20.2.70 NMAC Operating Permit Modification

for

Los Alamos National Laboratory

Operated by:

University of California
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

Owned by:

National Nuclear Security Administration
U.S. Department of Energy
Office of Los Alamos Site Operations
Los Alamos, New Mexico 87544

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1.0 Introduction

Los Alamos National Laboratory (LANL or the Laboratory) is a major source for Title V purposes and is required to have a Title V operating permit. This is due primarily to fuel combustion at industrial-type sources which provide infrastructure support to the research and development activities present at LANL.

LANL initially filed a Title V permit application with the New Mexico Environment (NMED) in December 1995. A comprehensive new permit application was filed in November 2002 and replaced the prior submittal. NMED issued LANL's initial Title V Operating Permit P100 on April 30, 2004.

This application is for the first modification to Title V Permit P100. The permit modification is required for new emission units which have been permitted or reviewed by NMED under the construction permit or new source review (NSR) program since issuance of the Title V permit. NMED implements a dual permit program whereby, unless exempt, new air emission sources must first obtain an NSR permit and subsequently be incorporated within the facility Title V permit.

1.1 Facility Description

LANL is a nonprofit scientific institution engaged in theoretical and experimental research and development primarily in support of national security. LANL was originally established in 1943, and since that time has been under the administrative authority of several federal agencies. LANL is currently under the authority of the National Nuclear Security Administration (NNSA) of the Department of Energy (DOE). The University of California (UC) is the current LANL management and operating contractor and has been since the Laboratory's inception.

The Laboratory is located in Los Alamos County in north central New Mexico approximately 60 miles north of Albuquerque and 25 miles northwest of Santa Fe. The facility encompasses 43 square miles of land which is situated at a high elevation and within rugged terrain defined by multiple mesas and canyons. The majority of the total land area is not occupied but used instead to provide buffer areas for safety and security purposes. Laboratory property is divided into Technical Areas (TA) which are used to define boundaries of developed sites, experimental areas, and waste disposal locations. The nearest communities to and which border the Laboratory are Los Alamos to the north and White Rock to the southeast. Additional surrounding land is largely undeveloped, with large tracts held by the Santa Fe National Forest, Bandelier National Monument, Bureau of Land Management, and San Ildefonso Pueblo. A site location map and map showing TA boundaries are included in Appendix B.

LANL's national security mission is to ensure the safety and reliability of the U.S. nuclear deterrent; reduce the threat of weapons of mass destruction, proliferation, and terrorism; and solve national problems in defense, energy, environment, and infrastructure. Work at LANL is performed for multiple programs within DOE, as well as non-DOE-sponsored work in support of other federal agencies, universities, institutions, and commercial firms which cannot be performed by the private sector but is compatible with the LANL mission.

The research and development activities at LANL are supported by an infrastructure of industrial-type operations that provide electricity, building and process heating and cooling, general construction and maintenance, and road repair. Air emissions from these support operations, primarily fuel combustion at the Laboratory power plant and other steam boilers throughout the facility, account for the majority of LANL emissions.

1.2 Purpose of Application

This application is for a modification to the LANL Title V operating permit. The purpose of the application is to incorporate in the operating permit the activities and permit conditions from NSR permits issued by NMED since issuance of Permit P100 in April 2004. In one instance, the application also includes an activity for which LANL submitted a Notice of Intent (NOI) application which NMED reviewed and determined an NSR permit was not required. All requested modifications have already undergone preconstruction permit review by NMED. A secondary purpose of the application is to remove emission sources within Permit P100 which have been closed. This application is considered a significant permit modification under 20.2.70 NMAC – Operating Permits.

Table 1.2-1 below identifies the activities which are the new or modified sources included within this permit modification.

Table 1.2-1 Emission Sources Included Within Permit Application

Emission Source	NSR Permit No.
Data Disintegrator	2195H
TA-3 Power Plant	2195BM1[(a)]
Soil Vapor Extraction	2195L[(b)]
TA-16 Flash Pad TA-11 Wood and Fuel Fire Test Site[(c)]	2195J
TA-36 Sled Track[(c)]	2195K

(a) Permit 2195BM1 was for installation of a new combustion turbine at the TA-3 Power Plant. However, this NSR permit also includes the power plant boilers for which existing NSR permit conditions were revised.
(b) 2195L is a Notice of Intent number. NMED determined an NSR permit was not required.
(c) These are existing open burn sources at LANL which required new NSR permits due to regulatory changes to 20.2.60 NMAC – Open Burning. These sources are currently referenced in Permit P100, Condition 9.0 – Open Burning.

Table 1.2-2 identifies the emission sources currently within Permit P100 which have been closed and taken out operation. This permit modification requests that these sources be removed from the permit.

Table 1.2-2 Emission Sources to be Removed from Permit P100

Emission Source	Current Permit P100 Condition
Boilers TA-16-1485-BS-1 and BS-2	2.3 Boilers and Heaters
Paper Shredder	2.8 Paper Shredder
Rock Crusher	2.10 Rock Crusher

As specified by 20.2.70 NMAC – Operating Permits, the scope and content of this application are limited to the requested revisions, which in this case are incorporation of the new or modified sources listed in Table 1.2-1 within the Title V permit. Specifically, 20.2.70.300.C NMAC states applications for permit modifications need supply information within the application only if it is related to a proposed change to the permit. Title V permittees are required to submit a comprehensive application every five years for permit renewal which addresses all emission units at the facility.

This application does not contain any request to revise the facility-wide emission limits for criteria and hazardous air pollutants in Condition 2.11 of Permit P100. The addition of the new or modified sources in Table 1.2-1 will not impact future compliance with these existing limits. Table 1.2-3 shows the most recent comparison of actual LANL facility-wide emissions with the facility-wide emission limits in Condition 2.11.

Table 1.2-3 Comparison of LANL Annual Emissions with Facility-Wide Emission Limits

Pollutant	2004 Annual Emissions (ton)[(a)]	Facility-Wide Emission Limits (tpy)
Nitrogen Oxides (NO_x)	50.5	245
Carbon Monoxide (CO)	35.4	225
Volatile Organic Compounds (VOCs)	11.4	200
Sulfur Dioxide (SO_2)	1.5	150
Particulate Matter (PM)	4.8	120
Hazardous Air Pollutants (HAPs)	6.7	24 combined
Highest Individual HAP (Hydrochloric Acid)	1.5	8 individual

(a) All values are from the LANL Semi-annual Title V Emissions Report dated March 23, 2005 and submitted to NMED.

1.3 Application Contents

Chapter 2 of this application contains a comprehensive description of each new or modified source listed in Table 1.2-1. The following information is included for each source: a general description, an operating schedule, a process flow diagram, emission estimates, a description of emissions control equipment, identification of applicable requirements, and proposed monitoring, recordkeeping, and reporting. Also included is a discussion of the emission sources in Table 1.2-2 which are to be removed from Permit P100. Chapter 3 of the application discusses, for the new or modified sources, compliance with applicable requirements and contains a compliance certification for the requirements. The permit application forms are included in Appendix A. Appendix B contains maps showing the general location of LANL and the location of each new or modified source. Appendix C contains a copy of the specific NSR permit conditions from the NSR permits listed in Table 1.2-1. Appendix D provides supporting information for emission estimates for the new or modified sources within the application.

2.0 Emission Unit Modifications

This chapter of the application provides detailed information for each new or modified emission unit which is part of this permit modification. Emission unit information is also provided within NMED operating permit application forms included in Appendix A. A map showing the location and UTM coordinates for each emission unit in this chapter is included within Appendix B. Specific NSR permit conditions, such as allowable emission limits, cited in this chapter are included in Appendix C. Appendix D contains additional supporting information with respect to emissions data provided in this chapter.

For each emission unit, the following information is provided in this chapter:

- General Description of Source Category,
- Operating Schedule,
- Process Flow Diagram,
- Emissions,
- Emissions Control Equipment,
- Applicable Requirements, and
- Proposed Monitoring, Recordkeeping, and Reporting

2.1 Data Disintegrator

2.1.1 General Description of Source Category

The data disintegrator was installed in TA-52-11 in July of 2004. This building had previously housed the paper shredder in Condition 2.8 of Permit P100. The paper shredder was taken off line and removed in July 2004 to make room for the data disintegrator. The data disintegrator was permitted for installation under NSR Air Quality Permit No. 2195H issued by NMED on October 22, 2003. The data disintegrator is capable of data destruction of paper, microfiche, film, plastic magnetic tape, and compact discs.

Paper materials suspended in the exhaust are processed through a cyclone separator and cloth tube filters. The paper particles captured by the cyclone separator and cloth tube filters are collected in a dumpster. The dumpster is then sent to the county landfill for disposal of the material. Microfiche, film, plastic magnetic tape, and compact disc material do not enter the external exhaust system and are instead captured in a separate collection system contained inside the building. This material is sent out for metals recycling and disposal.

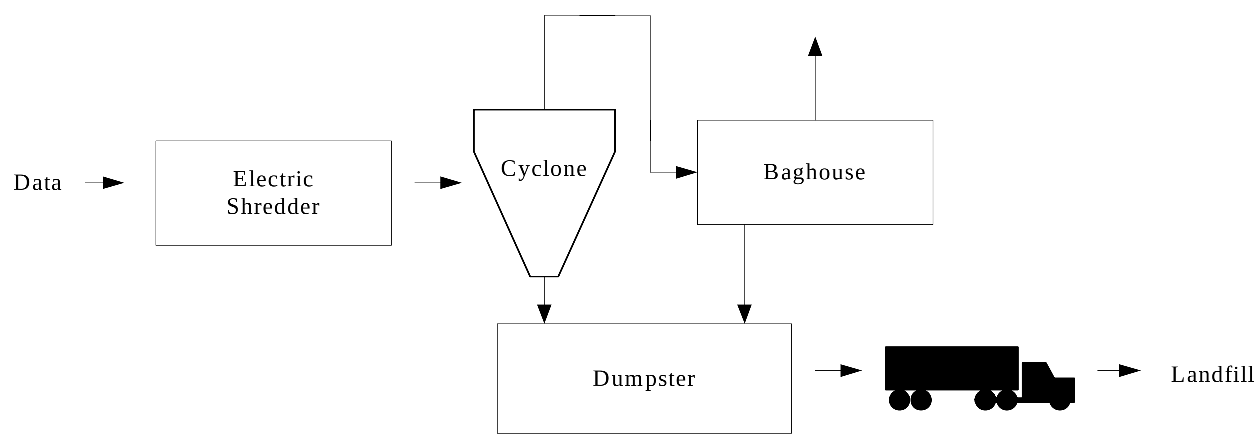
2.1.2 Operating Schedule

The maximum capacity of the data disintegrator is 1200 pounds of material per hour, 8760 hours/year for a total of 5256 ton/year of material shredded. However, the actual operating hours are more accurately characterized by a schedule of 1200 pounds of material per hour, 6.5 hours per day, and 5 days per week for a total of 1014 ton/year of material.

2.1.3 Process Flow Diagram

A process flow diagram for the data disintegrator is provided in Figure 2.1-1.

Figure 2.1-1 Process Flow Diagram for Data Disintegrator



2.1.4 Emissions

Data disintegrator operation is a source of particulate air emissions only. Emission estimates are based on manufacturer's data regarding particle size produced by the data disintegrator and efficiencies of the pollution control devices. The cyclone provides 75% control efficiency and the cloth tube filters provide 95% efficiency. Further, the manufacturer, Security Engineered Machinery (SEM), estimates that 15% of the material will remain suspended in the exhaust while 85% of the particles will fall into the collection system by gravity.

The estimated emissions are based on the following calculations and shown in Table 2.1-1.

$$\mathit{Uncontrolled\ Emission\ Rate}\left(\frac{lb}{hr}\right) = 1200\,\frac{lb}{hr} * (0.15)$$

$$\mathit{Controlled\ \ Emission\ \ Rate}\left(\frac{lb}{hr}\right) = 1200\,\frac{lb}{hr} * (0.15) * \left(\frac{100-75}{100}\right) * \left(\frac{100-95}{100}\right)$$

Table 2.1-1 Emissions Estimates for the Data Disintegrator

Emission	Emissions of TSP and PM_{10}	
	lb/hr	tpy
Uncontrolled	180	788
Controlled[a]	2.3	9.9

[a] Allowable emission rates from NSR Permit 2195H.

The controlled emissions, 2.3 pounds per hour (9.9 tons per year), of particulate matter are based on continuous operations. The data disintegrator does not operate on a continuous basis and the actual emissions are less.

2.1.5 Emissions Control Equipment

The data disintegrator exhaust system is equipped with both a ten horsepower cyclone separator and cloth tube filters to control particulate emissions. The cyclone is estimated to provide 75% control efficiency and the cloth tube filters are estimated to provide 95% efficiency.

2.1.6 Applicable Requirements

The data disintegrator is subject to the requirements set forth in NSR Permit 2195H. See Table 2.1-2.

Table 2.1-2 Applicable Requirements for the Data Disintegrator

Source Category	Applicable Requirement
Data Disintegrator (TA-52-11)	***Operating Requirements*** • Perform regular maintenance and repair of the cyclone and cloth tube filters per manufacturer's recommendations. ***Emission Limits*** • Emissions shall not exceed the controlled emission rates in Table 2.2-1.

2.1.7 Proposed Monitoring, Recordkeeping, and Reporting

Monitoring, recordkeeping, and reporting applicable to this source are set forth in Table 2.1-3.

Table 2.1-3 Proposed Monitoring, Recordkeeping, and Reporting for the Data Disintegrator

Source Category	Monitoring, Recordkeeping, and Reporting
Data Disintegrator (TA-52-11)	***Monitoring/Recordkeeping*** • Track the number of the boxes being shredded. (LANL proposed condition). • Document that the cyclone and cloth tube filters have been maintained according to the manufacturer's recommendations. ***Reporting*** • Report criteria pollutant emissions on a semiannual basis. (Condition 4.1 of Permit P100) • Report required monitoring on a semiannual basis. (Condition 4.2 of Permit P100)

2.2 Power Plant at Technical Area 3 (TA-3-22)

2.2.1 General Description of Source Category

The Technical Area 3 (TA-3) Power Plant provides space heating to most of the buildings at TA-3. Steam produced is also used for process needs and to produce electricity in one 10-megawatt and two 5-megawatt steam turbine generators. The plant consists of three dual fuel boilers with natural gas being the primary fuel and No. 2 fuel oil available for use as a standby fuel. Each boiler has a nameplate maximum heat input capacity of 210 MMBtu/hr. Because LANL is located at a high elevation, the boilers do not operate at nameplate capacity. The maximum heat input capacity, derated for altitude, is calculated to be 178.5 MMBtu/hr. This reflects a 15% decrease in input rating. Two of the boilers were manufactured by Edgemoor Iron Works and installed in 1950. The third boiler was manufactured by Union Iron Works and installed in 1951.

In July 2004, a construction permit for a 24.6 MW simple-cycle natural gas combustion turbine was issued by the NMED. The turbine, which runs solely on natural gas, has a design capacity of 24.6 MW at the average temperature and altitude for LANL. The turbine was manufactured by Rolls-Royce and is expected to be installed in the fall of 2005.

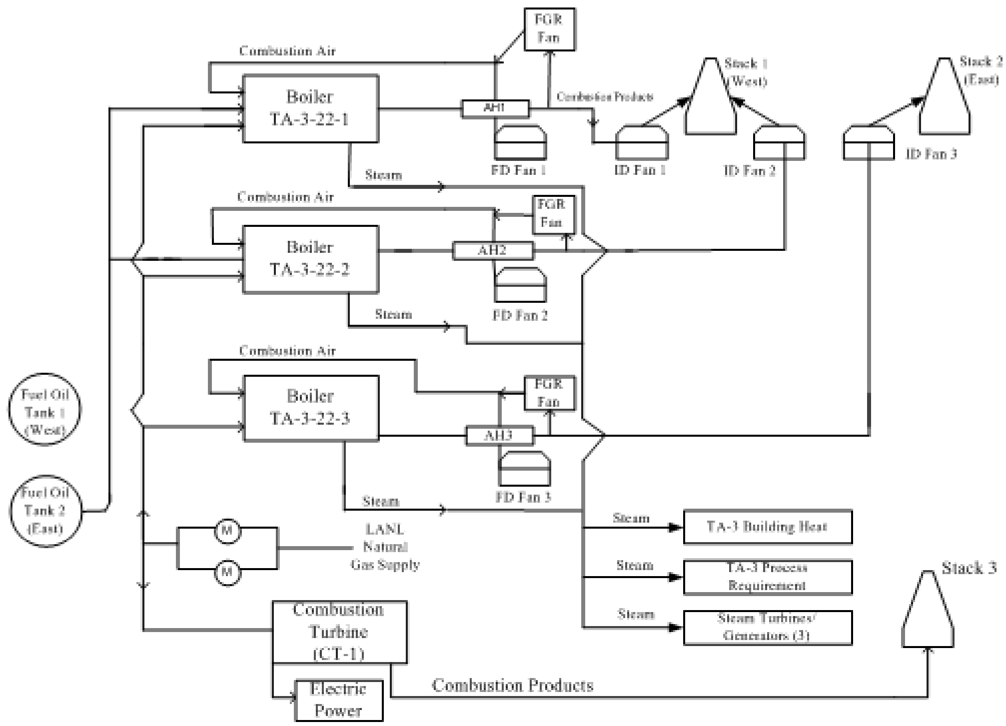
2.2.2 Operating Schedule

The plant operates 24 hours per day and 7 days per week. Normally, only two boilers are operated simultaneously, one of which is on hot standby and the other is running at partial capacity. Under maximum operating conditions, such as during peak generation of electricity, the third boiler can be brought on-line. The simple-cycle combustion turbine will also be used to ensure that electric power is available to LANL during periods of peak demand. When in operation, the turbine will only be operated at 100% load except for minimal time during startup and shutdown.

2.2.3 Process Flow Diagram

A process flow diagram for the TA-3-22 Power Plant is presented in Figure 2.2-1.

Figure 2.2-1 Process Flow Diagram for Technical Area 3 (TA-3-22) Power Plant



2.2.4 Emissions

Combustion of natural gas and fuel oil at the plant results in emissions of criteria pollutants (NO_x, CO, SO_x, PM, VOCs) and small quantities of HAPs. In September 2002, LANL completed installation of a flue gas recirculation (FGR) air pollution control system to reduce emissions of NO_x. NMED issued NSR Permit 2195B for the FGR project. In November of 2003, LANL submitted an air quality construction permit application to NMED to install a 24.6 MW simple-cycle combustion turbine. NMED issued NSR Permit 2195BM1 for the combustion turbine on July 30, 2004. This permit included new hourly and annual emission limits for applicable criteria pollutants for each emission unit. These maximum allowable emission rates are based on the maximum quantities of natural gas and fuel oil use allowed by the permit. The permit specifies maximum fuel quantities, used by all three boilers combined, of 2,000 MMscf of natural gas and 500,000 gallons of fuel oil in any 365 day period. The combustion turbine has a maximum fuel use restriction of 646 MMscf of natural gas in any 365 day period.

Tables 2.2-1 and 2.2-2 show the allowable emission rates from the combustion turbine construction permit.

Table 2.2-1. Criteria Pollutant Emission Rates[(a)]

Unit No.[(b)]	TSP (lb/hr)		PM_{10} (lb/hr)		NO_x (lb/hr)		CO (lb/hr)		VOC (lb/hr)		SO_x (lb/hr)	
	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
Boiler TA-3-22-1	1.3	4.3	1.3	3.0	10.2	11.3	7.0	6.5	1.0	0.3	1.1	9.6
Boiler TA-3-22-2	1.3	4.3	1.3	3.0	10.2	11.3	7.0	6.5	1.0	0.3	1.1	9.6
Boiler TA-3-22-3	1.3	4.3	1.3	3.0	10.2	11.3	7.0	6.5	1.0	0.3	1.1	9.6
Combustion Turbine (CT-1)	1.6		1.6		23.8		170.9		1.0		1.4	

[(a)] The allowable emissions estimates were calculated using a heat value of 137,000 Btu/gallon for diesel, a boiler derated capacity of 178.5 MMBtu/hr per unit, a natural gas heat content of 1012.9 Btu/scf, and a sulfur content of 0.05% for fuel oil.
[(b)] Unit numbers for the three boilers follow numbering for Permit P100. NSR Permit used B-1, B-2, and B-3 for the boilers.

Table 2.2-2. Criteria Pollutant Emission Rates[(a)] [(b)]

Unit	TSP (tpy)	PM_{10} (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)	SO_x (tpy)
Combined Boilers	8.4	8.2	60.2	41.3	5.6	7.9
CT-1	2.3	2.3	33.2	19.8	Neg.[(c)]	1.9

[(a)] The allowable emissions estimates were calculated using a heat value of 137,000 Btu/gallon for diesel, a boiler derated capacity of 178.5 MMBtu/hr per unit, a natural gas heat content of 1012.9 Btu/scf, and a sulfur content of 0.05% for fuel oil.
[(b)] 12-month rolling totals.
[(c)] NMED did not assign an emission limit to estimates less than or equal to 0.5 within NSR Permit 2195BM1.

The emission factors used in the combustion turbine permit application are shown in Table 2.2-3. LANL conducted an emissions compliance test on the power plant boilers in September 2002 and results were reported to NMED. From the test results, a NO_x controlled emission factor was derived by taking the average of the 3 test results (from each boiler) in lb/MMBtu. During the test, the FGR system was in operation and the boilers were burning natural gas. The average controlled emission factor is 0.058 lb NO_x/Mscf (based on an average natural gas heat content of 1030 Btu/scf). Using this controlled emission factor, and the uncontrolled NO_x emission factor from the FGR application of 0.163 lb/Mscf, an average NO_x control efficiency of approximately 64% is derived.

Emission factors for CO, VOC, TSP, PM_{10}, and SO_x for the boilers are from AP-42. The SO_x emission factor is based on the maximum sulfur content in the pipeline natural gas supplied by PNM of 2 grains of sulfur per 100 scf of natural gas.

The NO_x emission factor for combustion of fuel oil was derived by applying the average 64% reduction from the 2002 emission test to the AP-42 emission factor used in the FGR permit application of 24 lb/Mgal. The resulting factor is 8.64 lb/Mgal. The SO_x factor is based on maximum sulfur content in the fuel oil supplied of 0.05% sulfur.

Emission factors for the combustion turbine, except for PM and PM_{10} which are from AP-42, were supplied by Rolls-Royce, the combustion turbine manufacturer. For the combustion turbine, NO_x and CO emission concentrations are 25 ppmv at 15% O2, dry. Mass emission rates for NO_x and CO vary with ambient temperature and humidity. Lower ambient temperatures, with an increased density of air, increases the mass flow rate of air (and turbine power output) and the mass emission rate of pollutants. To account for this variability, annual mass emission rates are estimated for the combustion turbine at an average temperature of 47.9 °F and a relative humidity of 51%. These values represent averages from a 30 year climatology record for Los Alamos. Hourly mass emission rates are estimated based on a worst-case ambient temperature of minus 18 °F.

Variability occurs in emission rates with load conditions also. The turbine permit has a condition to limit operation of the combustion turbine at 100% load. The turbine will only be operated at 100% load except for minimal time during startup and shutdown. All emission estimates are based on the 100% load operating condition.

Table 2.2-3 Emission Factors Used in the Combustion Turbine Application

Fuel	Emission Factor Unit	TSP	PM_{10}	NO_x	CO	VOC	SO_x	HAP
Boiler - Natural gas[(a)(b)]	($lb/10^6 ft^3$)	7.6	7.6	58 [(c)]	40[(d)]	5.5	6[(e)]	1.89
Boiler - Distillate oil[(f)]	($lb/10^3 gal$)	2	1	8.64[(g)]	5	0.2	7.4[(h)]	6.11E-02[(i)]
Combustion Turbine[(j)(b)]	($lb/10^6 ft^3$)	7	7	102.9	61.3	0.4	6[(e)]	1.04

[(a)] Emission factors, unless otherwise indicated are from AP-42, 7/98, Section 1.4, Natural Gas Combustion, Tables 1.4-2, 1.4-3 and 1.4-4.
[(b)] The natural gas heat content of 1012.9 Btu/scf was used.
[(c)] Based on source test data from September 2002. This emission factor is the average value from the source test and takes into account the controlled emissions from the FGR system.
[(d)] AP-42, 1/95, Section 1.4, Natural Gas Combustion, Table 1.4-2.
[(e)] The SO_x emission factor is based on the maximum sulfur content in the pipeline natural gas supplied by PNM of 2 grains S/100 scf of natural gas.
[(f)] Emission factors, unless otherwise indicated, are from AP-42, 9/98, Section 1.3, Fuel Oil Combustion, Tables 1.3-1, 1.3-2, and 1.3-3.
[(g)] The factor assumes similar reduction for oil as that determined for natural gas using the September 2002 FGR compliance test.
[(h)] SO_x From AP-42, 9/98, Section 1.3 – Fuel Oil Combustion, Table 1.3-1 corrected by EPA on 4/28/00, using 0.05% S.
[(i)] Emission factors from AP-42, 9/98, Section 1.3, Fuel Oil Combustion, Tables 1.3-8 and 1.3-10, and EPA FIRE, 10/2000, database. Heating value of 137,000 Btu/gal used in emission factor conversions.
[(j)] Emission factors for NO_x, CO, SO_x, and VOC were provided by the turbine manufacturer (Rolls-Royce). Operation of the turbine will be at 100% load at an average ambient temperature of 47.9 °F and 51% humidity. PM and PM_{10} are taken from AP-42, 4/00, Section 3.1 – Stationary Gas Turbines. The CO emission factor from Rolls-Royce for the worst-case hourly emission estimate at minus 18 degrees F is 731 $lb/10^6 ft^3$.

HAP emission estimates for boilers were calculated using emission factors shown in Table 2.2-3. Natural gas emission factors for the boilers were taken from AP-42, 7/98, Section 1.4, Natural Gas Combustion, Table 1.4-2. Fuel oil emission factors for formaldehyde and polycyclic organic matter (POM) are from AP-42, 9/98, Section 1.3, Fuel Oil Combustion, Table 1.3-8 and trace metals are from Table 1.3-10. AP-42 does not contain additional organic HAP emission factors for distillate fuel oil combustion. The remaining HAP emission factors for distillate fuel oil use are from the external combustion boiler section of EPA's Factor Information Retrieval (FIRE) emission factor database (10/2000 version). HAP emission factors for combustion of natural gas in the combustion turbine were taken from AP-42, 4/2000, Section 3-1, Natural Gas Turbines, Table 3.1-3.

HAP emission estimates are shown in Table 2.2-4. Estimated emissions were calculated based on the maximum fuel usage allowed under Permit No. 2195BM1 and the emission factors in Table 2.2-3.

Table 2.2-4 HAP Emission Estimates for the TA-3 Power Plant

Fuel Type	Total HAP (tpy)
Boilers - Natural Gas	1.9
Boilers - Fuel Oil	0.015
Combustion Turbine - Natural Gas	0.00039
Total	1.92

A sample emission calculation is shown below. The NO_x emissions were calculated using a FGR control efficiency of 64%. This percentage was determined using 2002 emission test results.

$$\mathit{Emission}\ \mathrm{Rate}\left(\frac{\mathrm{ton}}{\mathrm{year}}\right)=\left[\mathrm{EF}\left(\frac{lb}{10^6\ ft^3}\right)*\mathrm{Nat.\,Gas\ Usage}\left(\frac{2{,}000\ \mathrm{MMscf}}{\mathrm{year}}\right)+\mathit{E}\mathrm{F}\left(\frac{\mathrm{lb}}{10^3\mathrm{gal}}\right)*\mathrm{Fuel\ Oil\ Usage}\left(\frac{500{,}000\ \mathrm{gal}}{\mathrm{year}}\right)\right]\left(\frac{\mathrm{ton}}{2000\ \mathrm{lb}}\right)$$

The TA-3 power plant currently is operated under a series of Operating Instructions to ensure the protection of employee safety and health, integrity of the equipment, and protection of the environment. Specific procedures for operating the boilers during startup, shutdown, and malfunction are currently in place. These procedures serve to minimize emissions during startup, shutdown, or malfunction. Specific procedures for operating the new combustion turbine during startup, shutdown, and malfunction will be developed prior to beginning operation.

2.2.5 Emissions Control Equipment

The primary air pollutant emitted from the TA-3 Power Plant is nitrogen oxides (NO_x). The flue gas recirculation (FGR) system was installed in 2002 to reduce the amount of NO_x emitted from the boilers. Approximately 64% of NO_x emissions are reduced by the FGR control system. In the FGR system, a portion of exhaust flue gas is recycled and mixed with combustion air before being fed to a burner. Combustion products in the recycled flue gas act as inerts or diluents during combustion of the fuel/air mixture and suppress NO_x formation primarily by reducing combustion temperatures.

NO_x emissions from the combustion turbine are controlled by a pre-mix, lean-burn series staged combustion system. This dry low-NO_x control technology, called Dry Low Emission (DLE), will lower the combustion turbine NO_x emissions by approximately 70%. Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_x formation.

2.2.6 Applicable Requirements

Unit-specific applicable requirements that apply to the TA-3 Power Plant are listed below in Table 2.2-5.

Table 2.2-5 Applicable Requirements for the TA-3 Power Plant

Source Category	Applicable Requirement
Power Plant **TA-3-22**	***Operating Requirements*** • The combustion turbine shall be in compliance with all applicable requirements of 40 CFR, Part 60, Subpart GG, and 40 CFR Part 60, Subpart A. For purposes of Subpart GG, the combustion turbine is subject to requirements applicable to turbines which commenced construction after October 3, 1977 and before July 8, 2004. (Condition 1.d of Permit 2195BM1) • The combustion turbine shall be equipped with the manufacturer's Dry Low Emissions (DLE) control technology to control NO_x emissions. (Condition 1.e of Permit 2195BM1) • Natural gas used by the boilers shall be pipeline quality and contain no more than 2 grains of total sulfur per 100 scf. No. 2 fuel oil used shall contain less than 0.05% sulfur by weight and not contain waste oils or solvents. (Condition 1.g of Permit 2195BM1)

Source Category	Applicable Requirement
Power Plant TA-3-22 (continued)	• The three power plant boilers combined shall not use more than 500,000 gallons of No. 2 fuel oil in any 365 day period. (Condition 1.g.i of Permit 2195BM1) • The three power plant boilers combined shall not use more than 2,000 MMscf of natural gas in any 365 day period. (Condition 1.g.ii of Permit 2195BM1). • The combustion turbine shall use pipeline quality natural gas containing no more than 2 grains of total sulfur per 100 scf. (Condition 1.i of Permit 2195BM1). • The combustion turbine shall not use more than 646 MMscf of natural gas in any 365 day period. (Condition 1.j of Permit 2195BM1). • The combustion turbine will operate at no less than 100% full load, except for minimal periods during startup and shutdown conditions. (Condition 1.f of Permit 2195BM1) ***Emission Limits*** • Emissions from each individual unit shall not exceed the hourly limits listed in Table 2.2-1 nor shall their combined totals exceed the annual limits (12-month rolling totals) in Table 2.2-2. (Condition 2.a of Permit 2195BM1) • Nitrogen dioxide emissions shall not exceed 0.3 lb/MMBtu of heat input from any boiler when burning natural gas or oil. (Conditions 2.b, 1.m, and 1.n of Permit 2195BM1, 20.2.33 NMAC, and 20.2.34 NMAC) • Visible emissions from the boilers or combustion turbine shall not equal or exceed an opacity of 20%. (Conditions 1.o and 2.c of Permit 2195BM1 and 20.2.61 NMAC) • Nitrogen oxide emissions from the combustion turbine shall not exceed 25 ppmv at 15% O_2. (Condition 2.d of Permit 2195BM1)

2.2.7 Proposed Monitoring, Recordkeeping, and Reporting

Monitoring, recordkeeping, and reporting is described below in Table 2.2-6. Currently required monitoring, recordkeeping, or reporting is followed with a citation to the basis for the requirement.

Table 2.2-6 Proposed Monitoring, Recordkeeping, and Reporting for the TA-3 Power Plant

Source Category	Monitoring, Recordkeeping, and Reporting
Power Plant **TA-3-22**	***Monitoring:*** • A volumetric fuel flow meter shall be connected to each or all boilers so that the total amount of natural gas being used can be monitored and continually recorded. This usage data shall be used to calculate a rolling 365-day total. (Conditions 1.h and 3.b of Permit 2195BM1) • A volumetric fuel flow meter shall be connected to the combustion turbine so that the total amount of natural gas being used will be monitored and continually recorded. This usage data shall be used to calculate a rolling 365-day total. Although the facility is not subject to 40 CFR Part 75, Federal Acid Rain requirements, the flow meter shall meet the initial certification requirement of 40 CFR Part 75, Appendix D 2.1.5 and the quality assurance requirements of 40 CFR Part 75, Appendix D 2.1.6. (Conditions 1.k, 3.f, and 4.c of Permit 2195BM1). • Total fuel oil used by all boilers shall be monitored and recorded so that combined use can be calculated on a rolling 365-day total. (Condition 3.a of Permit 2195BM1) • Hours of operation, including start-up and shut-down times, of the boilers and combustion turbine, shall be monitored and recorded daily. (Condition 1.l of Permit 2195BM1). • The operating load shall be monitored and recorded hourly during normal operations of the turbine. Periods of startup and shutdown shall not be included in the hourly monitoring, but shall be recorded separately. (Condition 3.e of Permit 2195BM1) • Compliance with NO_x and CO pound per hour emission limits

Source Category	Monitoring, Recordkeeping, and Reporting
Power Plant TA-3-22 (continued)	for the combustion turbine shall be determined by multiplying the daily total natural gas firing rate for the unit (in Mscf), by the manufacturer's guaranteed emission rates of 0.1029 pound NO_x and 0.731 pound CO per Mscf of gas burned. Divide each of these values by the number of hours of operation of the unit during that day. This method should be used daily to determine compliance with the hourly emission limits. (Conditions 3.g and 3.i of Permit 2195BM1) • Compliance with NO_x and CO annual emission limits for the combustion turbine shall be determined by multiplying the 365 day total natural gas firing rate for the unit (in Mscf), by the manufacturer's guaranteed emission rates of 0.1029 pound NO_x and 0.0613 pound CO per Mscf of gas burned. This must be performed at least once per quarter. (Conditions 3.h and 3.i of Permit 2195BM1) • Initial compliance tests are required on the combustion turbine for NO_x and CO. Tests shall be conducted within sixty days after the unit achieves maximum normal production, but no later than 180 day after initial startup. EPA reference methods 1 through 4, Method 7E for NO_x, and Method 10 for CO, must be used unless NMED approves an alternative test method. (Condition 6 of Permit 2195BM1) ***Recordkeeping:*** • A certification of total sulfur content of the No. 2 fuel oil used by the boilers shall be obtained from the supplier whenever No. 2 fuel oil is delivered to the facility. The certification must include the name of the supplier and a statement that sulfur content is less than or equal to 0.05% by weight. If the certification is not available at delivery, analysis of the fuel oil will be conducted to determine total sulfur content. If analysis is performed by LANL, a record shall be kept which shows the name of the supplier, the location where the sample was taken, the method used to determine sulfur content, and the results of the analysis. (Conditions 3.c, 3.d, 4.a.i, and 4.a.ii of Permit 2195BM1) • A record shall be kept to verify natural gas consumed is pipeline quality natural gas (less than 2 grains of total sulfur per 100 standard cubic feet). (Condition 4.b of Permit 2195BM1)

Source Category	Monitoring, Recordkeeping, and Reporting
Power Plant TA-3-22 (continued)	• Records of all measurement and monitoring data listed in the monitoring section above shall be retained at the plant site. (Condition 4.c of Permit 2195BM1) ***Reporting:*** • Report criteria pollutant and HAP emissions on a semiannual basis. (Condition 4.1 of Permit P100) • Report required monitoring on a semiannual basis. (Condition 4.2 of Permit P100)

2.3 Soil Vapor Extraction at TA-54 Material Disposal Area L

This source category is described in detail in the Notice of Intent (NOI) application which LANL submitted to NMED in December 2004. NMED reviewed the application and determined a new source review permit was not required for this operation. The NOI was assigned number 2195L.

2.3.1. General Description of Source Category

LANL used Material Disposal Area (MDA) L from the early 1960s until 1985 as the designated disposal area for non-radiological, containerized and uncontainerized liquid chemical wastes, including chlorinated solvents. Located at TA-54, MDA L consists of an elongated pit, three impoundments, and 34 shafts. Area L is the asphalted area atop MDA L and is currently used for RCRA-permitted chemical waste storage and treatment, and for mixed waste storage under interim status authority. All of the former disposal units are covered by asphalt and/or chemical waste storage structures.

Subsurface vapor phase hydrocarbons were detected during the mid-1980s, and the existence of a hydrocarbon vapor plume was verified during the RCRA Phase I characterization of MDA L. Ongoing monitoring of the hydrocarbon plume is done through quarterly soil pore-gas sampling, which has been conducted from 1995 to the present time. These data show hydrocarbon concentrations exceeding 1,000 ppmv near the source areas.

The soil vapor extraction (SVE) pilot test at MDA L will be used to evaluate both 1) the volume and rate of plume reduction, and 2) a means for determining and controlling any significant influx of the source (e.g. an increase in the liquid source caused by rupture of the buried drums) to assure the contaminant plume will not increase in size. Data from the pilot test will be used in the MDA L Corrective Measure Evaluation to assess the effectiveness of SVE as a remedy for remediation of the subsurface vapor-phase plume.

SVE is an *in situ* unsaturated (vadose) zone soil remediation technology in which a vacuum is applied to the soil to induce the controlled flow of air and remove volatile contaminants from the soil. For the pilot test at MDA L, the gas leaving the borehole will be treated to destroy the contaminants using a catalytic oxidation treatment unit.

The SVE equipment is a Model 100E electric catalytic oxidizer manufactured by Catalytic Combustion Corporation and owned and serviced by Drewelowe Remediation Equipment, Inc. This unit is an integrated vapor extraction and treatment system, and contains a Sutorbilt Model 3L-Legend P 100 scfm dry vacuum blower. The catalytic oxidation unit is directly connected to the vapor extraction wells using standard plumbing fittings and piping.

The process description is as follows: The vapor stream is pulled from the extraction well and is blown through a duct system that contains a vapor/liquid separator, a flame arrestor, a heat exchanger, an electric heater, and a catalyst bed. The vapor stream is preheated with the electric heater in order to reach the temperature necessary to initiate the catalytic oxidation of the hydrocarbons. The preheated hydrocarbon-laden stream is then passed through the bed of catalysts where the hydrocarbons are rapidly oxidized, and finally the stream is discharged to the exhaust stack.

Initial use of the SVE system is limited to a pilot study. However, if selected as part of the final remedy for the site, future use of the system may be more extensive and long-term.

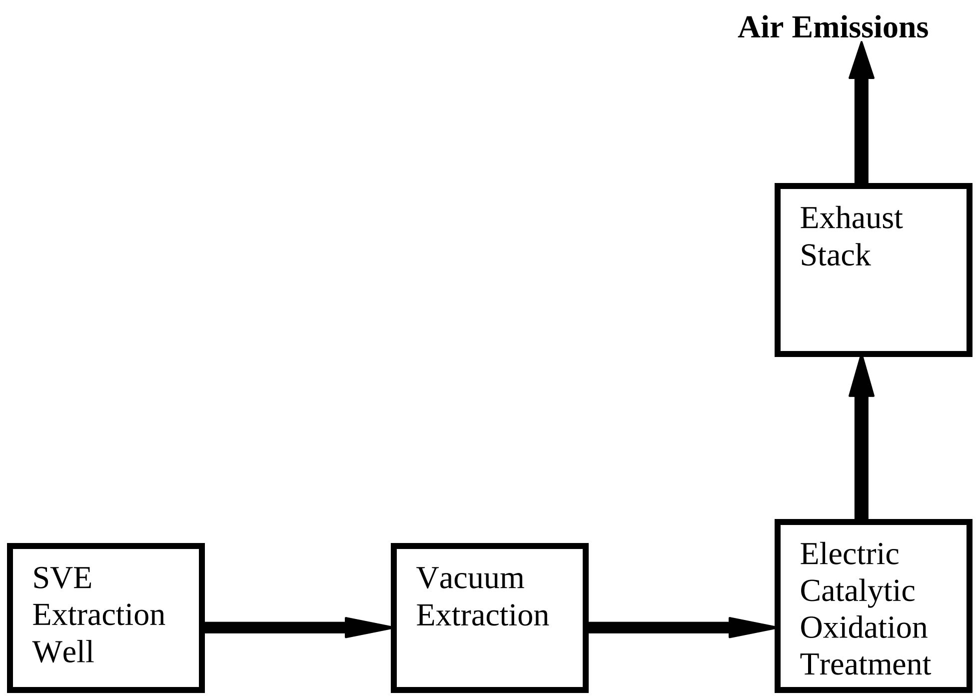
2.3.2. Operating Schedule

For the SVE pilot project, two extraction wells are used. The anticipated operating sequence of the SVE system during the pilot study includes short extraction and rebound intervals at the two extraction wells followed by longer duration extraction and rebound periods. Initial short extraction times will confirm the absence of a free liquid source and minimize gross scale movement of the plume. The SVE system will be connected to each of the new extraction wells in turn, and will run for short periods of time (on the order of days or weeks, depending on how quickly monitoring port concentrations respond with a reduction in measured values). The system will then be turned off, and the concentration rebound at the ports will be monitored. Once the short duration periods are completed, longer extraction times will be performed. Extraction at each of the wells will be conducted until measured concentrations within the area of influence have been significantly reduced. During these time periods, operation may be continuous up to 24 hours per day. If the SVE system is selected as part of the final remediation of the site, operation could continue for years and use additional extraction wells.

2.3.3. Process Flow Diagram

The process flow diagram is shown below in Figure 2.3-1.

Figure 2.3-1 Process Flow Diagram for SVE at TA-54 MDA L



2.3.4 Emissions

Emissions from the SVE system consist primarily of hydrocarbons drawn from extraction wells which may be characterized as volatile organic compounds (VOCs) and/or hazardous air pollutants (HAPs). Many, but not all, VOCs are also HAPs. Two HAPs emitted, hydrochloric acid (HCl) and hydrofluoric acid (HF), are formed during the oxidation process from Cl and F removed in the destruction of hydrocarbons. There are no emissions of the criteria pollutants (particulate matter, sulfur oxides, nitrogen oxides, or carbon monoxide).

A full description of the emission calculation methodology used and emission estimates was provided to NMED in the December 2004 NOI application. Emission estimates are based on the quarterly soil pore-gas monitoring data from the contaminant plume. In the SVE NOI application, LANL estimated emissions for each organic compound and totals for VOC and HAP. The lb/hr emission estimates are based on the single maximum concentration of an organic compound measured in the quarterly sampling. Annual tpy emission estimates are based on the average value of all quarterly sampling results. The measured ppmv concentrations were converted to lb/hr and tpy values using the ideal gas law with conservative assumptions and the maximum flow rate of the oxidation unit of 100 cfm. Maximum controlled emission estimates are shown in Table 2.3-1. The minimum destruction efficiency of 95% for the oxidation unit was used to estimate controlled emissions.

Table 2.3-1 Emission Estimates for Soil Vapor Extraction at TA-54 MDA L

Pollutant	lb/hr	lb/yr	tpy
VOC	0.4	174.2	0.1
HAP	1.3	506.3	0.3

2.3.5 Emissions Control Equipment

Air emissions from the SVE process are controlled by electric catalytic oxidation. Catalytic oxidation accelerates the rate of oxidation by adsorbing the oxygen and the contaminants onto the catalyst surface where they react to form carbon dioxide, water, and hydrochloric and hydrofluoric gas. The catalyst enables the oxidation reaction to occur at much lower temperatures (typically 600° to 1000° F) than those required by a conventional thermal oxidation unit. The hydrocarbon vapor stream drawn from extraction wells are passed through a catalyst bed which has a destruction efficiency of 95 to 99%. The catalyst is specifically designed to treat chlorinated and fluorinated hydrocarbon compounds and is manufactured by Engelhard Corporation.

2.3.6 Applicable Requirements

Unit-specific applicable requirements that apply to the SVE process at the TA-54 MDA L site are listed below in Table 2.3-2 followed by a citation of the basis for the requirement.

Table 2.3-2 Applicable Requirements for Soil Vapor Extraction at TA-54 MDA L

Source Category	Applicable Requirement
TA-54 MDA L SVE	***Operating Requirements*** • The catalytic oxidation unit shall be operated during all times soil pore gas is drawn through the system. (LANL proposed condition) • The minimum operating temperature of the catalytic oxidizer shall be 600 degrees F. (LANL proposed condition) ***Emission Limits*** • Visible emissions shall not equal or exceed an opacity of 20%. (20.2.61 NMAC)

2.3.7 Proposed Monitoring, Recordkeeping, and Reporting

Monitoring, recordkeeping, and reporting requirements are proposed below in Table 2.3-3.

Table 2.3-3 Proposed Monitoring, Recordkeeping, and Reporting for Soil Vapor Extraction at TA-54 MDA L

Source Category	Monitoring, Recordkeeping, and Reporting
TA-54 MDA L SVE	***Monitoring*** • The catalytic oxidizer shall be equipped with continuous temperature measuring and recording instrumentation. (LANL proposed condition) ***Recordkeeping*** • Temperature data collected shall be maintained in a file available for inspection. (LANL proposed condition) ***Reporting*** • Report criteria pollutant and HAP emissions on a semiannual basis. (Condition 4.1 of Permit P100) • Report required monitoring on a semiannual basis. (Condition 4.2 of Permit P100)

2.4 TA-16 Flash Pad and TA-11 Wood and Fuel Fire Test Site

The TA-16 Flash Pad and TA-11 Wood and Fuel Fire Test Site (Test Site) are emission sources operated by LANL's Engineering Sciences and Applications (ESA) Division where open burning occurs. For many years, each of these sites was regulated under open burn permits issued by NMED pursuant to the permit program under 20.2.60 NMAC – Open Burning. Condition 9.0 Open Burning of Permit P100 includes by reference the most current open burn permits as a permit condition. Effective in December 2003, 20.2.60 NMAC was significantly revised, including discontinuance of the open burn permit program. Following this regulatory revision, LANL worked with NMED to determine which requirements were applicable to existing open burn sites. NMED determined these two ESA open burn sites required an NSR permit under 20.2.72 NMAC pursuant to the requirements of 20.2.60.108 NMAC. LANL submitted an NSR permit application in June 2004 for these sites. NMED issued NSR Permit 2195J in March 2005.

2.4.1 General Description of Source Category

The TA-16 Flash Pad is used for thermal treatment by open burning of several waste streams containing high explosives (HE). It is used to treat both solids and liquids contaminated with HE as well as bulk HE. These materials are hazardous wastes and are regulated under hazardous waste interim status regulations until NMED issues a final permit. NSR Permit 2195J, and this modification to Permit P100, only include the open burning of scrap metal with low enough concentrations of HE such that there is no explosive hazard and the metal is not a hazardous waste. The 2003 revisions to 20.2.60 NMAC exempt hazardous wastes which are open burned and regulated by NMED pursuant to the New Mexico Hazardous Waste Act. Thus, the scrap metal which is treated at the Flash Pad was determined to not fall under this exemption, and the NSR permit was required.

Scrap metal which may contain small quantities of HE is flashed through the use of propane burners. The burners provide sufficient heat and temperature to destroy any HE present. The open burning or flashing takes place on a concrete pad. Once the metal has been treated, it is then recycled for use by a local vendor.

The TA-11 Test Site is utilized to assess the consequences of accident scenarios involving transportation containers. This is a test and evaluation activity at the Laboratory and is not related to waste disposal. Open burning is required as part of the accident scenario because fire is a likely consequence of a transportation accident. The TA-11 site has two locations located adjacent to one another. One is a drop tower at which a container is dropped onto a concrete pad. Wood is used on the pad to create a fire around the container. The second site is a small open tank where fuel is burned to create a fire for the container or component to be evaluated within.

2.4.2 Operating Schedule

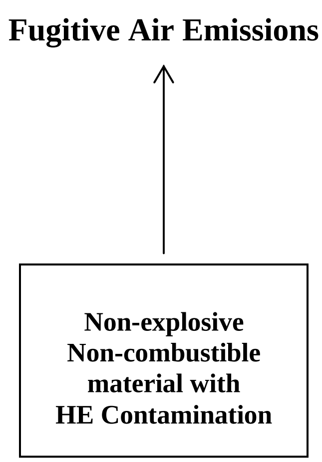
The TA-16 and TA-11 sites may operate on any day, but open burning occurs no earlier than one hour after sunrise and is completed no later than one hour prior to sunset.

The TA-11 site is also restricted to five wood burns per calendar year and five fuel burns per calendar year.

2.4.3 Process Flow Diagram

A process flow diagram for the TA-16 Flash Pad is shown below in Figure 2.4-1.

Figure 2.4-1 Process Flow Diagram for the TA-16 Flash Pad



Process flow diagrams for the TA-11 sites are shown below in Figures 2.4-2 and 2.4-3.

Figure 2.4-2 Process Flow Diagram for the TA-11 Wood Fire Test Site

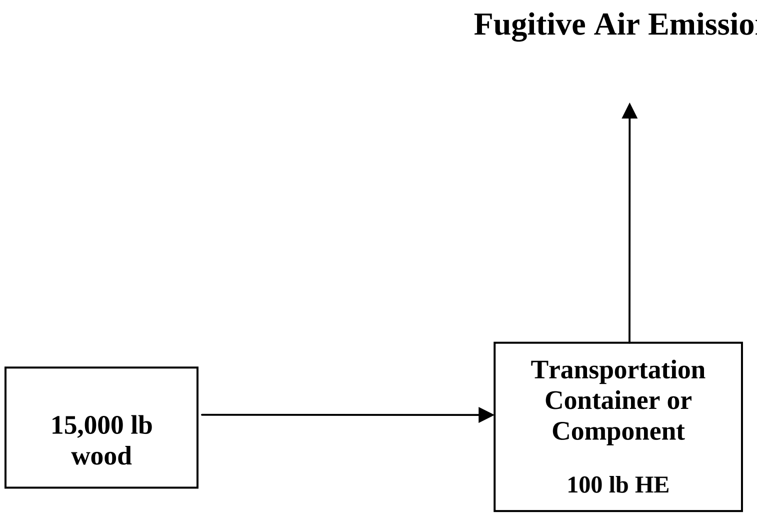
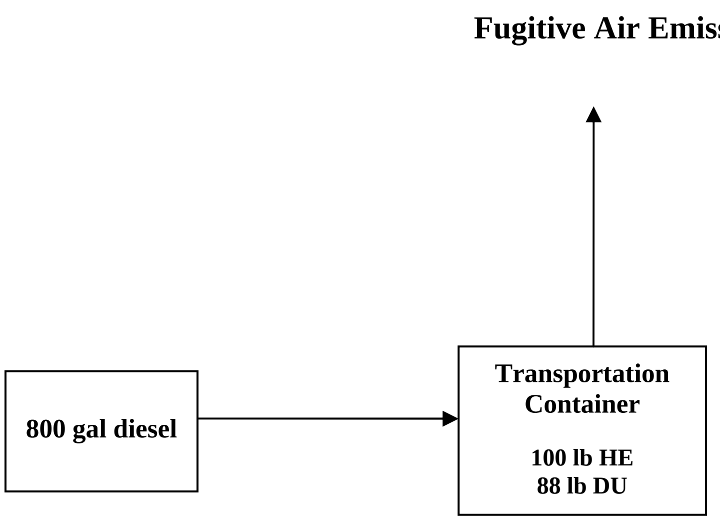


Figure 2.4-3 Process Flow Diagram for the TA-11 Fuel Fire Test Site



2.4.4 Emissions

The allowable emission rates or emission limits for the TA-16 Flash Pad and TA-11 Test Site have been established by NMED in NSR Permit 2195J. Table 2.4-1 below shows the allowable emission rates from Permit 2195J.

Table 2.4-1 Allowable Emission Rates for the TA-16 Flash Pad and TA-11 Test Site

	TSP		PM_{10}		NO_x		CO		VOC		SO_x	
Unit No.	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
TA-16 -FP	0.5	0.1	0.5	0.1	0.4	0.07	0.1	Neg.[a]	Neg.	Neg.	Neg.	Neg.
TA-11-WF	67.1	0.7	67.1	0.7	6.8	0.07	474.3	4.7	429.4	4.3	0.8	Neg.
TA-11-FF	680.3	1.7	680.3	1.7	23.5	0.06	177.9	0.4	29.3	0.1	39.6	0.1
Total	747.9	2.5	747.9	2.5	30.7	0.2	652.3	5.1	458.7	4.4	40.4	0.1

[a] NMED denoted estimates less than 0.1 as “Negligible” within NSR permit 2195J.

Table 2.4-2 shows the estimated HAP emissions for the TA-16 Flash Pad and TA-11 Test Site. These emission estimates are not allowable emission rates or emission limits.

Table 2.4-2 HAP Emission Estimates for the TA-16 Flash Pad and TA-11 Wood Test Site

	HAPs	
Unit No.	**lb/hr**	**tpy**
TA-16-FP	1.33E-03	2.43E-04
TA-11-WF	3.67E-02	3.67E-04
TA-11-FF	3.67E-04	3.0E-02

In order to estimate emissions from open burning of HE at either the TA-16 or TA-11 site, a review was conducted to determine the primary types of explosives used within the ESA Division. A majority of HE used was from two explosives – HMX and TNT. Field observations indicated HMX burns cleaner than TNT. Therefore, TNT was determined to conservatively best represent the types of explosives which could be burned.

A comparison was made between two sets of emission factors that could represent criteria pollutant emissions from open burn activities. One set of factors is from EPA's AP-42, Chapter 6.3, Explosives. The second set of factors is from the EPA approved document *Open Burn/Open Detonation Dispersion Model (OBODM) User's Guide*. The emission factors in this document were developed from emissions data collected by the Department of Defense in experiments conducted at the Dugway Proving Ground in Utah. The majority of the information collected is from tests in which small amounts of a fuel or explosive were burned or detonated, and the resulting products were sampled and assayed to quantify emissions. The AP-42 factors were found to be more conservative, i.e. higher, than those from the OBODM document and were used in estimating emissions. AP-42 did not provide a factor for SO_2, so the OBODM factor was used for this pollutant.

AP-42 does not provide emission factors for HAPs from the open burning of explosives. Thus, HAP emission factors from OBODM for TNT were used to estimate emissions.

Emission factors used to estimate emissions from the TA-16 Flash Pad are shown below in Table 2.4-3. Emission factor documentation is included in Appendix D within this application.

Table 2.4-3 Emission Factors for the TA-16 Flash Pad

Emission Factor[a] lb/lb HE					
PM	**CO**	**SO_x[b]**	**NO_x**	**VOC**	**HAP[b]**
9.00E-02	2.80E-02	1.40E-04	7.50E-02	5.5E-04	2.66E-04

[a] Emission factors are from AP-42, 1/95, Section 6.3, Explosives, Table 6.3-1, unless otherwise noted.
[b] Emission factors are from *Open Burn/Open Detonation Dispersion Model (OBODM) User's Guide*, SERDP, April 1998.

HE emission factors used for the TA-11 wood and fuel fire scenarios were the same as those used for HE at the TA-16 Flash Pad. Emission factors used to estimate criteria pollutant and HAP emissions from wood burning were from AP-42, Chapter 1.9, Residential Fireplaces. These factors best represent the incomplete combustion which occurs outside of an enclosed combustion device such as a boiler.

Emission estimates for fuel oil combustion for PM, CO, and VOC were based on emission factors obtained from the Building and Fire Research Laboratory of the National Institute of Standards and Technology. The factors were developed through the study of the open burning of oil spills as a potential remediation technique. NO_x estimates were based on a factor from AP-42, Chapter 1.3, Fuel Oil Combustion. HAP estimates were based on an EPA document *Emissions of Organic Air Toxics from Open Burning*, EPA-600/R-02-076.

Table 2.4-4 shows the emission factors used to estimate emissions for the TA-11 Test Site.

Table 2.4-4 Emission Factors for the TA-11 Test Site

Pollutant	Material		
	HE lb/lb HE	Wood[c] lb/ton	Fuel
PM	9.00E-02[a]	34.6	115 g/kg[d]
NO_x	7.50E-02[a]	2.6	2.00E-02 lb/gal[e]
CO	2.80E-02[a]	252.6	30 g/kg[d]
VOC	5.5E-04[a]	229	5 g/kg[d]
SO_x	1.40E-04[b]	0.4	Mass balance
HAP	2.66E-04[b]	1.60E-02	Organic[f] 1.91E+03 mg/kg Inorganic[g] 6.72E-03 lb/10^3 gal

[a] Emission factors are from AP-42, 1/95, Section 6.3, Explosives, Table 6.3-1.
[b] Emission factors are from *Open Burn/Open Detonation Dispersion Model (OBODM) User's Guide,* SERDP, April 1998.
[c] Emission factors are from AP-42, 10/96, Section 1.9, Residential Fireplaces, Table 1.9-1.
[d] Emission factors are from the National Institute of Standards and Technology, Building and Fire Research Laboratory.
[e] Emission factor is from AP-42, 9/98, Section 1.3, Fuel Oil Combustion, Table 1.3-1.
[f] Emission factor is from *Emissions of Organic Air Toxics from Open Burning,* EPA-600/R-02-076, Table 3-5.
[g] Emission factor is from AP-42, 9/98, Section 1.3, Fuel Oil Combustion, Table 1.3-10.

2.4.5 Emissions Control Equipment

By its nature, open burning is not amenable to the use of air pollution control equipment and none is present at the TA-16 Flash Pad or TA-11 Test Site. Permit restrictions on the types and quantities of materials burned serve to limit air emissions without control equipment.

2.4.6 Applicable Requirements

Applicable requirements are listed below in Table 2.4-5. All requirements are from NSR Permit 2195J.

Table 2.4-5 Applicable Requirements for the TA-16 Flash Pad and TA-11 Test Site

Source Category	Applicable Requirement
TA-16 Flash Pad	***Operating Requirements*** • Burns are authorized and regulated under this permit on scrap metal which is not a hazardous waste. (Condition 1.b of Permit 2195J) • Open burns on scrap metal shall consume no more than 5 lb of HE per day. (Condition 1.b of Permit 2195J) • Open burns shall take place no earlier than one hour after sunrise and shall be completed no later than one hour prior to sunset. (Condition 1.c of Permit 2195J) • If requested by NMED, LANL shall arrange open burn activities to provide NMED an opportunity to observe the activity during a facility inspection. (Condition 1.e of Permit 2195J) ***Emission Limits*** • Emissions shall not exceed the unit-specific lb/hr or tpy emission rates listed in Table 2.4.1. (Condition 2 of Permit 2195J) • Combined total emissions from the TA-16 Flash Pad and the TA-11 Test Site shall not exceed the total lb/hr or tpy emission limits in Table 2.4.1. (Condition 2 of Permit 2195J)

Source Category	Applicable Requirement
TA-11 Test Site	***Operating Requirements*** • Five wood fire burns are authorized per calendar year. Each burn shall consist of no more than 7.5 tons of wood, 100 lb of HE and 88 lb of DU. (Condition 1.b of Permit 2195J) • Wood used for the wood fire tests shall be clean wood in the form of hard lumber which has not been painted or treated and does not include wood waste or processed wood material such as plywood or particle board. (Condition 1.f of Permit 2195J) • Five one-hour fuel fire burns are authorized per calendar year. Each burn shall consist of no more than 800 gallons of fuel oil, 100 lb of HE and 88 lb of DU. (Condition1.b of Permit 2195J) • Open burns shall take place no earlier than one hour after sunrise and shall be completed no later than one hour prior to sunset. (Condition 1.c of Permit 2195J) ***Emission Limits*** • Emissions shall not exceed the unit-specific lb/hr or tpy emission rates listed in Table 2.4-1. (Condition 2 of Permit 2195J) • Combined total emissions from the TA-16 Flash Pad and the TA-11 Test Site shall not exceed the total lb/hr or tpy emission limits in Table 2.4-1. (Condition 2 of Permit 2195J)

2.4.7 Proposed Monitoring, Recordkeeping, and Reporting

Monitoring, recordkeeping, and reporting is listed below in Table 2.4-6.

Table 2.4.6 Proposed Monitoring, Recordkeeping, and Reporting for the TA-16 Flash Pad and TA-11 Test Site

Source Category	Monitoring, Recordkeeping, and Reporting
TA-16 Flash Pad **TA-11 Test Site**	***Monitoring/Recordkeeping*** • Records shall be generated and maintained for each burn which include: the date of each burn, the time of burn initiation, duration of each burn, the time when burning was completed and the type and quantities of materials burned. (Conditions 3 and 4 of Permit 2195J) ***Reporting*** • Written notification shall be provided to the NMED-Air Quality Bureau Enforcement Section of the week open burning is scheduled at the TA-11 Test Site no later than two weeks prior to the scheduled week. A second written notification with the date and time open burning is scheduled to occur shall be provided no later than 48 hours prior to the burn. (Condition 5.b of Permit 2195J) • Report criteria pollutant and HAP emissions on a semiannual basis. (Condition 4.1 of Permit P100) • Report required monitoring on a semiannual basis. (Condition 4.2 of Permit P100) • Submit on a semiannual basis a fire activity report which includes all information required to be maintained as a record for each burn. Reports shall be submitted for the reporting periods and by the deadlines established for the semiannual monitoring reports in Condition 4.3 of Permit P100. LANL may submit one report for all open burn sites. (Condition 5.a of Permit 2195J)

2.5 TA-36 Sled Track

The TA-36 Sled Track is operated by LANL's Dynamic Experimentation (DX) Division. For many years, this site has been regulated under an open burn permit issued by NMED pursuant to the permit program under 20.2.60 NMAC – Open Burning.

Condition 9.0 Open Burning of Permit P100 includes by reference the most current open burn permit as a permit condition. Effective in December 2003, 20.2.60 NMAC was significantly revised, including discontinuance of the open burn permit program. Following this regulatory revision, LANL worked with NMED to determine which requirements were applicable to existing open burn sites. NMED determined this site and the two ESA open burn sites discussed in Section 2.4 required NSR permits under 20.2.72 NMAC pursuant to the requirements of 20.2.60.108 NMAC. LANL submitted an NSR permit application in June 2004 for the TA-36 Sled Track. NMED issued NSR Permit 2195K in March 2005.

2.5.1 General Description of Source Category

The TA-36 Sled Track is used to conduct tests and evaluations of simulated transportation accidents where a transportation container is crushed and possibly detonates or burns. The Sled Track is a combination single and double rail system where an apparatus called a sled can be propelled by booster rockets to a speed approaching Mach 1.5. The transportation container is set up in front of a tunnel-like structure which is built using concrete blocks and has an impact plate behind it. The booster rocket propels the impact sled into the container which strikes the impact plate. During some experiments, the container detonates on impact. In other tests, there is no detonation. When this happens, a burn test is performed using clean hard wood which is piled around the container to simulate a fire which could occur following an accident.

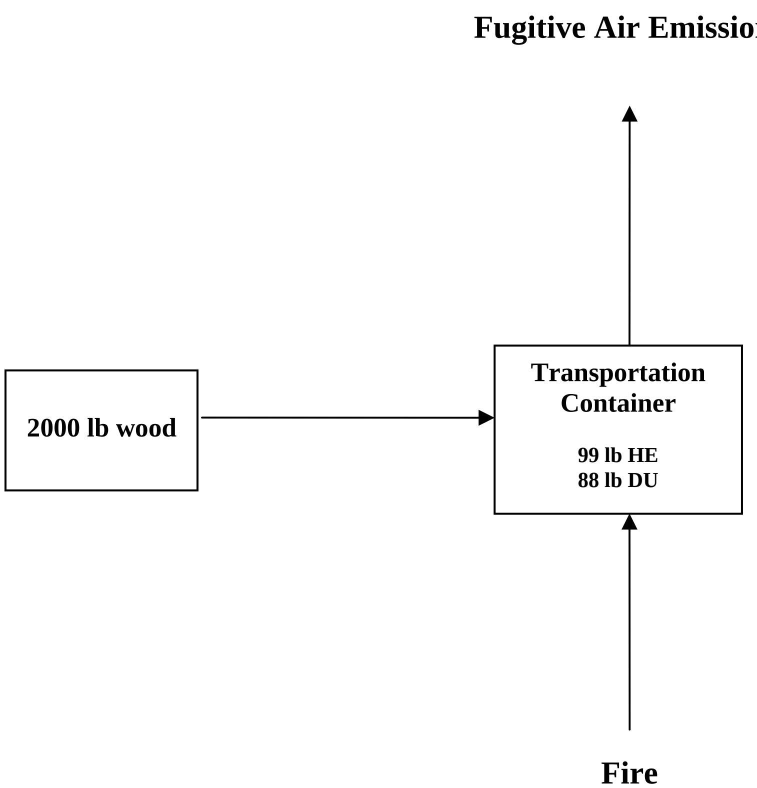
2.5.2 Operating Schedule

The TA-36 Sled Track may operate on any day, but open burning occurs no earlier than three hours after sunrise and is completed no later than one hour prior to sunset. The site is also restricted to eight tests with open burns per calendar year.

2.5.3 Process Flow Diagram

A process flow diagram for the Sled Track is shown below in Figure 2.5-1.

Figure 2.5-1 Process Flow Diagram for the TA-36 Sled Track



2.5.4 Emissions

The allowable emission rates or emission limits for the TA-36 Sled Track have been established by NMED in NSR Permit 2195K. Table 2.5-1 below shows the allowable emission rates from Permit 2195K.

Table 2.5-1 Allowable Emission Rates for the TA-36 Sled Track

	TSP		PM_{10}		NO_x		CO		VOC		SO_x	
Unit No.	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
TA-36 -ST-1	21.8	0.2	21.8	0.2	5.0	0.04	127.7	1.0	114.5	1.0	0.2	0.002

Table 2.5-2 shows the estimated HAP emissions for the TA-36 Sled Track. These emission estimates are not allowable emission rates or emission limits.

Table 2.5-2 HAP Emission Estimates for the TA-36 Sled Track

	HAP	
Unit No.	**lb/hr**	**tpy**
TA-36-ST-1	2.12E-02	1.70E-04

HE emission factors used for the TA-36 Sled Track were the same as those discussed in Section 2.4 for the TA-16 Flash Pad and TA-11 Test Site. Emission factors used to estimate criteria pollutant and HAP emissions from wood burning were also the same as for the TA-11 Test Site.

Table 2.5-3 shows the emission factors used to estimate emissions for the TA-36 Sled Track.

Table 2.5-3 Emission Factors for the TA-36 Sled Track

Pollutant	Material	
	HE lb/lb HE	**Wood[c] lb/ton**
PM	9.00E-02[a]	34.6
PM_{10}	9.00E-02[a]	34.6
NO_x	7.50E-02[a]	2.6
CO	2.80E-02[a]	252.6
VOC	5.5E-04[a]	229
SO_x	1.40E-04[b]	0.4
HAP	2.66E-04[b]	1.60E-02

[a] Emission factors are from AP-42, 1/95, Section 6.3, Explosives, Table 6.3-1.
[b] Emission factors are from *Open Burn/Open Detonation Dispersion Model (OBODM) User's Guide*, SERDP, April 1998.
[c] Emission factors are from AP-42, 10/96, Section 1.9, Residential Fireplaces, Table 1.9-1.

2.5.5 Emissions Control Equipment

By its nature, open burning is not amenable to the use of air pollution control equipment and none is present at the TA-36 Sled Track. Permit restrictions on the types and quantities of materials burned serve to limit air emissions without control equipment.

2.5.6 Applicable Requirements

Applicable requirements are listed below in Table 2.5-4. All requirements are from NSR Permit 2195K.

Table 2.5-4 Applicable Requirements for the TA-36 Sled Track

Source Category	Applicable Requirement
TA-36 Sled Track	***Operating Requirements*** • Eight open burns per calendar year are authorized at the sled track. (Condition 1.b of Permit 2195K) • Open burns shall take place no earlier than three hours after sunrise and shall be completed no later than one hour prior to sunset. Maximum burn time for each test shall not exceed eight hours. (Conditions 1.b and 1.e of Permit 2195K) • Each burn shall consist of no more than 2000 lb of clean wood, 99 lb of HE and 88 lb of DU. (Condition 1.d of Permit 2195K) • Wood shall be clean wood in the form of hard lumber which has not been painted or treated and does not include wood waste or processed wood material such as plywood or particle board. (Condition 1.f of Permit 2195K) ***Emission Limits*** • Emissions shall not exceed the unit-specific lb/hr or tpy emission rates listed in Table 2.5-1. (Condition 2 of Permit 2195K)

2.5.7 Proposed Monitoring, Recordkeeping, and Reporting

Monitoring, recordkeeping, and reporting is listed below in Table 2.5-5.

Table 2.5-5 Proposed Monitoring, Recordkeeping, and Reporting for the TA-36 Sled Track

Source Category	Monitoring, Recordkeeping, and Reporting
TA-36 Sled Track	***Monitoring/Recordkeeping*** • Records shall be generated and maintained for each burn which include: the date of each burn, the time of burn initiation, duration of each burn, the time when burning was completed and the type and quantities of materials burned. (Conditions 3 and 4 of Permit 2195K) ***Reporting*** • Written notification shall be provided to the NMED-Air Quality Bureau Enforcement Section, of the week open burning is scheduled, no later than two weeks prior to the scheduled week. A second written notification, with the date and time open burning is scheduled to occur, shall be provided no later than 48 hours prior to the burn. (Condition 5.b of Permit 2195K) • Report criteria pollutant and HAP emissions on a semiannual basis. (Condition 4.1 of Permit P100) • Report required monitoring on a semiannual basis. (Condition 4.2 of Permit P100) • Submit on a semiannual basis a fire activity report which includes all information required to be maintained as a record for each burn. Reports shall be submitted for the reporting periods and by the deadlines established for the

Source Category	Monitoring, Recordkeeping, and Reporting
TA-36 Sled Track (continued)	semiannual monitoring reports in Condition 4.3 of Permit P100. LANL may submit one report for all open burn sites. (Condition 5.a of Permit 2195K)

2.6 Closed Emission Units

Since Permit P100 was issued in April 2004, certain emission sources have been permanently closed at LANL. These sources are listed in Table 1.2-2 of this application and are briefly discussed here. LANL is requesting removal of these emission sources from Permit P100.

Condition 2.3 Boilers and Heaters of Permit P100 applies to boilers and heaters at LANL other than the boilers at the TA-3 Power Plant. A table at the beginning of the condition lists each boiler which does not qualify as an insignificant or trivial activity. Two boilers within this table, TA-16-1485-BS-1 and TA-16-1485-BS-2, have been permanently closed. These two units should be removed from the table. These units are not specifically cited in the remainder of this condition, and no further permit revisions are requested or required.

Condition 2.8 Paper Shredder applies to a paper shredder at TA-52-11 which is assigned Emission Unit No. TA-52-11 in Permit P100. This source has been permanently closed. This source and all conditions should be removed from the permit. This activity was replaced by the data disintegrator discussed in Section 2.1 of this application. The new data disintegrator was also installed at TA-52-11. NMED approved this new unit in NSR Permit 2195H.

The rock crusher in Condition 2.10 of Permit P100 has permanently closed. This condition should be removed from the permit in its entirety. LANL informed NMED of the permanent closure of the rock crusher by letter of June 10, 2004.

3.0 Applicable Requirements

This chapter of the application identifies applicable requirements that apply to the proposed permit modifications for which LANL is applying and discusses the current compliance status for each requirement. A certification of compliance for the proposed permit changes is also included as required by 20.2.70 NMAC.

3.1 Compliance Status with Applicable Requirements

Table 3.1-1 provides a list of the applicable requirements which currently apply to the proposed changes which are part of this permit modification. The majority of the requirements listed are existing permit conditions within new source review (NSR) or construction permits which have been issued to LANL. Within the table, the primary applicable requirements which require an analysis or discussion with respect to current compliance status are cited individually. These requirements include emission limits, operational restrictions, monitoring, recordkeeping, and reporting. Excluded from the analysis are those NSR permit conditions which are unlikely to be specifically listed in the revised operating permit, such as the general conditions which are attached to each NSR permit. Nevertheless, the compliance certification in Section 3.2 of this chapter is for all NSR permit conditions within the permits listed in Table 3.1-1.

Note that as required by Condition 5.1 of Permit P100, LANL submits to NMED an annual compliance certification report certifying the facility-wide compliance status with all permit terms and conditions. The most recent report was submitted in January 2005 to NMED for calendar year 2004 (beginning with the date of permit issuance April 30, 2004).

Table 3.1-1 Current Applicable Requirements for Permit Modification

Source	NSR Permit Number	Applicable Requirements
Data Disintegrator	2195H	All NSR permit conditions including:
		NSR Condition 1 – Construction/Modification/Revision and Operation
		NSR Condition 2 – Emission Limits
		NSR Condition 4 - Recordkeeping
TA-3 Power Plant	2195BM1	All NSR permit conditions including:
		NSR Condition 1 – Construction/Modification/Revision and Operation
		NSR Condition 2 – Emission Limits
		NSR Condition 3 – Monitor Requirements
		NSR Condition 4 - Recordkeeping
		NSR Condition 5 - Reporting
		NSR Condition 6 – Compliance Test
TA-54 Soil Vapor Extraction	N/A NOI 2195L	20.2.61 NMAC – Smoke and Visible Emissions
TA-16 Flash Pad and TA-11 Wood/Fuel Fire Test Site	2195J	All NSR permit conditions including:
		NSR Condition 1 – Construction and Operation
		NSR Condition 2 – Emission Limits
		NSR Condition 3 - Monitoring Requirements
		NSR Condition 4 – Recordkeeping
		NSR Condition 5 - Reporting
TA-36 Sled Track	2195K	All NSR permit conditions including:
		NSR Condition 1 – Construction and Operation
		NSR Condition 2 – Emission Limits
		NSR Condition 3 – Monitoring Requirements
		NSR Condition 4 - Recordkeeping
		NSR Condition 5 – Reporting

3.1.1 Data Disintegrator

The data disintegrator was issued NSR Permit 2195H on October 22, 2003, and began operation in August 2004. This equipment replaced the paper shredder currently within Section 2.8 of Operating Permit P100. The compliance status of the data disintegrator with respect to primary applicable requirements is discussed below.

NSR Condition 1 – Construction/Modification/Revision and Operation specifies the equipment permitted, including the type of control equipment which is a cyclone and cloth tube filters for removing particulate matter. LANL installed the equipment as described. This condition also requires the performance of regular maintenance and repair on the control equipment per manufacturer's recommendations. The required maintenance and repair has been conducted.

NSR Condition 2 – Emission Limits specifies allowable emission limits of 2.3 lb/hr and 9.9 tpy for both TSP and PM_{10}. The short-term lb/hr limit was shown by calculation in the NSR permit application for the data disintegrator to be met at the maximum processing rate of 1200 lb/hr with the required control equipment in operation. The specified maximum processing rate has not been exceeded. LANL has kept a log of the number of boxes of paper/media shredded and has used this information to calculate monthly and semi-annual TSP and PM_{10} emissions. This information was included in LANL's semi-annual operating permit emissions report submitted to NMED in March 2005. As shown in the report, the allowable tpy emission limits in NSR Permit 2195H have not been exceeded.

NSR Condition 4 – Recordkeeping requires records to be maintained which demonstrate compliance with the manufacturer's recommended repair and maintenance schedules for the control equipment. These records will be maintained on site.

3.1.2 Power Plant at Technical Area 3

NSR Permit 2195B-M1 was issued on July 30, 2004 for installation of a new Rolls-Royce RB211 simple-cycle combustion turbine at the TA-3 Power Plant. The turbine will be a peaking unit used to generate electricity during periods of high demand. In addition to adding the new combustion turbine to the existing TA-3 Power Plant NSR permit, revisions were made to the natural gas fuel usage restriction and allowable emission limits for the three existing boilers at the plant. The boilers themselves are already incorporated within Operating Permit P100, but this permit modification will incorporate into the operating permit the new NSR permit conditions for the boilers, as well as adding the combustion turbine.

The new combustion turbine has not begun operation as of the date of submission of this modification. Therefore, compliance with applicable requirements remains as demonstrated in the NSR permit application, which was reviewed and approved by NMED. Once operational, an initial compliance test for NO_x and CO will be conducted as required by NSR Condition 6. The remainder of this section discusses compliance with respect to the existing boilers.

Compliance with applicable requirements, including revised conditions in NSR Permit 2195BM1 for the existing boilers, has been certified in the first annual Title V operating permit compliance certification report submitted in January 2005 to NMED. This information is summarized below.

With respect to the boilers, NSR Condition 1 includes several conditions. Fuel use restrictions for natural gas and fuel oil are specified as 2,000 MM scf and 500,000 gal respectively. The January 2005 compliance certification states a 365 day rolling total for natural gas and fuel oil usage is maintained, and the restrictions have not been exceeded. The allowable sulfur content of both natural gas and fuel oil has also been met. The required volumetric fuel meter for natural gas usage is installed and usage is recorded. Hours of operation are monitored and recorded daily.

NSR Condition 2 – <u>Emission Limits</u> specifies short-term lb/hr and annual tpy allowable emission limits for the boilers. Compliance with NO_x and CO lb/hr emission limits was demonstrated in compliance tests conducted on each boiler in September 2002. Test results were provided to NMED in the 2002 operating permit application. Compliance with PM, SO_x, and VOC lb/hr emission limits was demonstrated by calculation and reviewed and approved by NMED in the NSR permit application. Emissions are calculated each month for all criteria pollutants and compared with the 12-month rolling total tpy emission limits. This information was provided to NMED in the semi-annual operating permit emissions report submitted to NMED in March 2005. As shown in the report, the annual tpy emission limits have not been exceeded.

NSR Condition 3 – Monitor Requirements requires natural gas and fuel oil to be monitored so that usage can be calculated on a rolling 365-day total. As stated in the January 2005 compliance certification report, this condition has been met. As required, either a supplier certification or analysis of the sulfur content of fuel oil is obtained for each oil delivery.

NSR Condition 4 – Recordkeeping requires records to be kept to verify the sulfur content of natural gas and fuel oil used at the plant. These records have been kept.

NSR Condition 6 – Compliance Test applies to the new combustion turbine only. The required test will be conducted after startup of the unit.

3.1.3 Soil Vapor Extraction at TA-54 Material Disposal Area L

LANL submitted to NMED a Notice of Intent (NOI) for the Soil Vapor Extraction (SVE) system in December 2004. NMED reviewed the application and determined an NSR permit was not required. The NOI was assigned number 2195L. The SVE system is not operational as of the date of submittal of this application.

Only one applicable requirement was identified in the NOI application. This is the general 20% opacity standard in 20.2.61 NMAC – Smoke and Visible Emissions. Since the SVE unit and oxidation catalyst is electric powered, i.e. no fuel is burned, this standard will be achieved in practice when the system is operational.

LANL is also proposing new operating requirements as shown in Table 2.3-2. A proposed permit condition is continuous operation of the catalytic oxidizer during times soil pore gas is drawn through the system. A minimum operating temperature for the oxidizer is also proposed to ensure destruction of VOCs and HAPs within the extracted soil pore gas. Continuous temperature measuring and recording instrumentation is proposed as a monitoring condition for the SVE system. Maintaining records of the temperature data is a proposed recordkeeping condition. LANL will comply with these proposed conditions once the SVE system is operational and the requested permit modification is issued.

3.1.4 TA-16 Flash Pad and TA-11 Wood and Fuel Fire Test Site

The TA-16 Flash Pad and TA-11 Wood and Fuel Fire Test Site (Test Site) were issued NSR Permit 2195J on March 29, 2005. These two sites have different purposes as described in Section 2.4 of this application, but each conducts open burning and each is within the same LANL organizational division.

The TA-11 Test Site has not operated since issuance of the NSR permit, and has also not operated at least since 1997 or earlier. When the TA-11 Test Site does conduct an open burn activity, it will operate in compliance with the conditions of NSR Permit 2195J.

The TA-16 Flash Pad has conducted open burns as allowed under NSR Permit 2195J since the permit was issued. All NSR permit conditions have been met during this time period. This includes compliance with the 5 lb of HE per day restriction in Condition 1.b and the time of day restriction in Condition 1.c. Compliance with both the lb/hr and tpy emissions limits in Condition 2 has been met. Emission estimates will be provided within the semi-annual operating permit emissions report once this Title V modification is issued. The requirements of NSR Condition 3 – <u>Monitoring Requirements</u> and Condition 4 – <u>Recordkeeping</u> have also been met during this time period. At the time of this submittal, the deadline under Condition 5.a to submit a semi-annual open burn activity report has not yet been reached. LANL will submit the report by the required deadline.

In summary, the TA-16 Flash Pad and TA-11 Test Site are in compliance with the conditions of NSR Permit 2195J. Note that these sites have previously been regulated under open burn permits which are currently cited in Condition 9 – <u>Open Burning</u> of Permit P100. LANL certified compliance with these permit conditions in the annual operating permit compliance certification report submitted to NMED in January 2005.

3.1.5 TA-36 Sled Track

The TA-36 Sled Track was issued NSR Permit 2195K on March 29, 2005. This site has not conducted an open burn activity since the date of permit issuance, or since 1997 or earlier. When the TA-36 Sled Track does conduct an open burn activity, it will operate in compliance with the conditions of NSR Permit 2195J. As with the TA-16 Flash Pad and TA-11 Test Site, this site has previously been regulated under an open burn permit which is cited in Condition 9 – <u>Open Burning</u> of Permit P100. LANL certified compliance with these permit conditions in the annual operating permit compliance certification report submitted to NMED in January 2005.

3.2 Compliance Certification

I certify, under penalty of law, that based on information and belief formed after reasonable inquiry, the statements and information contained in Chapter 3.0 of this application to modify Title V Operating Permit P100 concerning this facility's compliance status are true, accurate, and complete. The methods used for determining compliance are discussed in Chapter 2.0 and Chapter 3.0. The Los Alamos National Laboratory will continue to be in compliance with the applicable requirements in Chapter 3.0 for which it is currently in compliance, and will, in a timely manner, meet additional applicable requirements that become effective during the permit term. A responsible official of the facility shall submit a compliance certification to NMED annually.

Signed: *Original signed by* Date: *07/28/05*
Carolyn A. Mangeng
Associate Director for Technical Services (Acting)

Appendix A

Application Forms

NMED - AIR QUALITY BUREAU
2048 GALISTEO
SANTA FE, NM 87505
TELEPHONE: (505) 827-1494

NEW MEXICO ENVIRONMENT DEPARTMENT
AIR QUALITY BUREAU

OPERATING PERMIT APPLICATION FORM
(20.2.70 NMAC)

Please answer all questions in each section.
Use the abbreviation "NA" for "not applicable" wherever appropriate.
Specific instructions corresponding to numbers in brackets are on the back of each page.

SECTION 1 - GENERAL INFORMATION: (Subsection D of 20.2.70 NMAC)[1]

1. Company Name[2] U.S. Department of Energy (DOE)/Los Alamos National Laboratory (LANL) 2. Application Date: ____

3. Company Mailing Address: 528 35th Street, Los Alamos, NM 87544 4. Phone: (505) 667-5105

5. Owner's Name[3]: DOE, National Nuclear Security Administration 6. Phone: (505) 667-5105

7. Owner's Mailing Address: Los Alamos Site Office, 528 35th Street, Los Alamos, NM 87544

8. Plant or Facility Name[4]: Los Alamos National Laboratory 9. Phone: (505) 664-5265

10. Plant Mailing Address: P.O. Box 1663, Los Alamos, NM 87545

11. Plant Operator[5]: University of California 12. Phone: (505) 664-5265

13. Plant Operator Address: P.O. Box 1663, Los Alamos, NM 87545

14. Responsible Official[6]: Carolyn Mangeng Title: Associate Director of Technical Services 15. Phone: (505) 667-0079

16. Responsible Official Address: Los Alamos National Laboratory, P.O. Box 1663, MS A104, Los Alamos, NM 87545

17. Person to Contact at Site[7]: Steve Fong 18. Title: DOE General Engineer 19. Phone: (505) 665-5534

20. Company Air Permit Contact[8]: Dave Fuehne, Acting Group Leader, ENV-MAQ 21. Phone: (505) 665-8855

22. Company's State of Incorporation or Registration to do Business: N/A – Federal Agency

23. Company's Corporate or Partnership Relationship to any other Air Quality Permittee[9]: N/A

24. Name of Parent Company[10]: N/A

25. Address of Parent Company: N/A

26. Names of Subsidiary Companies[11]: N/A

27. Previous Air Quality Permits Issued to this facility (Permit Numbers): 632, 634, 636, 1081, 2195, 2195B, 2195F, GCP-3-2195G, 2195H, 2195J, 2195K, P100

28. Other Air Quality Permits Issued to this Applicant (Permit Numbers): N/A

29. Reason this source must have an 20.2.70 NMAC operating permit[12]: Major source (>100 tons/year allowable emissions) for nitrogen oxides, volatile organic compounds, sulfur dioxide, particulate matter, and carbon monoxide.

30. This Operating Permit Application is for (check one): ☐ New Permit; ☐ Permit Renewal; ☐ Minor Modification; ☒ Significant Modification.

If this Application is for Permit Renewal or Modification give: Current Operating Permit No. P100 Expiration Date April 30, 2009

31. Is this a permanent source?[13]: ☒ Yes ☐ No. If No, how long will this site be occupied? ____

32. Is this a portable source? [14]: ☐ Yes ☒ No

A. If yes, provide identifying numbers (Example: source unit numbers, equipment serial numbers, etc..): N/A

32B. If yes, date of anticipated relocation: N/A 32C. If yes, date of anticipated startup: N/A

33. Plant Operational Periods: (Subparagraph D(5)(f) of 20.2.70.300 NMAC)

33A. Specify standard operational periods:

8 hours per day, 8 am to 5 pm, 5 days per week, 5 weeks per month, 12 months per year.

33B. Specify maximum operational periods:

24 hours per day, am to pm, 7 days per week, 5 weeks per month, 12 months per year.

33C. Max Operational Hours in a Year 8760

34. Describe briefly type of plant and nature of process(es) and products [15]:

LANL is a national laboratory primarily engaged in national security and nuclear weapons research.

Plant Primary SIC code [16]: 9711 Plant Secondary SIC code [17]: N/A

35. Describe briefly any process(es) or products associated with any alternative operating scenarios described in this application [18]:

N/A

Plant Primary and Secondary SIC codes for this alternative process(es): N/A

'lant's Maximum Allowable Capacity (Specify Units) [19]:

Hourly: N/A Daily: N/A Annual: N/A

37. Plant Location [20]:

37A. County: Los Alamos 37B. Direction and distance from nearest town: Los Alamos

37C. Range: 6E Township: 19N Section: 22 37D. Latitude: 35° 51' 36" Longitude: 106° 17' 45"

37E. UTM Zone: 13 UTMH: 383.0 km UTMV: 3969.0 km

38. Plant Elevation 7220 Feet above mean sea level

39. Ownership of Land at Plant site (Private, State, Federal, etc.): Federal

NOTE: If the land at the plant site is Indian land, contact the Air Pollution Control Bureau permitting staff for assistance.

40. Distance, in meters, of plant site to nearest residence, school or occupied structure [21]: 1.5 km N (Royal Crest Trailer Park)

41. Is U.S.G.S. quadrangular map (or equivalent) attached with Plant location marked? [22]: ☒ Yes, ☐ No.

42. Identify all Class-1 areas, Indian Lands, Bernalillo County, and neighboring states that are within 50 miles of the facility, and give their radial distances

in miles: Taos Pueblo (43), Picuris Pueblo (35), Jicarilla Apache Indian reservation (42), San Juan Pueblo (12), Santa Clara Pueblo (6), San Ildefonso Pueblo (3), Pojoaque Pueblo (8), Nambe Pueblo (15), Tesuque Pueblo (12), Cochiti Pueblo (8), Santo Domingo Pueblo (17), Zia Pueblo (19), San Felipe Pueblo (24), Santa Ana Pueblo (25), Jemez Pueblo (12), Sandia Pueblo (38), Laguna Pueblo (48) Bernalillo County (35), Bandelier Wilderness (0), Pecos Wilderness (35), San Pedro Wilderness Park (27)

SECTION 2A - RAW MATERIALS PROCESSED [23]: (Paragraph 4 of Subsection D of 20.2.70.300 NMAC)
(Complete only if needed to determine emissions or if an applicable requirement exists for materials processed)

(Use additional sheets if necessary)

Unit No. [24]	Material [25]	Composition [26]	Condition [27]	Quantity Used [28] (Specify Units)
N/A				

SECTION 2B - MATERIALS PRODUCED: (Paragraph 4 of Subsection D of 20.2.70.300 NMAC)
(Complete only if needed to determine emissions or if an applicable requirement exists for materials produced)

(Use additional sheets if necessary)

Unit No.	Material [29]	Composition	Condition	Production Rates (Specify Units)
N/A				

SECTION 3A - LIQUID STORAGE TANKS - MATERIAL DATA [30]: (Paragraphs 5 and 6 of Subsection D of 20.2.70.300 NMAC)
(Complete asterisk * columns only if the tank has an applicable requirement or if necessary to calculate emissions)

(Use additional sheets if necessary)

Tank No. [31]	Liquid Stored [32]	Liquid Composition [33]	* Liquid Density (lb/gal)	* Vapor Molecular Weight (lb/lb-mole)	* Average Storage Temp., T_{av} (°F)	* True Vapor Pressure at T_{av} (psia)	* Maximum Storage Temp., T_{max} (°F)	* True Vapor Pressure at T_{max} (psia)
N/A								

SECTION 3B - LIQUID STORAGE TANKS - TANK DATA: (Paragraphs 5 and 6 Subsection D of 20.2.70.300 NMAC)
(Complete asterisk * columns only if the tank has an applicable requirement or if necessary to calculate emissions)

(Use additional sheets if necessary)

Tank No. [34]	Date Installed/ Modified[35]	Capacity (gal)	* Tank Diameter (ft)	* Roof Type [36]	* Seal Type[37]	* Vapor Space Height (ft) [38]	* Roof/ Shell Color [39]	* Paint Cond-ition [40]	* Annual Throughput (gal/yr) [41]	* Turnovers per Year [42]
N/A										

SECTION 4A - SOLID MATERIAL STORAGE - MATERIAL DATA [43]: (Paragraph 5.d of Subsection D of 20.2.70.300 NMAC)
(Complete asterisk * columns only if necessary to calculate emissions or if there is an applicable requirement for material storage)

(Use additional sheets if necessary)

Storage Unit No.[44]	Storage Material Name	* Emission Unit(s), Process or Operation Served [45]	Storage Type [46]	Storage Material Composition [47]	* Date Installed or Modified
N/A					

SECTION 4B - SOLID MATERIAL STORAGE - STORAGE DATA [48]: (Paragraph 5.d of Subsection D of 20.2.70.300 NMAC)
(Complete asterisk * columns only if necessary to calculate emissions or if there is an applicable requirement for material handling)

(Use additional sheets if necessary)

Storage Unit No. [49]	Transfer or Transport Method [50]		* Maximum Hourly Throughput (specify units)	* Annual Throughput (specify units)	Dust Control Method (During Storage and Transfer) [51]
	Incoming	Outgoing			
N/A					

SECTION 5 - FUEL USEAGE AND FUEL DATA [52]**:** (Paragraph 5.d of Subsection D of 20.2.70.300 NMAC)
(Complete asterisk * column only if needed to determine or regulate any emissions or if there is an applicable requirement for the fuel)

(Use additional sheets if necessary)

Emission Unit No. [53]	Type of Equipment [54]	Equipment Manufacturer and Model No.	Equipment Rated Capacity [55] Max Design / Actual Site (specify units)	* FUEL DATA [56]				
				Fuel Type [57]	Amount Per Year [58] (specify units)	Lower Heating Value [59] (specify units)	% of Sulfur [60]	% of Ash [61]
TA-3-22-1 TA-3-22-2 TA-3-22-3	Power Plant Boilers[(a)]	Edgemoor Iron Works (2) Models 4008 and 4009 Union Iron Works (1) Model 102824	210 MM Btu/hr max	Natural Gas	2,000 MMscf/yr	1012.9 Btu/scf	2gr/100scf max.	N/A max.
			178.5 MMBtu/hr site				N/A ave.	N/A ave.
			210 MMBtu/hr max	No. 2 Fuel Oil	500,000 Gallons	137,000 Btu/gal	0.05 max.	N/A max.
			178.5 MMBtu/hr site				N/A ave.	N/A ave.
CT-1	Simple Cycle Combustion Turbine Generation Set	Rolls-Royce RB211-6761 DLE	32 MW max	Natural Gas	646 MMscf/yr	1012.9 Btu/scf	2gr/100scf max.	N/A max.
			24.6 MW site				N/A ave.	N/A ave.
TA-11-FF	Fuel Container	N/A	N/A max	No. 2 Fuel Oil	4,000 Gallons	137,000 Btu/gal	0.34% max.	N/A max.
			N/A site				N/A ave.	N/A ave.
			max				max.	max.
			site				ave.	ave.
			max				max.	max.
			site				ave.	ave.
			max				max.	max.
			site				ave.	ave.
			site				ave.	ave.

[(a)]The power plant boilers are existing sources at LANL; however the applicable natural gas fuel limit was revised when NSR Permit 2195B was modified to include the CT-1 turbine.

SECTION 6 - AIR POLLUTION UNITS and CONTROL EQUIPMENT DATA [62]: (Paragraphs 5.e and 7.a of Subsection D of 20.2.70.300 NMAC)
(List all Air pollution units of plant, including the units listed in Sections 3 thru 5)

(Use additional sheets if necessary)

Emission Unit No.[63]	Process or Operation [64]	Is Air Pollution Control Equipment Installed (Yes/No) [65]	Air Pollution Control Equipment No.[66]	AIR POLLUTION CONTROL EQUIPMENT DATA		AIR POLLUTION CONTROL EQUIPMENT EFFICIENCY DATA		Applicable Requirements for this Process and/or Control [67]
				Equipment Type [68]	Manufacturer and Model No. [69]	% by Weight [70]	Method of Determination [71]	
TA-52-11	Data Disintegrator	Yes	1	Cyclone	Security Engineered Machinery (SEM) Model # 60N70-PL-SP Serial # 2720	75	Manufacturer's Rating	See Sections 2.1.6 and 2.1.7
			2	Cloth tube filters	SEM Model # FT40 Serial # 40-10750	95	Manufacturer's Rating	See Sections 2.1.6 and 2.1.7
TA-3-22-1 TA-3-22-2 TA-3-22-3	Power Plant Boilers (3)	Yes	1	Flue Gas Recirculation Fans	Robinson Industries	Average 64% Reduction of NO_x	2002 Source Test	See Sections 2.2.6 and 2.2.7
CT-1	Simple Cycle Combustion Turbine Generator Set	Yes[(b)]	1	Dry Low Emissions (pre-mix, lean burn staged combustion)	Rolls-Royce	70%	Manufacturer's Rating	See Sections 2.2.6 and 2.2.7
TA-54-SVE	Soil Vapor Extraction	Yes[(b)]	1	Electric Catalytic Oxidizer	Catalytic Combustion Cooperation	95 to 99%	Manufacturer's Rating	See Sections 2.3.6 and 2.3.7

[(b)]At the time of this application, the combustion turbine and soil vapor extraction system have not been installed. When installed, the control equipment listed will be present.

SECTION 7 - AIR POLLUTION EMISSION RATES [72]**:** (Paragraph 5.c of Subsection D of 20.2.70.300 NMAC)
(List all Air pollution units of plant, including the units listed in Sections 3 thru 6, and tank-flashing emissions estimates.)

(Use additional sheets if necessary)

Emission Unit No.[73]	ALLOWABLE AIR POLLUTANT EMISSION RATES (after control equipment) [74]												Emission Rate Units in
	Pollutant-1 NO_x	Pollutant-2 CO	Pollutant-3 SO_x	Pollutant-4 PM	Pollutant-5 PM_{10}	Pollutant-6 VOC	Pollutant-7 HAP[(c)]	Pollutant-8	Pollutant-9	Pollutant-10	Pollutant-11	Pollutant-12	
TA-3-22-1 TA-3-22-2 TA-3-22-3 Boilers	10.2/11.3 (gas/oil)	7.0/6.5 (gas/oil)	1.1/9.6 (gas/oil)	1.3/4.3 (gas/oil)	1.3/3.0 (gas/oil)	1.0/0.3 (gas/oil)	N/A						pounds/hr/ boiler
	60.2	41.3	7.9	8.4	8.2	5.6	1.9						tons/yr/total all boilers
TA-3-22-CT-1 Combustion Turbine	23.8	170.9	1.4	1.6	1.6	1.0	N/A						pounds/hr
	33.2	19.8	1.9	2.3	2.3	Neg.	3.9E-04						tons/yr
TA-52-11 Data Disintegrator	N/A	N/A	N/A	2.3	2.3	N/A	N/A						pounds/hr
	N/A	N/A	N/A	9.9	9.9	N/A	N/A						tons/yr
TA-54-SVE Soil Vapor Extraction	N/A	N/A	N/A	N/A	N/A	N/A	N/A						pounds/hr
	N/A	N/A	N/A	N/A	N/A	N/A	N/A						tons/yr
TA-16-FP Flash Pad	0.4	0.1	Neg.	0.5	0.5	Neg.	1.33E-03						pounds/hr
	0.07	Neg.	Neg.	0.1	0.1	Neg.	2.43E-04						tons/yr
TA-11-WF Wood Fire Test	6.8	474.3	0.8	67.1	67.1	429.4	3.67E-02						pounds/hr
	0.07	4.7	Neg.	0.7	0.7	4.3	3.67E-04						tons/yr
TA-11-FF Fuel Fire Test	23.5	177.9	39.6	680.3	680.3	29.3	3.67E-04						pounds/hr
	0.06	0.4	0.1	1.7	1.7	0.1	3.0E-02						tons/yr

[(c)] HAP values are estimates only and are not allowable emission rates. HAP emissions from these units are subject to the facility-wide emission limits in Permit P100.

SECTION 7 - AIR POLLUTION EMISSION RATES [75]**:** (Paragraph 5.c of Subsection D of 20.2.70.300 NMAC)
(List all Air pollution units of plant, including the units listed in Sections 3 thru 6, and tank-flashing emissions estimates.)

(Continued)

Emission Unit No.[76]	ALLOWABLE AIR POLLUTANT EMISSION RATES (after control equipment) [77]												Emission Rate Units in
	Pollutant-1 NO_x	Pollutant-2 CO	Pollutant-3 SO_x	Pollutant-4 PM	Pollutant-5 PM_{10}	Pollutant-6 VOC	Pollutant-7 HAP	Pollutant-8	Pollutant-9	Pollutant-10	Pollutant-11	Pollutant-12	
TA-16-FP TA-11-FF TA-11WF (combined)[(d)]	30.7	652.3	40.4	747.9	747.9	458.7	N/A						pounds/hr[(d)]
	0.2	5.1	0.1	2.5	2.5	4.4	N/A						tons/yr[(d)]
TA-36-ST-1 Sled Track	5.0	127.7	0.2	21.8	21.8	114.5	2.12E-02						pounds/hr
	0.04	1.0	0.002	0.2	0.2	1.0	1.70E-04						tons/yr
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													pounds/hr
													tons/yr
													tons/yr

[(d)] The values shown are from NSR Permit 2195J which has emission limits for the combined lb/hr and tpy totals of the three open burn activities within the permit.

SECTION 8 - STACK PARAMETERS [78]: (Paragraph 5.h of Subsection D of 20.2.70.300 NMAC)
(Complete only if dispersion modeling is required or if there is an applicable requirement for stack parameters)

(Use additional sheets if necessary)

Stack No. [79]	Emission Unit No. [80]	Stack Height (ft) [81]	Stack Inside Exit Diameter (ft) [82]	Stack Direction [83]	STACK EXIT GAS CONDITIONS [84]		
					Temp. (°F)	Velocity (ft/sec) [85]	Moisture % by Vol
N/A							

SECTION 9 - COMPLIANCE MONITORING DEVICES AND EQUIPMENT [86]: (Paragraph 5.e of Subsection D of 20.2.70.300 NMAC)

(Use additional sheets if necessary)

Monitor Unit No. [87]	Parameter To Be Monitored [88]	Pollutant To Be Monitored or Measured [89]	Type of Monitor or Instrument [90]	Monitor Manufacturer and Model Number	Range [91]	Sensitivity [92]	Accuracy [93]	Monitored Emission Unit No. [94]	Location of Monitor [95]
1 (East Leg)	Natural Gas Fuel Flow	N/A	Orifice (2.5" Diameter)	6" Daniel Simplex Orifce Plate Holder Catalog # 071C S/N 94320125	52–155 Mscfh (15" – 150" wc)	N/A (Primary Flow Element)	+/- 0.75%	TA-3-22-1 TA-3-22-2 TA-3-22-3	TA-03-0055
2 (West Leg)	Natural Gas Fuel Flow	N/A	Orifice (4.0" Diameter)	6" Daniel Simplex Orifce Plate Holder Catalog # 071C S/N 94320126	147–465 Mscfh (15" – 150" wc)	N/A (Primary Flow Element)	+/- 0.75%	TA-3-22-1 TA-3-22-2 TA-3-22-3	TA-03-0055
3	No. 2 Fuel Oil Fuel Flow	N/A	Volumetric Flow Meter	Bailey Model BQ74221	4-1576 gal/hr	2 gal/hr	5%	TA-3-22-1 TA-3-22-2 TA-3-22-3	Fuel Inlet 10 feet prior to burners, recorder in control room
4	Natural Gas Fuel Flow	N/A	Volumetric Flow Meter	To Be Determined (TBD)	(TBD)	(TBD)	(TBD)	CT-1	(TBD)
5	Temperature	N/A	Continuous Temperature	(TBD)	(TBD)	(TBD)	(TBD)	TA-54-SVE	(TBD)

SECTION 10 - STRATOSPHERIC OZONE PROTECTION PROGRAM (Title VI, Clean Air Act Amendments)
Please answer the following questions to determine the applicability of 40 CFR 82, Subparts A through G, to your facility.

1. Does your facility have any air conditioners or refrigeration equipment that uses CFCs, HCFCs or other ozone-depleting substances? ___X___yes ______no

2. Does any air conditioner(s) or any piece(s) of refrigeration equipment contain a refrigeration charge greater than 50 lbs? ___X____yes _______ no (If the answer is yes, describe what type of equipment and how many units are at the facility.)

Refrigerant Type	Number of Units[1]
CFC-11	3
CFC-12	13
HCFC-123	20
HCFC-22	158
HFC-134A	2
R-401A	4
R401B	1
R-502	4
R-507A	2

3. Do your facility personnel maintain, service, repair, or dispose of any motor vehicle air conditioners (MVACs) or appliances ("appliance" and "MVAC" as defined at 82. 152)? ___X___yes ______no

4. Cite and describe which Title VI requirements are applicable to your facility (i.e. 40CFR Part 82, Subpart A through G.)_______________________

40 CFR Part 82, Subpart A, Production and Consumption Controls
40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners
40 CFR Part 82, Subpart F, Recycling and Emissions Reduction
40 CFR Part 82, Subpart G, Significant New Alternative Policy Program
40 CFR Part 82, Subpart H, Halon Emissions Reduction

1 These numbers will change due to retrofitting, replacements, and disposals and should be considered estimates.

SECTION 11 - CERTIFICATION

I, Carolyn Mangeng, hereby certify on behalf of Los Alamos National Laboratory, that the information and data submitted in this application package are as complete, true and accurate as possible, to the best of my personal knowledge and professional expertise and experience.

Signed this 28th day of July, 2005, upon my oath of affirmation, before a notary of the State of New Mexico.

Original Signed By 7/28/05

SIGNATURE (Responsible Company Official) DATE

Carolyn Mangeng
PRINTED NAME

Associate Director for Technical Services (Acting)
Title

University of California, Los Alamos National Laboratory
Company

Subscribed and sworn to before me on this 28th day of July, 2005.

My authorization as a Notary of the State of New Mexico expires on the 20th day of May, 2007.

Original Signed By 7/28/05

NOTARY'S SIGNATURE DATE

Mary Alice Montoya
NOTARY'S PRINTED NAME

NOTARY SEAL

Appendix B

Maps

Appendix B

These pages have been removed for operational security purposes. Please contact ENV-MAQ at (505) 665-8855 for a hard copy of the application maps and plot plans.

Appendix C

NSR Permit Specific Conditions

Data Disintegrator

NSR Permit 2195H

State of New Mexico
ENVIRONMENT DEPARTMENT
Air Quality Bureau
2048 Galisteo St.
Santa Fe, NM 87505
Phone (505) 827-1494
Fax (505) 827-1523
www.nmenv.state.nm.us

BILL RICHARDSON
Governor

RON CURRY
Secretary

DERRITH WATCHMAN-MOORE
Deputy Secretary

CERTIFIED MAIL NO. 7001 2510 0001 2013 6225
RETURN RECEIPT REQUESTED

Permittee:

Los Alamos National Laboratory
Meteorology and Air Quality Group
P.O. Box 1663, MS J978
Los Alamos, NM 87545

NSR Air Quality Permit No. 2195-H
Los Alamos National Laboratory
Technical Area 52
AIRS No. 35-028-0001
IDEA NO. 856-PRN20030005

Company Official:

Jean Dewart
Group Leader, Meteorology and Air Quality
Group

____
Sandra Ely
Bureau Chief
Air Quality Bureau

October 22, 2003
Date of Issuance

Air Quality Permit No. 2195-H is issued by the Air Quality Bureau of the New Mexico Environment Department (Department) to Los Alamos National Laboratory pursuant to the Air Quality Control Act (Act) and regulations adopted pursuant to the Act including Title 20, New Mexico Administrative Code (NMAC), Chapter 2, Part 72, (20 NMAC 2.72), Construction Permits, Subpart II and is enforceable pursuant to the Act and the air quality control regulations applicable to this source.

This permit authorizes the construction and operation of a 1200 pound per hour Data Disintegrator at Technical Area 52 (TA-52). The function of the TA-52 facility is to perform experimental research activities. This facility is located in Township 19N, Range 6E, Section 22, approximately 1.3 miles south of Los Alamos, New Mexico in Los Alamos County.

The Department has reviewed the permit application for the proposed construction and has determined that the provisions of the Act and ambient air quality standards will be met.

Conditions have been imposed in this permit to assure continued compliance. 20 NMAC 2.72, Section 210.D, states that any term or condition imposed by the Department on a permit is enforceable to the same extent as a regulation of the Environmental Improvement Board.

TOTAL EMISSIONS

The total potential emissions from this facility, excluding exempted activities, are shown in the following table. Emission limitations for individual units are shown in Condition 2.

Total Potential Criteria Pollutant Emissions from Entire Facility (for information only, not an enforceable condition):

Pollutant	**Emissions** (tons per year)
Nitrogen Oxides (NOx)	245
Carbon Monoxide (CO)	225
Volatile Organic Compounds (VOC)	200
Sulfur Dioxide (SO2)	150
Particulate (TSP)	120
Particulate (PM10)	120

As per 20.2.75 NMAC, the Department will assess an annual enforcement/compliance fee as specified in Section 110. At time of permit issuance this fee is $220. This fee does not apply to sources which are assessed an annual fee in accordance with 20.2.71NMAC. The AQB will invoice the permittee for the amount.

Pursuant to 20 NMAC 2.72, and the specific regulatory citations in parenthesis, the facility is subject to the following conditions.

SPECIFIC CONDITIONS

1. Construction / Modification / Revision and Operation
(20 NMAC 2.72, Section 210.A)

a) The plant shall be modified and operated in accordance with all representations in the permit application dated June 24, 2003 and received June 25, 2003, unless modified by conditions of this permit.

The Department has relied on air quality modeling to issue this permit. Any change to the parameters used for this modeling may require a permit modification.

b) The equipment regulated by this permit consists of:

Table 1.1: Regulated Equipment List

Unit No.	Unit Type	Manuf.	Model No./ Serial No.	Year of Manuf.	Capacity Nameplate	Type of Control Equipment
1	Data Disintegrator /Industrial Shredder	Security Engineered Machinery	1424/11892	2002	1200 lb/hr	Cyclone w/ 75% control efficiency & Cloth tube filters w/95% control efficiency

c) This facility is subject to all applicable requirements including, but not limited to, the following regulations:

Table 1.2: applicable requirements

Citation	Title
20 NMAC 2.3	Ambient Air Quality Standards
20 NMAC 2.7	Excess Emissions During Malfunction
20 NMAC 2.70	Operating Permits
20 NMAC 2.71	Operating Permit Fees
20 NMAC 2.72	Construction Permits
20 NMAC 2.73	NOI & Emissions Inventory Requirements
20 NMAC 2.75	Construction Permit Fees

d) The permittee shall perform regular maintenance and repair on the cyclone and cloth tube filter(s) per manufacturer's recommendations.

2. Emission Limits
(20 NMAC 2.72, Sections 210.A and 210.B.1.b)

Table 2.1: Allowable Emissions

Unit	TSP		PM10		NOx		CO		VOC		SOx	
No.	(pph)	(tpy)	(pph)	(tpy)	(pph)	(tpy)	(pph)	(tpy)	(pph)	(tpy)	(pph)	(tpy)
1	2.3	9.9	2.3	9.9								

3. Monitoring Requirements
(20 NMAC 2.72, Section 210.B.4, 20 NMAC 2.72)

a) No Specific Conditions

4. Recordkeeping
(20 NMAC 2.72, Sections 210.B.4, and 210.D)

a) The permittee shall maintain adequate records on site to demonstrate compliance with manufacturer's recommended repair and maintenance schedules for the cyclone and the cloth tube filter(s).

All records required by any permit condition shall be maintained on-site by permittee for a minimum of five (5) years from the date of recording, and shall be made available to Department personnel upon request.

5. Reporting
(20 NMAC 2.72, Sections 210.B and 210.E, and 212)

a) No Specific Conditions

6. Compliance Test
(NMAC 2.72, Section 210.C, 213)

a) Compliance testing for the Data Disintegrator (Unit No. 1) is not required at this time. However, compliance test requirements from previous permits (if any) are still in effect, unless the tests have been satisfactorily completed. Compliance tests may be re-imposed if Department inspections indicate possible noncompliance with permit conditions subject to such testing, or noncompliance during the initial compliance or subsequent compliance tests, or if the tests were technically unsatisfactory.

b) If any compliance testing is required, it shall be conducted in accordance with EPA Reference Methods 1 through 4, Method 7E for NOx, Method 10 for CO, Method 5 for TSP, and contained in CFR Title 40, Part 60, Appendix A, and with the requirements of Subpart A, General Provisions, 60.8(f). For combined TSP and PM10, testing shall be in accordance with 40 CFR 51, Appendix M, Method 201. Alternative test method(s) may be used if the Department approves the change. The results of the NOx tests shall be expressed as nitrogen dioxide (NO_2) using a molecular weight of 46 lb/lb mole in all calculations (each ppm of NO/NO_2 is equivalent to 1.194×10^{-7} lb/SCF).

TA-3 Power Plant

NSR Permit 2195BM1

BILL RICHARDSON
Governor

State of New Mexico
ENVIRONMENT DEPARTMENT
Air Quality Bureau
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Santa Fe, NM 87505
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RON CURRY
Secretary

DERRITH WATCHMAN-MOORE
Deputy Secretary

CERTIFIED MAIL NO. 7003 0500 0005 1471 6900
RETURN RECEIPT REQUESTED

Permittee:

University of California for the
U.S. Department of Energy
Meteorology and Air Quality Group
P.O. Box 1663, MS J978
Los Alamos, NM 87545

NSR Air Quality Permit No.2195BM1
Los Alamos National Laboratory
AIRS No. 35-028-0001
IDEA No. 0856- PRN20030008

Company Official:

Jean Dewart
Group Leader
Meteorology and Air Quality Group

Sandra Ely
Bureau Chief
Air Quality Bureau

JUL 30 2004
Date of Issuance

Air Quality Permit No. 2195BM1 is issued by the Air Quality Bureau of the New Mexico Environment Department (Department) to Los Alamos National Laboratory pursuant to the Air Quality Control Act (Act) and regulations adopted pursuant to the Act including Title 20, New Mexico Administrative Code (NMAC), Chapter 2, Part 72, (20 NMAC 2.72), Construction Permits, Subpart II and is enforceable pursuant to the Act and the air quality control regulations applicable to this source.

This permit authorizes the modification and operation of the Technical Area – 3 Power Plant (TA-3). The function of the facility is to produce steam to heat buildings, generate electricity, and to be used in other lab associated activities. This facility is located in Township 19 North, Range 6 East, Section 17, approximately 0.25 miles South of the intersection of Trinity and Diamond in Los Alamos, New Mexico in Los Alamos County.

This permit supercedes all portions of Air Quality Permit No. 2195B-R1, issued September 27, 2000 and revised on November 21, 2002 except the portion requiring compliance tests. Compliance test conditions from previous permits are still in effect, in addition to compliance test requirements contained in this permit.

The Department has reviewed the permit application for the proposed modification and has determined that the provisions of the Act and ambient air quality standards will be met. Conditions have been imposed in this permit to assure continued compliance. 20 NMAC 2.72, Section 210.D, states that any term or condition imposed by the Department on a permit is enforceable to the same extent as a regulation of the Environmental Improvement Board.

TOTAL EMISSIONS

The total potential emissions from this facility, excluding exempted activities, are shown in the following table. Emission limitations for individual units are shown in Condition 2.

Total Potential Criteria Pollutant Emissions from Entire Facility (for information only, not an enforceable condition):

Pollutant	**Emissions** (tons per year)
Total Particulate Matter (TSP)	10.7
Particulate Matter 10 Microns (PM10)	10.5
Nitrogen Oxides (NOx)	93.4
Carbon Monoxide (CO)	61.1
Volatile Organic Compounds (VOC)	5.7
Sulfur Dioxide	9.8

Total Potential HAPS that exceed one ton per year (for information only, not an enforceable condition):

Pollutant	**Emissions** (tons per year)
Hexane	1.80

Pursuant to 20.2.75.11 NMAC, the Department will assess an annual fee for this facility. This regulation set the fee amount at $1,500 through 2004 and requires it to be adjusted annually for the Consumer Price Index on January 1. The current fee amount is available by contacting the Department or can be found on the Department's website. The AQB will invoice the permittee for the annual fee amount at the beginning of each calendar year. This fee does not apply to sources which are assessed an annual fee in accordance with 20.2.71 NMAC.

Pursuant to 20 NMAC 2.72, and the specific regulatory citations in parenthesis, the facility is subject to the following conditions.

SPECIFIC CONDITIONS

1. Construction / Modification / Revision and Operation
(20 NMAC 2.72, Section 210.A)

a) The equipment regulated by this permit consists of

Table 1.1: Regulated Equipment List

Unit No.	Make Model	Serial No.	Capacity	Manufacture Date	Other
B-1	Edgemoor Iron Works	4008	178.5 MMBtu/hr	1950	Equipped with a Flue Gas Recirculation Fan (F-1)
B-2	Edgemoor Iron Works	4009	178.5 MMBtu/hr	1950	Equipped with a Flue Gas Recirculation Fan (F-2)
B-3	Union Iron Works	11804	178.5 MMBtu/hr	1951	Equipped with a Flue Gas Recirculation Fan (F-3)
F-1	Robinson Industries	-	1800 rpm	2001	Flue Gas Recirculation Fan
F-2	Robinson Industries	-	1800 rpm	2001	Flue Gas Recirculation Fan
F-3	Robinson Industries	-	1800 rpm	2001	Flue Gas Recirculation Fan
CT-1	Rolls-Royce	RB211-6761 DLE	24.6 MW	2003	Simple Cycle Natural Gas Combustion Turbine Generator Set
TA-03-026	-	-	3,770 bbl	1950	No. 2 Fuel Oil Storage
TA-03-2382	-	-	5,455 bbl	1999	No. 2 Fuel Oil Storage

b) This facility is authorized to operate 24 hours per day, 7 days per week, and 52 weeks per year for a total of 8,760 hours per year.

c) This facility is subject to all applicable requirements including, but not limited to, the following regulations.

Table 1.2: Applicable Requirements

Citation	Title
40 CFR Part 50, Subpart C	Federal Ambient Air Quality Standards
40 CFR Part 60, Subpart A	General Provisions
40 CFR Part 60 Subpart GG	Standards of Performance for Stationary Gas Turbines
20 NMAC 2.3	Ambient Air Quality Standards
20 NMAC 2.7	Excess Emissions During Malfunction
20 NMAC 2.61	Smoke and Visible Emissions
20 NMAC 2.70	Operating Permits
20 NMAC 2.71	Operating Permit Fees
20 NMAC 2.72	Construction Permits
20 NMAC 2.73	NOI & Emissions Inventory Requirements
20 NMAC 2.75	Construction Permit Fees
20 NMAC 2.77	New Source Performance Standards

d) The Department has determined that Unit CT-1 (Rolls-Royce – Simple Cycle Combustion Turbine) (see Table 1.1), a combustion turbine, commenced construction after October 03, 1977 and before July 08, 2004, as defined by 40 CFR Part 60. The Department has also determined that Unit CT-1 is subject to and shall comply with all applicable requirements of 40 CFR, Part 60, Subpart GG and 40 CFR Part 60, Subpart A. Failure to comply with those requirements may be deemed non-compliance with this permit.

e) Unit CT-1 shall be equipped with Rolls-Royce Dry Low Emissions (DLE) control technology (pre-mix, lean-burn series staged combustion system) to control NOx emissions.

f) Unit CT-1 shall be operated at no less than 100% full load, except for minimal periods during startup and shutdown conditions.

g) Units B-1, B-2 and B-3 shall either use pipeline quality natural gas containing no more than 2 grains of total sulfur per 100 standard cubic foot or No. 2 fuel oil that is not a blend containing waste oils or solvents and contains less than or equal to 0.05% sulfur by weight.

i) Units B-1, B-2, and B-3 combined shall not use more than 500,000 gal of No. 2 fuel oil in any 365 day period.

ii) Units B-1, B-2, and B-3 combined shall not use more than 2,000 MM standard cubic feet (SCF) of natural gas in any 365 day period.

h) A volumetric fuel flow meter shall be connected to the facility or to Units B-1, B-2, and B-3 so that the total amount of natural gas being used by the boilers can be continually recorded.

i) Unit CT-1 shall use pipeline quality natural gas containing no more than 2 grains of total sulfur per 100 standard cubic foot.

j) Unit CT-1 shall not use more than 646 MM standard cubic feet (SCF) of natural gas in any 365 day period.

k) A volumetric fuel flow meter shall be connected to Unit CT-1 so that the total amount of natural gas being used can be continually recorded. Although the facility is not subject to 40 CFR Part 75, Federal Acid Rain requirements, the flow meter shall meet the initial certification requirements of 40 CFR Part 75, Appendix D 2.1.5 and the quality assurance requirements of 40 CFR Part 75, Appendix D 2.1.6.

l) Hours of operation, including start-up and shut-down times, of Units B-1, B-2, B-3 and CT-1 shall be monitored and recorded daily.

m) Existing Boiler Unit numbers B-1, B-2, and B-3 are subject to all the applicable requirements of 20 NMAC 2.33, Gas Burning Equipment - Nitrogen Dioxide.

n) Existing Boiler Unit numbers B-1, B-2, and B-3 are subject to all the applicable requirements of 20 NMAC 2.34, Oil Burning Equipment - Nitrogen Dioxide.

o) This facility is subject to all the applicable requirements of 20 NMAC 2.61, Smoke and Visible Emissions.

2. Emission Limits (20 NMAC 2.72, Sections 210.A and 210.B.1.b, 20.2.33 NMAC, 20.2.34 NMAC, 20.2.61 NMAC

a) The emissions from the individual units listed in Tables 2.1 and 2.2 shall not exceed the hourly or annual limits listed.

Table 2.1: Allowable Emissions

Unit No.	TSP pph		PM10 pph		NOx pph		CO pph		VOC pph		SOx pph	
	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
B-1	1.3	4.3	1.3	3.0	10.2	11.3	7.0	6.5	1.0	0.3	1.1	9.6
B-2	1.3	4.3	1.3	3.0	10.2	11.3	7.0	6.5	1.0	0.3	1.1	9.6
B-3	1.3	4.3	1.3	3.0	10.2	11.3	7.0	6.5	1.0	0.3	1.1	9.6
CT-1[2]	1.6		1.6		23.8		170.9		1.0		1.4	

Table 2.2: Allowable Emissions

Unit No.	TSP tpy	PM10 tpy	NOx tpy	CO tpy	VOC tpy	SOx tpy
Combined (B-1, B-2 & B-3) (TPY)[1] →	8.4	8.2	60.2	41.3	5.6	7.9
CT-1 (TPY)[1,2,3]	2.3	2.3	33.2	19.8	-	1.9

Notes to Tables 2.1 and 2.2: Allowable Emissions

1 Annual emission limits are 12-month rolling totals.

2 See Specific Conditions 3.g) and 3.h) for specific compliance determination methods for Unit CT-1.

3 "-" notation implies emission rates less than or equal to 0.5 pph or tpy.

b) The permittee shall not permit, cause, suffer or allow nitrogen dioxide emissions to the atmosphere in excess of 0.3 pounds per million British Thermal Units of heat input from Units B-1, B-2, and B-3.

c) The permittee shall not permit, cause, suffer or allow visible emissions from the stationary combustion equipment to equal or exceed opacity of 20 percent.

d) Nitrogen oxide emissions from the Unit CT-1 shall not exceed 25 ppmv at 15% O_2.

3. Monitor Requirements
(20 NMAC 2.72, Section 210.B.4, 20 NMAC 2.72)

a) Fuel oil consumption shall be monitored so that combined fuel oil usage of Units B-1, B-2, and B-3 can be calculated on a rolling 365-day total.

b) Natural gas consumption shall be monitored so that combined natural gas usage of Units B-1, B-2, and B-3 can be calculated on a rolling 365-day total.

c) A certification of total sulfur content of the No. 2 fuel oil used by Units B-1, B-2, and B-3 shall be obtained from the supplier whenever No. 2 fuel oil is delivered to the facility.

d) If the certification as specified by Specific Condition 3. c) is not available at delivery, the permittee shall analyze the No. 2 fuel oil to determine the total sulfur content. The analysis shall be conducted using Department approved methods and standards for determining total sulfur content of No. 2 fuel oil.

e) The operating load of Unit CT-1 specified by Specific Condition 1.f) shall be monitored and recorded hourly during normal operations of that unit. Periods of startup and shutdown shall not be included in the hourly monitoring, but shall be recorded separately.

f) Natural gas consumption shall be monitored so that natural gas usage for Unit CT-1 can be calculated on a rolling 365-day total.

g) Compliance with NOx pound per hour emission limits for Unit CT-1 shall be determined by multiplying the daily total natural gas firing rate for the unit (expressed in thousands of SCF), as recorded pursuant to Specific Condition 1.j), by the manufacturer's guaranteed emission rate of 0.1029 pounds NOx per thousand SCF of gas burned (applicable for worst-case conditions of negative 18 degrees Fahrenheit), and divided by the number of hours of operation of the unit during that day as recorded pursuant to Specific Condition 1.l). Compliance with NOx annual emission limits for Unit CT-1 shall be determined by multiplying the 365 day total natural gas firing rate for the unit (expressed in thousands of SCF), as recorded pursuant to Specific Condition 1.j), by the manufacturer's guaranteed emission rate of 0.1029 pounds NOx per thousand SCF of gas burned (applicable for annual average conditions of 47.9 degrees Fahrenheit).

h) Compliance with CO pound per hour emission limits for Unit CT-1 shall be determined by multiplying the daily total natural gas firing rate for the unit (expressed in thousands of SCF), as recorded pursuant to Specific Condition 1.j), by the manufacturer's guaranteed emission rate of 0.731pounds CO per thousand SCF of gas burned (applicable for worst-case conditions of negative 18 degrees Fahrenheit), and divided by the number of hours of operation of the unit during that day as recorded pursuant to Specific Condition 1.l). Compliance with CO annual emission limits for Unit CT-1 shall be determined by multiplying the 365 day total natural gas firing rate for the unit (expressed in thousands of SCF), as recorded pursuant to Specific Condition 1.j), by the manufacturer's guaranteed emission rate of 0.0613 pounds CO per thousand SCF of gas burned (applicable for annual average conditions of 47.9 degrees Fahrenheit).

i) At least once each calendar quarter the permittee shall use the method specified in Specific Conditions 3.g) and 3.h) to determine compliance of Unit CT-1 with the hourly and annual emission limits specified in this permit.

4. Recordkeeping
(20 NMAC 2.72, Sections 210.B.4, and 210.D)

a) Records shall be kept to verify the total sulfur content of the No. 2 fuel oil used by Units B-1, B-2, and B-3 and shall meet the following requirements:

i) Records of fuel supplier certifications shall be kept which include the name of the oil supplier and a statement the sulfur content of the oil delivered contains less than or equal to 0.05% sulfur buy weight; or

ii) If the permittee analyzes the fuel oil, records shall be kept which show the name of oil supplier, the location of the oil where the sample was taken for analysis, the method used to determine the sulfur content of the oil, and the results of the analysis for the sulfur content.

b) Records shall be kept to verify that the natural gas being consumed by Units B-1, B-2, B-3 and CT-1 is pipeline quality natural gas (less than or equal to 2 grains of total sulfur per 100 standard cubic foot).

c) The permittee shall keep records of all measurements and monitoring data required by Specific Condition 3. These records shall be retained at the plant site for a minimum of two (2) years from the time of recording and shall be made available to Department personnel upon request

5. <u>Reporting</u>
(20 NMAC 2.72, Sections 210.B and 210.E, and 212, NSPS 40 CFR 60 Subparts A and GG)

a) Records of all measurements and monitoring required by Condition 3 shall be reported to the Department upon request.

6. <u>Compliance Test</u>
(NMAC 2.72, Section 210.C, 213, and NSPS 40 CFR 60 Subparts A and GG)

a) Initial compliance tests are required on Unit(s) No. CT-1 for NOx and CO. Compliance test requirements from previous permits (if any) are still in effect for Units B-1, B-2 and B-3, unless the tests have been satisfactorily completed. Compliance tests may be re-imposed if Department inspections indicate possible noncompliance with permit conditions subject to such testing, or noncompliance during the initial compliance or subsequent compliance tests, or if the tests were technically unsatisfactory.

b) These tests shall be conducted within sixty (60) days after the unit(s) achieve the maximum normal production. If the maximum normal production rate does not occur within one hundred twenty (120) days of source startup, then the tests must be conducted no later than one hundred eighty (180) days after initial startup of the source.

c) The tests shall be conducted in accordance with EPA Reference Methods 1 through 4, Method 7E for NOx, Method 10 for CO and contained in CFR Title 40, Part 60,

Appendix A, and with the requirements of Subpart A, General Provisions, 60.8(f). Alternative test method(s) may be used if the Department approves the change. The results of the NOx tests shall be expressed as nitrogen dioxide (NO_2) using a molecular weight of 46 lb/lb mole in all calculations (each ppm of NO/NO_2 is equivalent to 1.194×10^{-7} lb/SCF).

cc: Section Chief, Compliance and Enforcement Section, AQB, Santa Fe
Espanola NMED Field Office

Enclosure: Industry/Consultant Feedback Questionnaire with envelope

TA-16 Flash Pad and TA-11 Test Site

NSR Permit 2195J

State of New Mexico
ENVIRONMENT DEPARTMENT
Air Quality Bureau
2048 Galisteo St.
Santa Fe, NM 87505
Phone (505) 827-1494
Fax (505) 827-1523
www.nmenv.state.nm.us

BILL RICHARDSON
GOVERNOR

RON CURRY
SECRETARY

DERRITH WATCHMAN-MOORE
DEPUTY SECRETARY

CERTIFIED MAIL NO. 7003 0500 0005 1471 8881
RETURN RECEIPT REQUESTED

Permittee:

US Department of Energy
Los Alamos National Laboratory
P.O. Box 1663, MS J978
Los Alamos, New Mexico 87545

NSR Air Quality Permit No. 2195-J
TA-11 Wood and Fuel Fire Test Site and TA-16 Flash Pad
AIRS No. 35-028-0001
AI No. 856 PRN-20040002

Company Official:

Ms. Jean Dewart
Group Leader

original document is signed

Sandra Ely
Bureau Chief
Air Quality Bureau

Date of Issuance

Air Quality Permit No. **2195-J** is issued by the Air Quality Bureau of the New Mexico Environment Department (Department) to Los Alamos National Laboratory ("LANL") pursuant to the Air Quality Control Act (Act) and regulations adopted pursuant to the Act including Title 20, New Mexico Administrative Code (NMAC), Chapter 2, Part 72, (20 NMAC 2.72), Construction Permits, Subpart II and is enforceable pursuant to the Act and the air quality control regulations applicable to this source.

This permit authorizes the construction and/or operation of LANL's wood and fuel fire test site located at Technical Area ("TA") – 11 and non-RCRA open burning activities associated with the flash pad located at TA-16. The function of the wood and fuel fire test site facility is to simulate and evaluate accident scenarios involving fire to determine the integrity of transportation containers and weapon components containing High Explosive ("HE") and Depleted Uranium ("DU") materials. The accident scenarios may generate emissions from open burning of HE, fuel oil, wood and DU materials.

The function of the flash pad is to use an open flame generated from propane burners on a concrete pad to ignite or burn residual HE material from equipment used at the LANL (e.g. piping, office furniture etc.,). These facilities are located in Township 18 and 19 North, Range 6 East and Sections 32 and 4, approximately five miles south of Los Alamos, New Mexico in Los Alamos County.

The Department has reviewed the permit application for the proposed construction and has determined that the provisions of the Act and ambient air quality standards will be met. Conditions have been imposed in this permit to assure continued compliance. 20 NMAC 2.72, Section 210.D, states that any term or condition imposed by the Department on a permit is enforceable to the same extent as a regulation of the Environmental Improvement Board.

TOTAL EMISSIONS

The total potential emissions from this facility, excluding exempted activities, are shown in the following table. Emission limitations for individual units are shown in Specific Condition 2.

Total Potential Criteria Pollutant Emissions from Entire Facility (for information only, not an enforceable condition):

Pollutant	**Emissions** (tons per year)
Nitrogen Oxides (NOx)	<1
Carbon Monoxide (CO)	<6
Volatile Organic Compounds (VOC)	<5
Particulate Matter – 10 (PM_{10})	<3
Sulfur Oxides (SOx)	<1

SPECIFIC CONDITIONS

Pursuant to 20 NMAC 2.72, and the specific regulatory citations in parenthesis, the facility is subject to the following conditions.

1. Construction and Operation
   (20 NMAC 2.72, Section 210.A, 210C,)

   a) The equipment regulated by this permit consists of

Table 1.1: Regulated Equipment List

Unit No.	Unit Description	Serial No.	Capacity	Manufacture Date
TA-16-FP	Flash Pad to Treat HE Contaminated Material	NA	NA	NA
TA-11-WF	Wood Fire Test Equipment	NA	NA	NA
TA-11-FF	Fuel Fire Test Equipment	NA	NA	NA

b) The flash pad is authorized burns on non-RCRA scrap metal; such burns shall consume no more than 5 lbs of HE per day. The Wood Fire Test Site is authorized five wood burns per calendar year, each burn consisting of no more than 7.5 tons of wood, 100 lbs of HE and 88 lbs of DU. The Fuel Fire Test Site is authorized five one-hour burns per calendar year, each burn consisting of no more than 800 gallons of fuel oil, 100 lbs of HE and 88 lbs of DU.

c) Each wood fire or fuel fire test or flashing activity shall take place no earlier than one hour after sunrise and shall be completed no later than one hour prior to sunset. The tests or flashing activity may occur on any day or week during a given calendar year.

d) This facility is subject to all applicable requirements including, but not limited to, the following regulations:

Table 1.2: Applicable Requirements

Citation	Title
20 NMAC 2.3	Ambient Air Quality Standards
20 NMAC 2.70	Operating Permits
20 NMAC 2.71	Operating Permit Fees
20 NMAC 2.72	Construction Permits
20 NMAC 2.73	NOI & Emissions Inventory Requirements
20 NMAC 2.75	Construction Permit Fees
40 CFR Part 61 Subpart H	NESHAP at 40 CFR Subpart H applies. However USEPA Region VI is the Administrator of this rule at LANL.

e) If requested by NMED, LANL shall arrange TA-16-FP activities to provide NMED an opportunity to observe this activity as part of a facility inspection.

f) Wood used for the wood fire tests shall be clean wood in the form of hard lumber which has not been painted or treated and does not include wood waste or processed wood material such as plywood or particle board.

2. Emission Limits (20 NMAC 2.72, Sections 210.A and 210.B.1.b

Table 2.1: Allowable Emissions

Unit No	TSP		PM10		NOx[1]		CO		VOCs		SOx	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
TA16-FP	0.5	0.1	0.5	0.1	0.4	0.07	0.1	Negl.	Negl.	Negl.	Negl.	Negl.
TA11-WF	67.1	0.7	67.1	0.7	6.8	0.07	474.3	4.7	429.4	4.3	0.8	Negl.
TA11-FF	680.3	1.7	680.3	1.7	23.5	0.06	177.9	0.4	29.3	0.1	39.6	0.1
Total	*747.9*	*2.5*	*747.9*	*2.5*	*30.7*	*0.2*	*652.3*	*5.1*	*458.7*	*4.4*	*40.4*	*0.1*

[1] Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2

3. Monitoring Requirements
(20 NMAC 2.72, Section 210.B.4, 20 NMAC 2.72)

a) LANL shall visually monitor each flashing activity and each wood fire and fuel fire test to ensure that associated open burning activities meet the requirements specified by this permit in condition 1 above.

4. Recordkeeping
(20 NMAC 2.72, Sections 210.B.4, and 210.D)

a) LANL shall generate and maintain records necessary to demonstrate compliance with permit conditions 1(b), (c), (d), (e) & (f).

5. Reporting
(20 NMAC 2.72, Sections 210.B and 210.E, and 212)

a) Concurrent with the semi-annual reports of its Title V permit, LANL shall submit a report of open burning activities authorized by this permit. The report shall include: the date of each open burn, type and quantities of materials burned, the time each burn was initiated, duration of each burn and the time when the burning was completed. LANL may include this information within one (1) report that includes other open burn sites.

b) LANL shall notify NMED's Air Quality Bureau Enforcement Section in writing of the week open burning associated with the TA-11 WF and FF sites is scheduled to occur no later than two weeks prior to the scheduled week. LANL shall provide a second written notification with the date and time open burning is scheduled to occur no later than forty-eight (48) hours prior to the burn. This will facilitate NMED's ability to conduct inspections to determine compliance with this permit.

6. Compliance Test
(NMAC 2.72, Section 210.C, 213)

a) Initial compliance tests are not required on Unit(s) TA-16-FP, TA-16-WF and TA-11 FF. Compliance test requirements from previous permits (if any) are still in effect, unless the tests have been satisfactorily completed. Compliance tests may be re-imposed if it is deemed necessary by the Department to determine whether the source is in compliance with applicable regulations or permit conditions.

cc: Section Chief, Compliance and Enforcement Section, AQB, Santa Fe
Los Alamos NMED DOE Oversight Bureau

Enclosure: Industry/Consultant Feedback Questionnaire with envelope

TA-36 Sled Track

NSR Permit 2195K

State of New Mexico
ENVIRONMENT DEPARTMENT
Air Quality Bureau
2048 Galisteo St.
Santa Fe, NM 87505
Phone (505) 827-1494
Fax (505) 827-1523
www.nmenv.state.nm.us

BILL RICHARDSON
GOVERNOR

RON CURRY
SECRETARY

DERRITH WATCHMAN-MOORE
DEPUTY SECRETARY

CERTIFIED MAIL NO. 7001 2510 0001 2015 4700
RETURN RECEIPT REQUESTED

Permittee:

US Department of Energy
Los Alamos National Laboratory
P.O. Box 1663, MS J978
Los Alamos, New Mexico 87545

NSR Air Quality Permit No. 2195-K
DX-TA-36 Sled Track
AIRS No. 35-028-0001
AI No. 856 PRN-20040003

Company Official:

Ms. Jean Dewart
Group Leader

original document is signed

Sandra Ely
Bureau Chief
Air Quality Bureau

Date of Issuance

Air Quality Permit No. **2195-K** is issued by the Air Quality Bureau of the New Mexico Environment Department (Department) to Los Alamos National Laboratory ("LANL") pursuant to the Air Quality Control Act (Act) and regulations adopted pursuant to the Act including Title 20, New Mexico Administrative Code (NMAC), Chapter 2, Part 72, (20 NMAC 2.72), Construction Permits, Subpart II and is enforceable pursuant to the Act and the air quality control regulations applicable to this source.

This permit authorizes the construction and/or operation of the LANL Dynamic Experimentation ("DX") Division Sled Track located at Technical Area ("TA") – 36. The function of the facility is to test and evaluate simulated accident scenarios involving transportation containers of High Explosive materials ("HE") and depleted uranium using a sled track. The accident scenarios may generate emissions from open burning of HE, wood and depleted uranium materials. This facility is located in Township 18 North, Range 6 East, Section 1, approximately four miles south of Los Alamos, New Mexico in Los Alamos County.

The Department has reviewed the permit application for the proposed construction and has determined that the provisions of the Act and ambient air quality standards will be met. Conditions have been imposed in this permit to assure continued compliance. 20 NMAC 2.72, Section 210.D, states that any term or condition imposed by the Department on a permit is enforceable to the same extent as a regulation of the Environmental Improvement Board.

TOTAL EMISSIONS

The total potential emissions from this facility, excluding exempted activities, are shown in the following table. Emission limitations for individual units are shown in Specific Condition 2.

Total Potential Criteria Pollutant Emissions from Entire Facility (for information only, not an enforceable condition):

Pollutant	**Emissions** (tons per year)
Nitrogen Oxides (NOx)	<1
Carbon Monoxide (CO)	1
Volatile Organic Compounds (VOC)	1
Particulate Matter – 10 (PM_{10})	<1
Sulfur Oxides – (SOx)	<1

SPECIFIC CONDITIONS

Pursuant to 20 NMAC 2.72, and the specific regulatory citations in parenthesis, the facility is subject to the following conditions.

1. Construction and Operation
(20 NMAC 2.72, Section 210.A, **210C,**)

a) The equipment regulated by this permit consists of

Table 1.1: Regulated Equipment List

Unit No.	Unit Description	Serial No.	Capacity	Manufacture Date	Other
ST-1	Sled Track	NA	NA	NA	NA

b) This facility is authorized to conduct eight transportation accident scenarios per calendar year using the sled track. Each test shall take place no earlier than three hours after sunrise and shall be completed no later than one hour prior to sunset. The eight tests may occur on any day or week during a given calendar year.

c) This facility is subject to all applicable requirements including, but not limited to, the following regulations:

Table 1.2: Applicable Requirements

Citation	Title
20 NMAC 2.3	Ambient Air Quality Standards
20 NMAC 2.70	Operating Permits
20 NMAC 2.71	Operating Permit Fees
20 NMAC 2.72	Construction Permits
20 NMAC 2.73	NOI & Emissions Inventory Requirements
20 NMAC 2.75	Construction Permit Fees
40 CFR Part 61, Subpart H	NESHAP at 40 CFR Part 61, Subpart H applies. However, USEPA Region VI is the Administrator of this rule at LANL.

d) For each scenario, LANL shall burn no more than 2000 pounds of clean wood, 99 pounds of HE material and 88 lbs of depleted uranium.

e) Maximum burn time for each test shall not exceed the lesser of eight hours per day or the number of hours necessary to be compliant with permit condition 1(b).

f) Wood used in conjunction with the sled track shall be clean wood in the form of hard lumber which has not been painted or treated and does not include wood waste or processed wood material such as plywood or particle board.

2. Emission Limits (20 NMAC 2.72, Sections 210.A and 210.B.1.b)

Table 2.1: Allowable Emissions

Unit No	TSP		PM10		NOx[1]		CO		VOCs		SO_x	
	pph	tpy[2]	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
ST-1	21.8	0.2	21.8	0.2	5.0	0.04	127.7	1.0	114.5	1.0	0.2	0.002

[1]Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO_2

[2]Annual emissions calculated based on the assumption that fire will last two hours instead of eight.

3. Monitoring Requirements
(20 NMAC 2.72, Section 210.B.4, 20 NMAC 2.72)

a) LANL shall monitor each sled track transportation accident scenario to ensure that associated open burning activities meet the requirements specified by this permit in condition 1 above.

4. Recordkeeping
(20 NMAC 2.72, Sections 210.B.4, and 210.D)

   a) LANL shall generate and maintain records necessary to demonstrate compliance with permit conditions 1(b) & (d-f).

5. Reporting
(20 NMAC 2.72 Sections 210.B and 210.E and 212)

   a) Concurrent with the semi-annual reports of its Title V permit, LANL shall submit a report of open burning activities authorized by this permit. The report shall include; the date of each open burn, type and quantities of materials burned, the time each burn was initiated, duration of each burn and the time when the burning was completed. LANL may include this information within one (1) report that includes other open burn sites.

   b) LANL shall notify NMED's Air Quality Bureau Enforcement Section in writing of the week open burning is scheduled to occur using the sled track no later than two weeks prior to the scheduled week. LANL shall provide a second written notification with the date and time open burning is scheduled to occur no later than forty-eight (48) hours prior to the burn. This will facilitate NMED's ability to conduct inspections to determine compliance with this permit.

6. Compliance Test
(NMAC 2.72, Section 210.C, 213)

   a) Initial compliance test are not required on Unit ST-1. Compliance test requirements from previous permits (in any) are still in effect, unless the tests have been satisfactorily completed. Compliance tests may be re-imposed if it is deemed necessary by the Department to determine whether the source is in compliance with applicable regulations or permit conditions.

cc: Section Chief, Compliance and Enforcement Section, A B, Santa Fe
Los Alamos NMED DOE Oversight Bureau

Enclosure: Industry/Consultant Feedback Questionnaire with envelope

Appendix D

Emissions Data

Data Disintegrator

S..URITY ENGINEERED MACHINERY

ENGINEERING REPORT

SEM Document Disintegrators with Waste Evacuation/Air Systems

This evaluation report is prepared as an outline of 'how' the disintegrator and waste collection units function and effectively provide a clean air environment to satisfy state and local requirements.

*****

The Document Destruction system is comprised of two basic units: (1) a mechanical cutting machine and (2) a Waste Evacuation/Air System.

The security disintegrator machine destroys paper, micrographics and other materials by a dry slicing and cutting process that leaves the end result in the shape of miniature confetti particles.

The Waste Evacuation system pulls the confetti waste particles through a security screen, located in the base of the machine. The confetti particles travel in an air stream via a rigid duct run, to a fan cyclone separator. The waste particles are then deposited into a waste container. The air system is supplied with a dust filter which exhausts clean filtered air. The optional air lock valve permits 'zero-pressure' discharge at the waste container, allowing waste particles to fall by gravity.

Since basis for concern of dust emission while using SEM Disintegrator systems is quite often brought up in discussion, the concern has been somewhat eased due to the fact that the waste materials and dust particles are traveling in a closed system/ductwork.

Engineers and consultants who have designed and installed the inter-connecting pneumatic/paper waste removal systems generally have been confident that these type of systems are in fact safe, due to the low concentration of materials in a rapidly moving air stream.

The after filters remove dust particles as small as 0.3 microns, returning clean air into the work area where permitted.

The cyclone efficiency is based on percentage and micron size as follows:

99%	-	20 microns
85%	-	10 microns
80%	-	9 microns
75%	-	8 microns ← Average
60%	-	7 microns
50%	-	6 microns
15%		2.5

The cloth tube filter efficiency is as follows:

99%	-	5 microns
98%	-	3 microns
97%	-	2 microns
93%	-	1 micron
90%	-	.6 micron
88%	-	.5 micron
85%	-	.4 micron
82%	-	.3 micron

95%

Most dust residue IS in the range of 5-20 microns. ∴ considering the upper range of efficiencies & taking an average to get 95%, this would be a conservative estimate

The cloth bag filter efficiency of F-type fan systems is approximately as follows:

N/A
(BAG TYPE)

99%	-	7 microns
98%	-	5 microns
91%	-	1 micron
85%	-	.5 micron

If you have any questions or need additional information, please contact us at 1-800-225-9293.

Very truly yours,

Lawrence W. Parker

Lawrence W. Parker
Engineering Manager

3/00 LWP

Notes: Leslie Martinez

1/16/03 - SEM 1800 308 9283 Paper Shredder.
-Mike Wakefield - Sales Rep. Model: 1424
→ Max. capacity not 2200 lbs/hr as shown on web due to lanl's requirements, a High Security Screen was purchased which reduces the capacity of the paper shredder.

* Optional features.
  - air lock valve
  - High Security Screen.
  - cloth-tube filter. FT40 - model.

→ w/ Regards to Exhaust Rate. & Particle distribution & Efficiency Mike referred me to the Engineers of these Systems.
Larry Parker / David LaFrances 1800 225 9293

Larry Parker, 1/16/03 SEM 1800-225-9293 Ext. 1040.
→ Exhaust Rate of 1200 cfm w/ a 7" duct.
- asked for pre & post air system emissions
- asked for Distribution of Efficiencies relative to PM.
- Air System is vented to Outdoors.

1-263-578 1/17/03 Ray Wakefield AGET Manufacturing - (cyclone/air Sys
10-15% of material shredded could potentially be emitted in an uncontrolled System (i.e. No Air System)

R

TA-3 Power Plant

1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

1.4.2 Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units.

Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some NO_x control options.

Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. CO_2[$lb/10^6$ scf] = (3.67) (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2×10^4 $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

1.3 Fuel Oil Combustion

1.3.1 General[1-3]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 being either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) may need to be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

1.3.2 Firing Practices[4]

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size. These factors can all strongly influence emissions as well as the potential for controlling emissions.

Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. In a watertube boiler, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes. The tube surfaces in the furnace (which houses the burner flame) absorb heat primarily by radiation from the flames. The tube surfaces in the boiler passes (adjacent to the primary furnace) absorb heat primarily by convective heat transfer.

Firetube boilers are used primarily for heating systems, industrial process steam generators, and portable power boilers. In firetube boilers, the hot combustion gases flow through the tubes while the water being heated circulates outside of the tubes. At high pressures and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers. This is because the high-pressure steam in firetube units is contained by the boiler walls rather than by multiple small-diameter watertubes, which are inherently stronger. As a consequence, firetube boilers are typically small and are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

A cast iron boiler is one in which combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low pressure steam or hot water, and generally burn oil or natural gas. They are used primarily in the residential and commercial sectors.

Another type of heat transfer configuration used on smaller boilers is the tubeless design. This design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filte
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emissio Factor (lb/10^3 ga
Boilers > 100 Million Btu/hr									
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.
No. 6 oil fired, normal firing, low NO_x burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3
No. 6 oil fired, tangential firing, low NO_x burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	C	24	D	5	A	2
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	A	10	D	5	A	2

Table 1.3-1. (cont.)

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
Boilers < 100 Million Btu/hr										
No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03)	157S	A	2S	A	55	A	5	A	10	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Distillate oil fired (1-02-005-02/03) (1-03-005-02/03)	142S	A	2S	A	20	A	5	A	2	A
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4[g]	B

[a] To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.120. SCC = Source Classification Code.

[b] References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[c] References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[d] References 6-7,15,19,22,56-62. Expressed as NO_2. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 $lb/10^3$ gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb $NO_2/10^3$ gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.

[e] References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[f] References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.

[g] Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 $lb/10^3$ gal.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION[a]

Firing Configuration[b] (SCC)	Controls	CPM - TOT[c,d]		CPM - IOR[c,d]		CPM - ORG[c,d]	
		Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	All controls, or uncontrolled	1.3[d,e]	D	65% of CPM-TOT emission factor[c]	D	35% of CPM-TOT emission factor[c]	D
No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01)	All controls, or uncontrolled	1.5[f]	D	85% of CPM-TOT emission factor[d]	E	15% of CPM-TOT emission factor[d]	E

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.
[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.
[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10^3 gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10^3 gal.
[e] References: 76-78.
[f] References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor (lb/10^3 gal)	Methane[b] Emission Factor (lb/10^3 gal)	NMTOC[b] Emission Factor (lb/10^3 gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code.

[b] References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-10. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^{12} Btu)										
	As	Be	Cd	Cr	Cu	Pb	Hg	Mn	Ni	Se	Zn
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	4	3	3	3	6	9	3	6	3	15	4

[a] Data are for distillate oil fired boilers, SCC codes 1-01-005-01, 1-02-005-01, and 1-03-005-01. References 29-32, 40-44 and 83. To convert from lb/10^{12} Btu to pg/J, multiply by 0.43.

Table 1.3-8. EMISSION FACTORS FOR NITROUS OXIDE (N_2O), POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^3 gal)		
	N_2O[b]	POM[c]	HCOH[c]
Utility/industrial/commercial boilers			
No. 6 oil fired (1-01-004-01, 1-02-004-01, 1-03-004-01)	0.11	0.0011 - 0.0013[d]	0.024 - 0.061
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.11	0.0033[e]	0.035 - 0.061
Residential furnaces (A2104004/A2104011)	0.05	ND	ND

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code. ND = no data.
[b] References 45-46. EMISSION FACTOR RATING = B.
[c] References 29-32.
[d] Particulate and gaseous POM.
[e] Particulate POM only.

3.1 Stationary Gas Turbines

3.1.1 General[1]

Gas turbines, also called "combustion turbines", are used in a broad scope of applications including electric power generation, cogeneration, natural gas transmission, and various process applications. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to over 268,000 hp, with an average size of 40,200 hp.[2] The primary fuels used in gas turbines are natural gas and distillate (No. 2) fuel oil.[3]

3.1.2 Process Description[1,2]

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that encircles the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate several can-shaped combustion chambers rather than a single continuous chamber. Annular and can-annular combustors are based on aircraft turbine technology and are typically used for smaller scale applications. A silo (frame-type) combustor has one or more combustion chambers mounted external to the gas turbine body. Silo combustors are typically larger than annular or can-annular combustors and are used for larger scale applications.

The combustion process in a gas turbine can be classified as diffusion flame combustion, or lean-premix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NO_X combustors. The majority of gas turbines currently manufactured are lean-premix staged combustion turbines.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at temperatures up to 2600°F. Energy from the hot exhaust gases, which expand in the power turbine section, are recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load.[2] Gas turbines may have one, two, or three shafts to transmit power between the inlet air compression turbine, the power turbine, and the exhaust turbine. The heat content of the exhaust gases exiting the turbine can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a] SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act.*

[b] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.

[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

[e] Benzene with SCONOX catalyst is 9.1 E-07, rating of D.

[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

SO-5130 – Carlyle Capital Markets Inc. - LANL – Expected Emissions Datasheets

From:	Neil Tyrrell	To:	Bill Blankenship [billx@lanl.gov]
Tel:	+1 740 393 8212	cc :	Mike Feree [mferree@starband.net]
Ref:	SO-5130		
Date:	November 6, 2003		

Assumptions

Description	RB211-6761
Combustor	DLE
HP6 Bleed	N/A
Project gas specification	See Right
Rating	Base Continous
AIT (Min / Design / Max)	-20 / 59 / 110 °F
Elevation	7387 ft a.s.l.
Relative Humidity	See below

Gas Fuel Specification

Nitrogen	0.612	% vol
Carbon Dioxide	0.375	% vol
Methane	94.09	% vol
Ethane	3.868	% vol
Propane	0.803	% vol
I Butane	-	% vol
N Butane	0.196	% vol
I Pentane	-	% vol
N Pentane	0.043	% vol
Hexane	0.01	% vol
Sulphur	0.0034	% vol
Fuel LHV	20970	BTU/lb
Fuel LHV	914.3 @ 77 F	BTU/scf
Fuel HHV	23,230	BTU/lb
Fuel HHV	1012.9 @ 77 F	BTU/scf

Based on the above assumptions, please find attached are the datasheets containing the expected emissions and brochure performance as per your request.

47.9°F AIT, 51% RH

Ambient Temperature	°F	47.9	47.9	47.9	47.9
Relative Humidity	%	51	51	51	51
% Load	%	100	90	80	75
Gross GenSet Power Output	kWe	24611	22150	19689	18459
Heat Rate (HHV)	BTU(HHV)/kWe.Hr	9686	9797	10024	10182
Fuel Consumption (HHV)	mmBTU(HHV)/hr	238.4	217.0	197.4	188.0
	mmSCF/hr	0.2283	0.2078	0.1890	0.1800
NOx @ 15% O2 Dry	vppm	25	25	25	25
CO @ 15% O2 Dry	vppm	25	49	161	290
UHC @ 15% O2 Dry	vppm	2.5	4.9	16.1	29.0
VOC @ 15% O2 Dry	vppm	0.3	0.5	1.6	2.9
SO2 @ 15% O2 Dry	vppm	1.0	1.0	1.0	1.0
NOx Measured	lb/hr	23.5	21.3	19.3	18.4
CO Measured Dry	lb/hr	14.0	25.3	76.0	129.7
UHC Measured Dry	lb/hr	0.8	1.4	4.3	7.4
VOC Measured Dry	lb/hr	0.1	0.1	0.4	0.7
SO2 Measured Dry	lb/hr	1.3	1.2	1.1	1.1
NOx Measured Dry	lb/mmSCF of fuel	102.9	102.5	102.1	102.2
CO Measured Dry	lb/mmSCF of fuel	61.3	121.7	402.0	720.4
UHC Measured Dry	lb/mmSCF of fuel	3.5	6.7	22.7	41.1
VOC Measured Dry	lb/mmSCF of fuel	0.4	0.5	2.1	3.9
SO2 Measured Dry	lb/mmSCF of fuel	5.8	5.7	5.7	5.9
Exhaust Nitrogen %	%Vol	75.08	75.21	75.32	75.37
Exhaust Oxygen %Vol	%Vol	13.827	14.21	14.515	14.66
Ex Carbon Dioxide %Vol	%Vol	3.244	3.0672	2.9263	2.8594
Ex Water Vapour %Vol	%Vol	6.949	6.609	6.337	6.208
Exhaust Argon %Vol	%Vol	0.8978	0.8994	0.9007	0.9013
Exhaust Neon %Vol	%Vol	0.0029	0.0029	0.0029	0.0029
Exhaust Mass Flow	lb/hr	578304	557460	532008	518724
Exhaust Temp	°F	938	898	872	862

TA-54 Soil Vapor Extraction

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DRE
REAL PROJECT SOLUTIONS®

Date: December 08, 2004

To:

Kristi Beguin
Ecologist
Science and Engineering Associates, Inc.
--a Subsidiary of Apogen Technologies--
505-661-0289
kristi.beguin@apogentech.com
1350 Central Ave. 3rd Floor
Los Alamos, NM 87544

From:

Michael J. Smith, Sr.
National Business Development Manager
Drewelow Remediation Equipment, Inc.
8509 Estrelita Drive
Las Vegas, Nevada 89128
Office: (702) 255-5933
Cell: (702) 526-3269
Fax: (702) 255-2261
Email: michaeljsmithsr@aol.com

Subject: Los Alamos, NM

Dear Ms. Beguin:

Based on the information you provided us, the DRE Real Project Solution® recommended for your project is our Model 100scfm Electric Catalytic Oxidizer equipped with a special Catalyst designed to treat Chlorinated and Fluorinated VOC Compounds. Since there are both chlorinated and fluorinated compounds in the process air stream the oxidation reaction across the catalyst will form HCl and HF from those compounds. Using the source concentration data, we calculated the number of moles of each chlorinated or fluorinated compound coming to the oxidizer. For each compound, the corresponding number of moles of either HCl or HF that would be produced is determined from the molecular formula. The sum of these individual calculations was then converted from molar units of measure to pounds/hr of HCl and HF.

Compound destruction efficiencies are developed based on the specifications provided by the catalyst manufacturer. The efficiencies reached are a product of the air flow through the catalyst and the amount of catalyst in the oxidizer. This ratio, known as the GHSV, is determined by the manufacturer through laboratory evaluation of the catalyst on the compounds in question. The process conditions were reviewed by the catalyst manufacturer and their recommendations regarding catalyst volume and operating temperatures are used by us when designing the oxidizer to meet the window of 95-99% destruction.

If you have any questions regarding this proposal please contact me at 702-255-5933.

Sincerely,

Michael J. Smith, Sr.

Michael J. Smith, Sr.
Business Development Manager
Drewelow Remediation Equipment, Inc.

Main Office
1523 Sterling Court
Escondido, CA 92029
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michaeljsmithsr@aol.com

TA-16 Flash Pad and TA-11 Test Site

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DPG Document No. DPG-TR-96-008b
April 1998

OPEN BURN/OPEN DETONATION DISPERSION MODEL (OBODM) USER'S GUIDE

Volume II. Technical Description

by

Jay R. Bjorklund[a], James F. Bowers[b]
Gregory C. Dodd[a] and John M. White[b]

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WEST DESERT TEST CENTER
U.S. ARMY DUGWAY PROVING GROUND
DUGWAY, UTAH 84022-5000

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SECTION 4. EMISSIONS FACTOR DATABASE

The OBODFUEL.OBD file contains a database of source information required by OBODM for 36 propellant, explosive, and pyrotechnic energetic fuels/ materials. For each fuel/material, the file contains a list of gases, volatile organic compounds, semivolatile organic compounds, and metals produced by open burning or open detonation. For each gas, compound, or metal, the file provides the molecular weight, density at 1 atmosphere and 20 °C, and emissions factor. As discussed below, the emissions factors were derived from OBOD experiments conducted at U.S. Army Dugway Proving Ground. The OBODM user can modify the OBODFUEL.OBD database file by entering updated emissions data or emissions data for new fuels or materials.

The emissions factors in the OBODFUEL.OBD file were developed from the emissions data in the 1997 OBOD Database Lite V1.2 program. The majority of the information in the 1997 Database Lite V1.2 comes from experiments in Dugway's BangBox™ facility in which small amounts of the fuel or material were burned or detonated, and the resulting gases, compounds, and metals were sampled and assayed to quantify the emissions. Limited data were also obtained from aircraft sampling of open air OBOD events during earlier OBOD programs at Dugway. Depending on the fuel/material and combustion product, the 1997 OBOD Database Lite V1.2 contains emissions factors for one to three trials. If emissions factors are available for only one trial, those emissions factors are provided in the OBODFUEL.OBD file. If emissions factors are available for two trials, OBODFUEL. OBD contains the highest emissions factor for each gas, compound, or metallic element as a safe-sided, "worst-case" estimate. If emissions factors are available for three trials, OBODFUEL.OBD contains the average emission factor for each combustion product. In some cases, two different sampling techniques were used for the same constituent. In these cases, OBODFUEL.OBD provides the highest of the average emissions factors obtained for that constituent using the two sampling methods. If a gas, compound, or metal was below the detection limit for all trials, that constituent is not included in the model database file.

The format of the OBODFUEL.OBD file is the MS-DOS text mode. The first line for each of the 36 propellant, explosive, and pyrotechnic energetic fuels and materials contains the name of the fuel/material, the estimated heat content and burn rate, and the number (N) of combustion products for which emissions data are provided. This line is followed by N lines, each listing the molecular weight, density, and emissions factors for one of the N products of combustion. Thus, OBODFUEL.OBD contains N+1 lines per propellant, explosive, or pyrotechnic energetic fuel or material. The effective heat contents and burn rates are not known for many materials. For those fuel/materials with unknown heat contents, OBODFUEL.OBD assigns a value of 1000 cal/g. This value should underestimate the actual heat release and buoyant rise for most fuels/materials, resulting in a tendency toward overestimation of maximum ground-level impacts. No burn rates are provided if the burn rate is not known. Also, in some cases the molecular weight and/or density could not be found and are not provided.

TNT (2,4,6-Trinitrotoluene)	925		1 49	
1,3-Butadiene	54.1	0.6211	0	1.70E-06*
1-Butene	56.1	0.5951	0	1.60E-06*
1-Hexane	86.2	0.6603	0	2.20E-06*
1-Pentene	70.1	0.6405	0	1.40E-06*
Acetylene	26.0	0.6181	0	1.70E-05*
Aluminum	27.0	2.7020	0	1.30E-03*
Antimony	121.8	6.6840	0	6.70E-07*
Barium	137.3	3.5100	0	8.20E-03*
Benzene	78.1	0.8787	0	4.10E-06*
CO	28.0	0.0013	0	1.00E-02*
CO2	44.0	0.0020	0	1.50E+00*
Cadmium	112.4	8.6420	0	4.00E-05*
Chromium	52.0	7.2000	0	2.30E-05*
Copper	63.5	8.9200	0	5.00E-04*
Cyclohexane	84.2	0.7781	0	1.60E-06*
Cyclopentane	70.1	0.7500	0	4.70E-07*
Cyclopentene	68.1	0.8000	0	4.60E-07*
Ethane	30.1	0.5720	0	7.40E-07*
Ethylbenzene	106.2	0.8670	0	4.70E-07*
Ethylene	28.1	0.0013	0	2.20E-05*
Lead	207.2	11.3437	0	9.00E-06*
Methylcyclohexane	98.2	0.0000	0	5.10E-06*
Methylcyclopentane	0.0	0.0000	0	7.00E-07*
Methylenechloride	84.9	1.3266	0	1.80E-04*
NO	30.0	0.0013	0	9.70E-03*
NO2	46.0	1.4494	9360	7.60E-04*
PM10	0.0	0.0000	0	9.30E-02*
Propane	44.1	0.5005	0	3.70E-07*
Propene	42.1	0.5193	0	7.20E-06*
RDX	222.1	1.8200	0	9.60E-06*
SO2	64.1	0.0029	0	1.40E-04*
Styrene	104.2	0.9060	0	1.50E-06*
Toluene	92.2	0.8669	0	5.10E-06*
Total Alkanes (Paraffins) (e.g. Octa	114.0	0.7030	0	8.60E-06*
Total Alkenes (Olefins) (e.g. Ethyle	62.0	0.9780	0	6.00E-05*
Total Aromatics (e.g. styrene)	104.2	0.9060	0	1.60E-05*
Total Non-methane Hydrocarbons	0.0	0.0000	0	4.00E-05*
Zinc	65.4	7.1400	0	1.00E-05*
cis-2-Pentene	70.1	0.6556	0	4.60E-07*
i-Butane	58.1	0.0000	0	4.60E-07*
i-Butene	56.1	0.0000	0	3.60E-06*
i-Pentane	72.2	0.0000	0	1.40E-06*
m-Ethyltoluene	135.2	0.9391	0	4.80E-07*
n-Heptane	100.2	0.6840	0	9.50E-07*
n-Hexane	86.1	0.6548	0	9.30E-07*
n-Octane	114.2	0.7025	0	2.90E-06*
n-Pentane	72.2	0.6262	0	3.30E-06*
trans-2-Butene	125.0	1.1830	0	9.50E-07*
trans-2-Pentene	84.2	0.6942	0	4.60E-07*
Composition B (56/38/6 HMX-TNT-WAX)	1319		1 37	
1-Butene	56.1	0.5951	0	1.30E-06*
1-Hexane	86.2	0.6603	0	1.60E-06*
Acetylene	26.0	0.6181	0	1.40E-05*
Benzene	78.1	0.8787	0	2.60E-06*
CO	28.0	0.0013	0	4.20E-03*
CO2	44.0	0.0020	0	1.10E+00*
Carbon Tetrachloride	153.8	1.5940	0	3.60E-07*
Ethane	30.1	0.5720	0	1.30E-06*
Ethylbenzene	106.2	0.8670	0	2.00E-06*
Ethylene	28.1	0.0013	0	1.40E-05*
Methylcyclohexane	98.2	0.0000	0	2.30E-06*
Methylcyclopentane	0.0	0.0000	0	3.60E-07*

1.3 Fuel Oil Combustion

1.3.1 General[1-3]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 being either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) may need to be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

1.3.2 Firing Practices[4]

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size. These factors can all strongly influence emissions as well as the potential for controlling emissions.

Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. In a watertube boiler, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes. The tube surfaces in the furnace (which houses the burner flame) absorb heat primarily by radiation from the flames. The tube surfaces in the boiler passes (adjacent to the primary furnace) absorb heat primarily by convective heat transfer.

Firetube boilers are used primarily for heating systems, industrial process steam generators, and portable power boilers. In firetube boilers, the hot combustion gases flow through the tubes while the water being heated circulates outside of the tubes. At high pressures and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers. This is because the high-pressure steam in firetube units is contained by the boiler walls rather than by multiple small-diameter watertubes, which are inherently stronger. As a consequence, firetube boilers are typically small and are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

A cast iron boiler is one in which combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low pressure steam or hot water, and generally burn oil or natural gas. They are used primarily in the residential and commercial sectors.

Another type of heat transfer configuration used on smaller boilers is the tubeless design. This design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
Boilers > 100 Million Btu/hr										
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, normal firing, low NO_x burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, low NO_x burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7	B
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	C	24	D	5	A	2	A
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	A	10	D	5	A	2	A

Table 1.3-1. (cont.)

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
Boilers < 100 Million Btu/hr										
No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03)	157S	A	2S	A	55	A	5	A	10	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Distillate oil fired (1-02-005-02/03) (1-03-005-02/03)	142S	A	2S	A	20	A	5	A	2	A
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4[g]	B

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.120. SCC = Source Classification Code.

[b] References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[c] References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[d] References 6-7,15,19,22,56-62. Expressed as NO_2. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 lb/10^3 gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO_2/10^3 gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.

[e] References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[f] References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.

[g] Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 lb/10^3 gal.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION[a]

Firing Configuration[b] (SCC)	Controls	CPM - TOT[c, d]		CPM - IOR[c, d]		CPM - ORG[c, d]	
		Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	All controls, or uncontrolled	1.3[d, e]	D	65% of CPM-TOT emission factor[c]	D	35% of CPM-TOT emission factor[c]	D
No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01)	All controls, or uncontrolled	1.5[f]	D	85% of CPM-TOT emission factor[d]	E	15% of CPM-TOT emission factor[d]	E

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.
[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.
[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10^3 gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10^3 gal.
[e] References: 76-78.
[f] References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor ($lb/10^3$ gal)	Methane[b] Emission Factor ($lb/10^3$ gal)	NMTOC[b] Emission Factor ($lb/10^3$ gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

[a] To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12. SCC = Source Classification Code.

[b] References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-8. EMISSION FACTORS FOR NITROUS OXIDE (N_2O), POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^3 gal)		
	N_2O[b]	POM[c]	HCOH[c]
Utility/industrial/commercial boilers			
No. 6 oil fired (1-01-004-01, 1-02-004-01, 1-03-004-01)	0.11	0.0011 - 0.0013[d]	0.024 - 0.061
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.11	0.0033[e]	0.035 - 0.061
Residential furnaces (A2104004/A2104011)	0.05	ND	ND

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code. ND = no data.
[b] References 45-46. EMISSION FACTOR RATING = B.
[c] References 29-32.
[d] Particulate and gaseous POM.
[e] Particulate POM only.

Table 1.3-10. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^{12} Btu)										
	As	Be	Cd	Cr	Cu	Pb	Hg	Mn	Ni	Se	Zn
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	4	3	3	3	6	9	3	6	3	15	4

[a] Data are for distillate oil fired boilers, SCC codes 1-01-005-01, 1-02-005-01, and 1-03-005-01. References 29-32, 40-44 and 83. To convert from lb/10^{12} Btu to pg/J, multiply by 0.43.

1.9 Residential Fireplaces

1.9.1 General[1-2]

Fireplaces are used primarily for aesthetic effects and secondarily as supplemental heating sources in houses and other dwellings. Wood is the most common fuel for fireplaces, but coal and densified wood "logs" may also be burned. The user intermittently adds fuel to the fire by hand. Fireplaces can be divided into 2 broad categories: (1) masonry (generally brick and/or stone, assembled on site, and integral to a structure) and (2) prefabricated (usually metal, installed on site as a package with appropriate duct work).

Masonry fireplaces typically have large fixed openings to the fire bed and have dampers above the combustion area in the chimney to limit room air and heat losses when the fireplace is not being used. Some masonry fireplaces are designed or retrofitted with doors and louvers to reduce the intake of combustion air during use.

Prefabricated fireplaces are commonly equipped with louvers and glass doors to reduce the intake of combustion air, and some are surrounded by ducts through which floor level air is drawn by natural convection, heated, and returned to the room. Many varieties of prefabricated fireplaces are now available on the market. One general class is the freestanding fireplace, the most common of which consists of an inverted sheet metal funnel and stovepipe directly above the fire bed. Another class is the "zero clearance" fireplace, an iron or heavy-gauge steel firebox lined inside with firebrick and surrounded by multiple steel walls with spaces for air circulation. Some zero clearance fireplaces can be inserted into existing masonry fireplace openings, and thus are sometimes called "inserts". Some of these units are equipped with close-fitting doors and have operating and combustion characteristics similar to wood stoves. (See Section 1.10, Residential Wood Stoves.)

Masonry fireplaces usually heat a room by radiation, with a significant fraction of the combustion heat lost in the exhaust gases and through fireplace walls. Moreover, some of the radiant heat entering the room goes toward warming the air that is pulled into the residence to make up for that drawn up the chimney. The net effect is that masonry fireplaces are usually inefficient heating devices. Indeed, in cases where combustion is poor, where the outside air is cold, or where the fire is allowed to smolder (thus drawing air into a residence without producing appreciable radiant heat energy), a net heat loss may occur in a residence using a fireplace. Fireplace heating efficiency may be improved by a number of measures that either reduce the excess air rate or transfer back into the residence some of the heat that would normally be lost in the exhaust gases or through fireplace walls. As noted above, such measures are commonly incorporated into prefabricated units. As a result, the energy efficiencies of prefabricated fireplaces are slightly higher than those of masonry fireplaces.

1.9.2 Emissions And Controls[1-13]

Fireplace emissions, caused mainly by incomplete combustion, include particulate matter (PM) (mainly PM less than 10 micrometers in diameter [PM-10]), carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), and volatile organic compounds (VOC). Significant quantities of unburnt combustibles are produced because fireplaces are inefficient combustion devices, with high uncontrolled excess air rates and without any sort of secondary combustion. The latter is especially important in wood burning because of its high volatile matter content, typically 80 percent by dry weight.

Table 1.9-1. EMISSION FACTORS FOR WOOD COMBUSTION IN RESIDENTIAL FIREPLACES[a]
(SCC 21-04-008-001)

Device	Pollutant	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Fireplace	PM-10[b]	34.6	B
	CO[c]	252.6	B
	SO_x[d]	0.4	A
	NO_x[e]	2.6	C
	N_2O[f]	0.3	E
	CO_2[g]	3400	C
	Total VOC[h]	229.0	D
	POM[j]	16 E-03	E
	Aldehydes[k,m]	2.4	E

[a] Units are in lb of pollutant/ton of dry wood burned. To convert lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code.
[b] References 2, 5, 7, 13; contains filterable and condensable PM; PM emissions are considered to be 100% PM-10.
[c] References 2, 4-6, 9, 11, 13.
[d] References 1, 8.
[e] References 4, 6, 9, 11; expressed as NO_2.
[f] Reference 21.
[g] References 5, 13.
[h] References 1, 4, 5. Data used to calculate the average emission factor were collected by various methods. While the emission factor may be representative of the source population in general, factors may not be accurate for individual sources.
[j] Reference 2.
[k] Data used to calculate the average emission factor were collected from a single fireplace and are not representative of the general source population.
[m] References 4, 11.

References For Section 1.9

1. DeAngelis, D. G., *et al., Source Assessment: Residential Combustion Of Wood,* EPA-600/2-80-042b, U. S. Environmental Protection Agency, Cincinnati, OH, March 1980.

2. Snowden, W. D., *et al., Source Sampling Residential Fireplaces For Emission Factor Development*, EPA-450/3-76-010, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1975.

3. Shelton, J. W., and L. Gay, *Colorado Fireplace Report*, Colorado Air Pollution Control Division, Denver, CO, March 1987.

4. Dasch, J. M., "Particulate And Gaseous Emissions From Wood-burning Fireplaces", *Environmental Science And Technology, 16*(10):643-67, October 1982.

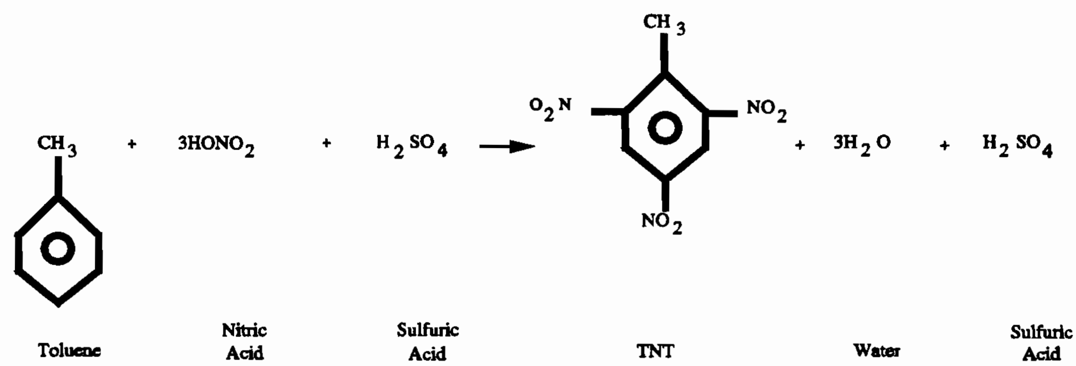
6.3 Explosives

6.3.1 General[1]

An explosive is a material that, under the influence of thermal or mechanical shock, decomposes rapidly and spontaneously with the evolution of large amounts of heat and gas. There are two major categories, high explosives and low explosives. High explosives are further divided into initiating, or primary, high explosives and secondary high explosives. Initiating high explosives are very sensitive and are generally used in small quantities in detonators and percussion caps to set off larger quantities of secondary high explosives. Secondary high explosives, chiefly nitrates, nitro compounds, and nitramines, are much less sensitive to mechanical or thermal shock, but they explode with great violence when set off by an initiating explosive. The chief secondary high explosives manufactured for commercial and military use are ammonium nitrate blasting agents and 2,4,6,-trinitrotoluene (TNT). Low explosives, such as black powder and nitrocellulose, undergo relatively slow autocombustion when set off and evolve large volumes of gas in a definite and controllable manner. Many different types of explosives are manufactured. As examples of high and low explosives, the production of TNT and nitrocellulose (NC) are discussed below.

6.3.2 TNT Production[1-3,6]

TNT may be prepared by either a continuous or a batch process, using toluene, nitric acid (HNO_3) and sulfuric acid as raw materials. The production of TNT follows the same chemical process, regardless of whether batch or continuous method is used. The flow chart for TNT production is shown in Figure 6.3-1. The overall chemical reaction may be expressed as:



The production of TNT by nitration of toluene is a 3-stage process performed in a series of reactors, as shown in Figure 6.3-2. The mixed acid stream is shown to flow countercurrent to the flow of the organic stream. Toluene and spent acid fortified with a 60 percent HNO_3 solution are fed into the first reactor. The organic layer formed in the first reactor is pumped into the second reactor, where it is subjected to further nitration with acid from the third reactor fortified with additional HNO_3. The product from the second nitration step, a mixture of all possible isomers of dinitrotoluene (DNT), is pumped to the third reactor. In the final reaction, the DNT is treated with a fresh feed of nitric acid and oleum (a solution of sulfur trioxide [SO_3] in anhydrous sulfuric acid). The crude TNT from this third nitration consists primarily of 2,4,6-trinitrotoluene. The crude TNT is washed to remove free acid, and the wash water (yellow water) is recycled to the early nitration stages. The washed TNT is then neutralized with soda ash and treated with a 16 percent aqueous sodium sulfite (Sellite) solution to remove contaminating isomers. The Sellite waste solution (red water) from the purification process is discharged directly as a liquid waste stream, is collected and sold, or is concentrated to a slurry and incinerated. Finally, the TNT crystals are melted and passed through hot air dryers, where most of the water is evaporated. The dehydrated product is solidified, and the TNT flakes packaged for transfer to a storage or loading area.

6.3.3 Nitrocellulose Production[1,6]

Nitrocellulose is commonly prepared by the batch-type mechanical dipper process. A newly developed continuous nitration processing method is also being used. In batch production, cellulose in the form of cotton linters, fibers, or specially prepared wood pulp is purified by boiling and bleaching. The dry and purified cotton linters or wood pulp are added to mixed nitric and sulfuric acid in metal reaction vessels known as dipping pots. The reaction is represented by:

$$\underset{\text{Cellulose}}{(C_6H_7O_2(OH)_3)_x} + \underset{\text{Nitric Acid}}{3HONO_2} + \underset{\text{Sulfuric Acid}}{H_2SO_4} \longrightarrow \underset{\text{Nitrocellulose}}{(C_6H_7O_2(ONO_2)_3)_x} + \underset{\text{Water}}{3H_2O} + \underset{\text{Sulfuric Acid}}{H_2SO_4}$$

Following nitration, the crude NC is centrifuged to remove most of the spent nitrating acids and is put through a series of water washing and boiling treatments to purify the final product.

6.3.4 Emissions And Controls[2-3,5-7]

Oxides of nitrogen (NO_x) and sulfur (SO_x) are the major emissions from the processes involving the manufacture, concentration, and recovery of acids in the nitration process of explosives manufacturing. Emissions from the manufacture of nitric and sulfuric acid are discussed in other sections. Trinitromethane (TNM) is a gaseous byproduct of the nitration process of TNT manufacture. Volatile organic compound (VOC) emissions result primarily from fugitive vapors from various solvent recovery operations. Explosive wastes and contaminated packaging material are regularly disposed of by open burning, and such results in uncontrolled emissions, mainly of NO_x and particulate matter. Experimental burns of several explosives to determine "typical" emission factors for the open burning of TNT are presented in Table 6.3-1.

Table 6.3-1 (English Units). EMISSION FACTORS FOR THE OPEN BURNING OF TNT[a,b]
(lb pollution/ton TNT burned)

Type Of Explosive	Particulates	Nitrogen Oxides	Carbon Monoxide	Volatile Organic Compounds
TNT	180.0	150.0	56.0	1.1

[a] Reference 7. Particulate emissions are soot. VOC is nonmethane.
[b] The burns were made on very small quantities of TNT, with test apparatus designed to simulate open burning conditions. Since such test simulations can never replicate actual open burning, it is advisable to use the factors in this Table with caution.

TA-36 Sled Track

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OPEN BURN/OPEN DETONATION DISPERSION MODEL (OBODM) USER'S GUIDE

Volume II. Technical Description

by

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SECTION 4. EMISSIONS FACTOR DATABASE

The OBODFUEL.OBD file contains a database of source information required by OBODM for 36 propellant, explosive, and pyrotechnic energetic fuels/ materials. For each fuel/material, the file contains a list of gases, volatile organic compounds, semivolatile organic compounds, and metals produced by open burning or open detonation. For each gas, compound, or metal, the file provides the molecular weight, density at 1 atmosphere and 20 °C, and emissions factor. As discussed below, the emissions factors were derived from OBOD experiments conducted at U.S. Army Dugway Proving Ground. The OBODM user can modify the OBODFUEL.OBD database file by entering updated emissions data or emissions data for new fuels or materials.

The emissions factors in the OBODFUEL.OBD file were developed from the emissions data in the 1997 OBOD Database Lite V1.2 program. The majority of the information in the 1997 Database Lite V1.2 comes from experiments in Dugway's BangBox™ facility in which small amounts of the fuel or material were burned or detonated, and the resulting gases, compounds, and metals were sampled and assayed to quantify the emissions. Limited data were also obtained from aircraft sampling of open air OBOD events during earlier OBOD programs at Dugway. Depending on the fuel/material and combustion product, the 1997 OBOD Database Lite V1.2 contains emissions factors for one to three trials. If emissions factors are available for only one trial, those emissions factors are provided in the OBODFUEL.OBD file. If emissions factors are available for two trials, OBODFUEL. OBD contains the highest emissions factor for each gas, compound, or metallic element as a safe-sided, "worst-case" estimate. If emissions factors are available for three trials, OBODFUEL.OBD contains the average emission factor for each combustion product. In some cases, two different sampling techniques were used for the same constituent. In these cases, OBODFUEL.OBD provides the highest of the average emissions factors obtained for that constituent using the two sampling methods. If a gas, compound, or metal was below the detection limit for all trials, that constituent is not included in the model database file.

The format of the OBODFUEL.OBD file is the MS-DOS text mode. The first line for each of the 36 propellant, explosive, and pyrotechnic energetic fuels and materials contains the name of the fuel/material, the estimated heat content and burn rate, and the number (N) of combustion products for which emissions data are provided. This line is followed by N lines, each listing the molecular weight, density, and emissions factors for one of the N products of combustion. Thus, OBODFUEL.OBD contains N+1 lines per propellant, explosive, or pyrotechnic energetic fuel or material. The effective heat contents and burn rates are not known for many materials. For those fuel/materials with unknown heat contents, OBODFUEL.OBD assigns a value of 1000 cal/g. This value should underestimate the actual heat release and buoyant rise for most fuels/materials, resulting in a tendency toward overestimation of maximum ground-level impacts. No burn rates are provided if the burn rate is not known. Also, in some cases the molecular weight and/or

TNT (2,4,6-Trinitrotoluene)	925		1 49	
1,3-Butadiene	54.1	0.6211	0	1.70E-06*
1-Butene	56.1	0.5951	0	1.60E-06*
1-Hexane	86.2	0.6603	0	2.20E-06*
1-Pentene	70.1	0.6405	0	1.40E-06*
Acetylene	26.0	0.6181	0	1.70E-05*
Aluminum	27.0	2.7020	0	1.30E-03*
Antimony	121.8	6.6840	0	6.70E-07*
Barium	137.3	3.5100	0	8.20E-03*
Benzene	78.1	0.8787	0	4.10E-06*
CO	28.0	0.0013	0	1.00E-02*
CO2	44.0	0.0020	0	1.50E+00*
Cadmium	112.4	8.6420	0	4.00E-05*
Chromium	52.0	7.2000	0	2.30E-05*
Copper	63.5	8.9200	0	5.00E-04*
Cyclohexane	84.2	0.7781	0	1.60E-06*
Cyclopentane	70.1	0.7500	0	4.70E-07*
Cyclopentene	68.1	0.8000	0	4.60E-07*
Ethane	30.1	0.5720	0	7.40E-07*
Ethylbenzene	106.2	0.8670	0	4.70E-07*
Ethylene	28.1	0.0013	0	2.20E-05*
Lead	207.2	11.3437	0	9.00E-06*
Methylcyclohexane	98.2	0.0000	0	5.10E-06*
Methylcyclopentane	0.0	0.0000	0	7.00E-07*
Methylenechloride	84.9	1.3266	0	1.80E-04*
NO	30.0	0.0013	0	9.70E-03*
NO2	46.0	1.4494	9360	7.60E-04*
PM10	0.0	0.0000	0	9.30E-02*
Propane	44.1	0.5005	0	3.70E-07*
Propene	42.1	0.5193	0	7.20E-06*
RDX	222.1	1.8200	0	9.60E-06*
SO2	64.1	0.0029	0	1.40E-04*
Styrene	104.2	0.9060	0	1.50E-06*
Toluene	92.2	0.8669	0	5.10E-06*
Total Alkanes (Paraffins) (e.g. Octa	114.0	0.7030	0	8.60E-06*
Total Alkenes (Olefins) (e.g. Ethyle	62.0	0.9780	0	6.00E-05*
Total Aromatics (e.g. styrene)	104.2	0.9060	0	1.60E-05*
Total Non-methane Hydrocarbons	0.0	0.0000	0	4.00E-05*
Zinc	65.4	7.1400	0	1.00E-05*
cis-2-Pentene	70.1	0.6556	0	4.60E-07*
i-Butane	58.1	0.0000	0	4.60E-07*
i-Butene	56.1	0.0000	0	3.60E-06*
i-Pentane	72.2	0.0000	0	1.40E-06*
m-Ethyltoluene	135.2	0.9391	0	4.80E-07*
n-Heptane	100.2	0.6840	0	9.50E-07*
n-Hexane	86.1	0.6548	0	9.30E-07*
n-Octane	114.2	0.7025	0	2.90E-06*
n-Pentane	72.2	0.6262	0	3.30E-06*
trans-2-Butene	125.0	1.1830	0	9.50E-07*
trans-2-Pentene	84.2	0.6942	0	4.60E-07*
Composition B (56/38/6 RDX-TNT-WAX)	1319		1 37	
1-Butene	56.1	0.5951	0	1.30E-06*
1-Hexane	86.2	0.6603	0	1.60E-06*
Acetylene	26.0	0.6181	0	1.40E-05*
Benzene	78.1	0.8787	0	2.60E-06*
CO	28.0	0.0013	0	4.20E-03*
CO2	44.0	0.0020	0	1.10E+00*
Carbon Tetrachloride	153.8	1.5940	0	3.60E-07*
Ethane	30.1	0.5720	0	1.30E-06*
Ethylbenzene	106.2	0.8670	0	2.00E-06*
Ethylene	28.1	0.0013	0	1.40E-05*
Methylcyclohexane	98.2	0.0000	0	2.30E-06*
Methylcyclopentane	0.0	0.0000	0	3.60E-07*

1.9 Residential Fireplaces

1.9.1 General[1-2]

Fireplaces are used primarily for aesthetic effects and secondarily as supplemental heating sources in houses and other dwellings. Wood is the most common fuel for fireplaces, but coal and densified wood "logs" may also be burned. The user intermittently adds fuel to the fire by hand. Fireplaces can be divided into 2 broad categories: (1) masonry (generally brick and/or stone, assembled on site, and integral to a structure) and (2) prefabricated (usually metal, installed on site as a package with appropriate duct work).

Masonry fireplaces typically have large fixed openings to the fire bed and have dampers above the combustion area in the chimney to limit room air and heat losses when the fireplace is not being used. Some masonry fireplaces are designed or retrofitted with doors and louvers to reduce the intake of combustion air during use.

Prefabricated fireplaces are commonly equipped with louvers and glass doors to reduce the intake of combustion air, and some are surrounded by ducts through which floor level air is drawn by natural convection, heated, and returned to the room. Many varieties of prefabricated fireplaces are now available on the market. One general class is the freestanding fireplace, the most common of which consists of an inverted sheet metal funnel and stovepipe directly above the fire bed. Another class is the "zero clearance" fireplace, an iron or heavy-gauge steel firebox lined inside with firebrick and surrounded by multiple steel walls with spaces for air circulation. Some zero clearance fireplaces can be inserted into existing masonry fireplace openings, and thus are sometimes called "inserts". Some of these units are equipped with close-fitting doors and have operating and combustion characteristics similar to wood stoves. (See Section 1.10, Residential Wood Stoves.)

Masonry fireplaces usually heat a room by radiation, with a significant fraction of the combustion heat lost in the exhaust gases and through fireplace walls. Moreover, some of the radiant heat entering the room goes toward warming the air that is pulled into the residence to make up for that drawn up the chimney. The net effect is that masonry fireplaces are usually inefficient heating devices. Indeed, in cases where combustion is poor, where the outside air is cold, or where the fire is allowed to smolder (thus drawing air into a residence without producing appreciable radiant heat energy), a net heat loss may occur in a residence using a fireplace. Fireplace heating efficiency may be improved by a number of measures that either reduce the excess air rate or transfer back into the residence some of the heat that would normally be lost in the exhaust gases or through fireplace walls. As noted above, such measures are commonly incorporated into prefabricated units. As a result, the energy efficiencies of prefabricated fireplaces are slightly higher than those of masonry fireplaces.

1.9.2 Emissions And Controls[1-13]

Fireplace emissions, caused mainly by incomplete combustion, include particulate matter (PM) (mainly PM less than 10 micrometers in diameter [PM-10]), carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), and volatile organic compounds (VOC). Significant quantities of unburnt combustibles are produced because fireplaces are inefficient combustion devices, with high uncontrolled excess air rates and without any sort of secondary combustion. The latter is especially important in wood burning because of its high volatile matter content, typically 80 percent by dry weight.

Table 1.9-1. EMISSION FACTORS FOR WOOD COMBUSTION IN RESIDENTIAL FIREPLACES[a]
(SCC 21-04-008-001)

Device	Pollutant	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Fireplace	PM-10[b]	34.6	B
	CO[c]	252.6	B
	SO_x[d]	0.4	A
	NO_x[e]	2.6	C
	N_2O[f]	0.3	E
	CO_2[g]	3400	C
	Total VOC[h]	229.0	D
	POM[j]	16 E-03	E
	Aldehydes[k,m]	2.4	E

[a] Units are in lb of pollutant/ton of dry wood burned. To convert lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code.

[b] References 2, 5, 7, 13; contains filterable and condensable PM; PM emissions are considered to be 100% PM-10.

[c] References 2, 4-6, 9, 11, 13.

[d] References 1, 8.

[e] References 4, 6, 9, 11; expressed as NO_2.

[f] Reference 21.

[g] References 5, 13.

[h] References 1, 4, 5. Data used to calculate the average emission factor were collected by various methods. While the emission factor may be representative of the source population in general, factors may not be accurate for individual sources.

[j] Reference 2.

[k] Data used to calculate the average emission factor were collected from a single fireplace and are not representative of the general source population.

[m] References 4, 11.

References For Section 1.9

1. DeAngelis, D. G., *et al.*, *Source Assessment: Residential Combustion Of Wood*, EPA-600/2-80-042b, U. S. Environmental Protection Agency, Cincinnati, OH, March 1980.

2. Snowden, W. D., *et al.*, *Source Sampling Residential Fireplaces For Emission Factor Development*, EPA-450/3-76-010, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1975.

3. Shelton, J. W., and L. Gay, *Colorado Fireplace Report*, Colorado Air Pollution Control Division, Denver, CO, March 1987.

4. Dasch, J. M., "Particulate And Gaseous Emissions From Wood-burning Fireplaces", *Environmental Science And Technology, 16*(10):643-67, October 1982.

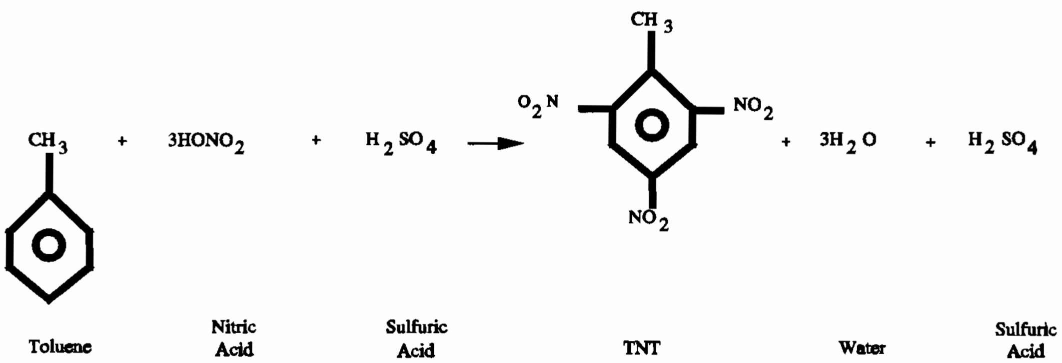
6.3 Explosives

6.3.1 General[1]

An explosive is a material that, under the influence of thermal or mechanical shock, decomposes rapidly and spontaneously with the evolution of large amounts of heat and gas. There are two major categories, high explosives and low explosives. High explosives are further divided into initiating, or primary, high explosives and secondary high explosives. Initiating high explosives are very sensitive and are generally used in small quantities in detonators and percussion caps to set off larger quantities of secondary high explosives. Secondary high explosives, chiefly nitrates, nitro compounds, and nitramines, are much less sensitive to mechanical or thermal shock, but they explode with great violence when set off by an initiating explosive. The chief secondary high explosives manufactured for commercial and military use are ammonium nitrate blasting agents and 2,4,6,-trinitrotoluene (TNT). Low explosives, such as black powder and nitrocellulose, undergo relatively slow autocombustion when set off and evolve large volumes of gas in a definite and controllable manner. Many different types of explosives are manufactured. As examples of high and low explosives, the production of TNT and nitrocellulose (NC) are discussed below.

6.3.2 TNT Production[1-3,6]

TNT may be prepared by either a continuous or a batch process, using toluene, nitric acid (HNO_3) and sulfuric acid as raw materials. The production of TNT follows the same chemical process, regardless of whether batch or continuous method is used. The flow chart for TNT production is shown in Figure 6.3-1. The overall chemical reaction may be expressed as:



The production of TNT by nitration of toluene is a 3-stage process performed in a series of reactors, as shown in Figure 6.3-2. The mixed acid stream is shown to flow countercurrent to the flow of the organic stream. Toluene and spent acid fortified with a 60 percent HNO_3 solution are fed into the first reactor. The organic layer formed in the first reactor is pumped into the second reactor, where it is subjected to further nitration with acid from the third reactor fortified with additional HNO_3. The product from the second nitration step, a mixture of all possible isomers of dinitrotoluene (DNT), is pumped to the third reactor. In the final reaction, the DNT is treated with a fresh feed of nitric acid and oleum (a solution of sulfur trioxide [SO_3] in anhydrous sulfuric acid). The crude TNT from this third nitration consists primarily of 2,4,6-trinitrotoluene. The crude TNT is washed to remove free acid, and the wash water (yellow water) is recycled to the early nitration stages. The washed TNT is