major source of air pollution. However, most states require the facility to obtain air construction and air operating permits. The procedures for obtaining these permits are similar to those outlined below for obtaining a Title V operating permit, but may require less detail, information, and regulatory agency coordination.

A1.6.1.2.19. Step 19: Develop well-defined alternative operating scenarios that enable operational flexibility. For Title V sources, fewer permit restrictions allow greater operational flexibility. Look for opportunities to eliminate or modify existing limits on emissions units that lack a regulatory basis, thereby restricting operational flexibility. Also, attempt to eliminate or modify existing limits on emissions units that actually emit below regulatory trigger levels but are permitted to emit above regulatory trigger levels. Try to establish facility-wide emissions caps instead of source-specific emission limits. Develop operating scenarios for identified future (next five years) modifications. Identify all regulatory requirements associated with each alternative operating scenario and evaluate the requirements to determine if they are realistic and achievable on a continuous basis. Operational flexibility is achieved through optimal permit conditions, as shown in Table A1.23.

Table A1.23. Permit Conditions and Operational Flexibility

Permit Conditions	Operational Flexibility
"High" short-term emission rates	Flexible operation scheduling
"Long" averaging times for emission monitoring and reporting	Flexible use of fuel and raw material
Minimal record-keeping requirements	Minimized administrative burden
Installation-wide emission limits	Alternative operating methods
Installation-modification capability	Small project implementation

A1.6.1.2.20. Step 20: Determine monitoring requirements for each emission unit. Monitoring is used to demonstrate continuous air quality compliance and enables the responsible official (installation commander) to certify compliance annually. Consequently, the proposed monitoring program needs to be realistic and achievable. As a starting point, review current monitoring requirements. Maximize the use of existing monitoring and record keeping procedures instead of accepting or implementing new ones that will increase administrative burden. Consider the cost and resources necessary for conducting monitoring. If existing procedures are insufficient, evaluate the use of periodic parameter monitoring, or other means of demonstrating compliance in place of the more expensive continuous emissions monitors (CEMs). Develop detailed monitoring protocols and establish reporting, record keeping, and quality assurance/quality control (QA/QC) methods.

A1.6.1.2.21. Step 21: Complete the Compliance Certification for the Title V permit application. Upon submittal of the Title V operating permit application, and annually thereafter, the responsible official for the installation is required to submit a certification to the regulatory authority regarding the installation compliance status during the previous reporting period (typically one year). This compliance certification must be accompanied by a compliance schedule and plan if there were any instances of non-compliance.

A1.6.1.2.22. Step 22: Submit the permit application package to the appropriate permitting authority. The guidance described in steps 14, 15, and 16 of this section applies to both Title V and non-Title V operating permit applications:

- Communicate well in advance to manage agency expectations.
- Provide a timely response to requests for additional information.
- Routinely monitor the agency's progress in processing the permit application.
- Carefully review all permit stipulations and beware of restrictive permit language.
- Be cognizant of potential public opposition to the permit and be well-prepared for any public hearings.

A1.6.1.2.23. Step 23: After you have received the construction and/or operating permit for the new generator unit, become familiar with all the permit conditions and limitations. Implement all monitoring, record keeping, and reporting requirements.

A1.6.2. Recommended Compliance Methods.

A1.6.2.1. Citizen Lawsuits and Criminal Penalties. The CAAA established strong enforcement powers for EPA and states to ensure compliance with air quality regulations and permit conditions, including criminal provisions. The CAAA also allows citizen enforcement in the form of citizen suits, including fines of up to $25,000 per day per violation. Criminal penalties, which could result from knowing violations of the act, carry fines of up to $1 million and jail terms of up to 30 years.

A1.6.2.2. Sovereign Immunity. Air Force activities cited for violations under the CAAA are directed by Air Force policy to assert "sovereign immunity" for the payment of fines and penalties. The Base Civil Engineer should attempt to negotiate a satisfactory compliance agreement or consent order that excludes the payment of fines and penalties. This includes refusal to pay even a nominal amount assessed as a fine and refusal of any offer for a "suspended" fine to resolve a violation. Payment of even nominal fines or penalties by Air Force activities could adversely affect the Air Force's ability to assert sovereign immunity in other situations. If the regulatory authority persists in trying to assess the fine, request assistance from the command air quality manager and the Air Force Legal Services Agency, Environmental Law and Litigation Division. Air Force policy authorizes Air Force activities to render payment for properly documented administrative and investigative costs related to the enforcement action.

A1.6.2.3. Reports to Regulatory Agencies. Regulatory authorities use the Title V operating permit as a compliance monitoring vehicle. Semi-annual compliance reports are required. These provide a wealth of information to the agencies and to the general public regarding the compliance status of each installation. Annually, the installation commander will be required to submit a certification of compliance, listing any incidents of non-compliance since the previous reporting period. Because of this increased scrutiny, air quality compliance is a major issue for the environmental management group at Air Force installations.

A1.6.2.4. Recommendations. The key recommendations listed below will assist the BCE and the environmental function to comply with the CAAA regulations with respect to generators:

A1.6.2.4.1. Involve the environmental management group early when planning a generator improvement project.

A1.6.2.4.2. Develop a risk management strategy that balances compliance costs with potential for non-compliance.

A1.6.2.4.3. Assess compliance with air quality regulations.
A1.6.2.4.4. Develop procedures to address all of the permit conditions to ensure that compliance is maintained.

A1.6.2.4.5. Establish good professional rapport with local and state air pollution control agency personnel.

A1.6.2.4.6. Maintain an accurate and up-to-date air emissions inventory for the installation, including a list of insignificant sources.

A1.6.2.4.7. Hold application pre-submittal conferences with the regulatory agency during the permitting process.

A1.6.2.4.8. During the permitting process, focus on operational flexibility, sustained compliance, cost control, and control of the regulatory process.

A1.6.2.4.9. If possible, propose compliance verification methods that use existing process monitoring and record keeping procedures, and that do not require continuous emissions monitoring or stack testing.

A1.6.2.4.10. Develop or obtain a database management system to record, manipulate, and report detailed installation emissions and compliance information collected under the Title V operating permit process.

A1.6.3. Hypothetical Case Study. The following hypothetical case study outlines an approach for maintaining air quality compliance during the acquisition and installation of a new generating unit. The installation in this case study is a Title V source located in an ozone non-attainment area. This case is typical of the generators employed at an Air Force installation.

Note: This case study demonstrates how to manually calculate potential air emissions. Many Air Force facilities use computer software tools, such as the Air Quality Utility Information System [AQUIS], to complete the calculations.

A1.6.3.1. Review of Steps to Achieve Regulatory Compliance.

A1.6.3.1.1. Step 1: Determine the necessity of additional generator capacity or modification of existing generator capacity. The base civil engineering group identifies the need for an additional 2500 kW of standby power output.

A1.6.3.1.2. Step 2: Define generator specifications. A diesel-fired, reciprocating IC engine with a rated 3600 hp is initially identified as the generator unit preferred to meet this electrical power need. This engine, which consumes 200 gal/hr diesel fuel at full load, is needed to provide emergency power in the event of a power outage. Typically, the generator will be operated only during periodic maintenance to ensure good mechanical condition. The average operating time for this unit for periodic maintenance and anticipated power outages is estimated at 400 hours per year. The Base Civil Engineer wants the unit on line within one year.

A1.6.3.1.3. Step 3: Coordinate initial project with environmental management groups. The environmental project manager meets with staff from other base departments involved in the project. The group discusses project schedule, anticipated length of time the regulatory agency needed to conduct pre-construction review and issue a construction permit, and potentially applicable regulations (project may require NSR if emissions are high enough and installation of LAER emission control).

A1.6.3.1.4. Step 4: Determine preliminary emission estimates of proposed generator unit. Using the generator information, the environmental function calculates the potential air emissions for the generator unit using AQUIS, and checks the AQUIS calculations manually using the screening-level emission factors from paragraph A1.3.3. A summary of allowable emissions from the proposed generators is given in Table A1.24. Potential emissions of NOx and formaldehyde (HAP) are calculated as follows:

- NOx: 2500 kW $\times$ 400 hours/year $\times$14.6 g NOx/kW-hr $\times$ 0.0022 lb/g = 32,000 lb/yr NOx
- Heat Input: 200 gal/hr $\times$ 400 hours/year $\times$ 0.137 MMBtu/gal = 10,960 MMBtu/yr
- Formaldehyde: 10,960 MMBtu/yr $\times$ 0.00118 lb formaldehyde/MMBtu = 12.9 lb/yr formaldehyde

Because NOx is the pollutant of concern for this generator (the generator emits more NOx than any other pollutant), preliminary emission estimates predict an increase of 16 tpy NOx. Manufacturer-provided emissions factors may be obtained to refine this estimate at a later step.

Table A1.24. Case Study Emissions Estimates

Pollutant	Emission Factor	Units	Allowable Emissions (tpy)
Criteria			
NOx	14.6	g/kW-hr	16.1
CO	3.34	g/kW-hr	3.7
PM_{10}	0.27	g/kW-hr	0.3
SO_2[1]	2.46	g/kW-hr	2.7
NMHCs	1.53	g/kW-hr	1.7
HAPs			
Acetaldehyde	3.30E-04	g/Mj	3.6E-03
Acrolein	4.30E-05	g/Mj	4.7E-04
Aldehydes	3.00E-02	g/Mj	3.3E-01
Benzene	4.00E-04	g/Mj	4.4E-03
1,3-Butadiene	4.00E-06	g/Mj	4.4E-05
Formaldehyde	5.10E-04	g/Mj	5.6E-03
Naphthalene	3.60E-05	g/Mj	3.9E-04
Propylene	1.10E-03	g/Mj	1.2E-02
Toluene	1.80E-04	g/Mj	2.0E-03
Xylenes	1.20E-04	g/Mj	1.3E-03

[1] Based on fuel oil sulfur content of 0.5 wt%.

A1.6.3.1.5. Step 5: Conduct regulatory applicability review. The Air Force installation is located in an attainment area for all criteria pollutants except ozone, which is serious non-attainment. The thresholds for CAAA Title V status are 50 tpy of NOx or VOCs; 100 tpy of SO_2, PM_{10}, or CO; 10 tpy any individual HAP; and 25 tpy of any combination of HAPs (see Table A1.12). The installation is already a major source because of other emission units at the installation; therefore, it is also a major source with respect to non-attainment area NSR. As a result, the installation can increase its allowable emissions by 25 tpy NOx over the life of its existing Title V permit before construction permit applications will become subject to non-attainment area NSR. However, the preliminary emission estimates show a proposed allowable emissions increase of only 16 tons, assuming there were no other increases at the facility to cause the total increase to exceed 25 tpy. Therefore, it appears that non-attainment area NSR will not apply. Instead, minor source pre-construction review will apply. In determining Title V status, these emissions are calculated on the basis of the proposed allowable emissions (400 hours/year). If the generator is permitted to run continuously, Table A1.21 shows that its emissions will be well over 100 tpy NOx, and, as such, it will be subject to NSR.

A1.6.3.1.6. Step 6: Determine the permitting requirements for the proposed generator. Figures A1.6.1 and A1.6.3 show that the generators are not a major source and are not required to undergo non-attainment area NSR. They will, however, be required to obtain a construction permit from the state regulatory agency.

A1.6.3.1.7. Step 7: Determine appropriate control technology requirements based on the NAAQS attainment status, generator type, and generator size. Because the generator is an IC engine, no NSPS regulations apply. Since the generator is located at a major source of air pollution, RACT will apply.

A1.6.3.1.8. Step 8: Investigate alternatives that would enable the project to reduce or avoid permitting, control technology requirements, or classification as a major source. The only way the generator can avoid RACT is to apply to the regulatory agency to reduce source-wide emissions below Title V trigger levels, including the proposed increase in emissions associated with the new generator. The environmental function decides that this would present an unacceptable restriction on operations.

A1.6.3.1.9. Step 9: Hold a pre-application meeting with the appropriate permitting authority (state or local regulatory agency, or EPA). During a meeting with the state regulators responsible for pre-construction review, the environmental function presents the Base plans to install a new generator and the Base determination that a construction permit can be obtained for the proposed emission unit without going through non-attainment area NSR. A plan for submittal of the application is discussed, including information needed by the agency to review the application. The agency representative agrees that NSR is not necessary if the emissions from the unit are limited below NSR triggers through restrictions on either hours of operation or fuel use.

A1.6.3.1.10. Step 17: Determine if the new generator will constitute a major source under Title V. The generator by itself does not constitute a major source, but it must be assimilated into the installation Title V permit (or permit application if the agency has not yet issued the permit).

A1.6.3.1.11. Step 18: Schedule and attend a Title V application pre-submittal meeting with the regulatory agency. Because the generator does not trigger Title V, a full meeting may not be necessary at this point of the process. The previous pre-application meeting (step 9) should suffice. Be sure to request that the regulatory agency assimilate the construction permit (upon issuance) into the Title V permit, or find out what is necessary to make this happen.

A1.6.3.1.12. Step 19: Develop well-defined alternative operating scenarios that enable operational flexibility. Because the Base intends to use the generator only for standby electrical generation, only one operating scenario must be permitted.

A1.6.3.1.13. Step 20: Determine monitoring requirements for each emission unit. State regulations require that the facility maintain monthly records of fuel consumption by the unit. In addition, because the permit establishes a limit on hours of operation, monthly records of hours of operation will be required. RACT requires the generators to meet an hourly NOx emission limit (based on lb/MMBtu), as stated in the regulations. To show compliance with

RACT, the installation will be required to conduct annual stack testing of the generator for NOx.

A1.6.3.1.14. Step 21: Complete the Compliance Certification for the Title V permit application. The Base Commander is required to sign the compliance certification prior to issuance of the Title V permit and annually thereafter. After completion of construction of the generator (following issuance of the construction permit), the environmental function can use the monitoring, record keeping, and stack testing results to certify compliance with the construction permit, allowing the agency to assimilate the construction permit into the Title V permit.

A1.6.3.1.15. Step 22: Prepare and submit the permit application package to the appropriate regulatory agency. The environmental function obtains the appropriate forms from the agency and completes the application, providing all information required in the instructions. The environmental function also includes all information requested by the agency in the pre-application submittal meetings to facilitate review of the application and issuance of the permit. The application is submitted to the agency with the appropriate fee for pre-construction review.

A1.6.3.1.16. Step 23: After receipt of the construction and/or operating permit for the new generator unit, become familiar with all the permit conditions and limitations and implement all monitoring, record keeping, and reporting requirements. Upon receipt of the draft permit from the regulatory agency, the environmental function carefully reviews the draft permit for consistency with the application. Any inconsistencies are discussed and resolved with the agency before the installation initiates public notification of the agency's intent to issue the permit. Upon receipt of an acceptable draft application, the installation initiates the public notice process by publishing a notice in a local newspaper of general circulation in the affected area. After 30 days of public notice, the agency issues the construction permit. Construction of the generator unit then commences.

A1.7. Supporting Information.

A1.7.1. Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document:

ACT	alternative control techniques
AFB	Air Force Base
AFCESA	Air Force Civil Engineer Support Agency
AFI	Air Force Instruction
A/F	air/fuel (air-to-fuel)
AGE	aerospace ground equipment
AQUIS	Air Quality Utility Information System
BACT	best available control technology
BART	best available retrofit technology
BSFC	brake-specific fuel consumption
Btu	British thermal unit
CFR	Code of Federal Regulations
CAA	Clean Air Act

CAAA	Clean Air Act Amendments
CEM	continuous emission monitoring
CI	compression ignition
CO	carbon monoxide
CO_2	carbon dioxide
CTG	Control Techniques Guideline
DoD	U.S. Department of Defense
EO	Executive Order
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
ETL	Engineering Technical Letter
FGD	flue gas desulfurization
FGR	flue gas recirculation
GACT	generally available control technology
gal	gallon
HAPs	hazardous air pollutants
HC	hydrocarbon
Hi-Vol	high volume air sampler
hp	horsepower
HRSG	heat recovery steam generator
IC	internal combustion
IR	ignition timing retard
kg	kilogram
kj	kilojoule
kW	kilowatt
LAER	lowest achievable emission rate
lb	pound
LBE	large bore engine
L-E	low-emission combustion
LEA	low excess air
LNB	low NOx burner
LPG	liquefied petroleum gas
MACT	maximum achievable control technology
Mj	megajoule
MM	million
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NGPD	non-gasoline petroleum distillates
NMHC	non-methane hydrocarbon
NO	nitrogen monoxide
NO_2	nitrogen dioxide
NOV	Notice Of Violation
NOx	nitrogen oxides

NSCR	non-selective catalytic reduction
NSPS	New Source Performance Standards
NSR	New Source Review
O_3	ozone
Pb	lead
PM	particulate matter
PM_{10}	particulate matter less than 10 micrometers
$PM_{2.5}$	particulate matter less than 2.5 micrometers (also referred to as fine particulate matter)
PSC	prestratified charge
PSD	Prevention of Significant Deterioration
PTE	potential to emit
QA/QC	quality assurance/quality control
RACT	reasonably available control technology
RAP	reduced air preheat
RBLC	RACT/BACT/LAER Clearinghouse
SC	staged combustion
scf	standard cubic feet
SCR	selective catalytic reduction
SI	spark ignition
SIC	Standard Industrial Classification
SIP	state implementation plan
SIRE	small industrial reciprocating engines
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SOx	sulfur oxides
tpy	tons per year
TSP	total suspended particulate
VOC	volatile organic compound

A1.7.2. Glossary of Terms.

A1.7.2.1. *Air Quality Control Region* — An area designated by the Federal Government in which communities share a common air-pollution problem. Sometimes several states are involved.

A1.7.2.2. *Air Quality Utility Information System (AQUIS)* — A database to track air emission sources, calculate emissions generated, and estimate future emissions.

A1.7.2.3. *Annual Capacity Factor* — The ratio between the actual heat input to a steam generating unit from an individual fuel or combustion of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,700 hours during that 12-month period at the maximum design heat input capacity (40 CFR 60.41 (c)).

A1.7.2.4. *Attainment Area* – An area considered to have air quality as good as or better than the National Ambient Air Quality Standards (NAAQS) as defined in the Clean Air Act. An area may be an attainment area for one pollutant and a nonattainment area for others.

A1.7.2.5. *Best Available Control Technology (BACT)* – An emission limitation based on the maximum degree of reduction of a pollutant emitted from a major source that a permitting authority determines is achievable, taking into account energy, environmental, and economic impacts and other costs. BACT determinations are made on a case-by-case basis. They are used for major new or modified emission sources in attainment areas, and are applied to each major pollutant. The limitation may be achieved through the application of a variety of control technologies, process modifications, or operating procedures.

A1.7.2.6. *BACT/LAER Information System (BLIS)* – EPA’s database that contains all air operating permits in the U.S. for which a control technology determination has been made.

A1.7.2.7. *Boiler Derating* – A combustion control strategy for the control of oxides of nitrogen in which a boiler’s capacity is decreased, either by changing operating parameters or by equipment modifications.

A1.7.2.8. *Cogeneration Steam Generating Unit* – A steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source (40 CFR 60.41(c)).

A1.7.2.9. *Continuous Emissions Monitoring Systems (CEMS)* – A monitoring system for continuously measuring the emissions of a pollutant from an affected facility (40 CFR 60.51(a)).

A1.7.2.10. *Duct Burner* – A device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit (40 CFR 60.41 (c)).

A1.7.2.11. *Electrostatic Precipitator (ESP)* – A particulate matter control device which uses electrical forces to remove particulates from a gas stream and collect the pollutants on collector plates.

A1.7.2.12. *Emerging Technology* – Any SO_2 control system that is not defined as a conventional technology and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology (40 CFR 60.41 (c)).

A1.7.2.13. *Federally Enforceable* – All limitations and conditions enforceable by the Administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within any applicable state implementation plan, and any permit requirements established pursuant to 40 CFR 52.21 or under 40 CFR 51.18, and 40 CFR 51.24 (40 CFR 60.41(b)).

A1.7.2.14. *Flue Gas Desulfurization (FGD)* — The process of removing oxides of sulfur from a flue gas steam.

A1.7.2.15. *Flue Gas Recirculation (FGR)* — A combustion control technology for the control of oxides of nitrogen, in which a thermal diluent is introduced into a combustion chamber to reduce combustion temperature, thereby decreasing the amount of nitrogen oxides produced during combustion.

A1.7.2.16. *Fuel Pretreatment* — A process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit (40 CFR 60.41(c)).

A1.7.2.17. *Hazardous Air Pollutants (HAPs)* — 189 pollutants listed in the CAAA-90 and regulated by the U.S. EPA by the NESHAPs; hazardous air pollutants at Air Force installations include various volatile organic compounds.

A1.7.2.18. *Heat Input* — Heat derived from combustion of fuel in a steam generating unit, not including the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (40 CFR 60.41(c)).

A1.7.2.19. *Higher Heating Value* — Heat derived from combustion of a substance where all water formed is condensed into the liquid state (gross heating value).

A1.7.2.20. *Lowest Achievable Emission Rate (LAER)* — An emission rate which reflects the most stringent emission limitation contained in any State Implementation Plan for the same class or category of source, or which reflects the most stringent emission limitation achieved in practice for the same class or category of source, whichever is more stringent.

A1.7.2.21. *Lime Spray Drying* — A flue gas desulfurization control technology utilizing a spray dryer absorber and lime to remove sulfur oxides from a flue gas stream.

A1.7.2.22. *Low NO_X Burner* — A combustion control technology for the control of oxides of nitrogen in which combustion stages are partitioned and controlled to achieve a desired air-to-fuel ratio, reducing nitrogen oxide formation and resulting in more complete combustion within the furnace.

A1.7.2.23. *Maximum Achievable Control Technology (MACT)* — An emission limitation which reflects the maximum degree of reduction of one or more hazardous air pollutants, determined on a case-by-case basis where no applicable emission limitation has been established. This limitation applies to new, reconstructed, or modified sources of hazardous air pollutants.

A1.7.2.24. *Maximum Heat Input Capacity of A Steam Generating Unit* — Determined by operating the facility at maximum capacity for 24 hours and using the heat loss method described in Sections 5 and 7.3 of the American Society of Mechanical Engineers (ASME) *Power Test Codes* 4.1 (see 40 CFR 60.17(h)) no later than 180 days after initial startup of the facility and within 60 days after reaching maximum production rate at which the facility will be operated (40 CFR 60.51(a)).

A1.7.2.25. *Modification* — In relation to New Source Performance Standards (NSPS), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies, except for the following cases:

- Maintenance, repair, and replacement which the Administrator determines to be routine for a source category
- An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility
- An increase in the hours of operation
- Use of an alternate fuel or raw material if, prior to the date any standard under this section becomes applicable to that source type, the existing facility was designed to accommodate the alternate use. A facility will be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as assessed prior to the change (40 CFR 60.14). Use of alternative fuels or raw materials requiring changes in the facility design subsequent to the effective date of the standard are not exempt from being defined as a modification.

A1.7.2.26. *National Ambient Air Quality Standards (NAAQS)* — Standards that set attainment levels for criteria pollutants; areas that meet standards are areas of attainment, and areas that do not meet the standards are areas of non-attainment.

A1.7.2.27. *National Emission Standards for Hazardous Air Pollutants (NESHAP)* — Standards that set the emission levels for hazardous air pollutants from stationary sources.

A1.7.2.28. *New Source Performance Standards (NSPS)* — Uniform national EPA air emission and water effluent standards that limit the amount of pollution allowed from new or modified existing sources. New source performance standards can be found in 70 *Code of Federal Regulations* Part 60.

A1.7.2.29. *Nonattainment Area* — Geographic area that does not meet one or more of the national ambient air quality standards for the criteria pollutants designated through CAA.

A1.7.2.30. *Off-Stoichiometric Firing* — A combustion control technology for the control of oxides of nitrogen which is equivalent to staged combustion.

A1.7.2.31. *Opacity* — The degree to which emissions reduce the transmission of light and obscure view of an object in the background (40 CFR 60.2).

A1.7.2.32. *Reasonably Achievable Control Technology (RACT)* — The lowest emission limitation that a particular source is capable of meeting by the application of emission control technology that is reasonably available considering technical and economic feasibility. Reasonably available control technology usually is applied to existing sources in nonattainment areas, in most cases less stringent than new source performance standards.

A1.7.2.33. *Selective Catalytic Reduction (SCR)* — A post-combustion control technology for the removal of oxides of nitrogen, in which the oxides are reduced to elemental nitrogen in the presence of a catalyst in a separate reactor vessel, after the injection into the gas stream of a reducing agent (ammonia).

A1.7.2.34. *Selective Non-catalytic Reduction (SNCR)* — A post-combustion control technology for the removal of oxides of nitrogen in which urea- or ammonia-based chemical are injected into a gas stream to reduce the oxides to elemental nitrogen. The reduction reaction takes place at a higher temperature than that for SCR, eliminating the requirement to use a catalyst.

A1.7.2.35. *State Implementation Plans (SIP)* — State plans for the establishment, regulation, and enforcement of air pollution standards. State implementation plans approved by the EPA are Federally enforceable.

A1.7.2.36. *Stationary Source* — A fixed, non-moving producer of pollution, such as power plants and other facilities using industrial combustion processes, paint spray booths, fuel storage tanks, and solvent cleaning facilities.

A1.7.2.37. *Stationary Gas Turbine* — Any simple cycle gas turbine, regenerative cycle gas turbine, or any gas turbine portion of a combined cycle steam/electric generating system that is not self-propelled. It may be mounted on a vehicle for portability (40 CFR 60.331).

A1.7.2.38. *Very Low Sulfur Oil* — An oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a SO_2 emission rate equal to or less than 0.5 lb/MMBtu heat input (40 CFR 60.41b).

A1.7.2.39. *Volatile Organic Compounds (VOCs)* — A variety of compounds that are easily air borne; those emitted at Air Force installations are hazardous air pollutants and regulated by NESHAPs, and are a precursor to ambient ozone, a criteria pollutant regulated by NAAQS. These organic compounds participate in atmospheric photochemical reactions except for those designated by EPA as having negligible photochemical reactivity.

A1.7.3. NAAQS Attainment Status. Table A1.25 provides a snapshot of NAAQS attainment status as of 30 Nov 96. For updated information for these and other Air Force facilities, contact the facility’s Environmental Flight or Headquarters, Air Force Center of Environmental Excellence (AFCEE), Regional Environmental Office (Atlanta, Dallas, or San Francisco).

Table A1.25. Snapshot of NAAQS Attainment Status as of 30 Nov 96

State	Base Name	CO	O_3	PM_{10}	SO_2	Lead
Alabama	Gunter AFB	attainment	attainment	not designated	attainment	not designated
	Maxwell AFB	attainment	attainment	not designated	attainment	attainment
Alaska	Eareckson AFB	attainment	attainment	attainment	attainment	attainment
	Eielson AFB	MODERATE NA	attainment	not designated	attainment	attainment
	Elmendorf AFB	attainment	attainment	unclassifiable	attainment	attainment
Arizona	Davis-Monthan AFB	MODERATE NA	attainment	attainment	attainment	attainment
	Luke AFB	MODERATE NA	MODERATE NA	MODERATE NA	attainment	attainment
Arkansas	Little Rock AFB	attainment	attainment	attainment	attainment	attainment
California	Beale AFB	MODERATE NA	SERIOUS NA	MODERATE NA	attainment	attainment
	Edwards AFB	attainment	SERIOUS NA	SERIOUS NA	attainment	attainment
	Los Angeles AFB	EXTREME NA	EXTREME NA	EXTREME NA	attainment	attainment
	March AFB	MODERATE NA	EXTREME NA	MODERATE NA	attainment	attainment
	McClellan AFB	MODERATE NA	MODERATE NA	MODERATE NA	attainment	attainment
	Onizuka AFS	attainment	NON-ATTAINMENT	NON-ATTAINMENT	attainment	attainment
	Travis AFB	unclassified	NON-ATTAINMENT	NON-ATTAINMENT	attainment	attainment
	Vandenberg AFB	attainment	NON-ATTAINMENT	NON-ATTAINMENT	attainment	attainment
Colorado	Air Force Academy	MODERATE NA	attainment	attainment	attainment	attainment
	Cheyenne Mtn. AFS	MODERATE NA	attainment	attainment	attainment	attainment
	Falcon AFB	MODERATE NA	attainment	attainment	attainment	attainment
	Peterson AFB	MODERATE NA	attainment	attainment	attainment	attainment
Connecticut	none					
Delaware	Dover AFB	attainment	SEVERE NA	attainment	attainment	attainment
District of Columbia	Bolling AFB	MODERATE NA	SERIOUS NA	not designated	attainment	not designated
	Headquarters Air Force	MODERATE NA	SERIOUS NA	not designated	attainment	not designated
Florida	Cape Canaveral AFS	attainment	attainment	attainment	attainment	unclassifiable
	Eglin AFB	attainment	attainment	unclassifiable	unclassifiable	unclassifiable
	Hurlburt Field	attainment	attainment	unclassifiable	unclassifiable	unclassifiable

	MacDill AFB	attainment	attainment	unclassifiable	unclassifiable	unclassifiable
	Patrick AFB	attainment	attainment	unclassifiable	attainment	unclassifiable
	Tyndall AFB	attainment	attainment	unclassifiable	unclassifiable	unclassifiable

Table A1.25. Snapshot of NAAQS Attainment Status as of 30 Nov 96 (Continued)

State	Base Name	CO	O_3	PM_{10}	SO_2	Lead
Georgia	Dobbins ARB	attainment	SERIOUS NA	not designated	attainment	not designated
	Moody AFB	attainment	attainment	not designated	attainment	not designated
	Robins AFB	attainment	attainment	not designated	attainment	not designated
Hawaii	Hickam AFB	attainment	attainment	attainment	attainment	attainment
Idaho	Mountain Home AFB	attainment	attainment	attainment	attainment	attainment
Illinois	O'Hare ARS	attainment	SEVERE NA	MODERATE NA	attainment	not designated
	Scott AFB	attainment	MODERATE NA	not designated	attainment	not designated
Indiana	none					
Iowa	none					
Kansas	McConnell AFB	attainment	attainment	not designated	attainment	not designated
Kentucky	none					
Louisiana	Barksdale AFB	attainment	attainment	not designated	attainment	not designated
Maine	none					
Maryland	Andrews AFB	attainment	SERIOUS NA	not designated	attainment	not designated
Massachusetts	Hanscom AFB	attainment	SERIOUS NA	attainment	attainment	attainment
Michigan	K.I. Sawyer AFB	attainment	attainment	attainment	attainment	attainment
Minnesota	Minneapolis IAP	MODERATE NA	attainment	attainment	NON-ATTAINMENT	not designated
Mississippi	Columbus AFB	attainment	attainment	attainment	attainment	attainment
	Keesler AFB	attainment	attainment	attainment	attainment	attainment
Missouri	Whiteman AFB	attainment	attainment	attainment	attainment	attainment
Montana	Malmstrom AFB	attainment	attainment	attainment	attainment	not designated
Nebraska	Offutt AFB	attainment	attainment	not designated	attainment	not designated
Nevada	Nellis AFB	MODERATE NA	attainment	MODERATE NA	attainment	not designated
New Hampshire	none					
New Jersey	McGuire AFB	attainment	SEVERE NA	not designated	attainment	not designated

Table A1.25. Snapshot of NAAQS Attainment Status as of 30 Nov 96 (Continued)

State	Base Name	CO	O_3	PM_{10}	SO_2	Lead
New Mexico	Cannon AFB	attainment	attainment	not designated	attainment	not designated
	Holloman AFB	attainment	attainment	not designated	attainment	not designated
	Kirtland AFB	MODERATE NA	attainment	not designated	attainment	not designated
New York	Griffiss AFB	attainment	attainment	not designated	attainment	not designated
	Niagara Falls IAP	attainment	MARGINAL NA	not designated	attainment	not designated
	Plattsburgh AFB	attainment	attainment	not designated	attainment	not designated
North Carolina	Pope AFB	attainment	attainment	attainment	attainment	attainment
	Seymore Johnson AFB	attainment	attainment	attainment	attainment	attainment
North Dakota	Grand Forks AFB	attainment	attainment	attainment	attainment	attainment
	Minot AFB	attainment	attainment	attainment	attainment	attainment
Ohio	Newark AFB	attainment	MARGINAL NA	not designated	attainment	not designated
	Wright-Patterson AFB	attainment	MODERATE NA	attainment	attainment	attainment
Oklahoma	Altus AFB	attainment	attainment	not designated	attainment	not designated
	Tinker AFB	attainment	attainment	attainment	attainment	attainment
	Vance AFB	attainment	attainment	attainment	attainment	attainment
Oregon	none					
Pennsylvania	none					
Rhode Island	none					
South Carolina	Charleston AFB	attainment	attainment	not designated	attainment	not designated
	Shaw AFB	attainment	attainment	not designated	attainment	not designated
South Dakota	Ellsworth AFB	attainment	attainment	not designated	attainment	not designated
Tennessee	Arnold AFB	attainment	attainment	not designated	attainment	not designated
Texas	Brooks AFB	attainment	attainment	not designated	attainment	attainment
	Dyess AFB	attainment	attainment	not designated	attainment	not designated
	Goodfellow AFB	attainment	attainment	not designated	attainment	not designated
	Kelly AFB	attainment	attainment	not designated	attainment	unclassified
	Lackland AFB	attainment	attainment	not designated	attainment	unclassified
	Laughlin AFB	attainment	attainment	not designated	attainment	not designated

	Randolph AFB	attainment	attainment	not designated	attainment	unclassified
	Reese AFB	attainment	attainment	not designated	attainment	not designated
	Sheppard AFB	attainment	attainment	attainment	attainment	attainment
Utah	Hill AFB	MODERATE NA	attainment	not designated	attainment	not designated

Table A1.25. Snapshot of NAAQS Attainment Status as of 30 Nov 96 (Continued)

State	Base Name	CO	O_3	PM_{10}	SO_2	Lead
Vermont	none					
Virginia	Langley AFB	attainment	MARGINAL NA	not designated	attainment	not designated
Washington	Fairchild AFB	attainment	attainment	unclassified	attainment	not designated
	McChord AFB	MODERATE NA	MARGINAL NA	MODERATE NA	attainment	not designated
West Virginia	none					
Wisconsin	General Mitchell IAP	attainment	SEVERE NA	not designated	attainment	not designated
Wyoming	Francis E. Warren AFB	attainment	attainment	attainment	attainment	not designated

A1.7.4. Directory of Federal and State Regulatory Agencies. Tables A1.7.2, A1.7.3, and A1.7.4 provide addresses, telephone numbers, and e-mail addresses for the most commonly contacted Federal and state regulatory agencies.

Table A1.26. U.S. EPA Headquarters and Research Triangle Park

Office of the Assistant Administrator for Air and Radiation
U.S. Environmental Protection Agency
Mail Code ANR-443
401 M Street, S.W.
Washington, DC 20460
(202) 382-7400

Office of the General Counsel
U.S. Environmental Protection Agency
Mail Code LE-130
401 M Street, S.W.
Washington, DC 20460
(202) 475-8040

Emission Factor Clearinghouse
Research Triangle Park, NC 27711
(919) 541-5285

EPA Model Clearinghouse
Research Triangle Park, NC 27711
(919) 541-5683

Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Mail Code MD-10
Research Triangle Park, NC 27722
(919) 541-5616
www.epa.gov/oar/

National Air Toxics Information Clearinghouse
Montgomery, AL
(205) 270-3410

Control Technology Center
U.S. EPA
Research Triangle Park, NC 27711
(919) 541-0800
www.epa.gov/oar/oaqps/ctc/

RACT/BACT/LEAR Clearinghouse
Research Triangle Park, NC 27711
(919) 541-0800
www.rtpnc.epa.gov

Table A1.27. U.S. EPA Regional Offices

Region I
John F. Kennedy Federal Building
Room 2203
Boston, MA 02203
Telephone (617) 565-3715
Fax: (617) 565-3468

Region II
Jacob K. Javitz Federal Building
26 Federal Plaza
New York, NY 10278
Telephone: (212) 264-2657
Fax: (212) 264-8100

Region III
841 Chestnut Building
Philadelphia, PA 19107
Telephone: (215) 597-9800
Fax: (215) 597-7906

Region IV
345 Courtland Street, N.E.
Atlanta, GA 30365
Telephone: (404) 347-4727
Fax: (404) 347-4486

Region V
230 South Dearborn Street
Chicago, IL 60604
Telephone: (312) 353-2000
Fax: (312) 886-9096

Region VI
First Interstate Bank Tower at Fountain Place
1445 Ross Avenue, 12th Floor
Suite 1200
Dallas, TX 75202
Telephone: (214) 655-6444
Fax: (214) 655-2142

Region VII
726 Minnesota Avenue
Kansas City, KS 66101
Telephone: (913) 551-7000
Fax: (913) 236-2845

Region VIII
999 18th Street, Suite 500
Denver, CO 80202-2405
Telephone: (303) 293-1603
Fax: (303) 293-1647

Region IX
1235 Mission Street
San Francisco, CA 94103
Telephone: (415) 556-6322
Fax: (415) 744-1070

Region X
1200 Sixth Avenue
Seattle, WA 98101
Telephone: (206) 442-1200
Fax: (206) 442-4672

Table A1.28. State Air Pollution Regulatory Agencies

ALABAMA	Alabama Department of Environmental Management 1751 Dickinson Drive Montgomery, AL 36130 Phone: (205) 271-7861 Fax: (205) 271-7950 www.alaweb.asc.edu/govern.html
ALASKA	Alaska Department of Environment Conservation, Air Quality Division 410 Willoughby Avenue, Suite 105 Juneau, AK 99801 Phone: (907) 465-4086 Fax: (907) 465-5129 www.state.ak.us/local/akpages/env.conserv/home.htm
ARIZONA	Arizona Department of Environmental Quality, Publications Division 1700 West Washington Phoenix, AZ 85007 Phone: (602) 542-4086 Fax: (602) 542-4366 www.state.az.us/pages/stateser.html
ARKANSAS	Arkansas Department of Pollution Control, Air Division P.O. Box 9813 Little Rock, AR 72219 Phone: (501) 570-2162 Fax: (501) 568-4632 www.state.ar.us/html/index4.html
CALIFORNIA	California Environmental Protection Agency, Air Resources Board P.O. Box 2815 1102 Q Street Sacramento, CA 95812 Phone: (916) 322-6022 Fax: (916) 322-6003 www.calepa.cahwet.gov/
COLORADO	Colorado Department of Health, Air Pollution Control Division APCD-CC-B1 4300 Cherry Creek Drive South Denver, CO 80222-1530 Phone: (303) 692-3278 Fax: (303) 782-5493 www.state.co.us/govdir/cdphe_dir/cdphehom.html
DISTRICT OF COLUMBIA	District of Columbia Department of Consumer and Regulatory Affairs Air Quality Branch Office of Documents District Building, Room 406

Washington, DC 2004
Phone: (202) 404-1180 ext. 5065

Table A1.28. State Air Pollution Regulatory Agencies (Continued)

DELAWARE	Delaware Department of Natural Resources and Environmental Control Air Resources Section 89 Kings Highway P.O. Box 1401 Dover, DE 19903 Phone: (302) 739-4791 Fax: (302) 739-3106
FLORIDA	Florida Department of Environmental Regulation, Bureau of Air Regulations 2600 Blair Stone Road Tallahassee, FL 32399-2400 Phone: (850) 488-1344 Fax: (850) 922-6979 www.dep.state.fl.us/index.html
GEORGIA	Georgia Department of Natural Resources, Air Protection Division 205 Butler Street Southeast Floyd Towers East, Suite 1162 Atlanta, GA 30334 Phone: (404) 363-7000 Fax: (404) 651-9425 www.dnr.state.ga.us/index.html
HAWAII	Hawaii Department of Health, Clean Air Branch P.O. Box 3378 Honolulu, HI 96801 Phone: (808) 586-4200 Fax: (808) 586-4359 www.htdc.org/~dlnr/
IDAHO	Idaho Department of Health and Welfare, Division of Environmental Quality Administrative Procedures Section 450 West State Street, 10th Floor Boise, ID 83720-5548 www.state.id.us/comindex.html
KANSAS	Kansas Department of Health and Environment, Bureau of Air Quality Forbes Field, Building 740 Topeka, KS 66620 Phone: (913) 296-1587 Fax: (913) 296-6247 www.ink.org/public/kdhe
LOUISIANA	Louisiana Department of Environmental Quality, Office of Air Quality P.O. Box 82135 Baton Rouge, LA 70884-2135 Phone: (504) 765-0219 Fax: (504) 765-0222

www.deq.state.la.us/

Table A1.28. State Air Pollution Regulatory Agencies (Continued)

MARYLAND	Maryland Department of the Environment, Air Management Administration 2500 Broening Highway Baltimore, MD 21224 Phone: (410) 631-3240 Fax: (410) 631-3202
MASSACHUSETTS	Massachusetts Department of Environmental Quality, Air Quality Control Division 1 Winter Street Boston, MA 02108 Phone: (617) 292-5630 www.magnet.state.ma.us/dep/dephome.htm
MICHIGAN	Michigan Department of Natural Resources, Air Quality P.O. Box 30028 Lansing, MI 48909 Phone: (517) 373-7023 Fax: (517) 373-1265 www.deq.state.mi.us/
MISSISSIPPI	Mississippi Department of Environmental Quality, Air Division P.O. Box 10385 Jackson, MS 39289-0385 Phone: (601) 961-5104 Fax: (601) 961-5742
MISSOURI	Missouri Department of Natural Resources, Environmental Quality Division P.O. Box 176 Jefferson City, MO 65102 Phone: (314) 751-4817 www.state.mo.us/dnr/homednr.htm
MONTANA	Montana Department of Health and Environmental Sciences, Air Quality Bureau Cogswell Building Helena, MT 49620 Phone: 406) 444-3454 Fax: (406) 444-1374
NEBRASKA	Nebraska Department of Environmental Quality, Air Quality Division P.O. Box 98922 State House Station Lincoln, NE 68509-8922 Phone: (402) 471-2189 Fax: (402) 471-2909 www.nrc.state.ne.us

Table A1.28. State Air Pollution Regulatory Agencies (Continued)

NEVADA	Nevada Department of Conservation and Natural Resources, Division of Environmental Protection Bureau of Air Quality 333 West Nye Lane Carson City, NV 89710 Phone: (702) 687-5065 Fax: (702) 885-0868 www.state.nv.us/
NEW JERSEY	New Jersey Department of Environmental Protection, Office of Energy Air Quality Regulations, CN 418 401 East State Street, 7th Floor Trenton, NJ 08625 Phone: (609) 633-1122 Fax: (609) 633-6198 www.state.nj.us
NEW MEXICO	New Mexico Health and Environment Department, Air Quality Bureau 1190 St. Francis Drive, Room South 2100 Santa Fe, NM 87502 Phone: (505) 827-0042 Fax: (505) 827-0045 www.nmenv.state.nm
NEW YORK	New York Department of Environmental Conservation, Division of Air 50 Wolf Road, Room 132 Albany, NY 12233-3251 Phone: (518) 457-6379 Fax: (518) 457-0794
NORTH CAROLINA	North Carolina Department of Natural Resources and Community Development, Division of Environmental Management Air Quality Section P.O. Box 29535 Raleigh, NC 27626 Phone: (919) 733-1489 Fax: (919) 733-1812 www.ehnr.state.nc.us/ehnr/
NORTH DAKOTA	North Dakota Department of Health and Consolidated Laboratories, Division of Environmental Engineering 1200 Missouri Avenue, Room 304 Bismarck, ND 58502-5520 Phone: (701) 221-5188 Fax: (701) 221-5200 www.ehs.health_state.nd.us/ndhd/index.html-ssi

Table A1.28. State Air Pollution Regulatory Agencies (Continued)

OHIO	Ohio Environmental Protection Agency, Division of Air Pollution Control 1600 Watermark Drive Columbus, OH 43215 Phone: (614) 644-2270 Fax: (614) 644-3681 www.epa.ohio.gov/
OKLAHOMA	Oklahoma Department of Health, Air Quality Services 1000 Northeast 10th Street Oklahoma City, OK 73117-1299 Phone: (405) 271-5220 Fax: (405) 231-7339 www.state.ok.us/
SOUTH CAROLINA	South Carolina Department of Health and Environmental Control, Bureau of Air Quality Control 2600 Bull Street Columbia, SC 29201 Phone: (803) 734-4552 Fax: (803) 734-4556 www.state.sc.us/dhec/
SOUTH DAKOTA	South Dakota Department of Environmental and Natural Resources, Office of Minerals & Mining Joe Foss Building 523 East Capitol Pierre, SD 57501-3181 Phone: (605) 773-4201 Fax: (605) 773-6035 www.state.sd.us/state/executive/denr/denr.html
TENNESSEE	Tennessee Department of Health and Environment, Air Pollution Control 9th Floor, L&C 401 Church Street Nashville, TN 37243-1531 Phone: (615) 532-0599 Fax: (615) 532-0614 www.state.tn.us/environment/
TEXAS	Texas Department of Rules and Regulations 12124 Park 35 Circle Austin, TX 78753 Phone: (512) 908-1000 Fax: (512) 908-1457 www.tnrcc.texas.gov/
UTAH	Utah Division of Air Quality P.O. Box 144820 Salt Lake City, UT 84114-4820 Phone: (801) 536-4000 Fax: (801) 536-4099

www.eq.state.ut.us/

Table A1.28. State Air Pollution Regulatory Agencies (Continued)

VIRGINIA	Virginia Department of Air Pollution Control P.O. Box 10089 Richmond, VA 23240 Phone: (804) 786-2504 Fax: (804) 225-3933 www.deq.state.va.us/
WASHINGTON	Washington Department of Ecology, Air Quality Program P.O. Box 47600 Olympia, WA 98504-7600 Phone: (360) 459-6507 Fax: (360) 438-8148 www.wa.gov/ecology
WYOMING	Wyoming Department of Environmental Quality, Division of Air Quality 122 West 25th Street Cheyenne, WY 92002 Phone: (307) 777-7391 Fax: (307) 777-7682 www.state.wy.us

DISTRIBUTION LIST

DEPARTMENT OF DEFENSE

Defense Commissary Service (1)
Director of Facilities
Bldg 8400
Lackland AFB TX 78236-5000

AAFES/ATTN: CFE (1)
PO Box 660320
Dallas TX 75266-0320

Defense Technical Information Center (1)
ATTN: DTIC-FDA
Alexandria VA 22034-6145

SPECIAL INTEREST ORGANIZATIONS

IHS (S. Carter) (1)
15 Inverness Way East Stop A-111
Englewood CO 80112

Construction Criteria Database (1)
National Institute of Bldg Sciences
1201 L Street NW, Suite 400
Washington DC 20005