Curia New Mexico, LLC
4401 Alexander Blvd. NE
Albuquerque, NM 87107

Air Permit Modification Application to Install a Diesel-Fired Emergency Generator and a Natural Gas-Fired Boiler

Construction Permit No. 1097-M3-2AR

22 March 2023

Project No.: 0654619

RECEIVED March 30, 2023
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Table of Contents

Attachment 1

Completed Permit Application Checklist

City of Albuquerque
Environmental Health Department
Air Quality Program

Construction Permit (20.11.41 NMAC)
Application Checklist

This checklist must be returned with the application

Any person seeking a new air quality permit, a permit modification, or an emergency permit under 20.11.41 NMAC (Construction Permits) shall do so by filing a written application with the Albuquerque-Bernalillo County Joint Air Quality Program, which administers and enforces local air quality laws for the City of Albuquerque ("City") and Bernalillo County ("County"), on behalf of the City Environmental Health Department ("Department").

The Department will rule an application administratively incomplete if it is missing or has incorrect information. The Department may require additional information that is necessary to make a thorough review of an application, including but not limited to technical clarifications, emission calculations, emission factor usage, additional application review fees if any are required by 20.11.2 NMAC, and new or additional air dispersion modeling.

If the Department has ruled an application administratively incomplete three (3) times, the Department will deny the permit application. Any fees submitted for processing an application that has been denied will not be refunded. If the Department denies an application, a person may submit a new application and the fee required for a new application. The applicant has the burden of demonstrating that a permit should be issued.

The following are the minimum elements that shall be included in the permit application before the Department can determine whether an application is administratively complete and ready for technical review. It is not necessary to include an element if the Department has issued a written waiver regarding the element and the waiver accompanies the application. However, the Department shall not waive any federal requirements.

At all times before the Department has made a final decision regarding the application, an applicant has a duty to promptly supplement and correct information the applicant has submitted in an application to the Department. The applicant's duty to supplement and correct the application includes but is not limited to relevant information acquired after the applicant has submitted the application and additional information the applicant otherwise determines is relevant to the application and the Department's review and decision. While the Department is processing an application, regardless of whether the Department has determined the application is administratively complete, if the Department determines that additional information is necessary to evaluate or make a final decision regarding the application, the Department may request additional information and the applicant shall provide the requested additional information.

NOTICE REGARDING PERMIT APPEALS: A person who has applied for or has been issued an air quality permit by the Department shall be an obligatory party to a permit appeal filed pursuant to 20.11.81 NMAC.

NOTICE REGARDING SCOPE OF A PERMIT: The Department's issuance of an air quality permit only authorizes the use of the specified equipment pursuant to the air quality control laws, regulations and conditions. Permits relate to air quality control only and are issued for the sole purpose of regulating the emission of air contaminants from said equipment. Air quality permits are not a general authorization for the location, construction and/or operation of a facility, nor does a permit authorize any particular land use or other form of land entitlement. It is the applicant's/permittee's responsibility to obtain all other necessary permits from the appropriate agencies, such as the City Planning Department or County Department of Planning and Development Services, including but not limited to site plan approvals, building permits, fire department approvals and the like, as may be required by law for the location, construction and/or operation of a facility. For more information, please visit the City Planning Department website at https://www.cabq.gov/planning and the County Department of Planning and Development Services website at https://www.bernco.gov/planning.

The Applicant shall:

20.11.41.13(A) NMAC – Pre-Application Requirements:

Item	Completed	NA[1]	Waived[2]
(1) Request a pre-application meeting with the Department using the pre-application meeting request form.	☒	☐	☐
(2) Attend the pre-application meeting. Date of Pre-application meeting: 10/20/22	☒	☐	☐

1. *Not Applicable*
2. *It is not necessary to include an element if the Department has issued a written waiver regarding the element and the waiver accompanies the application. However, the Department shall not waive any federal requirements.*

20.11.41.13(B) NMAC – Applicant's Public Notice Requirements:

Item	Included in Application	NA[1]	Waived[2]
(1) Provide public notice in accordance with the regulation, including by certified mail or electronic copy to the designated representative(s) of the recognized neighborhood associations and recognized coalitions that are within one-half mile of the exterior boundaries of the property on which the source is or is proposed to be located.	☒	☐	☐
• Contact list of representative(s) of neighborhood associations and recognized coalitions cannot be more than three months old from the application submittal date.	☒	☐	☐
• Provide notice using the Notice of Intent to Construct form.	☒	☐	☐
(2) In accordance with the regulation, post and maintain in a visible location a weather proof sign provided by the Department.	☒	☐	☐

1. *Not Applicable; For emergency permits, the public notice requirements in 20.11.41.24 NMAC shall apply instead.*
2. *It is not necessary to include an element if the Department has issued a written waiver regarding the element and the waiver accompanies the application. However, the Department shall not waive any federal requirements.*

The Permit Application shall include:

20.11.41.13(E) NMAC – Application Contents

Item	Included In Application	NA[1]	Waived[2]
(1) A complete permit application on the most recent form provided by the Department.	☒	☐	☐
(2) The application form includes:			
a. The owner's name, street and post office address, and contact information;	☒	☐	☐
b. The facility/ operator's name, street address and mailing address, if different from the owner;	☒	☐	☐
c. The consultant's name, and contact information, if applicable;	☒	☐	☐
d. All information requested on the application form is included (*i.e.*, the form is complete).	☒	☐	☐
(3) Date application is submitted.	☒	☐	☐
(4) Sufficient attachments for the following:			
a. Ambient impact analysis using an atmospheric dispersion model approved by the U.S. Environmental Protection Agency, and the Department to demonstrate compliance with the applicable ambient air quality standards. *See* 20.11.01 NMAC. If you are modifying an existing source, the modeling must include the	☒	☐	☐

Item	Included In Application	NA[1]	Waived[2]
emissions of the entire source to demonstrate the impact the new or modified source(s) will have on existing plant emissions.			
b. The air dispersion model has been executed pursuant to a protocol that was approved in advance by the Department.	☒	☐	☐
c. Air dispersion modeling approved protocol date: 12/23/22	☒	☐	☐
d. Basis or source for each emission rate (including manufacturer's specification sheet, AP-42 section sheets, test data, or corresponding supporting documentation for any other source used).	☒	☐	☐
e. All calculations used to estimate potential emission rates and controlled/proposed emissions.	☒	☐	☐
f. Basis for the estimated control efficiencies and sufficient engineering data for verification of the control equipment operation, including if necessary, design, drawing, test report and factors which affect the normal operation.	☒	☐	☐
g. Fuel data for each existing and/or proposed piece of fuel burning equipment.	☒	☐	☐
h. Anticipated maximum production capacity of the entire facility and the requested production capacity after construction and/or modification.	☒	☐	☐
i. Stack and exhaust gas parameters for all existing and proposed emission stacks.	☒	☐	☐
(5) An operational and maintenance strategy detailing:	☒	☐	☐
a. steps the applicant will take if a malfunction occurs that may cause emission of a regulated air contaminant to exceed a limit that is included in the permit;	☒	☐	☐
b. the nature of emission during routine startup or shutdown of the source and the source's air pollution control equipment; and	☒	☐	☐
c. the steps the application will take to minimize emissions during routine startup or shutdown.	☒	☐	☐
(6) A map, such as a 7.5'-topographic quadrangle map published by the U.S. Geological Survey or a map of equivalent or greater scale, detail, and precision, including a City or County zone atlas map that shows the proposed location of each process equipment unit involved in the proposed construction, modification, or operation of the source, as applicable.	☒	☐	☐
(7) An aerial photograph showing the proposed location of each process equipment unit involved in the proposed construction, modification, relocation or technical revision of the source except for federal agencies or departments involved in national defense or national security as confirmed and agreed by the Department in writing.	☒	☐	☐
(8) A complete description of all sources of regulated air contaminants and a process flow diagram depicting the process equipment unit or units at the facility, both existing and proposed, that are proposed to be involved in routine operations and from which regulated air contaminant emissions are expected to be emitted.	☒	☐	☐
(9) A full description of air pollution control equipment, including all calculations and the basis for all control efficiencies presented, manufacturer's specifications sheets, and site layout and assembly drawings; UTM (universal transverse mercator) coordinates shall be used to identify the location of each emission unit.	☒	☐	☐
(10) A description of the equipment or methods proposed by the applicant to be used for emission measurement.	☒	☐	☐
(11) The maximum and normal operating time schedules of the source after completion of construction or modification, as applicable.	☒	☐	☐
(12) Any other relevant information as the Department may reasonably require, including without limitation:	☒	☐	☐
a. Applicants shall provide documentary proof that the proposed air quality permitted use of the facility's subject property is allowed by the zoning designation of the City or County zoning laws, as applicable. Sufficient documentation includes: (i) a zoning certification from the City Planning Department or County Department of Planning and Development Services, as applicable, if the property is subject to City or County zoning jurisdiction; or (ii) a zoning verification from both planning	☒	☐	☐

Item	Included In Application	NA[1]	Waived[2]
departments if the property is not subject to City or County zoning jurisdiction.[3] A zone atlas map shall not be sufficient.			
(13) The signature of the applicant, operator, owner or an authorized representative, certifying to the accuracy of all information as represented in the application and attachments, if any.	☒	☐	☐
(14) A check or money order for the appropriate application fee or fees required by 20.11.2 NMAC (Fees).	☒	☐	☐

1. *Not Applicable*
2. *It is not necessary to include an element if the Department has issued a written waiver regarding the element and the waiver accompanies the application. However, the Department shall not waive any federal requirements.*
3. *For emergency permit applications, applicants are not required to submit documentation for the subject property's zoning designation.*

Attachment 2

Pre-Permit Application Meeting Request Form

Pre-Permit Application Meeting Request Form

Air Quality Program- Environmental Health Department

Please complete appropriate boxes and email to aqd@cabq.gov or mail to:

Environmental Health Department
Air Quality Program
P.O. Box 1293
Room 3047
Albuquerque, NM 87103

Name:	Kurt Parker (ERM-West, Inc)
Company / Organization	Curia New Mexico, LLC
Point of Contact (phone # of email)	Phone: 720-200-7156
Preferred form of Contact (Circle One):	kurt.parker@erm.com
Preferred Meeting date/time	October 11 (0800-0900 or 1300-1400), October 12, 2022 (0800 - 1000)

Description of Project:

Curia New Mexico, located 4401 Alexander Blvd, is in the final design of a 60,000 square foot expansion that will include the addition of a new advanced isolated high-speed, fill-finish vial line. The current operation is managed under air quality minor construction permit #1007-M3-1TR.

With this expansion, Curia plans to install a ~16.7 MMBtu natural gas fired steam packaged firetube boiler that will support process heating and comfort that will be permitted as part of the overall expansion. In addition, to the boiler, a Cummings 1750 kW diesel fired EPA NSPS Tier 2 Stationary Emergency Generator will be instated to support backup power, when required. The standby generator will be requested to be permitted under a 500 hour per annum operation limitation.

Curia is requesting to modify the current construction permit to support the addition of the 1750 kW generator. Further Curia is requesting the 16.7 MMBtu boiler be managed under a separate permit. Basic information on the Boiler and Generator are provided. Spec's are based on proposed suppliers and may be subject to change.

Boiler:
Johnson Boiler Co.
Steam Packaged Firetube Boiler
Model PFTA 400-4
Boiler Hp - 400 Hp

Burner
Industrial Combustion
Burner size (168) – 16,700 MBTU/hr
Burner Config . Ultra-Low-NOx Configuration
NT series (NG @ 3% O_2) - < 9 ppm NOx

Generator:
Power Generation 1750DQKAD
Standby – 1750 kW
Engine Model - QSK60-G6 NR2
EPA Tier 2 ; EPA-1164

Attachment 3

Completed Pre-Permit Application Meeting Checklist

City of Albuquerque

Environmental Health Department
Air Quality Program

Pre-Permit Application Meeting Checklist

Any person seeking a permit under 20.11.41 NMAC, Authority-to-Construct Permits, shall do so by filing a written application with the Department. Prior to submitting an application, the applicant shall contact the department in writing and request a pre-application meeting for information regarding the contents of the application and the application process. This checklist is provided to aid the applicant and **a copy must be submitted with the application.**

Applications that are ruled incomplete because of missing information will delay any determination or the issuance of the permit. The Department reserves the right to request additional relevant information prior to ruling the application complete in accordance with 20.11.41 NMAC.

Name: __Kurt Parker________________________________
Contact:__Phone: 720-200-7156, Email: kurt.parker@erm.com__________________
Company/Business: __Curia New Mexico, LLC__________________________

☐ Fill out and submit a Pre-Permit Application Meeting Request form
⇒ Available online at http://www.cabq.gov/airquality

☐ Emission Factors and Control Efficiencies
Notes:

Emergency Generator Emission Factors from Manufacturer:

Certified Diesel Fuel Emission Limits	Grams per BHP-hr			Grams per KW_m-hr		
D2 Cycle Exhaust Emissions	NOx + NMHC	CO	PM	NOx + NMHC	CO	PM
Test Results	4.5	0.3	0.04	4.5	0.3	0.04
EPA Emission Limits	4.8	2.6	0.15	4.8	2.6	0.15

Emission Factors from AP-42 [Based on AP-42, Fifth Edition, Volume 1, Chapter 3, Section 3.4, Tables 3.4-3 and 3.4-4 (10/96) for Large Stationary Diesel (greater than 600 hp)]:

Preliminary Draft

Generator Specifications

Rating (Standby)	1750	KW
Fuel Consumption - full	119	(gal/hr)
Heat Input Capacity	16.30507	(MMBtu/hr)
Operating Hours	500	(Hr/Yr)

Generator set Diesel (Uncontrolled)

Pollutant	Emission Factor (lb/hp*hr)	Emission Factor (lb/MMBtu)	Emission Factor (lb/hr)	Calculated PTE Emissions (ton/yr)
$PM/PM_{10}/PM_{2.5}$	7.00E-04	1.07E-01	1.7664	4.42E-01
SOx	1.21E-05	1.86E-03	0.0306	7.66E-03
NOx	2.40E-02	3.67E+00	60.5613	15.14
VOC	6.42E-04	9.82E-02	1.6200	4.05E-01
CO	5.50E-03	8.41E-01	13.8786	3.47
Benzene	5.08E-06	7.76E-04	0.0128	3.20E-03
Formaldehyde	5.16E-07	7.89E-05	0.0013	3.26E-04

Boiler: Johnson Boiler Co.
Steam Packaged Firetube Boiler
Model PFTA 400-4
Burner: Industrial Combustion
Burner size (168) – 16,700 MBTU/hr
Burner Config: **Ultra-Low-NOx Configuration**
NT series (NG @ 3% O_2) - < 9 ppm NOx

NTXL Burner - Ultra-Low-NOx Configuration
Burner size – 16,700 MBTU/hr; 400 Hp (80% efficiency)
General Emission Estimates with Ultra Low NOx Configuration

Emission Estimates - Natural Gas (1,000 Btu/CF)				
Parameter	ppmv Corr @ 3% O_2	Lbs/MBTU	Lbs/hr Full Rate	TPY Full Rate
NOx	9	0.011	0.175	0.765
CO	50	0.037	0.6	2.624
CO_2	2.55 lb/lb fuel	119.76	1,953	8,553

City of Albuquerque- Environmental Health Department
Air Quality Program- Permitting Section
Phone: (505) 768-1972 Email: aqd@cabq.gov

Preliminary Draft

Boiler Specifications

Horsepower	400	
Burner Max Rate (Gas Input)	16.7	MMBTU/HR
Burner Max Rate (Oil Input)	120	US GAL/HR
Fuel Heat Content (Natural Gas)	1000	BTU/CF
Fuel Heat Content (#2 Oil)	140000	BTU/Gallon

Operating Hours (Hr/Y) 8760

Boiler Stack Emissions - Natural Gas (Uncontrolled)

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMcf)	Emission Factor (lb/hr)	Calculated PTE Emissions (lb/yr)	Calculated PTE Emissions (ton/yr)
NOx	0.083	83	1.3861	12,142.24	**6.07**
CO	0.061	61	1.0187	8,923.81	**4.46**
VOC	0.0054	5.5	0.09018	789.98	**0.39**
$PM/PM_{10}/PM_{2.5}$	0.0075	7.6	0.12525	1,097.19	**0.55**
SO_2	0.00059	0.6	0.009853	86.31	**0.04**
Benzene	0.00000206	0.0021	3.4402E-05	0.30	**0.00**
Formaldehyde	0.0000735	0.075	0.00122745	10.75	**0.01**

Emission factors from EPA AP-42 industrial boiler unit with a Low NOx burner

☐ Air Dispersion modeling guidelines and protocol
Notes: Standby/Emergency generator is exempted from the air dispersion modeling requirements.

Modeling will be required for this boiler.

☐ Department Policies
Notes: Standby/Emergency generator is allowed to operate for 500 hrs/yr as per state regulations.

☐ Air quality permit fees
Notes: The applicable fee for the permit modification application is $1,971 since it is a modification to an existing permit and the highest fee pollutant has a proposed allowable emission rate equal to or greater than 5 tpy and less than 25 tpy.

☐ Public notice requirements

- ☐ Replacement Part 41 Implementation
  - ☐ *20.11.41*.13 B. Applicant's public notice requirements
    - ☐ Providing public notice to neighborhood association/coalitions
      - Neighborhood association:______________________________
      - Coalition: ____________________________________

      Notes: The notice needs to be sent to the neighborhood associations and coalitions.

- Posting and maintaining a weather-proof sign
  Notes:

- Regulatory timelines
  - 30 days to rule application complete
  - 90 days to issue completed permit
  - Additional time allotted if there is significant public interest and/or a significant air quality issue
    - Public Information Hearing
    - Complex permitting action

  Notes:

City of Albuquerque- Environmental Health Department
Air Quality Program- Permitting Section
Phone: (505) 768-1972   Email: aqd@cabq.gov

Attachment 4

Air Quality Permit Application Form

City of Albuquerque – Environmental Health Department
Air Quality Program
Please mail this application to **P.O. Box 1293, Albuquerque, NM 87103**
or hand deliver between 8:00 am – 5:00 pm Monday – Friday to:
3rd Floor, Suite 3023 – One Civic Plaza NW, Albuquerque, NM 87102
(505) 768-1972 aqd@cabq.gov

Application for Air Pollutant Sources in Bernalillo County
Source Registration (20.11.40 NMAC) and Construction Permits (20.11.41 NMAC)

Submittal Date: March 22, 2023

Owner/Corporate Information ☒ **Check here and leave this section blank if information is exactly the same as Facility Information below.**

Company Name:			
Mailing Address:	City:	State:	Zip:
Company Phone:	Company Contact:		
Company Contact Title:	Phone:	E-mail:	

Stationary Source (Facility) Information: Provide a plot plan (legal description/drawing of the facility property) with overlay sketch of facility processes, location of emission points, pollutant type, and distances to property boundaries.

Facility Name: **Curia New Mexico, LLC**			
Facility Physical Address: **4401 Alexander Boulevard NE**	City: **Albuquerque**	State: **NM**	Zip: **87107**
Facility Mailing Address (if different):	City:	State:	Zip:
Facility Contact: **John Gerback, Jr.**	Title: **Sr. Manager EH&S**		
Phone: **505-340-5989**	E-mail: **John.GerbackJr@curiaglobal.com**		
Authorized Representative Name[1]: **John Gerback, Jr.**	Authorized Representative Title: **Sr. Manager EH&S**		

Billing Information ☐ **Check here if same contact and mailing address as corporate** ☒ **Check here if same as facility**

Billing Company Name:			
Mailing Address:	City:	State:	Zip:
Billing Contact:	Title:		
Phone:	E-mail:		

Preparer/Consultant(s) Information ☐ **Check here and leave section blank if no Consultant used or Preparer is same as Facility Contact.**

Name: **Kurt Parker**	Title: **ERM Partner**		
Mailing Address: **1200 17th Street, Floor 10**	City: **Denver**	State: **CO**	Zip: **80202**
Phone: **720-200-7156**	Email: **kurt.parker@erm.com**		

1. See 20.11.41.13(E)(13) NMAC.

Application for Air Pollutant Sources in Bernalillo County
Source Registration (20.11.40 NMAC) and Construction Permits (20.11.41 NMAC)

General Operation Information (if any question does not pertain to your facility, type N/A on the line or in the box)

Permitting action being requested (please refer to the definitions in 20.11.40 NMAC or 20.11.41 NMAC):			
☐ New Permit	☒ Permit Modification Current Permit #: **1097-M3-2AR**	☐ Technical Permit Revision Current Permit #:	☐ Administrative Permit Revision Current Permit #:
☐ New Registration Certificate	☐ Modification Current Reg. #:	☐ Technical Revision Current Reg. #:	☐ Administrative Revision Current Reg. #:

UTM coordinates of facility (Zone 13, NAD 83): **13S 352446.57E 3888958.32N**	
Facility type (*i.e.*, a description of your facility operations): **Curia New Mexico, LLC is a contract manufacturing organization (CMO) that specializes in delivering injectable sterile liquid, suspension, and lyophilized biologic and pharmaceutical products.**	
Standard Industrial Classification (SIC Code #): **2834**	North American Industry Classification System (NAICS Code #): **325412**
Is this facility currently operating in Bernalillo County? **Yes**	If **YES**, list date of original construction: **1984** If **NO**, list date of planned startup:
Is the facility permanent? **Yes**	If **NO**, list dates for requested temporary operation: From Through
Is the facility a portable stationary source? **No**	If **YES**, is the facility address listed above the main permitted location for this source?
Is the application for a physical or operational change, expansion, or reconstruction (*e.g.*, altering process, or adding, or replacing process or control equipment, etc.) to an existing facility? **Yes**	
Provide a description of the requested changes: **Addition of one 1750-kW diesel-fired standby/emergency generator and the addition of one 16.7 MMBtu natural gas-fired boiler and updates/corrections to permit limits/conditions for existing sources.**	
What is the facility's operation? ☒ Continuous ☐ Intermittent ☐ Batch	

Estimated percent of production/operation:	Jan-Mar: **25**	Apr-Jun: **25**	Jul-Sep: **25**	Oct-Dec: **25**
Requested operating times of facility:	**24** hours/day	**7** days/week	**4** weeks/month	**12** months/year

Will there be special or seasonal operating times other than shown above? This includes monthly- or seasonally-varying hours. **Yes**
If **YES**, please explain: **Operating hours for standby/emergency generator will be 500 hours per year**
List raw materials processed: **Emergency Generator: Diesel; Boiler: Natural gas**
List saleable item(s) produced: **N/A**

USE INSTRUCTIONS: For the forms on the following pages, please do not alter or delete the existing footnotes or page breaks. If additional footnotes are needed then add them to the end of the existing footnote list for a given table. Only update the rows and cells within tables as necessary for your project. Unused rows can be deleted from tables. If multiple scenarios will be represented then the Uncontrolled and Controlled Emission Tables, and other tables as needed, can be duplicated and adjusted to indicate the different scenarios.

Regulated Emission Sources Table

(*E.g.*, Generator-Crusher-Screen-Conveyor-Boiler-Mixer-Spray Guns-Saws-Sander-Oven-Dryer-Furnace-Incinerator-Haul Road-Storage Pile, etc.) Match the Units listed on this Table to the same numbered line if also listed on Emissions Tables & Stack Table.

Unit Number and Description[1]		Manufacturer	Model #	Serial #	Manufacture Date	Installation Date	Modification Date[2]	Process Rate or Capacity (Hp, kW, Btu, ft^3, lbs, tons, yd^3, etc.)[3]	Fuel Type
1	**Emergency Generator**	**Engine: Cummins**	**6CT 8 3G**	**45068185**	**Unknown**	**Unknown**	**N/A**	**180 hp**	**Diesel**
		Generator: Onan Generator Set	**125QSEA-714108**	**1940555595**	**Unknown**	**Unknown**		**125 kW**	
2	**Emergency Generator**	**Removed from Permit in 2022**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
3	**Emergency Generator**	**Engine: Cummins**	**QSL9-G**	**73472926**	**2012(1)**	**2012(1)**	**N/A**	**464 hp**	**Diesel**
		Generator: Onan	**DQDAB-1216217**	**L120426818**				**225 kW**	
4	**Emergency Generator**	**Engine: Cummins**	**QSK19-G8**	**37274123**	**2018**	**2018**	**N/A**	**967 hp**	**Diesel**
		Generator: Cummins	**DQPAA-1755965**	**B180322832**					
5	**Boiler**	**Superior**	**6-X-500**	**18659**	**2018**	**2018**	**N/A**	**4.2 MMBtu/hr**	**Natural Gas**
6	**Emergency Generator**	**Engine: Cummins Inc.**	**QSK60-G6 NR2**	**To Be Determined**	**To Be Determined**	**To Be Determined**	**N/A**	**2508 bhp**	**Diesel**
		Generator: Cummins Inc.	**DQKAD**					**1750 kW**	
7	**Boiler**	**Johnston**	**PFTA 400-4**	**To Be Determined**	**To Be Determined**	**To Be Determined**	**N/A**	**16,700 MBtu/hr**	**Natural Gas**
CHEM	**Site Wide Chemical and Solvent Usage**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
								/	
								/	
								/	
								/	

NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Unit numbers must correspond to unit numbers in the previous permit unless a complete cross reference table of all units in both permits is provided.
2. To determine whether a unit has been modified, evaluate if changes have been made to the unit that impact emissions or that trigger modification as defined in 20.11.41.7(U) NMAC. If not, put N/A.
3. Basis for Equipment Process Rate or Capacity (*e.g.*, Manufacturer's Data, Field Observation/Test, etc.) _____
   Submit information for each unit as an attachment.

(1) Year in the permit is stated as 2008, engine and generator nameplate have date of manufacture as 2012. Photos of nameplates referenced in Attachment 8: Basis of Emission Rates.

Emissions Control Equipment Table

Control Equipment Units listed on this Table should either match up to the same Unit number as listed on the Regulated Emission Sources, Controlled Emissions and Stack Parameters Tables (if the control equipment is integrated with the emission unit) or should have a distinct Control Equipment Unit Number and that number should then also be listed on the Stack Parameters Table.

Control Equipment Unit Number and Description		Controlling Emissions for Unit Number(s)	Manufacturer	Model # | Serial #	Date Installed	Controlled Pollutant(s)	% Control Efficiency[1]	Method Used to Estimate Efficiency	Rated Process Rate or Capacity or Flow
7	**Integrated FGR**	**7**	**Boiler: Johnston** **Burner: Industrial Combustion**	**Boiler: PFTA 400-4 | To Be Determined** **Burner: NTDG-168 | To Be Determined**	**To Be Determined**	**NOx**	**<9 ppm**	**Manufacturer specifications**	**16,700 MBtu/hr**
				|					
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				|					

NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Basis for Control Equipment % Efficiency (*e.g.*, Manufacturer's Data, Field Observation/Test, AP-42, etc.). _____
   Submit information for each unit as an attachment.

Exempted Sources and Exempted Activities Table

See 20.11.41 NMAC for exemptions.

Unit Number and Description		Manufacturer	Model #	Serial #	Manufacture Date	Installation Date	Modification Date[1]	Process Rate or Capacity (Hp, kW, Btu, ft^3, lbs, tons, yd^3, etc.)[2]	Fuel Type
	N/A							/	
								/	
								/	
								/	
								/	
								/	
								/	
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NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. To determine whether a unit has been modified, evaluate if changes have been made to the unit that impact emissions or that trigger modification as defined in 20.11.41.7(U) NMAC. Also, consider if any changes that were made alter the status from exempt to non-exempt. If not, put N/A.
2. Basis for Equipment Process Rate or Capacity (*e.g.*, Manufacturer's Data, Field Observation/Test, etc.) _____
   Submit information for each unit as an attachment.

Uncontrolled Emissions Table

(Process potential under physical/operational limitations during a 24 hr/day and 365 day/year = 8760 hrs)

Regulated Emission Units listed on this Table should match up to the same numbered line and Unit as listed on the Regulated Emissions and Controlled Tables. List total HAP values per Emission Unit if overall HAP total for the facility is ≥ 1 ton/yr.

Unit Number*	Nitrogen Oxides (NO_X)		Carbon Monoxide (CO)		Nonmethane Hydrocarbons/Volatile Organic Compounds (NMHC/VOCs)		Sulfur Dioxide (SO_2)		Particulate Matter ≤ 10 Microns (PM_{10})		Particulate Matter ≤ 2.5 Microns ($PM_{2.5}$)		Hazardous Air Pollutants (HAPs)		Method(s) used for Determination of Emissions (AP-42, Material Balance, Field Tests, etc.)
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	
1. Emergency Generator	**7.250**	**1.810**	**1.560**	**0.390**	**0.580**	**0.140**	**0.480**	**0.120**	**0.510**	**0.130**	**0.510**	**0.130**	**5.68E-09**	**1.42E-09**	**Criteria Pollutants are from existing permit; HAPs: AP-42 Tables 3.3-1,2, and 1.3-10**
2. Emergency Generator	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**Removed from permit per Revision on 10/05/2022**
3. Emergency Generator	**2.899**	**0.725**	**2.670**	**0.667**	**0.153**	**0.038**	**0.113**	**0.028**	**0.153**	**0.038**	**0.153**	**0.038**	**2.29E-08**	**5.72E-09**	**EPA Tier 3 Standards for 130<kW>560; HAPs: AP-42 Tables 3.3-2 and 1.3-10; SO2: Manufacturer Specs**
4. Emergency Generator	**9.666**	**2.416**	**5.564**	**1.391**	**0.509**	**0.127**	**0.012**	**0.003**	**0.318**	**0.079**	**0.318**	**0.079**	**2.78E-08**	**6.95E-09**	**EPA Tier 2 Standards for kW>560; AP-42 Tables 3.4-1,3,4, and Table 1.3-10**
5. Boiler	**0.130**	**0.570**	**0.160**	**0.700**	**0.034**	**0.150**	**0.004**	**0.020**	**0.020**	**0.090**	**0.020**	**0.090**	**4.65E-02**	**2.04E-01**	**Criteria Pollutants are from existing permit; AP-42 Tables 1.4-2,3, and 4**
6. Emergency Generator	**25.069**	**6.267**	**14.431**	**3.608**	**1.319**	**0.330**	**0.030**	**0.008**	**0.825**	**0.206**	**0.825**	**0.206**	**2.65E-08**	**6.61E-09**	**EPA Tier 2 Standards for kW>560; AP-42 Tables 3.4-1,3,4 and Table 1.3-10**
7. Boiler	**0.524**	**2.295**	**1.375**	**6.024**	**0.090**	**0.394**	**0.010**	**0.043**	**0.124**	**0.545**	**0.124**	**0.545**	**0.185**	**0.810**	**Manufacturer Emission Values for NOX; AP-42 Tables 1.4-1,2,3, and 4**
CHEM	-	-	-	-	**1.280**	**4.000**	-	-	-	-	-	-	-	-	**Existing permit limit/ Mass Balance**
Totals of Uncontrolled Emissions	**45.537**	**14.083**	**25.760**	**12.780**	**3.965**	**5.180**	**0.649**	**0.222**	**1.950**	**1.089**	**1.950**	**1.089**	**0.231**	**1.013**	

NOTE: To add extra rows in Word, click anywhere in the second-to-last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

*A permit is required and this application along with the additional checklist information requested on the Permit Application checklist must be provided if:
(1) any one of these process units <u>or</u> combination of units, has an uncontrolled emission rate greater than or equal to (≥) 10 lbs/hr or 25 tons/yr for any of the above pollutants, excluding HAPs, based on 8,760 hours of operation; or
(2) any one of these process units <u>or</u> combination of units, has an uncontrolled emission rate ≥ 2 tons/yr for any single HAP or ≥ 5 tons/yr for any combination of HAPs based on 8,760 hours of operation; or
(3) any one of these process units <u>or</u> combination of units, has an uncontrolled emission rate ≥ 5 tons/yr for lead (Pb) or any combination of lead and its compounds based on 8,760 hours of operation; or
(4) any one of the process units <u>or</u> combination of units is subject to an Air Board or federal emission limit or standard.

* If all of these process units, individually <u>and</u> in combination, have an uncontrolled emission rate less than (<) 10 lbs/hr or 25 tons/yr for all of the above pollutants (based on 8,760 hours of operation), but > 1 ton/yr for any of the above pollutants, then a source registration is required. <u>A Registration is required, at minimum, for any amount of HAP emissions. Please complete the remainder of this form.</u>

Controlled Emissions Table

(Based on current operations with emission controls OR requested operations with emission controls)

Regulated Emission Units listed on this Table should match up to the same numbered line and Unit as listed on the Regulated Emissions and Uncontrolled Tables. List total HAP values per Emission Unit if overall HAP total for the facility is ≥ 1 ton/yr.

Unit Number	Nitrogen Oxides (NO_X)		Carbon Monoxide (CO)		Nonmethane Hydrocarbons/Volatile Organic Compounds (NMHC/VOCs)		Sulfur Dioxide (SO_2)		Particulate Matter ≤ 10 Microns (PM_{10})		Particulate Matter ≤ 2.5 Microns ($PM_{2.5}$)		Hazardous Air Pollutants (HAPs)		Control Method	% Efficiency[1]
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr		
1. Emergency Generator	**7.250**	**1.810**	**1.560**	**0.390**	**0.580**	**0.140**	**0.480**	**0.120**	**0.510**	**0.130**	**0.510**	**0.130**	**5.68E-09**	**1.42E-09**	**N/A**	**N/A**
2. Emergency Generator-Removed[2]	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
3. Emergency Generator	**2.899**	**0.725**	**2.670**	**0.667**	**0.153**	**0.038**	**0.113**	**0.028**	**0.153**	**0.038**	**0.153**	**0.038**	**2.29E-08**	**5.72E-09**	**N/A**	**N/A**
4. Emergency Generator	**9.666**	**2.416**	**5.564**	**1.391**	**0.509**	**0.127**	**0.012**	**0.003**	**0.318**	**0.079**	**0.318**	**0.079**	**2.78E-08**	**6.95E-09**	**N/A**	**N/A**
5. Boiler	**0.130**	**0.570**	**0.160**	**0.700**	**0.034**	**0.150**	**0.004**	**0.020**	**0.020**	**0.090**	**0.020**	**0.090**	**4.65E-02**	**2.04E-01**	**N/A**	**N/A**
6. Emergency Generator	**25.069**	**6.267**	**14.431**	**3.608**	**1.319**	**0.330**	**0.030**	**0.008**	**0.825**	**0.206**	**0.825**	**0.206**	**2.65E-08**	**6.61E-09**	**N/A**	**N/A**
7. Boiler	**0.524**	**2.295**	**1.375**	**6.024**	**0.090**	**0.394**	**0.010**	**0.043**	**0.124**	**0.545**	**0.124**	**0.545**	**0.185**	**0.810**	**Integrated Control**	**N/A**
CHEM	**-**	**-**	**-**	**-**	**1.280**	**4.000**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**N/A**	**N/A**
Totals of Controlled Emissions	**45.537**	**14.083**	**25.760**	**12.780**	**3.965**	**5.180**	**0.649**	**0.222**	**1.950**	**1.089**	**1.950**	**1.089**	**0.231**	**1.013**		

NOTE: To add extra rows in Word, click anywhere in the second-to-last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Basis for Control Method % Efficiency (*e.g.*, Manufacturer's Data, Field Observation/Test, AP-42, etc.). _____
   Submit information for each unit as an attachment.

2. #2 Emergency generator removed from the permit in 2022.

Hazardous Air Pollutants (HAPs) Emissions Table

Report the Potential Emission Rate for each HAP from each source on the Regulated Emission Sources Table that emits a given HAP. Report individual HAPs with ≥ 1 ton/yr total emissions for the facility on this table. Otherwise, report total HAP emissions for each source that emits HAPs and report individual HAPs in the accompanying application package in association with emission calculations. If this application is for a Registration solely due to HAP emissions, report the largest HAP emissions on this table and the rest, if any, in the accompanying application package.

Unit Number	Total HAPs															
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
1. Emergency Generator	**5.68E-09**	**1.42E-09**														
2. Emergency Generator-Removed	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
3. Emergency Generator	**2.29E-08**	**5.72E-09**														
4. Emergency Generator	**2.78E-08**	**6.95E-09**														
5. Boiler	**4.65E-02**	**2.04E-01**														
6. Emergency Generator	**2.65E-08**	**6.61E-09**														
7. Boiler	**0.185**	**0.810**														
Totals of HAPs for all units:	**0.231**	**1.013**														

NOTE: To add extra rows in Word, click anywhere in the second-to-last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

Use Instructions: Copy and paste the HAPs table here if need to list more individual HAPs.

Purchased Hazardous Air Pollutant Table*

Product Categories (Coatings, Solvents, Thinners, etc.)	Hazardous Air Pollutant (HAP), or Volatile Hazardous Air Pollutant (VHAP) Primary To The Representative As Purchased Product	Chemical Abstract Service (CAS) Number of HAP or VHAP from Representative As Purchased Product	HAP or VHAP Concentration of Representative As Purchased Product (pounds/gallon, or %)	Concentration Determination (CPDS, SDS, etc.)[1]	Total Product Purchases For Category	(-)	Quantity of Product Recovered & Disposed For Category	(=)	Total Product Usage For Category
1. N/A – Only non-HAP VOCs used at this facility					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
2.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
3.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
4.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
5.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
6.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
7.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
8.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
9.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
.					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr
TOTALS					lb/yr gal/yr	(-)	lb/yr gal/yr	(=)	lb/yr gal/yr

NOTE: To add extra rows in Word, click anywhere in the second-to-last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

NOTE: Product purchases, recovery/disposal and usage should be converted to the units listed in this table. If units cannot be converted please contact the Air Quality Program prior to making changes to this table.

1. Submit, as an attachment, information on one (1) product from each Category listed above which best represents the average of all the products purchased in that Category. CPDS = Certified Product Data Sheet; SDS = Safety Data Sheet

*** A Registration is required, at minimum, for any amount of HAP or VHAP emission.**
Emissions from purchased HAP usage should be accounted for on previous tables as appropriate.
A permit may be required for these emissions if the source meets the requirements of 20.11.41 NMAC.

Material and Fuel Storage Table

(*E.g.*, Tanks, barrels, silos, stockpiles, etc.)

Storage Equipment		Product Stored	Capacity (bbls, tons, gals, acres, etc.)	Above or Below Ground	Construction (Welded, riveted) & Color	Installation Date	Loading Rate[1]	Offloading Rate[1]	True Vapor Pressure	Control Method	Seal Type	% Eff.[2]
6	**Tank**	**Diesel Fuel**	**1600 gal**	**Above Ground**	**To Be Determined**	**To Be Determined**	**To Be Determined**	**To Be Determined**	**To Be Determined**	**N/A**	**N/A**	**N/A**

NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Basis for Loading/Offloading Rate (*e.g.*, Manufacturer's Data, Field Observation/Test, etc.). _____
   Submit information for each unit as an attachment.
2. Basis for Control Method % Efficiency (*e.g.*, Manufacturer's Data, Field Observation/Test, AP-42, etc.). _____
   Submit information for each unit as an attachment.

Stack Parameters Table

If any equipment from the Regulated Emission Sources Table is also listed in this Stack Table, use the same numbered line for the emission unit on both tables to show the association between the Process Equipment and its stack.

Unit Number and Description		Pollutant (CO, NOx, PM_{10}, etc.)	UTM Easting (m)	UTM Northing (m)	Stack Height (ft)	Stack Exit Temp. (°F)	Stack Velocity (fps)	Stack Flow Rate (acfm)	Stack Inside Diameter (ft)	Stack Type
5	**Existing Boiler**	**CO, NOx, PM10, PM2.5, SO2, VOC, HAP**	**352468.5**	**3888870.3**	**35.007**	**494**	**18.668**	**1560.848**	**1.332**	**Vertical with Rain Cap**
6	**Emergency Generator**	**CO, NOx, PM10, PM2.5, SO2, VOC, HAP**	**352389.3**	**3889015.4**	**To Be Determined**	**866**	**To Be Determined**	**13,119**	**To Be Determined**	**Horizontal**
7	**Boiler**	**CO, NOx, PM10, PM2.5, SO2, VOC, HAP**	**352388.9**	**3888987.6**	**43.996**	**407**	**33.629**	**5328.31**	**1.834**	**Vertical**
										Select
										Select
										Select
										Select

NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

Certification

NOTICE REGARDING SCOPE OF A PERMIT: The Environmental Health Department's issuance of an air quality permit only authorizes the use of the specified equipment pursuant to the air quality control laws, regulations and conditions. Permits relate to air quality control only and are issued for the sole purpose of regulating the emission of air contaminants from said equipment. Air quality permits are not a general authorization for the location, construction and/or operation of a facility, nor does a permit authorize any particular land use or other form of land entitlement. It is the applicant's/permittee's responsibility to obtain all other necessary permits from the appropriate agencies, such as the City of Albuquerque Planning Department or Bernalillo County Department of Planning and Development Services, including but not limited to site plan approvals, building permits, fire department approvals and the like, as may be required by law for the location, construction and/or operation of a facility. For more information, please visit the City of Albuquerque Planning Department website at https://www.cabq.gov/planning and the Bernalillo County Department of Planning and Development Services website at https://www.bernco.gov/planning.

NOTICE REGARDING ACCURACY OF INFORMATION AND DATA SUBMITTED: Any misrepresentation of a material fact in this application and its attachments is cause for denial of a permit or revocation of part or all of the resulting registration or permit, and revocation of a permit for cause may limit the permitee's ability to obtain any subsequent air quality permit for ten (10) years. Any person who knowingly makes any false statement, representation, or certification in any application, record, report, plan or other document filed or required to be maintained under the Air Quality Control Act, NMSA 1978 §§ 74-2-1 to 74-2-17, is guilty of a misdemeanor and shall, upon conviction, be punished by a fine of not more than ten thousand dollars ($10,000) per day per violation or by imprisonment for not more than twelve months, or by both.

I, the undersigned, hereby certify that I have knowledge of the information and data represented and submitted in this application and that the same is true and accurate, including the information and date in any and all attachments, including without limitation associated forms, materials, drawings, specifications, and other data. I also certify that the information represented gives a true and complete portrayal of the existing, modified existing, or planned new stationary source with respect to air pollution sources and control equipment. I understand that there may be significant penalties for submitting false information, including the possibility of fines and imprisonment for knowing violations. I also understand that the person who has applied for or has been issued an air quality permit by the Department is an obligatory party to a permit appeal filed pursuant to 20.11.81 NMAC. Further, I certify that I am qualified and authorized to file this application, to certify the truth and accuracy of the information herein, and bind the source. Moreover, I covenant and agree to comply with any requests by the Department for additional information necessary for the Department to evaluate or make a final decision regarding the application.

Signed this 22 day of March, 2023

John Gerback
Print Name

Sr. Manager of EHS
Print Title

[signature]
Signature

Role: ☐ Owner ☐ Operator

☒ Other Authorized Representative

Attachment 5

Notice of Intent Form, Public Sign Notice Guideline Form, List of Neighborhood Associations and Neighborhood Coalitions, and Proof of Public Notices

NOTICE FROM THE APPLICANT

Notice of Intent to Apply for Air Quality Construction Permit

You are receiving this notice because the New Mexico Air Quality Control Act (20.11.41.13B NMAC) requires any owner/operator proposing to construct or modify a facility subject to air quality regulations to provide public notice by certified mail or electronic mail to designated representatives of recognized neighborhood associations and coalitions within 0.5-mile of the property on which the source is or is proposed to be located.

This notice indicates that the owner/operator intends to apply for an Air Quality Construction Permit from the Albuquerque – Bernalillo County Joint Air Quality Program. Currently, no application for this proposed project has been submitted to the Air Quality Program. Applicants are required to include a copy of this form and documentation of mailed notices with their Air Quality Construction Permit Application.

Proposed Project Information

Applicant's name and address:
Nombre y domicilio del solicitante: Curia New Mexico, LLC; 4401 Alexander Blvd. NE, Albuquerque, NM 87107

Owner / operator's name and address:
Nombre y domicilio del propietario u operador: Curia New Mexico, LLC; 4401 Alexander Blvd. NE, Albuquerque, NM 87107

Contact for comments and inquires:
Datos actuales para comentarios y preguntas:

Name *(Nombre)*: John Gerback, Jr.
Address *(Domicilio)*: 4401 Alexander Blvd. NE, Albuquerque, NM 87107
Phone Number *(Número Telefónico)*: (505) 340-5989
E-mail Address *(Correo Electrónico)*: John.GerbackJr@curiaglobal.com

Actual or estimated date the application will be submitted to the department:
Fecha actual o estimada en que se entregará la solicitud al departamento: March 22, 2023

Description of the source:
Descripción de la fuente: Permitted emission sources include emergency generators, boilers, and solvent and chemical usage.

Exact location of the source or proposed source:
Ubicación exacta de la fuente o fuente propuesta: 4401 Alexander Blvd. NE, Albuquerque, New Mexico 87107

Nature of business:
Tipo de negocio: Curia New Mexico, LLC is a contract manufacturing organization (CMO) that specializes in delivering injectable sterile liquid, suspension, and lyophilized biologic and pharmaceutical products.

Process or change for which the permit is requested:
Proceso o cambio para el cuál de solicita el permiso: Installation of one 1750-kW diesel-fired standby/emergency generator and one 16.7 MMBtu natural gas-fired boiler and updates/corrections to permit basis/limits for existing sources.

Maximum operating schedule:
Horario máximo de operaciones: Standby/Emergency Generator: 500 hrs/yr, Boiler: 8760 hrs/yr

Normal operating schedule:
Horario normal de operaciones: Readiness Testing/Non-emergency Use: 100 hrs/yr, Boiler: 8760 hrs/yr

Preliminary estimate of the maximum quantities of each regulated air contaminant the source will emit:
Estimación preliminar de las cantidades máximas de cada contaminante de aire regulado que la fuente va a emitir:

Air Contaminant *Contaminante de aire*	**Proposed Construction Permit** *Permiso de Construcción Propuesto*		**Net Changes (for permit modification or technical revision)** *Cambio Neto de Emisiones (para modificación de permiso o revisión técnica)*	
	pounds per hour *libras por hora*	tons per year *toneladas por año*	pounds per hour *libras por hora*	tons per year *toneladas por año*
CO	25.760	12.780	+15.816	+9.639
NOx	45.537	14.083	+25.461	+8.529
VOC	3.965	5.180	+1.522	+0.752
SO2	0.649	0.222	+0.043	+0.049
PM10	1.950	1.089	+0.952	+0.749
PM2.5	1.950	1.089	+0.952	+0.749
HAP	0.231	1.013	+0.231	+1.013

Questions or comments regarding this Notice of Intent should be directed to the Applicant. Contact information is provided with the Proposed Project Information on the first page of this notice. To check the status of an Air Quality Construction Permit application, call 311 and provide the Applicant's information, or visit www.cabq.gov/airquality/air-quality-permits.

The Air Quality Program will issue a Public Notice announcing a 30-day public comment period on the permit application for the proposed project when the application is deemed complete. The Air Quality Program does not process or issue notices on applications that are deemed incomplete. More information about the air quality permitting process is attached to this notice.

Air Quality Construction Permitting Overview

This is the typical process to obtain an Air Quality Construction Permit for Synthetic Minor and Minor sources of air pollution from the Albuquerque – Bernalillo County Joint Air Quality Program.

Step 1: Pre-application Meeting: The Applicant and their consultant must request a meeting with the Air Quality Program to discuss the proposed action. If air dispersion modeling is required, Air Quality Program staff discuss the modeling protocol with the Applicant to ensure that all proposed emissions are considered.

> **Notice of Intent from the Applicant:** Before submitting their application, the Applicant is required to notify all nearby neighborhood associations and interested parties that they intend to apply for an air quality permit or modify an existing permit. The Applicant is also required to post a notice sign at the facility location.

Step 2: Administrative Completeness Review and Preliminary Technical Review: The Air Quality Program has 30 days from the day the permit is received to review the permit application to be sure that it is administratively complete. This means that all application forms must be signed and filled out properly, and that all relevant technical information needed to evaluate any proposed impacts is included. If the application is not complete, the permit reviewer will return the application and request more information from the Applicant. Applicants have three opportunities to submit an administratively complete application with all relevant technical information.

> **Public Notice from the Department:** When the application is deemed complete, the Department will issue a Public Notice announcing a 30-day public comment period on the permit application. This notice is distributed to the same nearby neighborhood associations and interested parties that the Applicant sent notices to, and published on the Air Quality Program's website.
>
> During this 30-day comment period, individuals have the opportunity to submit written comments expressing their concerns or support for the proposed project, and/or to request a Public Information Hearing. If approved by the Environmental Health Department Director, Public Information Hearings are held after the technical analysis is complete and the permit has been drafted.

Step 3: Technical Analysis and Draft Permit: Air Quality Program staff review all elements of the proposed operation related to air quality, and review outputs from advanced air dispersion modeling software that considers existing emission levels in the area surrounding the proposed project, emission levels from the proposed project, and meteorological data. The total calculated level of emissions is compared to state and federal air quality standards and informs the decision on whether to approve or deny the Applicant's permit.

Draft Permit: The permit will establish emission limits, standards, monitoring, recordkeeping, and reporting requirements. The draft permit undergoes an internal peer review process to determine if the emissions were properly evaluated, permit limits are appropriate and enforceable, and the permit is clear, concise, and consistent.

> **Public Notice from the Department:** When the technical analysis is complete and the permit has been drafted, the Department will issue a second Public Notice announcing a 30-day public comment period on the technical analysis and draft permit. This second Public Notice, along with the technical analysis documentation and draft permit, will be published on the Air Quality Program's website, and the public notice for availability of the technical analysis and draft permit will only be directly sent to those who requested further information during the first comment period.

During this second 30-day comment period, residents have another opportunity to submit written comments expressing their concerns or support for the proposed project, and/or to request a Public Information Hearing.

Possible Public Information Hearing: The Environmental Health Department Director may decide to hold a Public Information Hearing for a permit application if there is significant public interest and a significant air quality issue. If a Public Information Hearing is held, it will occur after the technical analysis is complete and the permit has been drafted.

Step 4: Public Comment Evaluation and Response: The Air Quality Program evaluates all public comments received during the two 30-day public comment periods and Public Information Hearing, if held, and updates the technical analysis and draft permit as appropriate. The Air Quality Program prepares a response document to address the public comments received, and when a final decision is made on the permit application, the comment response document is published on the Air Quality Program's website and distributed to the individuals who participated in the permit process. If no comments are received, a response document is not prepared.

Step 5: Final Decision on the Application: After public comments are addressed and the final technical review is completed, the Environmental Health Department makes a final decision on the application. If the permit application meets all applicable requirements set forth by the New Mexico Air Quality Control Act and the federal Clean Air Act, the permit is approved. If the permit application does not meet all applicable requirements, it is denied.

Notifications of the final decision on the permit application and the availability of the comment response document is published on the Air Quality Program's website and distributed to the individuals who participated in the permit process.

The Department must approve a permit application if the proposed action will meet all applicable requirements and if it demonstrates that it will not result in an exceedance of ambient air quality standards. Permit writers are very careful to ensure that estimated emissions have been appropriately identified or quantified and that the emission data used are acceptable.

The Department must deny a permit application if it is deemed incomplete three times, if the proposed action will not meet applicable requirements, if estimated emissions have not been appropriately identified or quantified, or if the emission data are not acceptable for technical reasons.

For more information about air quality permitting, visit www.cabq.gov/airquality/air-quality-permits

City of Albuquerque

Environmental Health Department
Air Quality Program

Public Notice Sign Guidelines

Any person seeking a permit under 20.11.41 NMAC, Authority-to-Construct Permits, shall do so by filing a written application with the Department. *Prior to submitting an application, the applicant shall post and maintain a weather-proof sign provided by the department. The applicant shall keep the sign posted until the department takes final action on the permit application; if an applicant can establish to the department's satisfaction that the applicant is prohibited by law from posting, at either location required, the department may waive the posting requirement and may impose different notification requirements.* **A copy of this form must be submitted with your application.**

Applications that are ruled incomplete because of missing information will delay any determination or the issuance of the permit. The Department reserves the right to request additional relevant information prior to ruling the application complete in accordance with 20.11.41 NMAC.

Name: __Curia New Mexico, LLC____
Contact:__John Gerback, Jr.____
Company/Business: _Curia New Mexico, LLC_______________________________________

☐ ☒ The sign must be posted at the more visible of either the proposed or existing facility entrance (or, if approved in advance and in writing by the department, at another location on the property that is accessible to the public)

☐ ☒ The sign shall be installed and maintained in a condition such that members of the public can easily view, access, and read the sign at all times.

☐ ☒ The lower edge of the sign board should be mounted a minimum of 2' above the existing ground surface to facilitate ease of viewing

☐ ☒ Attach a picture of the completed, properly posted sign to this document

☐ ☐ **Check here if the department has waived the sign posting requirement.**
Alternative public notice details:

Ver. 11/13

Proposed Air Quality Construction Permit

Permiso de Construcción de Calidad del Aire Propuesto

1. **Applicant's Name:**
   Nombre del solicitante: Curia New Mexico, LLC
   Owner or Operator's Name:
   Nombre del Propietario u Operador: Curia New Mexico, LLC
2. **Actual or Estimated Date the Application will be Submitted to the Department:**
   Fecha Actual o Estimada en que se Entragará la Solicitud al Departamento: March 17, 2023
3. **Exact Location of the Source or Proposed Source:**
   Ubicación Excata de la Fuente o Fuente Propuesta: 4401 Alexander Blvd. NE ABQ, NM 87107
4. **Description of the Source:**
   Descripción de la Fuente: Permitted emission sources include emergency generators, boilers, & solvent & Chem usag
   Nature of Business: Curia NM, LLC is a contract manufacturing organization (CMO) that specializes
   Tipo de Negocio: in delivering injectable sterile liquid, suspension, and lyophilized biologic and pharmaceutical product
   Process or change for which a permit is requested:
   Proceso o cambio para el cuál se solicita el permiso: Installation of one 1750-KW diesel-fired standby/emergency genera and one 16.7 mmBtu natural gas-fired boiler and updates/corrections to permit basis/limits for existing sources.

Preliminary estimate of the maximum quantities of each regulated air contaminant the source will emit:
Estimación preliminar de las cantidades máximas de cada contaminante de aire regulado que la fuente va a emitir:

Air Contaminant *Contaminante de Aire*	Proposed Construction Permit *Permiso de Construcción Propuesto*		Net Change Emissions (for permit modification) *Cambio Neto de Emisiones (para modificación de permiso)*	
	Pounds per hour *libras por hora*	Tons per year *toneladas por año*	Pounds per hour *libras por hora*	Tons per year *toneladas por año*
NO_X	45.537	14.083	+25.461	+8.529
CO	25.760	12.780	+15.816	+9.639
VOC	3.965	5.180	+1.522	+0.752
SO_2	0.649	0.222	+0.043	+0.049
PM_{10}	1.950	1.089	+0.952	+0.749
$PM_{2.5}$	1.950	1.089	+0.952	+0.749
HAP	0.231	1.013	+0.231	+1.013

5. **Maximum Operating Schedule:**
   Horario Máximo de Operaciones: Standby/emergency generator: 500 hrs/year; boiler: 8760 hrs/year
   Normal Operation Schedule:
   Horario Normal de Operaciones: Readiness testing/non-emergency use: 100 hrs/year; boiler: 8760 hrs/year
6. **Current Contact Information for Comments and Inquiries**
   Datos actuales para Comentarios y Preguntas

Name *(Nombre)*: John Gerback, Jr.
Address *(Domicilio)*: 4401 Alexander Blvd NE, ABQ, NM 87107
Phone Number *(Número Telefónico)*: (505) 340-5989
Email Address *(Correo Electrónico)*: john.gerbackjr@curia.global.com

Call 311 for additional information concerning this project, the Air Quality Program, or to file a complaint.
Llame al 311 para obtener información adicional sobre este proyecto, del Programa de Calidad del Aire, o para presenter una queja.
Gọi 311 để biết thêm thông tin hoặc để khiếu nại về dự án này, Chương Trình Chất Lượng Không Khí

City of Albuquerque, Environmental Health Department, Air Quality Program – Stationary Source Permitting
Ciudad de Albuquerque, Departamento de Salud Ambiental, Programa de Calidad del Aire - Permisos para Fuentes Inmóviles
(505) 768-1972, aqd@cabq.gov

THIS SIGN SHALL REMAIN POSTED UNTIL THE DEPARTMENT TAKES FINAL ACTION ON THE PERMIT APPLICATION
ESTE AVISO DEBERÁ DE MANTENERSE PUESTO HASTA QUE EL DEPARTAMENTO TOME UNA DECISIÓN SOBRE LA SOLICITUD DE PERMISO


WARNING
THESE PREMISES ARE UNDER 24 HOUR VIDEO SURVEILLANCE
NO TRESPASSING
NO SOLICITING
NO LOITERING
NO TRESPASSING

Timothy M. Keller,
Mayor

Public Participation

List of Neighborhood Associations
and Neighborhood Coalitions
MEMORANDUM

To: Curia of New Mexico
From: Kyle Tumpane, Environmental Health Scientist
Subject: Determination of Neighborhood Associations and Coalitions within 0.5 mile of 4401 Alexander Blvd. NE in Bernalillo County, NM
Date: December 1, 2022 – Updated February 23, 2023

DETERMINATION:

On December 1, 2022, I used the City of Albuquerque Zoning Advanced Map Viewer (http://coagisweb.cabq.gov/) to verify which City of Albuquerque Neighborhood Associations (NA), Homeowner Associations (HOA) and Neighborhood Coalitions (NC) are located within 0.5 mile of 4401 Alexander Blvd. NE in Bernalillo County, NM.

I then used the City of Albuquerque Office (COA) of Neighborhood Coordination's Monthly Master NA List dated February 2023 and the Bernalillo County (BC) Monthly Neighborhood Association February 2023 Excel file to update the contact information for each NA and NC located within 0.5 mile of 4401 Alexander Blvd. NE in Bernalillo County, NM.

The table below contains the contact information, which will be used in the City of Albuquerque Environmental Health Department's public notice. Duplicates have been deleted.

COA/BC Association or Coalition	Name	Email or Mailing Address*
Neighborhood Coalition D4C	Mildred Griffee Ellen Dueweke Coalition Email	mgriffee@noreste.org edueweke@juno.com sect.dist4@gmail.com
Neighborhood Coalition D7C	Tyler Richter Michael Kious	tyler.richter@gmail.com mikekious@aol.com
North Edith Commercial Corridor Association	Michael Haederle Evelyn Harris	haederle@yahoo.com grumpyeh46@comcast.net
North Edith Corridor Association	Christine Benavidez Evelyn Harris	christine61benavidez@gmail.com grumpyeh46@comcast.net
North Valley Coalition	Peggy Norton Doyle Kimbrough Association Email	peggynorton@yahoo.com newmexmba@aol.com nvcabq@gmail.com

If email address is not listed, provide public notice via certified mail and include a copy of each mail receipt with the application submittal.

From:	Alaina Juhl
To:	mgriffee@noreste.org; edueweke@juno.com; sect.dist4@gmail.com; tyler.richter@gmail.com; mikekious@aol.com; haederle@yahoo.com; grumpyeh46@comcast.net; christine61benavidez@gmail.com; peggynorton@yahoo.com; newmexmba@aol.com; nvcabq@gmail.com
Cc:	John.GerbackJr@curiaglobal.com; Paul.Sokolowski@curiaglobal.com; Kurt Parker; Tawnya Chott; Anthony Griego; cmunoz-dyer@cabq.gov
Subject:	Updated Public Notice of Proposed Air Quality Construction Permit Application- Curia New Mexico
Date:	Thursday, March 16, 2023 9:52:00 AM
Attachments:	Notice of Intent Form.pdf

Dear Neighborhood Association/Coalition Representative(s),

Please be advised that this notice replaces the notice that was previously sent on January 9, 2023. In addition to the proposed new emergency generator; this permit application includes the addition of a new boiler and permit updates/corrections for existing sources.

Why did I receive this public notice?

You are receiving this notice in accordance with New Mexico Administrative Code (NMAC) 20.11.41.13.B(1) which requires any applicant seeking an Air Quality Construction Permit pursuant to 20.11.41 NMAC to provide public notice by certified mail or electronic mail to the designated representative(s) of the recognized neighborhood associations and recognized coalitions that are within one-half mile of the exterior boundaries of the property on which the source is or is proposed to be located.

What is the Air Quality Permit application review process?

The City of Albuquerque, Environmental Health Department, Air Quality Program (Program) is responsible for the review and issuance of Air Quality Permits for any stationary source of air contaminants within Bernalillo County. Once the application is received, the Program reviews each application and rules it either complete or incomplete. Complete applications will then go through a 30-day public comment period. Within 90 days after the Program has ruled the application complete, the Program shall issue the permit, issue the permit subject to conditions, or deny the requested permit or permit modification. The Program shall hold a Public Information Hearing pursuant to 20.11.41.15 NMAC if the Director determines there is significant public interest and a significant air quality issue is involved.

What do I need to know about this proposed application?

Applicant Name	Curia New Mexico, LLC
Site or Facility Name	Curia New Mexico
Site or Facility Address	4401 Alexander Blvd, Albuquerque, NM 87107
New or Existing Source	EXISTING
Anticipated Date of Application Submittal	03/22/2023
Summary of Proposed Source to Be Permitted	The application is to modify existing Construction Permit #1097-M3-2AR. The modification is for the addition of a new emergency generator, a new boiler, and updates/corrections to permit basis/limits for existing sources.

What emission limits and operating schedule are being requested?

See attached Notice of Intent to Construct form for this information.

How do I get additional information regarding this proposed application?

For inquiries regarding the proposed source, contact:

- John Gerback, Jr.
- John.GerbackJr@curiaglobal.com
- (505) 340-5989

For inquiries regarding the air quality permitting process, contact:

- City of Albuquerque Environmental Health Department Air Quality Program
- aqd@cabq.gov
- (505) 768-1972

Regards,

Alaina Juhl
Consultant 1, Engineering

ERM
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T +1 720 200 7145 | **M** +1 303 886 5532
E alaina.juhl@erm.com | **W** www.erm.com

ERM The business of sustainability

Attachment 6

Ambient Impact Analysis Dispersion Model Report

Will be provided as separate submittal

Prepared for:

Curia New Mexico, LLC
4401 Alexander Blvd. NE
Albuquerque, NM 87107

Dispersion Modeling Analysis for Two Natural Gas Fired Boilers

Construction Permit No. 1097-M3-2AR
Curia New Mexico, LLC

14 February 2023

Project No.: 0654619

Document details	The details entered below are automatically shown on the cover and the main page footer. PLEASE NOTE: This table must NOT be removed from this document.
Document title	Dispersion Modeling Analysis for Two Natural Gas Fired Boilers
Document subtitle	Curia New Mexico, LLC
Project No.	0654619
Date	14 February 2023
Client Name	Curia New Mexico, LLC

Signature Page

14 February 2023

Dispersion Modeling Analysis for Two Natural Gas Fired Boilers

Curia New Mexico, LLC

Vicki Hoffman
Principal Consultant, Scientist

Kurt Parker
Partner

ERM-West, Inc.
1340 Treat Blvd., Suite 550
Walnut Creek, California 94597
T: 925 946 0455
F: 925 946 9968

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1. DISPERSION MODELING ANALYSIS

ERM-West, Inc. (ERM) has completed this modeling analysis to illustrate compliance with Significant Impact Levels (SILs), National Ambient Air Quality Standards (NAAQS) and the New Mexico Ambient Air Quality Standards (NMAAQS). The analysis has been prepared in support of the permit application for Curia New Mexico, LLC (Curia) for a facility expansion project. Curia is a contract manufacturing organization that specializes in delivering injectable sterile liquid, suspension, and lyophilized biologic and pharmaceutical products.

Curia, located at 4401 Alexander Blvd in Albuquerque, New Mexico, is in the final design of a 60,000 square foot expansion that will include the addition of a new advanced isolated high-speed, fill-finish vial line (the Proposed Project). The current operation is managed under air quality minor construction permit #1097-M3-2AR (Revised 10/05/2022). The Universal Transverse Mercator (UTM) coordinates at the approximate center of the Curia property are 352467.5 m E, 3888838.5 m N (North American Datum of 1983 [NAD83] Zone 13). The site location is provided on Figure 1.

With this expansion, Curia plans to install a ~16.7 MMBtu natural gas fired steam packaged firetube boiler that will support process and comfort heating that will be permitted as part of the overall expansion.

ERM has completed this modeling report describing the atmospheric dispersion modeling for the existing 4.2 MMBtu boiler and the proposed 16.7 MMBtu boiler (Proposed Project) as requested by the City of Albuquerque. Both are natural gas-fired boilers. The modeling analysis was performed in support of the air permitting process. For the purposes of this analysis, it is assumed that the boilers operate 24 hours per day and 7 days per week. This document presents the methodologies used for performing an air quality impact analysis.

The dispersion modeling was performed for carbon monoxide (CO), nitrogen dioxide (NO_2), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), and sulfur dioxide (SO_2) for comparison to the Significant Impact Levels (SILs). For pollutants that exceeded the SILs (NO_2 1-hour and annual average and $PM_{2.5}$ 24-hour and annual average) subsequent dispersion modeling was performed for comparison to the NAAQS and the NMAAQS. The following sections describe the methodologies and procedures that have been used to conduct the air quality dispersion modeling for the existing boiler and the Proposed Project. The remainder of this modeling report addresses the following issues:

- Significant Impact Levels and Ambient Air Quality Standards
- Ambient Background Air Quality
- Atmospheric Dispersion Modeling and Results

2. SIGNIFICANT IMPACT LEVELS AND AMBIENT AIR QUALITY STANDARDS

Dispersion modeling was performed for CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2. Modeled concentrations were compared to the significant impact levels (SILs) as summarized in *Table 18* of the *New Mexico Air Quality Bureau Air Dispersion Modeling Guidelines* (New Mexico Environment Department [NMED] July 2022) and as summarized in Table 1 below. Maximum concentrations of 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$ exceeded the SILs. Therefore, additional dispersion modeling was required which included emission sources from nearby facilities. The resulting modeled concentrations were added to background concentrations as supplied by the City of Albuquerque (Section 4.7). The summed values were then compared to the NAAQS and the NMAAQS as summarized in Table 2.

Table 1: Significant Impact Levels

Pollutant	Averaging Period	Significance Level
CO	8-hour 1-hour	500 2,000
NO_2	Annual 24-hour 1-Hour	1.0 5.0 7.5
$PM_{2.5}$	Annual 24-hour	0.2 1.2
PM_{10}	Annual[1] 24-hour	NA 5.0
SO_2	Annual 24-hour 3-hour 1-hour	1.0 5.0 25.0 7.8

Notes:
[1] There is no annual NAAQS or NMAAQS for PM_{10}, and because this is not a PSD source, annual PM_{10} was not included in the modeling analysis.

Table 2: Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS (µg/m^3)	NMAAQS (µg/m^3)
CO	8-hour 1-hour	10,303.6 40,069.6	9,960.1 14,997.5
NO_2	Annual 24-hour 1-Hour	99.66 ---- 188.03	94.02 188.03 ----
$PM_{2.5}$	Annual 24-hour	12 35	---- ----
PM_{10}	Annual 24-hour	---- 150	---- ----
SO_2	Annual 24-hour 3-hour 1-hour	---- ---- 1309.3 196.4	52.4 261.9 ---- ----

3. AMBIENT BACKGROUND AIR QUALITY

Pollutant background data were obtained from staff at the City of Albuquerque as summarized below. If available, data from the Jefferson monitoring station were used. If not available, the data from the Del Norte Monitoring location were used. Table 3 summarizes the background pollutant concentrations for use in the analysis. Background data are not included for CO, PM_{10} or SO_2 as the SILs were not exceeded and therefore the emissions are not expected to cause and or contribute to an exceedance of the NAAQS or NMAAQS. For NO_2, 1-hour seasonal background data were used as summarized in Table 4. These data were supplied by the City of Albuquerque and were input directly into the dispersion model.

Table 3: Background Concentrations and Ambient Air Quality Standards

Pollutant	Averaging Time	Background Monitored Data (µg/m³)	
		Jefferson Monitor (µg/m³)	Del Norte Monitor (µg/m³)
NO_2	Annual 24-hour[1] 1-Hour	---- ---- ----	19 ---- Hourly/seasonal (Table 4)
$PM_{2.5}$	Annual 24-hour	22.0 8.4	---- ----

Notes:
[1] No 24-hour NO_2 concentrations have been calculated by the City of Albuquerque and therefore are not available. If the 1-hour NO_2 concentrations meets the NAQQS and the NMAAQS, it is assumed that the 24-hour concentration is also in compliance.

Table 4: 1-Hour NO_2 Seasonal Background Concentration[1]

Hour	Season			
	Winter (µg/m³)	Spring (µg/m³)	Summer (µg/m³)	Fall (µg/m³)
1	72.1	47.6	29.3	65.6
2	67.8	48.3	27.7	59.7
3	67.7	46	26.4	57.9
4	68.4	48.9	26.6	58.9
5	69.1	51.7	32.7	58.0
6	69.7	63.9	39.3	57.8
7	72.8	70.7	46.4	63.5
8	77.6	71.8	48.5	64.5
9	80	61.1	34.2	65.9
10	71.4	48	27.3	55.0
11	62	28.6	24.3	47.3
12	48.1	18.9	19.9	35.4
13	36.9	17.6	17	28.2
14	35.1	15.7	15.9	25.3
15	33.6	14.8	17.4	24.2
16	37.2	15.3	19.4	28.0
17	48.4	17.1	20.4	38.0
18	73	19.4	19.3	69.6
19	79.3	38.5	21.7	79.1
20	78.1	53.2	30.9	77.1

Hour	Season			
	Winter (µg/m^3)	Spring (µg/m^3)	Summer (µg/m^3)	Fall (µg/m^3)
21	77.3	48	34.1	73.4
22	76.5	56.3	30.8	70.4
23	75	58.8	34.9	69.7
24	72.4	57.9	33.6	70.9

Notes:

1 Hourly/seasonal background data were input directly into AERMOD for 1-hour concentrations

4. ATMOSPHERIC DISPERSION MODELING

Air quality dispersion modeling was conducted to simulate the downwind transport of pollutants emitted by the 4.2 MMbtu boiler and the Proposed Project. The analysis estimates maximum offsite concentrations using the AERMOD modeling system developed by the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC). AERMOD incorporates air dispersion for both surface and elevated sources and for areas with either simple and/or complex terrain. The AERMOD modeling system includes three components: a meteorological data preprocessor (AERMET), a terrain data preprocessor (AERMAP), and the dispersion model (AERMOD). Regulatory default technical options were selected for the AERMOD modeling. These regulatory default options are found in the AERMOD User's Manual. They include stack tip downwash and a routine for processing concentration averages during calm winds and when there are missing meteorological data.

4.1 Meteorological Data

Meteorological data from the Albuquerque International Airport was used as input to AERMOD. These hourly meteorological inputs were obtained from the City of Albuquerque's website (Dispersion Modeling Guidelines & Data — City of Albuquerque (cabq.gov)). These data are the most appropriate for the Proposed Project, as discussed with the City of Albuquerque modeling staff. The location of the monitoring station is 35.05N and 106.6 W. The Airport is located approximately 5 miles south of the Proposed Project. The five-year data set (2014-2018) were processed using AERMINUTE version 15272 and AERMET version 19191. The profile base elevation will be set at 1,622 meters as obtained from Google Earth. Figure 2 illustrates the 5-year wind rose. The predominant winds come from the north, and less frequently from the southwest. The least frequent wind direction is from the northeast.

4.2 Receptor Grid

The ambient air boundary for Curia is defined as the recently installed fence along the property boundary. Figure 3 illustrates the property boundary and the assumed ambient air boundary. A cartesian grid with variable receptor spacing was used. Receptors were placed along the property boundary at 25-meter (m) increments to a distance of approximately 200 m. Additional receptors were placed at 50 m increments to a distance of 1,000 m, at 100 m increments to a distance of 2,500 m, at 250 m increments to a distance of approximately 5,000 m (5 kilometers [km]), and at 500 m increments to a distance of 10 km. A fine receptor grid of 10 m increments to a distance of 100 meters was used to better define the locations of maximum impacts for 1-hour and annual NO_2 concentrations, and 24-hour and annual $PM_{2.5}$ concentrations for the AAQS analysis. Receptor locations are provided in the UTM, NAD83, Zone 13, coordinate system. Receptor elevations were obtained from United States Geological Survey national elevation data (NED). As part of the AERMOD modeling system, AERMAP was run to calculate elevations and terrain maximum heights for each modeled receptor. The initial receptor grid is illustrated in Figure 4. Cumulative impact modeling was performed for only those receptors which exceeded the SILs.

4.3 Aerodynamic Downwash

The modeling includes an evaluation of building downwash on structures adjacent to the stacks. It is assumed that the stacks may be below Good Engineering Practice (GEP) heights. The formula for GEP height estimation is:

$$H_s = H_b + 1.50L_b$$

where: H_s = GEP stack height
H_b = building height
L_b = the lesser building dimension of the height, length, or width

The effects of aerodynamic downwash due to buildings and other structures will be accounted for by using wind direction-specific building parameters calculated by the USEPA-approved Building Parameter Input Program Prime (BPIP-Prime) and the algorithms included in the AERMOD air dispersion model. Figure 3 illustrates the locations of the structures to be included in the downwash analysis.

4.4 Emission Rates

Emission rates from the existing 4.2 MMBtu natural gas fired boiler was obtained from the Air Quality Construction Permit #1097-M3-2AR and is included in Appendix A. Natural gas combustion emissions for the proposed 16.7 MMBtu boiler were calculated using the EPA AP42 emission factors found in Table 1.4-2. Detailed emission calculations are included in Appendix A. Table 5 summarizes the emission rates for both boilers.

Table 5: Proposed Project Emission Rates

Pollutant	Averaging Time	16.7 MMBtu Boiler	4.2 MMBtu Boiler
CO	Annual (TPY) 1-hour (lb/hr)	6.02 1.38	0.700 0.160
Lead	Annual (TPY) 1-hour (lb/hr)	3.59E-05 8.19E-06	----[1]
NO_2	Annual (TPY) 1-hour (lb/hr)	2.29 0.52	0.570 0.130
$PM_{2.5}$	Annual (TPY) 1-hour (lb/hr)	0.55 0.12	0.090 0.020
PM_{10}	Annual (TPY) 1-hour (lb/hr)	0.55 0.12	0.090 0.020
SO_2	Annual (TPY) 1-hour (lb/hr)	0.04 0.01	0.020 0.004

Notes:
[1] No lead emission is included in the permit for this boiler and, therefore, will not be included in the modeling analysis.

4.5 Source Information

Both boiler stacks were modeled as point sources. Table 6 summarizes the stack parameters used in the AERMOD dispersion modeling. For the proposed 16.7 MMBtu boiler, parameters were obtained from the manufacturer's information and are provided in Appendix B. The base elevations for each stack were obtained from the AERMAP output. Figure 3 illustrates the location of the boiler stacks.

Table 6: Boiler Stack Parameters

Modeling Source ID	UTM Coordinates	Base Elevation (m)	Stack Height (m)	Exit Temperature (°K)	Exit Velocity (m/s)	Stack Diameter (m)
4.2MMBTU[1]	352468.5 E, 3888870.3 N	1542.67	10.67	529.82	5.69	0.406
16.7MMBTU	352388.9 E, 3888987.6 N	1540.98	13.41	481.48	10.25	0.559

Notes:
[1] Please note that the 4.2 MMBtu boiler stack has a rain cap, and the dispersion modeling was performed accordingly.

For NO_2 SIL modeling, the NO_x emissions were converted to NO_2 using the Ambient Ratio Method 2 (ARM2) using default values of 0.5 for the minimum in-stack ratio and 0.9 for the maximum in-stack ratio. For the cumulative NO_2 modeling, the Ozone Limiting Method (OLM) was used.

4.6 AERMOD Settings

The air quality modeling analyses employs the USEPA's AMS/EPA Regulatory Model (AERMOD), version 22112. The following settings were used in the AERMOD model:

- Complex terrain – receptor elevations and hill scales
- Rural dispersion coefficients (to be conservative)
- Regulatory default model parameters, including:
  - Calm correction
  - Buoyancy induced dispersion
  - Final plume rise
  - Default wind profile coefficients
  - Default vertical potential temperature gradients.
  - Stack-tip downwash

4.7 Dispersion Modeling Results

A series of modeling runs using the AERMOD model were performed for CO, NO_2, PM_{10}, $PM_{2.5}$ and SO_2. Maximum concentrations were compared to pollutant specific SILs for various averaging times as summarized in Table 7 below. As shown, all maximum modeled concentrations are below the SIL except for 1-hour, 24-hour and annual NO_2 and 24-hour and annual $PM_{2.5}$. Figures 5 through 8 illustrate the receptor locations that exceed the SILs for NO_2 and $PM_{2.5}$. Electronic modeling files are included in Appendix C.

Table 7: Pollutant Specific Modeled Concentrations and Significant Impact Levels

Pollutant	Averaging Time	Maximum Modeled Concentrations ($\mu g/m^3$)[1]	Significant Impact Level ($\mu g/m^3$)	Above SIL?
CO[1]	1-Hour	68.04	2,000	No
	8-Hour	35.55	500	No
NO_2[2]	1-Hour	**22.26**	**7.5**	**Yes**
	24-Hour	**7.57**	**5**	**Yes**
	Annual	**1.45**	**1**	**Yes**
$PM_{2.5}$[3]	24-Hour	**1.64**	**1.2**	**Yes**
	Annual	**0.33**	**0.2**	**Yes**
PM_{10}[4]	24-Hour	1.94	5	No
	Annual	N/A	N/A	No
SO_2[5]	1-Hour	0.51	7.8	No
	3-Hour	0.38	25	No
	24-Hour	0.16	5	No
	Annual	0.037	1	No

Notes:

[1] The 1 and 8-hour CO is the high-first-high (H1H) over a five-year period.
[2] The 1-hour NO_2 modeling was performed using the Ambient Molar Ratio version 2 (ARM2) method. The 1-hour NO_2 concentration is the H1H averaged over a five-year period. The annual NO_2 concentration is the highest H1H of each of the five years modeled.
[3] The $PM_{2.5}$ 24-hour and annual concentrations are the H1H averaged over a five1year period.
[4] The PM_{10} 24-hour and annual concentrations are the H1H over a five-year period.
[5] The SO_2 1-hour concentration is the H1H averaged over a five-year period. The SO_2 3-hour, 24-hour and annual concentrations are the H1H of the five-year period modeled.

4.7.1 Cumulative Dispersion Modeling and Results

As described in the *Protocol for Dispersion Modeling for Two Natural Gas Fired Boilers* (ERM 2022), a cumulative modeling analysis was performed for NO_2 and $PM_{2.5}$ based on the initial SIL modeling results (Table 7). As requested by the City of Albuquerque, nearby facilities with emissions of NO_2 and $PM_{2.5}$ were included in the refined cumulative modeling analysis. Emission rates and modeling release parameters were supplied by the City of Albuquerque (CAQB) and are summarized in Tables 8 through 10. Only receptors exceeding the SILs were included in this analysis. An additional receptor grid with 10-meter increments was placed surrounding the maximum receptor out to a distance of at least 100 meters. Modeled concentrations were added to background concentrations of NO_2 and $PM_{2.5}$ and compared to the NAAQS and NMAAQS. The cumulative PM2.5 modeling was performed using the existing 4.2 MMBtu boiler, the Proposed Project and emissions from the Black Rock HMA 3443 facility as recommended by Curia (see Appendix C).

For NO_2 modeling, the Ozone Limiting Method (OLM) was used. The in-stack ratios (ISR) were supplied by the City of Albuquerque for project sources as well as surrounding sources. Table 11 summarizes ISR values used in the cumulative NO_2 modeling.

Electronic modeling files are included in Appendix C.

Table 8: Surrounding Point Sources used in NO_2 NAAQS and NMAAQS Modeling

Facility	Modeling Source ID	Stack Release Type	Easting (m)	Northing (m)	Stack Height (ft)	Stack Exit Temperature (F)	Stack Diameter (ft)	Exit Velocity (fps)	NO_2 Emission Rates (lb/hr)
BlackRock HMA 3443	BRHMASTK	Vertical	351989.1	3888524.4	23.19	240	4.61	74.89	10.4
	BR_HEAT	Rain cap	352031.5	3888495.7	12	600	1	20.71	0.26
HollyFrontier 0559-M3-4TR	H1	Vertical	351099	3888758	20	525	3	21	1.47
	B1	Vertical	351114	3888760	20	400	2	21	0.82
	B2	Vertical	351112	3888772	20	390	1.33	34	0.82
	CO_1	Vertical	351096	3888816	22	350	3.28	15	0.03
Vulcan RAP 1626-7AR	27	Vertical	353502	3890082	10.00656	965.03	0.66	81.36	35.3
Mega Corp 1292	4	Horizontal	353038.06	3890776.5	8	800	0.4	72.18	10.9
Vulcan Osuna HMA 0104-M2-4AR	VOHMASTK	Vertical	353231	3890478	30.75	225	5.67	45	27.5
	VOH_HEAT	Vertical	353248	3890453	10	800	0.5	60	0.37
Roadrunner CBP 0271-2AR	Road1	Vertical	353275.4	3890786.3	6.5617	440.33	0.25	16.40	0.39
Roadrunner CBP 0505-M1-4AR	RR_5	Vertical	353271.8	3890757.6	6.5617	440.33	0.25	16.40	0.7
Vulcan Big-I HMA 1479-M3-5AR	VBI_6	Vertical	351348.8	3886146.8	40	304	5.68	46.5	15.6
	VBI_13	Vertical	351367	3886168.5	8.76	600	0.3	4.1	0.28

Table 9: Surrounding Point Sources used in $PM_{2.5}$ NAAQS and NMAAQS Modeling1

Facility	Source ID	Stack Release Type	Easting (m)	Northing (m)	Stack Height (ft)	Stack Exit Temperature (F)	Stack Diameter (ft)	Exit Velocity (fps)	$PM_{2.5}$ Emission Rates (lb/hr)
BlackRock HMA 3443	HMASTK	Vertical	351989.1	3888524.4	23.19	240	4.61	74.89	9.2
	HMAHEAT	Rain cap	352031.5	3888495.7	12	600	1	20.71	0.01976
	HMAFILL	Horizontal	352006	3888510	47	Ambient	0.5	42.44	0.02712

Table 10: Surrounding Volume Sources used in $PM_{2.5}$ NAAQS and NMAAQS Modeling

Facility[1]	Source ID	Easting (m)	Northing (m)	Release Height (m)	Init. Horizontal Dimension (m)	Init. Vertical Dimension (m)	$PM_{2.5}$ Emission Rates (lb/hr)[2]
BlackRock HMA 3443	DRUMUNL	352018	3888500.6	2	0.47	0.93	0.09374
	HMASILO	352011.8	3888485.5	4	0.47	0.93	0.11648
	HMAPILE1	351972.2	3888576.9	2.4384	4.25	2.2677	0.01555
	HMAPILE2	351990.1	3888577.3	2.4384	4.25	2.2677	0.02502
	HMAPILE3	352008.5	3888577.5	2.4384	4.25	2.2677	0.02502
	HMAPILE4	352026.9	3888577.3	2.4384	4.25	2.2677	0.02502
	HMAPILE5	352045.4	3888577.3	2.4384	4.25	2.2677	0.02502
	HMABIN1	352002	3888542.4	6	1.16	2.33	0.02502
	HMABIN2	352006.5	3888542.4	6	1.16	2.33	0.02502
	HMABIN3	352010.8	3888542.4	6	1.16	2.33	0.02502
	HMABIN4	352015.4	3888542.4	6	1.16	2.33	0.02502
	HMABIN5	352019.7	3888542.4	6	1.16	2.33	0.02502
	HMATP1	352022.1	3888541.2	2	0.47	0.93	0.00481
	HMASCR	352025.9	3888540.2	4	1.16	2.33	0.0185
	HMATP2	352025.3	3888537.8	2	0.47	0.93	0.00481
	HMATP3	352020	3888518.7	2	0.47	0.93	0.00481
	RAPPILE	352073.3	3888527.8	2.4384	4.25	2.2677	0

Facility[1]	Source ID	Easting (m)	Northing (m)	Release Height (m)	Init. Horizontal Dimension (m)	Init. Vertical Dimension (m)	$PM_{2.5}$ Emission Rates (lb/hr)[2]
BlackRock HMA 3443 (continued)	RAPBIN1	352042.5	3888534.1	6	1.16	2.33	0
	RAPBIN2	352041.5	3888529.6	6	1.16	2.33	0
	RAPTP1	352039.5	3888522.4	2	0.47	0.93	0
	RAPSCR	352038.6	3888513.6	4	1.16	2.33	0
	RAPTP2	352040	3888514.6	2	0.47	0.93	0
	RAPCRH	352039.9	3888524.2	6	1.16	2.33	0
	RAPTP3	352036.6	3888513	2	0.47	0.93	0
	RAPTP4	352018.6	3888506.2	2	0.47	0.93	0
	AS_0001	351930.9	3888505.2	3.4	6.05	3.16	0.00135
	AS_0002	351943.5	3888501.8	3.4	6.05	3.16	0.00135
	AS_0003	351956	3888498.3	3.4	6.05	3.16	0.00135
	AS_0004	351968.5	3888494.9	3.4	6.05	3.16	0.00135
	AS_0005	351981.1	3888491.4	3.4	6.05	3.16	0.00135
	AS_0006	351993.6	3888488	3.4	6.05	3.16	0.00135
	AS_0007	352006.1	3888484.5	3.4	6.05	3.16	0.00135
	AS_0008	352018.7	3888481.1	3.4	6.05	3.16	0.00135
	AS_0009	352031.2	3888477.6	3.4	6.05	3.16	0.00135
	AS_0010	352043.7	3888474.2	3.4	6.05	3.16	0.00135
	AS_0011	352056.3	3888470.7	3.4	6.05	3.16	0.00135
	AS_0012	352068.8	3888467.2	3.4	6.05	3.16	0.00135
	CM_0001	351966.5	3888466.6	3.4	6.05	3.16	0.00008
	CM_0002	351975.2	3888470.2	3.4	6.05	3.16	0.00008
	CM_0003	351987.8	3888467	3.4	6.05	3.16	0.00008
	CM_0004	352000.4	3888463.8	3.4	6.05	3.16	0.00008
	CM_0005	352013	3888460.6	3.4	6.05	3.16	0.00008
	CM_0006	352025.6	3888457.4	3.4	6.05	3.16	0.00008
	CM_0007	352036.6	3888457.9	3.4	6.05	3.16	0.00008
	CM_0008	352042.8	3888469.3	3.4	6.05	3.16	0.00008
	CM_0009	352049	3888480.7	3.4	6.05	3.16	0.00008
	CM_0010	352057.2	3888490.1	3.4	6.05	3.16	0.00008

Facility[1]	Source ID	Easting (m)	Northing (m)	Release Height (m)	Init. Horizontal Dimension (m)	Init. Vertical Dimension (m)	$PM_{2.5}$ Emission Rates (lb/hr)[2]
BlackRock HMA 3443 (continued)	RAPBIN1	352065.6	3888499	3.4	6.05	3.16	0.00008
	RAPBIN2	352056.6	3888506.4	3.4	6.05	3.16	0.00008
	RAPTP1	352047.7	3888499.8	3.4	6.05	3.16	0.00008
	RAPSCR	352045	3888487.3	3.4	6.05	3.16	0.00008
	RAPTP2	352045.2	3888474.3	3.4	6.05	3.16	0.00008
	RAPCRH	352057.2	3888470.5	3.4	6.05	3.16	0.00008
	RAPTP3	352069.7	3888467	3.4	6.05	3.16	0.00008
	RAPTP4	351966.8	3888466.8	3.4	6.05	3.16	0.00002
	AS_0001	351970.4	3888479.4	3.4	6.05	3.16	0.00002
	AS_0002	351973.9	3888491.9	3.4	6.05	3.16	0.00002
	AS_0003	351985.4	3888490.2	3.4	6.05	3.16	0.00002
	AS_0004	351997.9	3888486.6	3.4	6.05	3.16	0.00002
	MF_0006	352001.8	3888498.5	3.4	6.05	3.16	0.00002
	MF_0007	352003.4	3888504.2	3.4	6.05	3.16	0.00002
	MF_0008	351999.9	3888491.7	3.4	6.05	3.16	0.00002
	MF_0009	352005.7	3888484.5	3.4	6.05	3.16	0.00002
	MF_0010	352018.3	3888481.1	3.4	6.05	3.16	0.00002
	MF_0011	352030.8	3888477.6	3.4	6.05	3.16	0.00002
	MF_0012	352043.3	3888474.2	3.4	6.05	3.16	0.00002
	MF_0013	352055.9	3888470.8	3.4	6.05	3.16	0.00002
	MF_0014	352068.4	3888467.3	3.4	6.05	3.16	0.00002
	AG_0001	351955.6	3888597.1	3.4	6.05	3.16	0.00236
	AG_0002	351968.6	3888597.2	3.4	6.05	3.16	0.00236
	AG_0003	351981.6	3888597.4	3.4	6.05	3.16	0.00236
	AG_0004	351994.6	3888597.5	3.4	6.05	3.16	0.00236
	AG_0005	352007.6	3888597.7	3.4	6.05	3.16	0.00236
	AG_0006	352020.6	3888597.8	3.4	6.05	3.16	0.00236
	AG_0007	352033.6	3888597.9	3.4	6.05	3.16	0.00236
	AG_0008	352045.7	3888598.1	3.4	6.05	3.16	0.00236

Notes:

1 The Black Rock HMA 3443 facility was modeled using the aggregate scenario emissions for $PM_{2.5}$ as recommended by the City of Albuquerque with Jefferson Monitoring Station background concentrations.

2 Where available, 100% Aggregate Scenario Emissions were used from the data provided by the City of Albuquerque.

Table 11: NO_2/NOx In-Stack Ratios for Surrounding Sources used in NO2 NAAQS and NMAAQS Modeling

Facility	Modeling Source ID	In-Stack Ratio
BlackRock HMA 3443	BRHMASTK	0.5
	BR_HEAT	0.5
HollyFrontier 0559-M3-4TR	H1	0.2
	B1	0.2
	B2	0.2
	CO_1	0.2
Vulcan RAP 1626-7AR	27	0.2
Mega Corp 1292	4	0.2
Vulcan Osuna HMA 0104-M2-4AR	VOHMASTK	0.2
	VO_HEAT	0.2
Roadrunner CBP 0271-2AR	Road1	0.2
Roadrunner CBP 0505-M1-4AR	5	0.2
Vulcan Big-I HMA 1479-M3-5AR	6	0.2
	13	0.2

4.7.2 Cumulative Dispersion Modeling Results

The modeling results are summarized in Tables 12 through 15. All NO_2 and $PM_{2.5}$ concentrations, when added to background, are below both the NAAQS and the NMAAQS. Figure 9 illustrates the locations of maximum impacts.

Table 112: NO_2 1-hour NAAQS and NMAAQS Results

Pollutant		Modeled Concentration (µg/m³)¹	Background Concentration (µg/m³)²	Total Concentrations (µg/m³)³	Ambient Air Quality Standard (µg/m³)
NO_2	NAAQS	----	----	171.13	188.03
	NMAAQS	----	----	171.13	N/A

Notes:
1. The 1-hour NO_2 modeled concentration is the H8H averaged over a five-year period. The modeling files including "total" concentration and background concentration.
2. Background concentration determined from Hourly-Seasonal Background Data provided by the City of Albuquerque (see Table 4) entered directly into AERMOD.
3. The 1-hour NO_2 modeling was performed using the OLM.

Table 12: Annual NO_2 NAAQS and NMAAQS Results

Pollutant		Modeled Concentration (µg/m³)¹	Background Concentration (µg/m³)	Total Concentrations (µg/m³)²	Ambient Air Quality Standard (µg/m³)
NO_2	NAAQS	3.165	19	22.165	99.66
	NMAAQS	3.165	19	22.165	94.02

Notes:

1. The annual NO_2 concentration is the H1H for the five years modeled.
2. The annual NO_2 modeling was performed using the Ambient Molar Ratio version 2 (ARM2) method.

Table 14: 24-Hour $PM_{2.5}$ NAAQS and NMAAQS Results

Pollutant		Modeled Concentration (µg/m³)	Background Concentration (µg/m³)	Total Concentrations (µg/m³)	Ambient Air Quality Standard (µg/m³)
$PM_{2.5}$	NAAQS	1.82	22	23.82	35
	NMAAQS	1.82	22	23.82	N/A

Note:

1. The 24-hour $PM_{2.5}$ modeled concentration is the H8H averaged over a five-year period.

Table 135: Annual $PM_{2.5}$ NAAQS and NMAAQS Results

Pollutant		Modeled Concentration (µg/m³)	Background Concentration (µg/m³)	Total Concentrations (µg/m³)	Ambient Air Quality Standard (µg/m³)
$PM_{2.5}$	NAAQS	0.77	8.4	9.17	12
	NMAAQS	0.77	8.4	9.17	N/A

Note:

1 The annual $PM_{2.5}$ concentration is the H1H averaged over a five-year period.

FIGURES

Figure 1: Site Location Map

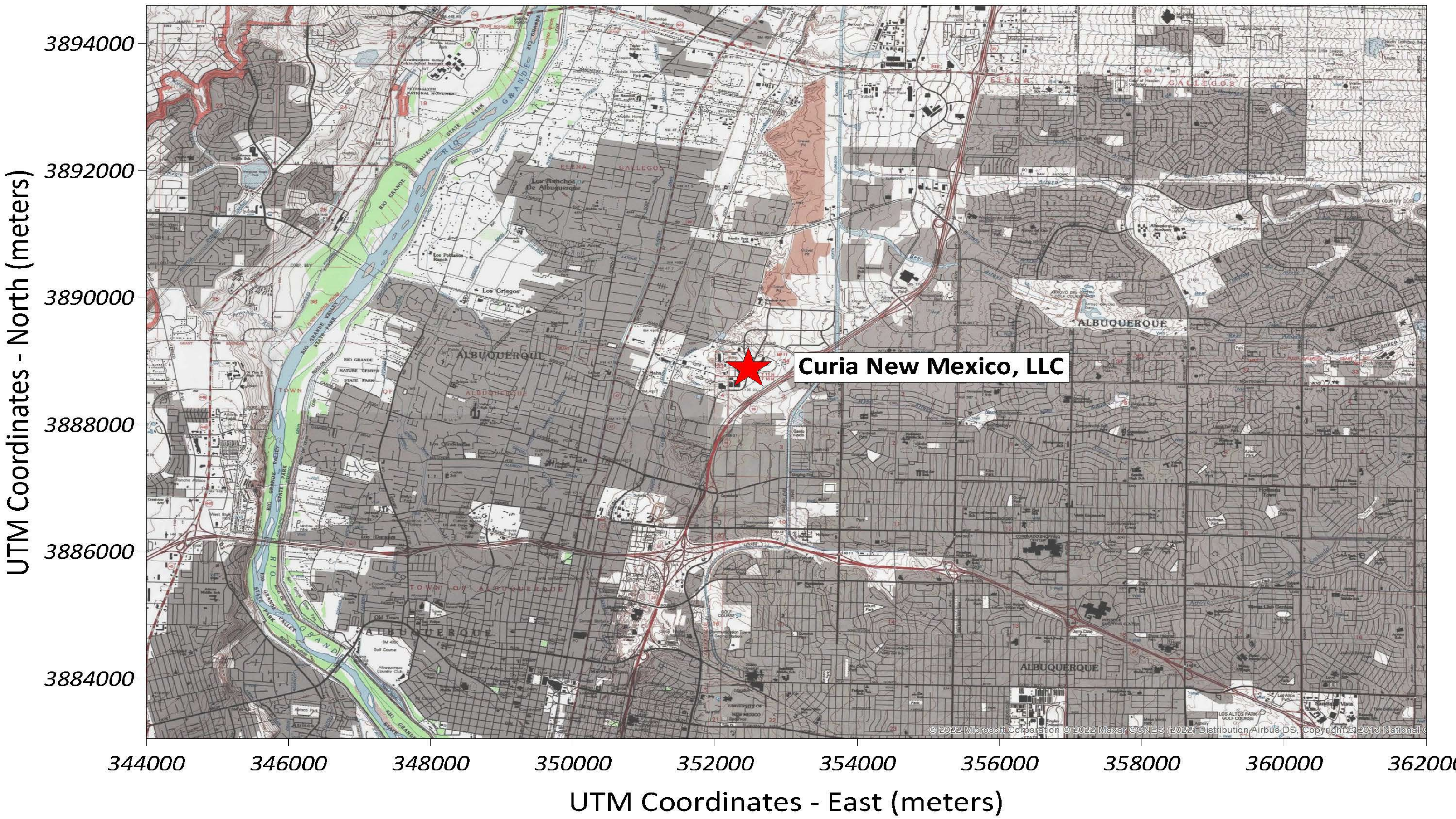

Figure 1

Site Location Map
Boiler Modeling Analysis
Curia New Mexico, LLIC
Albuquerque, NM

Environmental Resources Management
www.erm.com

Figure 2: 5-Year Windrose

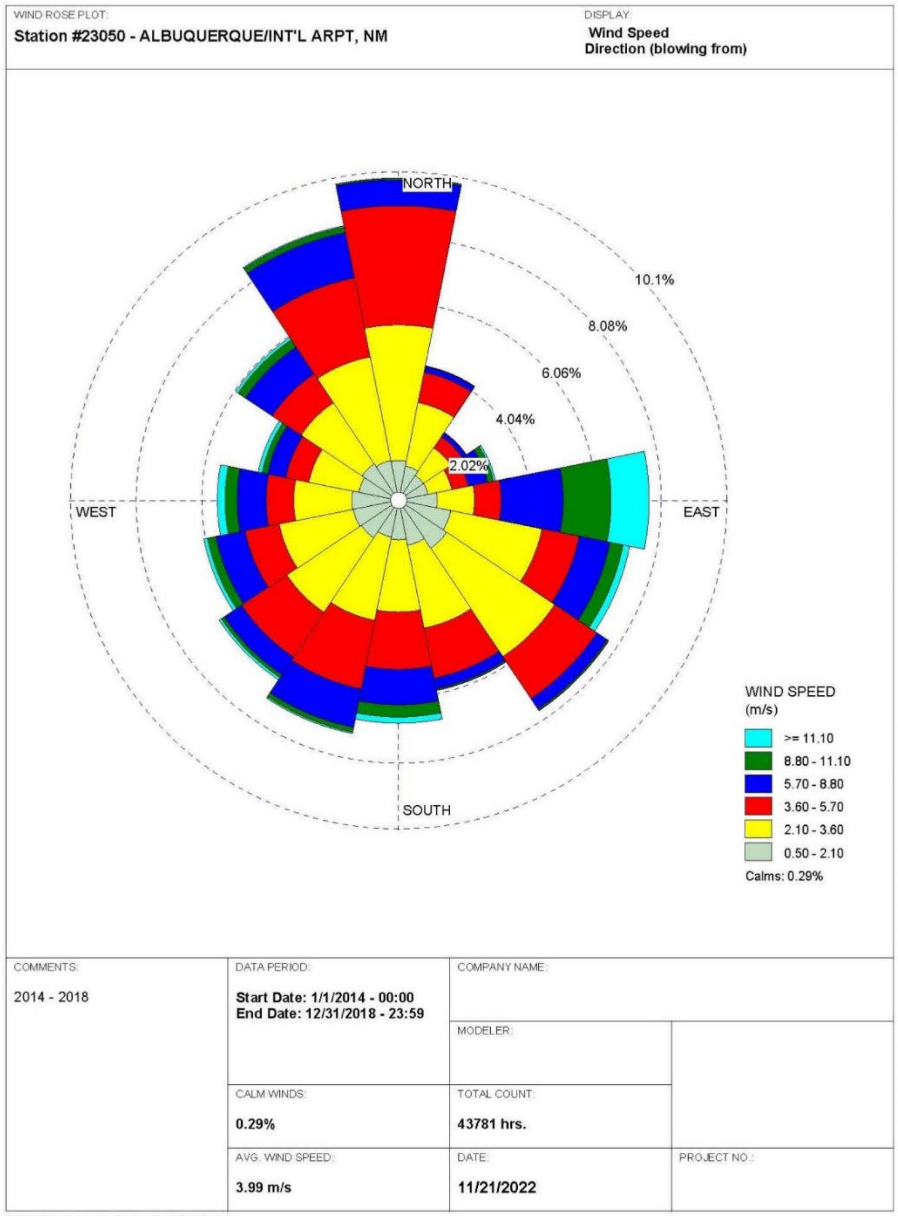

Figure 2

Five Year (2014 – 2018) Wind Rose – Albuquerque International Airport
Boiler Modeling Analysis
Curia New Mexico, LLC
Albuquerque, NM

Environmental Resources Management
www.erm.com

Figure 3: Property Boundary and Building Inputs

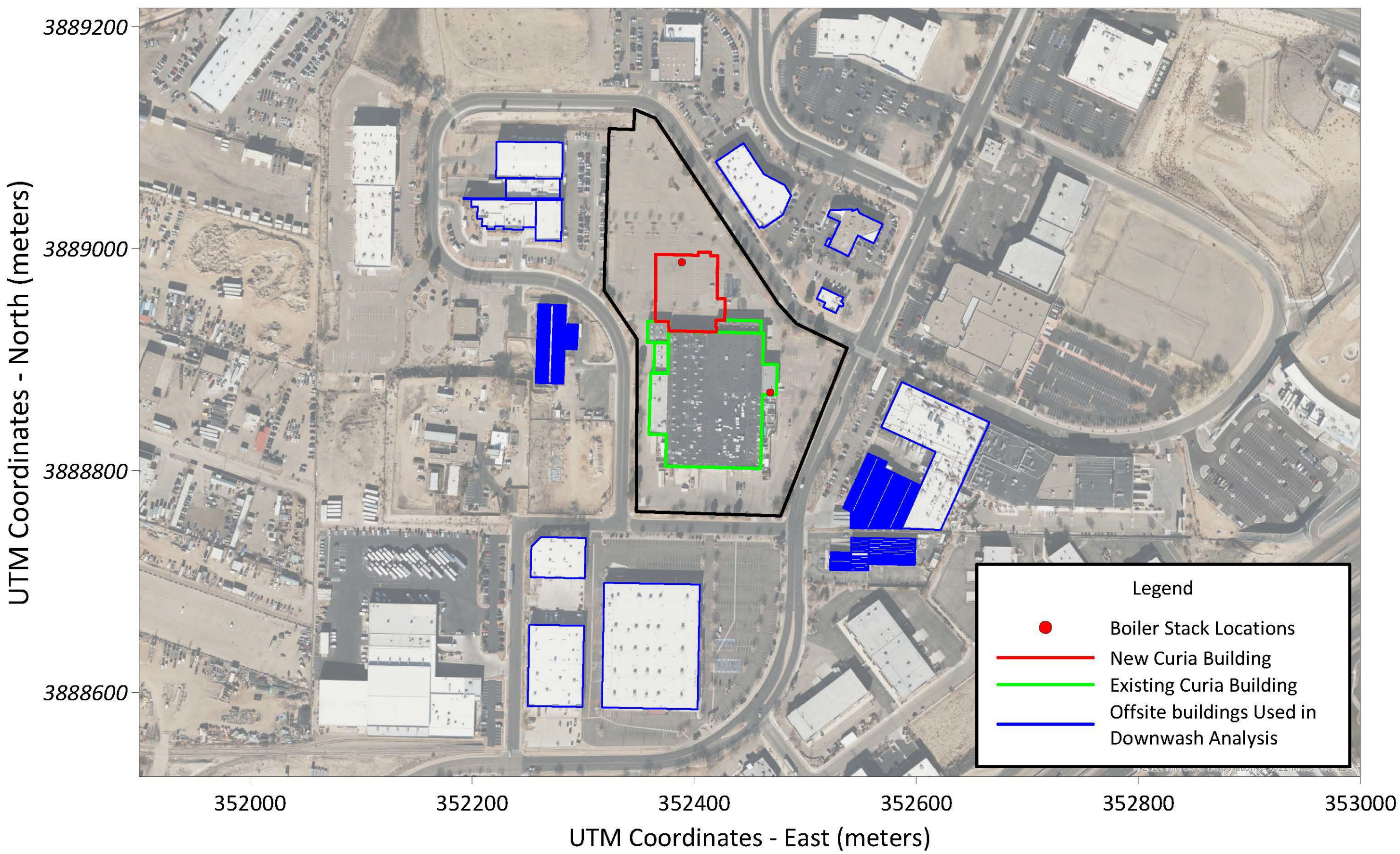

Figure 3

Property Boundary, Buildings & Stack Locations
Boiler Modeling Analysis
Curia New Mexico, LLIC
Albuquerque, NM

ERM

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Figure 4: Receptor Grid

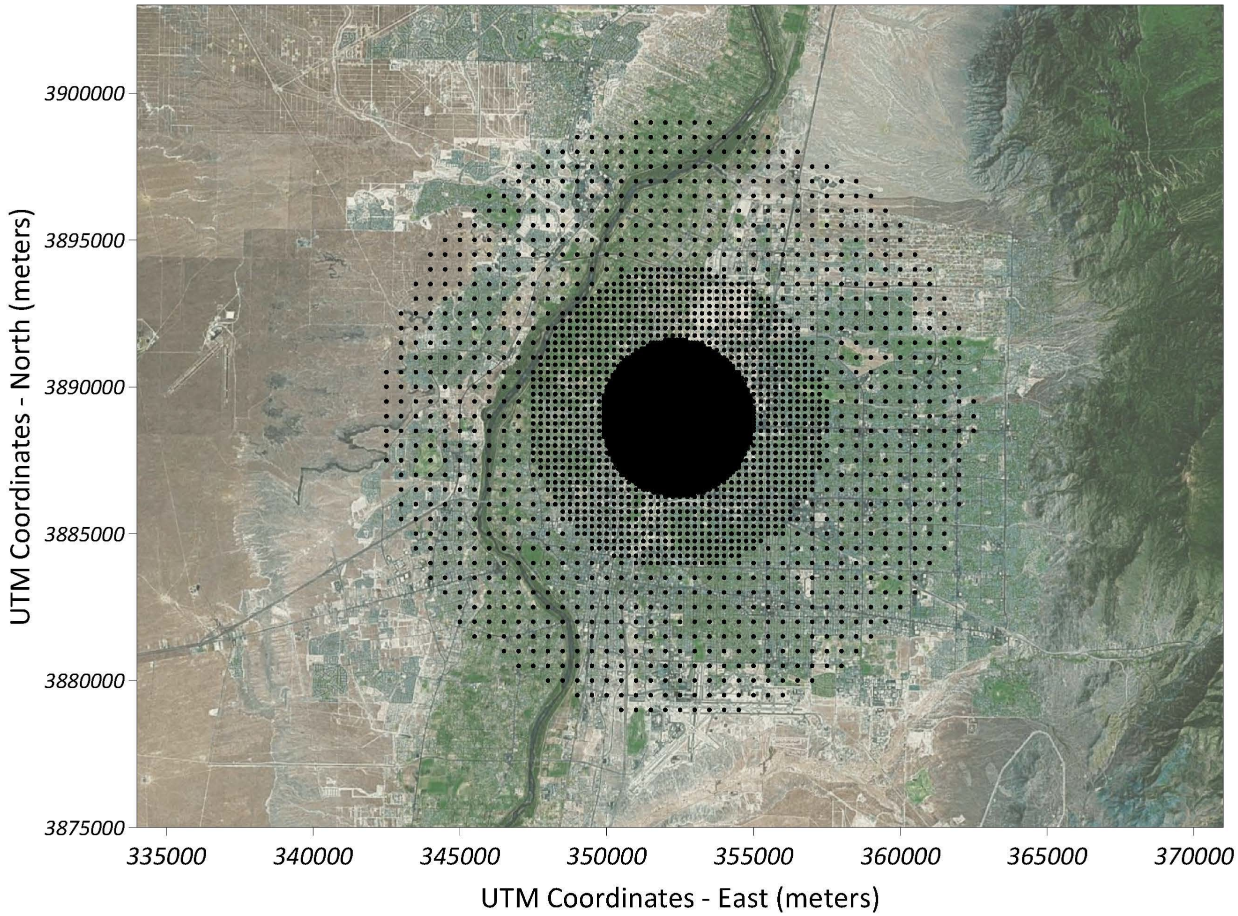

Figure 4

Environmental Resources Management
www.erm.com

Receptor Grid
Boiler Modeling Analysis
Curia New Mexico, LLIC
Albuquerque, NM

Figure 5: 1-HR NO_2 Receptors Greater than SIL

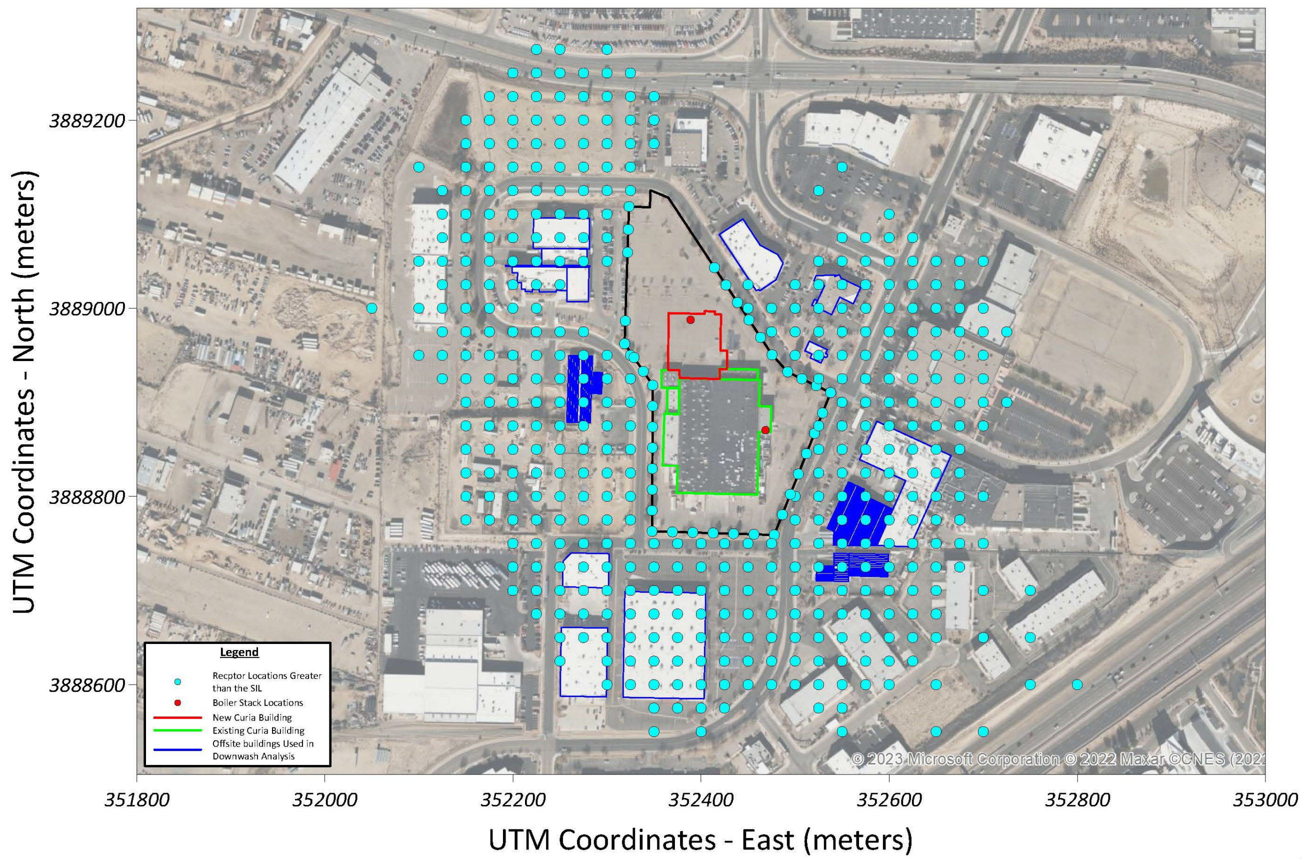

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Figure 5

Receptor Locations Exceeding the 1-Hour NO_2 SIL
Boiler Modeling Analysis
Curia New Mexico, LLC
Albuquerque, NM

Figure 6: Annual NO_2 Receptors Greater than SIL

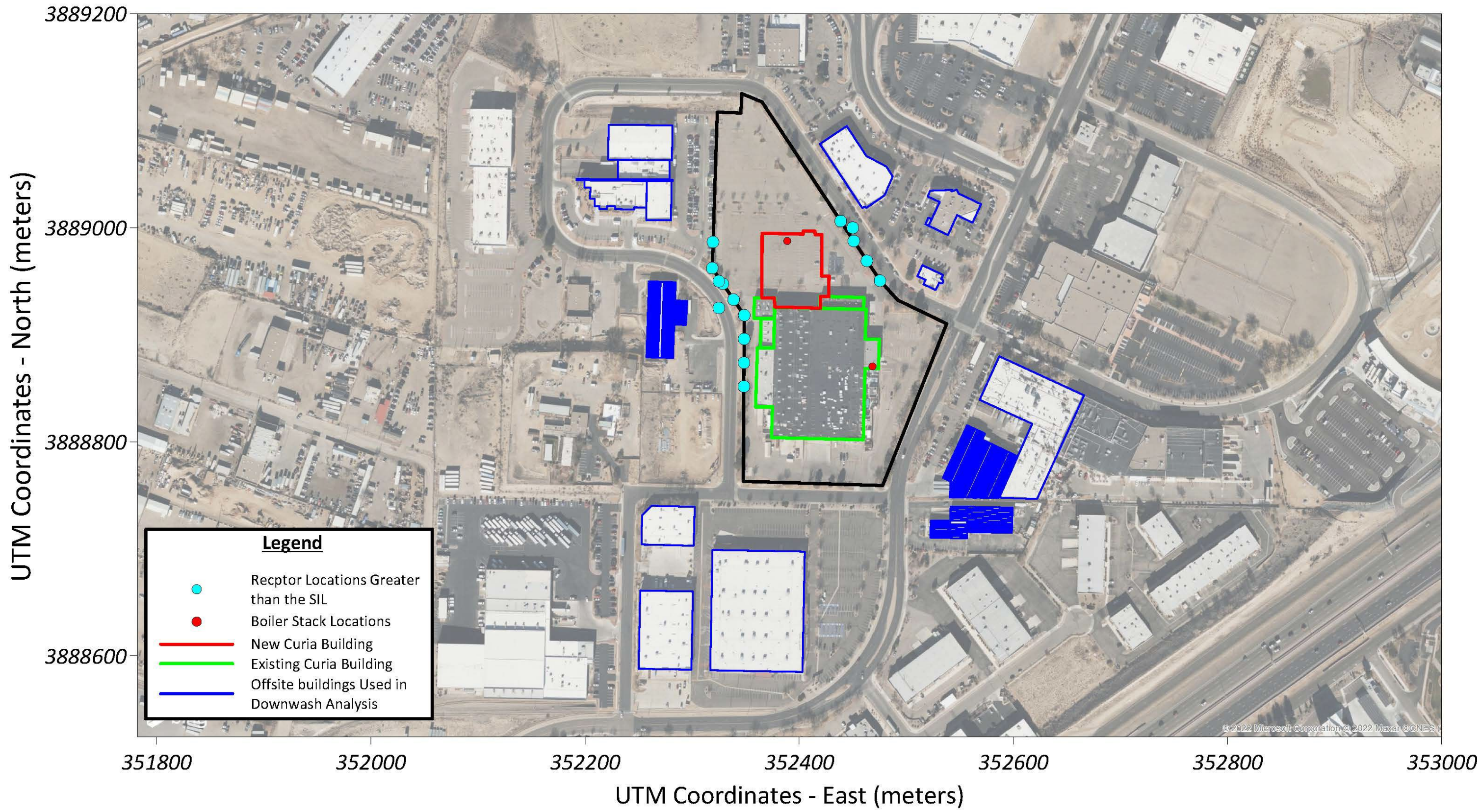

Figure 6

Receptor Locations Exceeding the Annual NO_2 SIL
Boiler Modeling Analysis
Curia New Mexico, LLC
Albuquerque, NM

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Figure 7: 24-HR $PM_{2.5}$ Receptors Greater than SIL

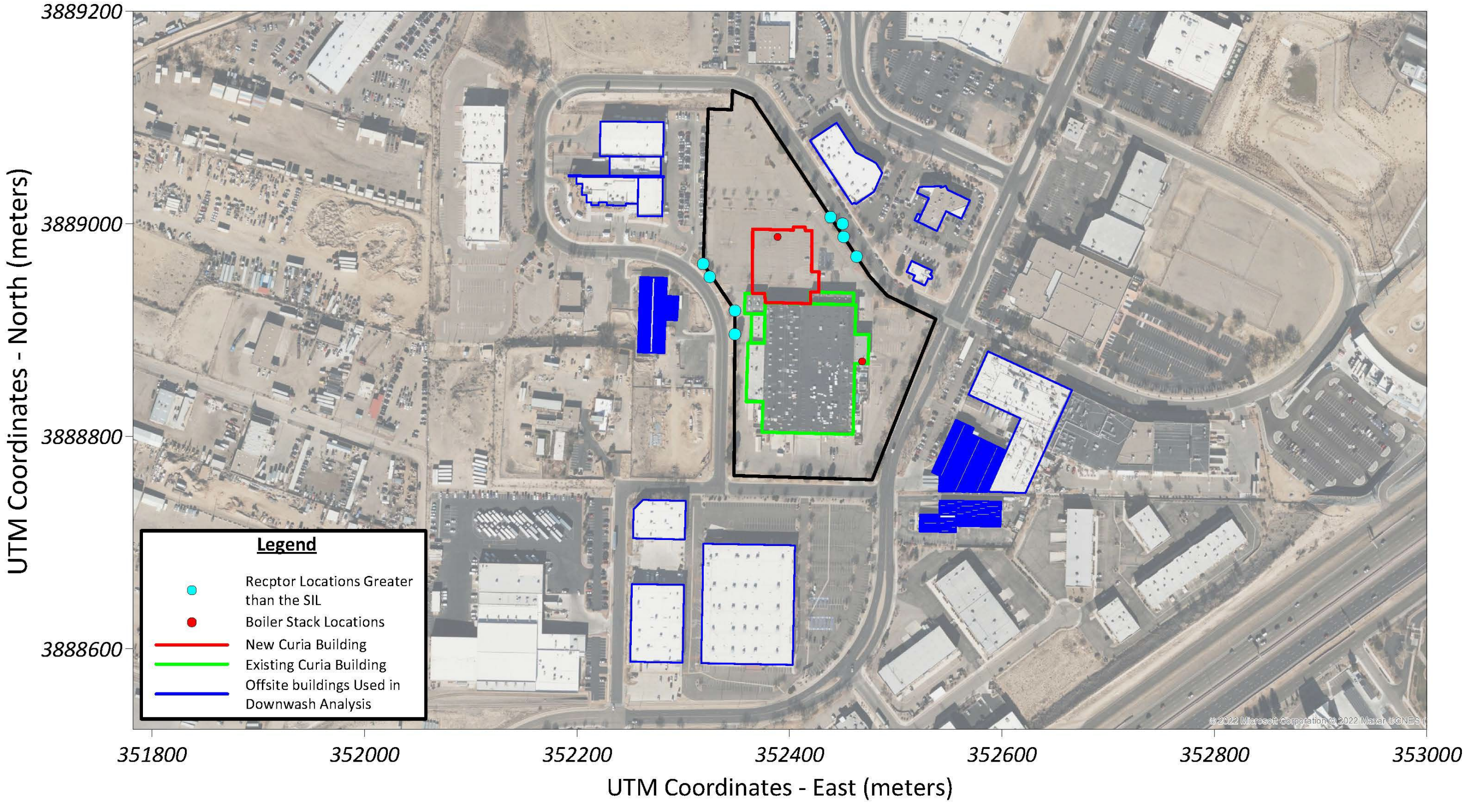

Figure 7

Receptor Locations Exceeding the 24-Hour $PM_{2.5}$ SIL
Boiler Modeling Analysis
Curia New Mexico, LLC
Albuquerque, NM

Environmental Resources Management
www.erm.com

Figure 8: Annual $PM_{2.5}$ Receptors Greater than SIL

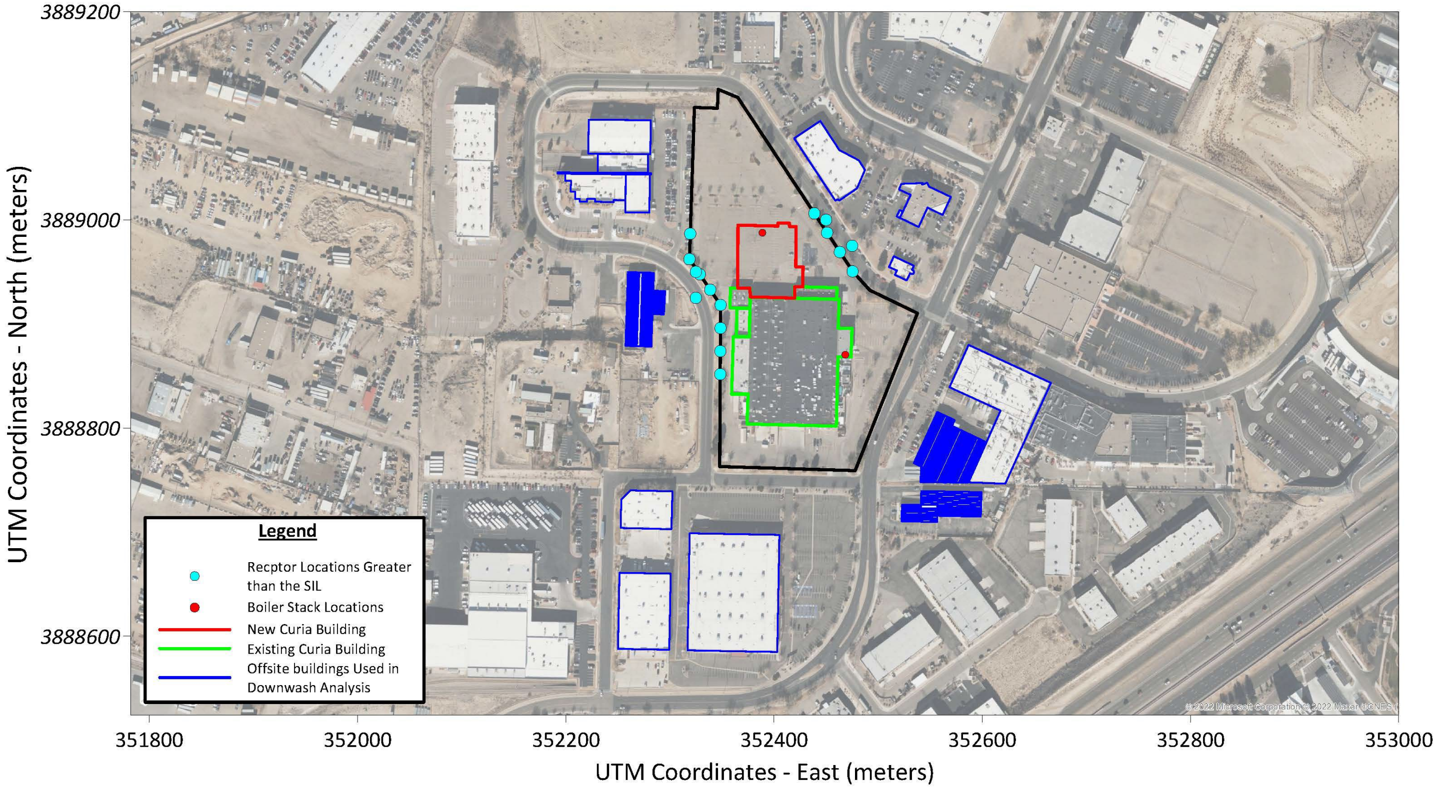

Figure 8

Receptor Locations Exceeding the Annual $PM_{2.5}$ SIL
Boiler Modeling Analysis
Curia New Mexico, LLC
Albuquerque, NM

Environmental Resources Management
www.erm.com

Figure 9: Maximum Locations

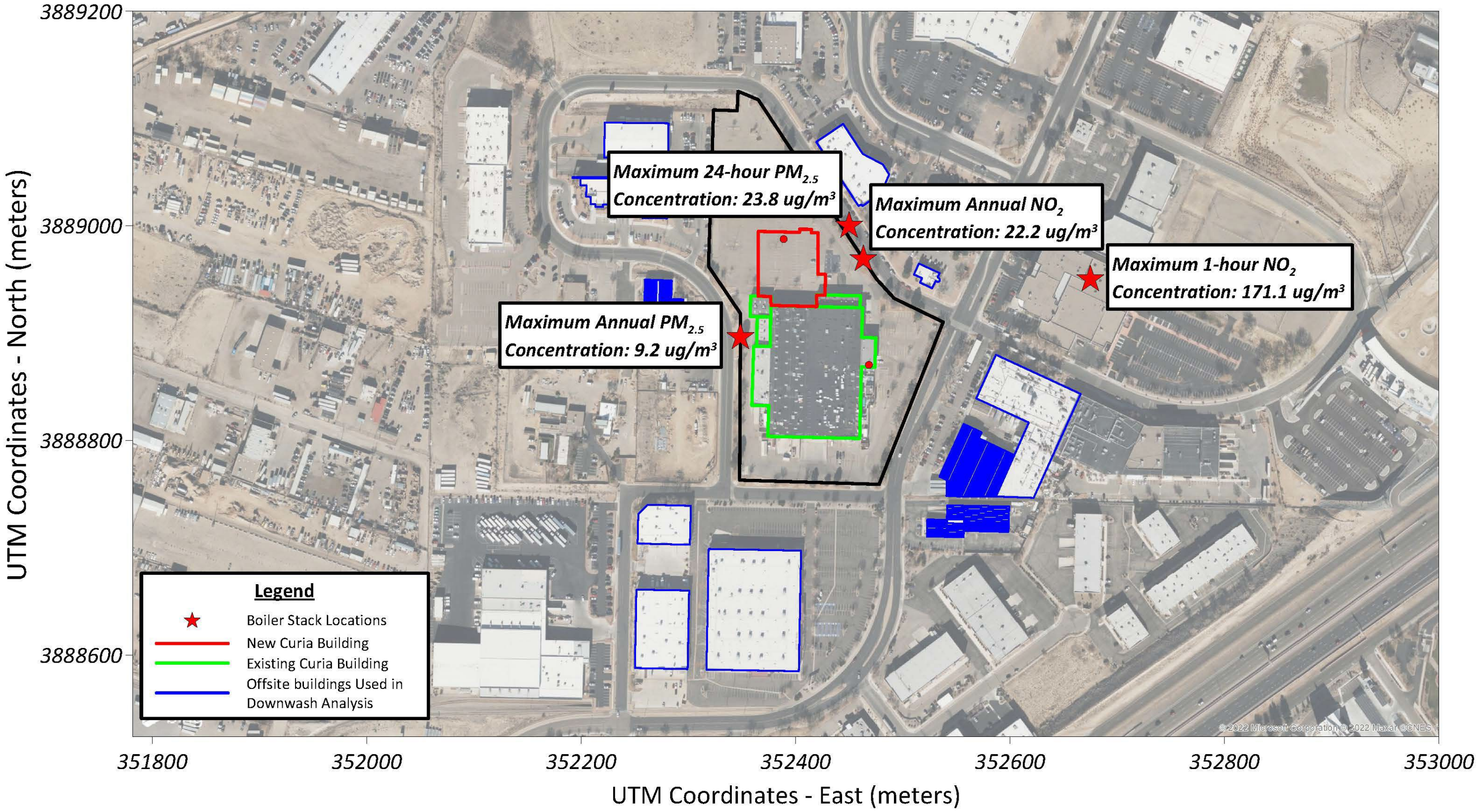

Figure 9

Maximum 1-Hour and Annual NO_2 Concentrations Including Background
and 24-Hour and Annual $PM_{2.5}$ Concentrations Including Background
Boiler Modeling Analysis
Curia New Mexico, LLC
Albuquerque, NM

Environmental Resources Management
www.erm.com

APPENDIX A AIR QUALITY CONSTRUCTION PERMIT #1097-M3-2AR

CITY OF ALBUQUERQUE

Environmental Health Department

Ángel Martinez Jr., Director

John Gerback, Jr.
Curia New Mexico
4401 Alexander Boulevard NE
Albuquerque, New Mexico 87107

October 5, 2022

Sent Via E-mail: John.gerbackjr@curia.com

Subject: **Air Quality Construction Permit #1097-M3-2AR (Revised)**
Certificate of Registration AIRS #NM/001/00510
Facility Name: Curia New Mexico, LLC
Facility Location: 4401 Alexander Boulevard NE, Albuquerque, NM 87107

Dear Mr. Gerback Jr.:

This letter constitutes an Administrative Revision to Construction Permit No.1097-M3-1TR for the Curia New Mexico, LLC (formerly Oso BioPharmaceuticals Manufacturing, LLC) located at 4401 Alexander Boulevard NE, Albuquerque, NM 87107. The City of Albuquerque, Environmental Health Department – Air Quality Program (Program) has reviewed your request received on August 5, 2021 pursuant to Federal Clean Air Act (CAA), and Title 20, Chapter 11, Part 41 of Albuquerque – Bernalillo County Air Quality Control Board New Mexico Administrative Code (NMAC), Section 28, Paragraph A.

The Program has assigned Construction Permit No. 1097-M3-2AR (Revised 10/05/2022) to the construction permit as amended by this letter. Unless specifically altered by this letter, all terms and conditions of Construction Permit No. 1097-M3-1TR are still in effect, except for the following administrative amendments:

PO Box 1293

Albuquerque

NM 87103

www.cabq.gov

1. Transfer of Ownership

Current Owner (Company Name, Company Contact and Company Address)	**New Owner*** (Company Name, Company Contact and Company Address)
Oso BioPharmaceuticals Manufacturing, LLC John Gerback, Jr. 4401 Alexander Boulevard NE Albuquerque, NM 87107	Curia New Mexico, LLC John Gerback, Jr. 4401 Alexander Boulevard NE Albuquerque, NM 87107

2. Facility Name Change

Current Facility Name	**New Facility Name**
Oso BioPharmaceuticals Manufacturing, LLC	Curia New Mexico, LLC

3. Removal of Unit #2 – Emergency Generator

	Engine Information	Generator Information
Manufacturer:	McGraw Edison	Onan
Model Number:	634D-1	101983
Serial Number:	B853874Z32	
Rated Capacity:	50hp	
Fuel:	Diesel	

4. Update Serial Numbers for Units #4 and #5:

	Unit #4	Unit #5
Unit Description:	Emergency Generator (Diesel)	Boiler (Natural Gas)
Manufacturer:	Engine: Cummins Generator: Cummins	Superior
Model Number	Engine: QSK19-G8 Generator: DQPAA-1755965	6-X-500
Serial Number:	Engine: 37274123 Generator: B180322832	18659
Manufacture and Installation Date:	2018	2018
Rated Capacity:	967 hp	4,200,000 Btu/ hr

This letter shall be attached to Construction Permit No. 1097-M3-1TR issued by the Program March 21, 2018 to serve as an acknowledgement by the Program that this Administrative Revision is authorized.

If you have any further questions, please do not hesitate to contact me by phone at (505) 768-1948 or via email at cmunoz-dyer@cabq.gov.

Sincerely,

Carina G. Munoz-Dyer
Environmental Health Manager
Permitting Division
Air Quality Program
Environmental Health Department
City of Albuquerque

Enclosure: Air Quality Construction Permit #1097-M3-1TR

Timothy M. Keller, Mayor

AIR QUALITY CONSTRUCTION PERMIT #1097-M3-1TR
FACILITY CDS #NM/001/00510
Facility ID: FA0003846; Record ID: PR0009226

Danny Nevarez, Acting Director

Issued to: Oso Biopharmaceuticals Manufacturing, LLC
4401 Alexander Blvd. NE
Albuquerque, New Mexico 87131

Certified Mail #7006 2760 0005 1562 9842
Return Receipt Requested

Responsible Official: David Lee, General Manager

Pursuant to the New Mexico Air Quality Control Act, Chapter 74, Article 2 New Mexico Statutes Annotated 1978 (As Amended); the Joint Air Quality Control Board Ordinance, 9-5-1 to 9-5-99 ROA 1994; the Bernalillo County Joint Air Quality Control Board Ordinance, Bernalillo County Ordinance 94-5; the Albuquerque-Bernalillo County Air Quality Control Board (A-BC AQCB) Regulation Title 20, New Mexico Administrative Code (20 NMAC), Chapter 11, Part 40 (20.11.40 NMAC), Air Contaminant Source Registration; and A-BC AQCB Regulation Title 20, NMAC, Chapter 11, Part 41 (20.11.41 NMAC), Construction Permits; **Oso Biopharmaceuticals Manufacturing, LLC** (Company or Permittee) is hereby issued this **CONSTRUCTION PERMIT** and authorized to operate the following equipment at:

Facility/Location	Facility Process Description	SIC	NAICS
Oso Biopharmaceuticals Manufacturing, LLC 4401 Alexander Blvd. NE Albuquerque, NM 87107 UTM 352421 E, 3888863 N	Pharmaceutical Manufacturing	2834	325412

This **CONSTRUCTION PERMIT** #1097-M3-1TR has been issued based on the review of the application received by the Albuquerque Environmental Health Department (Department), Air Quality Program on March 20, 2018 which was deemed complete on March 20, 2018, and on the National Ambient Air Quality Standards, New Mexico Ambient Air Quality Standards, and Air Quality Control Regulations for Albuquerque/Bernalillo County, as amended. As these standards and regulations are updated or amended, the applicable changes will be incorporated into Construction Permit #1097-M3-1TR and will apply to the facility. This permit supersedes all portions of Authority-to-Construct Permit #1097-M3 issued on December 22, 2017.

Issued on the 21st day of March, 2018

Isreal L. Tavarez

Isreal L. Tavarez, Environmental Health Manager
Permitting Division
Air Quality Program
Environmental Health Department
City of Albuquerque

I. CONDITIONS-- Conditions have been imposed in this permit to assure continued compliance. 20.11.41.19.D NMAC states that any term or condition imposed by the Department on a permit or permit modification is enforceable to the same extent as a regulation of the Board. Pursuant to 20.11.41 NMAC, the facility is subject to the following conditions:

1. <u>Construction and Operation</u>-- Compliance will be based on Department inspections of the facility, reviews of production records, and timely submission of appropriate permit applications for modifications, equipment substitutions, and relocations.

a) This permit modification authorizes the following:

i. Revision of a 3.4 MMBtu/hr natural gas fired Cleaver Brooks boiler to a 4.2 MMBtu/hr natural gas fired Superior boiler with a lox NOx burner.

b) This permit authorizes the construction and operation of the following equipment:

Unit No.	Description	Manufacturer	Model No.	Serial No.	Date of Mfg.	Rated Capacity/ Process Rate	Unit Subject to NSPS
1	Emergency Generator (Diese Fired)	Engine: Cummins	6CT 8 3G	45068185	Unknown	180 hp	No
		Generator: Onan Generator Set	125QSEA-714108	1940555595		125 kW	
2	Emergency Generator (Diese Fired)	Engine: McGraw Edison	634D-1 101983	B853874Z32	Unknown	50 hp	No
		Generator: Onan					
3	Emergency Generator (Diese Fired)	Engine: Cummins	QSL9-G	73472926	2008	464 hp	Yes
		Generator: Onan	DQDAB-1216217	L120426818		275 kW	
4	Emergency Generator (Diese Fired)	Engine: Cummins	QSK19-G8	TBD*	TBD*	967 hp	Yes
		Generator Cummins					
5	Boiler (Natural Gas Fired)	Superior	Seminole 6-5-500-S150	TBD*	TBD*	4,200,000 Btu/hr	No

** TBD - to be determined, see Condition 5(c)*

c) All equipment shall be maintained as per manufacturer specifications to ensure the emissions remain at or below the permitted levels.

d) This facility shall be constructed and operated in accordance with information provided on the permit application received **March 20, 2018** and in accordance with the legal authority specified above and the conditions of this permit.

e) Prior to any asbestos demolition or renovation work, the Department must be notified and proper permits shall be obtained and Code of Federal Regulations (CFR), Title 40, Part 61 (40 CFR 61) Subpart M may apply.

f) Units #3 and #4 are subject to Federal NSPS, 40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, and Subpart A - General Provisions. Units #3 and #4 commenced construction after July 11, 2005 and were manufactured after April 1, 2006. Accordingly, Units #3 and #4 shall comply with all applicable requirements of 40 CFR 60 Subparts A and IIII.

g) National Emissions Standard for Hazardous Air Pollutants (NESHAP) found in 40 CFR 63 Subpart ZZZZ -- National Emission Standards for Hazardous Air Pollutants for Source Category: Stationary Reciprocating Internal Combustion Engines apply and this facility shall comply with the specific requirements found in this subpart as well as the general requirements of 40 CFR 63 Subpart A - General Provisions. The permittee shall comply with the specific requirements of Subpart ZZZZ applicable to new engines.

h) The following equipment located at the facility is restricted to operate as follows:

i. Units #1 and #2 shall each be restricted to a maximum of 500 hours of operation based on a 12-month rolling total, and shall only be operated during loss of commercial power and as required by the manufacturer for engine exercising/maintenance. The unit(s) shall not be operated to generate power for peak shaving or sale to third parties, but only to provide emergency power for the facility. Routine or non-emergency operation of the units or operation for any other purposes, except as stated above, shall be a violation of this permit.

ii. Units #3 and #4 shall be restricted to a maximum of 500 hours of operation based on a 12-month rolling total, and shall only be operated during loss of commercial power and as required by the manufacturer for engine exercising/maintenance. Pursuant to 40 CFR 60 Subpart IIII §60.4211(f), Units #3 and #4 shall be limited to 100 hours per year of maintenance checks and readiness testing. Units #3 and #4 may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for the facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. Routine or non-emergency operation of the unit or operation for any other purposes, except as stated above, shall be a violation of this permit.

iii. The permittee shall meet the diesel fuel requirements as required by 40 CFR 60 Subpart IIII §60.4207(b).

iv. The permittee shall operate and maintain Units #3 and #4 according to the manufacturer's written instructions or procedures developed by the permittee that have been approved by the manufacturer. In addition, the permittee may only change those settings that are allowed by the manufacturer. The permittee must also meet the requirements of 40 CFR Parts 89, 94, and/or 1068 as they apply. This condition is Pursuant to 40 CFR 60 Subpart IIII §60.4211.

v. In accordance with 40 CFR 63 Subpart ZZZZ §63.6590(c), an affected source that is a new or reconstructed stationary RICE located at an area source "must meet the requirements of this part by meeting the requirements of 40 CFR 60 Subpart IIII, for compression ignition engines." The permittee shall comply with the specific requirements of Subpart IIII applicable to new stationary compression ignition internal combustion engines meeting the definition of a new engine.

vi. Facility solvent and chemical usage shall not result in emissions exceeding 4.0 tons per year of non-HAP Volatile Organic Compounds (VOCs) based on a 12-month rolling total.

vii. Unit #5 may operate continuously.

i) Changes in plans, specifications, and other representations proposed in the application documents shall not be made if they will increase the potential to emit or cause a change in the method of control of emissions or in the character of emissions. Any such proposed changes shall be submitted as a modification to this permit.

No modification shall begin prior to issuance of a permit.

j) The emission of a regulated air pollutant in excess of the quantity, rate, opacity, or concentration specified in an air quality regulation or permit condition that results in an excess emission is a violation of the air quality regulation or permit condition and may be subject to an enforcement action. The owner or operator of a source having an excess emission shall, to the extent practicable, operate the source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. This condition is pursuant to 20.11.49.14 NMAC.

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2. **Unit Emission Limits**-- Condition 2, Unit Emission Limits, has been placed in the permit in accordance with 20.11.41.19.B and C NMAC and 40 CFR 60 Subpart IIII, to allow the Department to determine compliance with the terms and conditions of the permit. These were the emission rates stated in the permit application and are the basis of the Department's review. Compliance will be based on Department inspections of the facility and upon compliance with the emission limits and opacity readings conducted in accordance with the test methods specified in Condition 6 **Compliance Tests**.

   a) Units #1, #2, #3, #4, and #5 shall not exceed the emissions limits stated in the table below. Ton per year (tpy) emission limits shall be based on a 12-month rolling total.

Unit Emission Limits

Unit #	NO_x lb/hr[1]	NO_x tpy	NO_x + NMHC lb/hr[3]	NO_x + NMHC tpy	CO lb/hr	CO tpy	SO_2 lb/hr	SO_2 tpy	VOC lb/hr	VOC tpy	TSP lb/hr	TSP tpy	PM_{10} lb/hr	PM_{10} tpy	$PM_{2.5}$ lb/hr	$PM_{2.5}$ tpy	Percent Opacity	Record Keeping Require-ments[1]	Monitoring Require-ments[1]	Reporting Require-ments[1]	Compliance Testing Require-ments[1]
1	7.25	1.81	-	-	1.56	0.39	0.48	0.12	0.58	0.14	0.51	0.13	0.51	0.13	0.51	0.13	20%, 40% @ startup	Yes	Yes	Yes	No
2	2.02	0.50	-	-	0.43	0.11	0.13	0.03	0.16	0.04	0.14	0.04	0.14	0.04	0.14	0.04	20%, 40% @ startup	Yes	Yes	Yes	No
3	-	-	3.07	0.77	2.66	0.66	0.11	0.03	-	-	0.15	0.04	0.15	0.04	0.15	0.04	20%, 40% @ startup	Yes	Yes	Yes	No
4	-	-	10.23	2.56	5.54	1.39	0.23	0.06	-	-	0.32	0.008	0.32	0.008	0.32	0.008	20%, 40% @ startup	Yes	Yes	Yes	No
5	0.13	0.57	-	-	0.16	0.70	0.004	0.02	0.034	0.15	0.02	0.09	0.02	0.09	0.02	0.09	20%	Yes	Yes	Yes	Yes
TOTALS	**9.4**	**2.88**	**13.3**	**3.33**	**10.35**	**3.25**	**0.95**	**0.26**	**0.77**	**0.33**	**1.14**	**0.31**	**1.14**	**0.31**	**1.14**	**0.31**					

[1] *For emissions inventory reporting, the combined total of the NOx and NMHC emission rates shall not exceed the combined NMHC+NOx emission limits specified in the table above. See Condition 5(g)and 5(f) for individual NOx and NMHC lb/hr emission rates.*
[2] *Refer to Conditions 3, 4, and 5 for unit-specific record keeping, monitoring, and reporting requirements*
[3] *Refer to Condition 6 unit specific compliance testing requirements*

   b) In accordance with 40 CFR 60 Subpart IIII §60.4205(b), owner and operators of 2007 model year and later emergency stationary diesel-powered engines with a displacement of less than 30 liters per cylinder that are not fire engines must comply with the emission standards for new non-road diesel engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary diesel engine. Units #3 and #4 shall comply with the emission standards in 40 CFR 89.112(a) for the maximum permitted engine power or the pound per hour (lb/hr) and opacity emission limits as specified in Condition 2(a).

Emission Standards		
Pollutant	g/kW-hr	g/hp-hr
NMHC−NO_x	6.4	4.8
CO	3.5	2.6
PM	0.15	0.20

c) For Unit #4, compliance with CO, NOx + NMHC, TSP, PM_{10}, and $PM_{2.5}$ pound per hour (lb/hr) emissions limits, shall be shown by meeting the requirements of 40 CFR 60 Subpart IIII §60.4211(c).

d) Units #1, #2, #3, and #4 shall not cause or allow visible air emissions from any stationary diesel powered engine to exceed 20 percent opacity for any six (6) minute timed average. During the first twenty (20) minutes of cold start-up, the visible emissions shall not exceed 40 percent opacity for any (6) minute timed average. No increase of load shall be applied so as to cause an emission having an opacity greater than 40 percent during any time interval. This condition is pursuant to 20.11.5.13.C NMAC.

e) Process Equipment Unit #5 shall not cause or allow visible emissions to exceed 20 percent opacity for any six (6) minute timed average pursuant to 20.11.5.12 NMAC.

3. **Record keeping**--Condition 3 has been placed in the permit in accordance with 20.11.41.19.B(4) NMAC, 20.11.41.19.C(8) and (11) NMAC, and 40 CFR 60 Subpart IIII to allow the Department to determine compliance with the terms and conditions of the permit. Compliance will be based on Department inspection of records and logs.

   a) Maintain an accurate monthly log for Units #1, #3, #3, and #4 hours of operation, both as a monthly total and as a 12-month rolling total.

   b) Record and maintain a monthly log of all chemical/solvent usages for VOC (non-HAP) emissions in tons based on a 12-month rolling total. The emissions shall be calculated using the weight percent of each VOC, information on MSDS sheets, and usage records.

   c) The Facility shall maintain all (Material Safety Data Sheets) MSDS sheets for all chemicals and solvents used at the facility.

   This information shall be retained at the plant site for the most recent two-year period and shall be made available to Department personnel upon request.

4. **Monitoring**--Condition 4 has been placed in the permit in accordance with 20.11.41.19.B(4) NMAC, 20.11.41.19.C(7),(8),(9),(10) and (11) NMAC, and 40 CFR 60 Subpart IIII, to allow the Department to determine compliance with the terms and conditions of the permit. Compliance will be based on Department inspection of equipment and logs. The permittee shall install the appropriate equipment deemed necessary by the Department for performance testing and continuous emissions monitoring.

   a) Install an hour meter system and monitor Units #1 and #2 monthly hours of operation.

   b) Install a non-resettable hour meter prior to the startup of Units #3 and #4. This condition is pursuant to 40 CFR 60 Subpart IIII §60.4209(a).

   c) Monitor the annual hours of operation for Units #1, #2, #3, and #4.

5. **Reporting**-- Condition 5 has been placed in the permit in accordance with 20.11.41.19.B(4) NMAC, 20.11.41.19.C(9) and (11) NMAC, 20.11.41.21 NMAC, and 20.11.90 NMAC to allow the Department to determine compliance with the terms and conditions of the permit. Compliance will be based on timely submittal of the reports, notifications, and required information and shall be made in accordance with 40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60 Subpart A - General Provisions, and 20.11.41.21 NMAC.

   The permittee shall notify the Department in writing of:

   a) The anticipated startup of the source not less than thirty (30) days prior to that date (20.11.41.21.A(1) NMAC);

   b) The actual date of initial startup of the source within fifteen (15) days after the initial startup date

(20.11.41.21.A(3) NMAC);

c) All information labeled "TBD" cited under Condition 1(b) within thirty (30) days of installation;

d) Any change in control or ownership, name, address, or contact information. The permittee may request an administrative permit revision in accordance with 20.11.41.28.A NMAC;

e) Any permit update or correction as required by 20.11.41 NMAC no more than 60 days after the permittee knows or should have known about the condition that requires updating or correction of the permit (20.11.41.21.A(6) NMAC);

f) Replacement of emission units for which an allowable emissions limit has been established in the permit may be requested through a technical permit revision in accordance with 20.11.41.28.B NMAC;

g) An annual (January 1 through December 31 of the previous year) emissions inventory to include the annual hours of operation for Units #1, #2, and #5 together with descriptions of any reconfiguration of process technology and air pollution equipment by March 15 every year. All pollutants shall be reported using actual hours of operation; and,

h) An annual (January 1 through December 31 of the previous year) emissions inventory to include the annual hours of operation for Unit #3 together with descriptions of any reconfiguration of process technology and air pollution equipment by March 15 every year. The emissions inventory shall be calculated based on each individual pollutant's permitted pound per hour rate and reported for the actual hours of operation. **The combined NMHC+NO_X emission standard shall be reported as individual emissions. The emission rate for NO_X is 3.03 lb/hr and NMHC is 0.04 lb/hr.** Emission rates that are determined through compliance testing shall be used for all emission inventory reporting requirements (20.11.41.21.B NMAC); and,

i) An annual (January 1 through December 31 of the previous year) emissions inventory to include the annual hours of operation for Unit #4 together with descriptions of any reconfiguration of process technology and air pollution equipment by March 15 every year. The emissions inventory shall be calculated based on each individual pollutant's permitted pound per hour rate and reported for the actual hours of operation. **The combined NMHC+NO_X emission standard shall be reported as individual emissions. The emission rate for NO_X is 9.718 lb/hr and NMHC is 0.51 lb/hr.** Emission rates that are determined through compliance testing shall be used for all emission inventory reporting requirements (20.11.41.21.B NMAC).

j) The permittee of a source having an excess emission shall provide the Department with the following reports on forms provided by the Department:
   i. INITIAL REPORT: The permittee shall file an initial report, no later than the end of the next regular business day after the time of discovery of an excess emission pursuant to 20.11.49.15.A(1) NMAC;

   ii. FINAL REPORT: The permittee shall file a final report, no later than 10 days after the end of the excess emission. If the period of an excess emission extends beyond 10 days, the permittee shall submit the final report to the department within 72 hours of the date and time the excess emission ceased. This condition is pursuant to 20.11.49.15.A(2) NMAC and 20.11.49.15.C NMAC; and,

   iii. ALTERNATIVE REPORTING: If the facility is subject to the reporting requirements of 40 CFR Parts 60, 61, and 63 and the federal requirements duplicate the requirements of 20.11.49.15 NMAC, then the federal reporting requirements shall suffice. This condition is pursuant to 20.11.49.15.D NMAC.

6. **Compliance Tests**-- Condition 6 has been placed in the permit in accordance with 40 CFR 60 Subpart A - General Provisions, 20.11.41.22 NMAC, and 20.11.90.13 NMAC. Compliance will be based on the satisfactory completion of the compliance tests, the timely submittal of the emission unit test results to the Department, and on meeting the emission limits specified in Condition 2.

   a) Initial and annual compliance testing requirements for Units #1, #2, #3, #4, and #5 have not been imposed at this time.

b) Compliance tests and a testing schedule may be re-imposed (or imposed) if inspections of the source indicate non-compliance with permit conditions or the previous test showed non-compliance or was technically unsatisfactory. All compliance tests shall be conducted in accordance with EPA Methods contained in Appendix A of 40 CFR 60, unless otherwise approved by the Department.

c) For all compliance tests, the owner or operator shall notify the Department at least fifteen (15) days prior to the test date and allow a representative of the Department to be present at the test (20.11.41.22 NMAC and 40 CFR 60 Subpart A - General Provisions).

d) For all compliance tests, the permittee shall provide for the Department's approval a written test protocol at least fifteen (15) days prior to the anticipated test date. The protocol shall describe the test methods to be used (including sampling locations), and shall describe data reduction procedures. Any variation from the established sampling and analytical procedures or from facility operating conditions shall be presented for Department approval.

e) For all compliance tests, the test protocol and compliance test report shall conform to the standard format specified by the Department.

f) All compliance tests shall be conducted at ninety (90%) percent of the unit's permitted capacity or greater to demonstrate compliance with the permitted emission limits. Compliance testing at other than 90% production levels shall be performed at the Department's request and/or approval.

g) One copy of the compliance test results shall be submitted to the Department Enforcement Section within thirty (30) days after the completion of testing.

Unit Specific Compliance Testing

Unit Number	Initial Compliance Test	Frequency of Compliance Test
1	Not required*	Not required*
2	Not required*	Not required*
3	Not required*	Not required*
4	Not required*	Not required*
5	Not required*	Not required*

*Compliance tests have not been imposed for this unit at this time, but may be imposed if inspections of the source indicate non-compliance with permit conditions.

7. **Modifications**-- Condition 7 has been placed in the permit in accordance with 20.11.41.7.U NMAC to enable the Department to review proposed changes to the facility which may constitute a permit modification prior to such changes. Compliance will be based on Department inspections and the submittal of a new permit application for any modification.

   a) Any future physical changes or changes in the method of operation which results in an increase in the pre-controlled emission rate may constitute a modification as defined by 20.11.41.7.U NMAC. No modification shall begin prior to issuance of a permit. Modifications or revisions to this permit shall be processed in accordance with 20.11.41 NMAC.

8. **Compliance Assurance/Enforcement**-- All air pollution emitting facilities within Bernalillo County are subject to all applicable Albuquerque/Bernalillo County Air Quality Control Regulations, whether listed in this permit or not.

   a) The issuance of a permit or registration does not relieve the Facility from responsibility of complying with the provisions of the Air Quality Control Act, and the laws and regulations in force pursuant to the Act (20.11.41.18 NMAC).

b) Any conditions imposed upon the Facility as the result of a Construction Permit or any other permit issued by the Department shall be enforceable to the same extent as a regulation of the Board (20.11.41.19.D NMAC).

c) The Department is authorized to issue a compliance order requiring compliance and assessing a civil penalty not to exceed Fifteen Thousand and no/100 Dollars ($15,000) per day of noncompliance for each violation, commence a civil action in district court for appropriate relief, including a temporary and permanent injunction (74-2-12 NMSA).

d) Scheduled and Unscheduled Inspection (74-2-13 NMSA)-- The Department will conduct scheduled and unscheduled inspections to insure compliance with the Air Quality Control Act, the laws and regulations in force pursuant to the Act, and this Permit, and, upon presentation of credentials:

   i. Shall have a right of entry to, upon, or through any premises on which an emission source is located or on which any records required to be maintained by regulations of the Board or by any permit condition are located;

   ii. May at any reasonable time have access to and copy any records required to be established and maintained by Regulations of the Board, or any permit condition;

   iii. May inspect any monitoring equipment and method required by Regulations of the Board or by any permit condition; and,

   iv. Sample any emissions that are required to be sampled pursuant to Regulation of the Board, or any permit condition.

e) Any credible evidence may be used to establish whether the facility has violated or is in violation of any regulation of the Board, or any other provision of law. Credible evidence and testing shall include, but is not limited to (20.11.41.27A and B NMAC):

   i. A monitoring method approved for the source pursuant to 20.11.42 NMAC "Operating Permits" and incorporated into an operating permit;

   ii. Compliance methods specified in the Regulations, conditions in a permit issued to the facility, or other provision of law;

   iii. Federally enforceable monitoring or testing methods, including methods in 40 CFR Parts 51, 60, 61, and 75; and,

   iv. Other testing, monitoring or information-gathering methods that produce information comparable to that produced by any CFR method and approved by the Department and EPA.

9. **Posting of the Permit**-- Compliance will be based on Department inspections of the facility, which show that a copy of the permit has been posted in a visible location. A copy of this permit shall be posted in a visible location at the plant site at all times. The permit shall be made available to Department personnel for inspection upon request.

10. **Annual Fees**-- Condition 10 has been placed in the permit in accordance with 20.11.2 NMAC to allow the Department to determine compliance with the terms and conditions of the permit. Compliance will be based on the receipt of the annual emissions fee due each year to the Department pursuant to 20.11.2 NMAC. Every owner or operator of a source that is required to obtain a Source Registration, a Construct Permit, an operating permit, or a preconstruction permit shall pay an annual emissions fee pursuant to 20.11.2 NMAC, 20.11.40 NMAC, 20.11.41 NMAC, 20.11.42 NMAC, 20.11.60 NMAC, 20.11.61 NMAC, or 20.11.62 NMAC.

II. ADDITIONAL REQUIREMENTS

1. **Permit Cancellation**-- The Department may cancel any permit if the construction or modification is not

commenced within two (2) years from the date of issuance or if, during the construction or modification, work is suspended for a total of one (1) year pursuant to 20.11.41.20.B NMAC.

Application for permit modifications, relocation notices, and items listed under **ADDITIONAL REQUIREMENTS** shall be submitted to:

Albuquerque Environmental Health Department
Air Quality Program
Permitting Section
P.O. Box 1293
Albuquerque, New Mexico 87103

Test protocols and compliance test reports shall be submitted to:

Albuquerque Environmental Health Department
Air Quality Program
Attention: Enforcement Supervisor
P.O. Box 1293
Albuquerque, New Mexico 87103

All reports shall be submitted to:

Albuquerque Environmental Health Department
Air Quality Program
Attention: Compliance Officer
P.O. Box 1293
Albuquerque, New Mexico 87103

APPENDIX A

Estimated Emissions

Proposed Emission Unit #7

16.7 MMBTU/hr Natural Gas Boiler - Johnston MODEL: PFTA 400-4
Ultra-Low-NOx Configuration

Manufacturer Provided Specifications:

4-Pass Steam Packaged Firetube Boiler		
w/ IC-SA-1755 NT Series Burner		
Gas Input	16,700	MBTU/hr
Fuel Heat Content (Natural Gas)	1,020	BTU/CF
Burner Max Rate (Gas Input)	16,373	SCFH

Manufacturer Specified Emission Rate:

NOx	9	< ppm

Operating Hours (Hr/yr) 8760

Boiler Stack Emissions - Natural Gas (Uncontrolled)

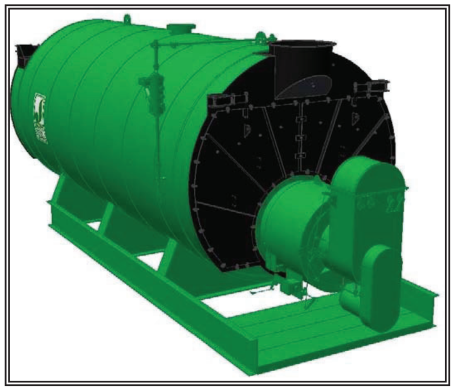
Pollutant	Emission Factor (lb/MMcf)	Emission Factor Source	Pounds Per Hour (lb/hr)	Tons Per Year (TPY)
CO	84	EPA AP-42, Table 1.4-1	1.38	6.02
NOx	32	EPA AP-42, Table 1.4-1 Controlled Low NOx Burners /Flue Gas Recirculation (Manufacturer <9 ppm)	0.52	2.29
VOC	5.5	EPA AP-42, Table 1.4-2	0.09	0.39
SO_2	0.6	EPA AP-42, Table 1.4-2	0.01	0.04
$PM/PM_{10}/PM_{2.5}$	7.6	EPA AP-42, Table 1.4-2	0.12	0.55
Lead	0.0005	EPA AP-42, Table 1.4-2	8.19E-06	3.59E-05

APPENDIX B BOILER MANUFACTURER INFORMATION

JOHNSTON BOILER COMPANY

MODEL: PFTA 400-4

4-Pass Steam Packaged Firetube Boiler



Ratings & Performance Data

Horsepower 400			
Steam Storage, ft^3	74.8	Natural Gas Flow, SCFH (1,000 Btu/ft^3)**	16,305
Steam Disengaging Area, ft^2	82.2	Combustion Air (15% Excess), SCFM***	2,984
Total Heating Surface, ft^2	2,026	Flue Gas Flow Rate, lb/hr***	14,219
Furnace Outside Diameter, in	42.0	Stack Flue Gas Velocity, ft/min***	2,017
Furnace Heat Release Rate, Btu/ft^3 hr**	161,000	#2 Oil Flow, gal/hr (140,000 BTU/gal)**	112.3
Total Combustion Volume, ft^3	148.0	#6 Oil Flow, gal/hr (150,000 BTU/gal)**	104.2
Total Heat Release Rate, Btu/ft^3 hr**	110,000	Flue Gas Side Pressure Drop, in. H_2O	3.9
Water Content N.W.L., gal	2,435	Water Content Flooded, gal.	2,995
Approx. Dry Weight 15#, lb	27,400	Approx. Operating Weight 15#, lb.	48,000
Approx. Dry Weight 150#, lb	31,400	Approx. Operating Weight 150#, lb.	52,000
Approx. Dry Weight 200#, lb	35,100	Approx. Operating Weight 200#, lb.	55,700
Approx. Dry Weight 250#, lb	39,600	Approx. Operating Weight 250#, lb.	60,200
Approx. Dry Weight 300#, lb	44,200	Approx. Operating Weight 300#, lb.	64,800

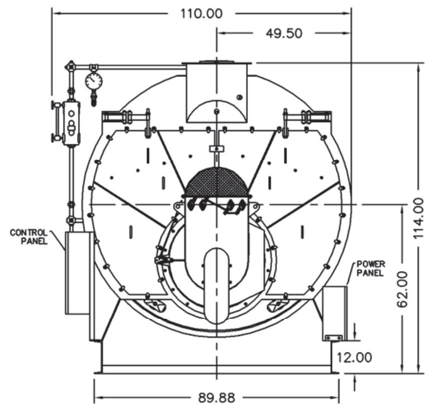
Performance Data

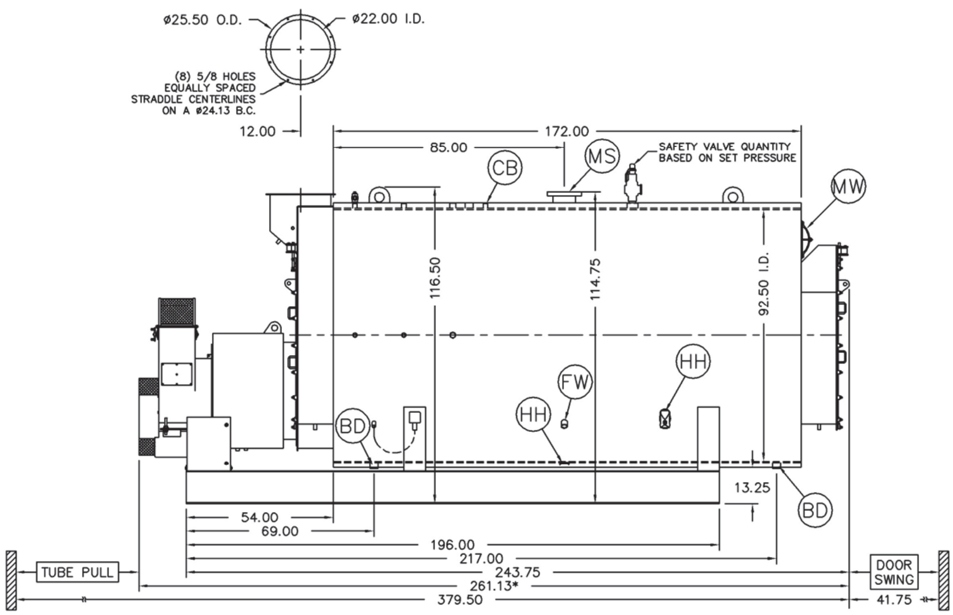
Operating Pressure (psig)	Steam Rate (lb/hr)	Natural Gas		#2 Oil		#6 Oil	
		Stack Temp (F)	%Eff	Stack Temp (F)	%Eff	Stack Temp (F)	%Eff
10	13,891	308	84.6	320	87.7	335	88.2
50	13,622	366	83.2	379	86.2	394	86.7
100	13,476	407	82.1	419	85.2	436	85.7
150	13,395	435	81.4	448	84.4	466	84.9
200	13,344	458	80.8	470	83.8	489	84.3
250	13,312	476	80.4	489	83.4	508	83.8
300	13,291	492	79.9	505	82.9	525	83.4

*Based on 228°F feedwater and 3% O_2, ** Values calculated at 100 psi operating pressure, ***Calculated Firing Natural Gas

Drawings - 4-Pass Steam Packaged Firetube Boiler

Connection & Opening Schedule			
Conn.	Description	Type	Qty
FW	Feedwater Inlet	2.00 FNPT	2
MS*	Main Steam	6.00 300# RF	1
CB	Continuous Blowoff	1.00 FNPT	1
BD	Blowdown Outlet	2.00 FNPT	2
MW	Manway	12 X 16	1
HH	Hand Hole	4 X 6	7
*10.00 150#RF Flange on 15 psig Design			

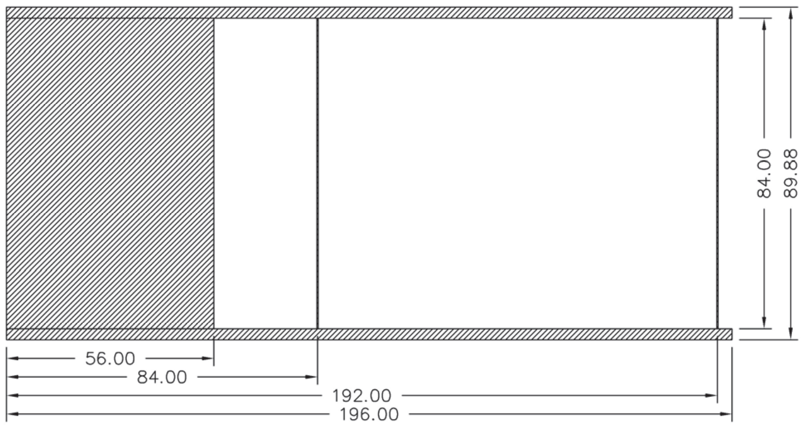


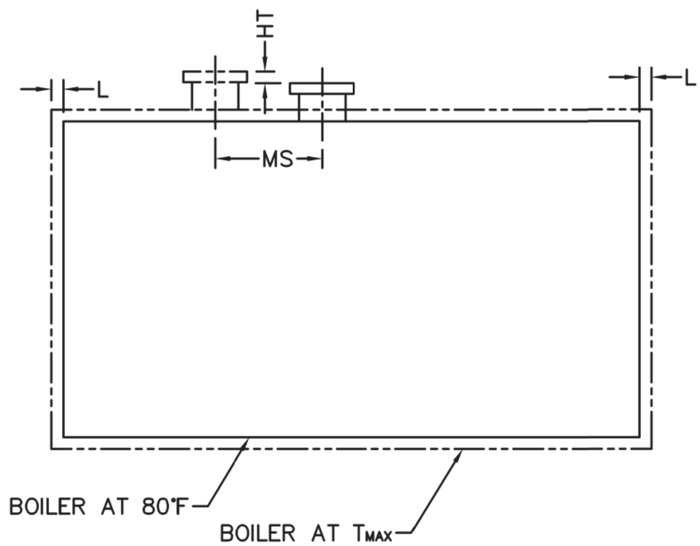


Notes:
150# Steam design shown, all dimensions given in inches.
Fuel piping and/or optional boiler trim may increase overall width.
Specifications subject to change to incorporate engineering advances.
***May vary on low-NO_x designs**

MODEL: PFTA 400-4

Base Diagram



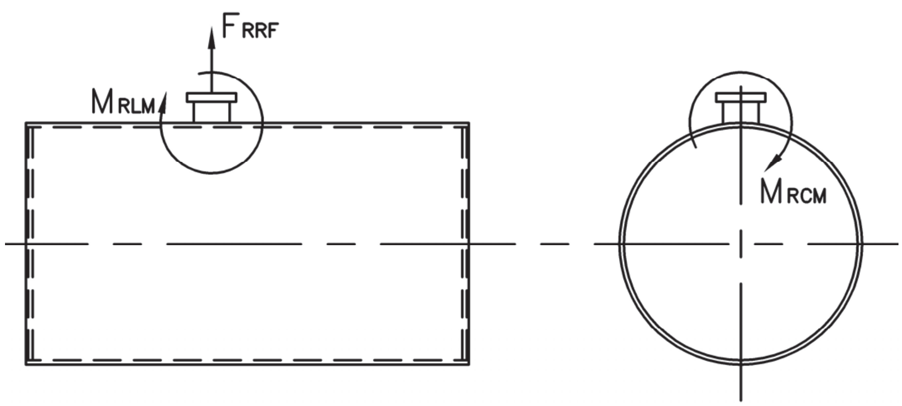


Thermal Expansion					
psig	15	150	200	250	300
Metal T_{MAX} (F)	240	366	388	406	421
L (in)	0.088	0.147	0.159	0.168	0.176
MS (in)	0.001	0.002	0.002	0.002	0.002
HT (in)	0.095	0.160	0.172	0.182	0.191

MODEL: PFTA 400-4

Nozzle Loadings

Maximum Allowable Load on Boiler Steam Nozzle					
	15# Design	150# Design	200# Design	250# Design	300# Design
F_{RRF}, lb	8,980	2,775	4,335	5,495	4,920
M_{RCM}, in-lb	60,810	28,745	46,625	61,140	56,770
M_{RLM}, in-lb	117,350	24,765	36,950	46,030	47,465



Stack Emissions-Natural Gas (1,000 Btu/CF)				
	PPMv (Corr to 3% O_2)	lb/MBtu	lb/hr @ Full Rate	Ton/Yr @ Full Rate
NO_x *	110	0.131	2.135	9.352
	30	0.036	0.582	2.551
	9	0.011	0.175	0.765
CO	50	0.037	0.60	2.624
CO_2	2.55 lb/lb fuel	119.76	1,953	8,553
H_20	2.03 lb/lb fuel	106.16	1,731	7,582
Stack Emissions-#2 Oil** (140,000 Btu/gal)				
NO_x	128	0.174	2.738	11.992
CO	50	0.037	0.578	2.530
CO_2	3.20 lb/lb fuel	168.53	2,650	11,608
H_20	1.12 lb/lb fuel	71.20	1,120	4,904
* 110 ppm "A" Burner, 30 ppm A-FGR Burner, 9 ppm FIR Burner				
**0.02% fuel bound Nitrogen				

Distributed By:

JOHNSTON BOILER COMPANY

300 Pine Street
P.O. Box 300
Ferrysburg, MI 49409-0300
Telephone: (616) 842-5050
Net: www.johnstonboiler.com

Printed Feb. 2008

APPENDIX C ELECTRONIC MODELING FILES

Data files provided electronically in flash drive.

Attachment 7

Air Quality Zoning Requirement

City of Albuquerque
Environmental Health Department
Air Quality Program

Construction Permit (20.11.41 NMAC)
Zoning Requirement Cover Letter

This Cover Letter Must Be Returned With The Application Along With All Required Attachments

The Albuquerque-Bernalillo County Joint Air Quality Program, which administers and enforces local air quality laws for the City of Albuquerque ("City") and Bernalillo County ("County"), on behalf of the City Environmental Health Department ("Department").

Any person seeking a new air quality permit or a permit modification under 20.11.41 NMAC (Construction Permits) shall provide documentary proof that the proposed air quality permitted use of the facility's subject property is allowed by the zoning designation of the City or County zoning laws, as applicable. Sufficient documentation may include (i) a zoning certification from the City Planning Department or County Department of Planning and Development Services, as applicable, if the applicant is subject to City or County zoning jurisdiction; or (ii) a zoning verification from both planning departments if the applicant is not subject to City or County zoning jurisdiction. A zone atlas map shall not be sufficient. At this time, applicants are not required to submit documentation for the subject property's zoning designation when applying for an emergency permit, a new portable stationary source, a relocation of a portable stationary source, or a technical or administrative revision to an existing permit.

The Department will rule an application administratively incomplete if it is missing or has incorrect information. If the Department has ruled an application administratively incomplete three (3) times, the Department will deny the permit application. Any fees submitted for processing an application that has been denied will not be refunded. If the Department denies an application, a person may submit a new application and the fee required for a new application. The applicant has the burden of demonstrating that a permit should be issued.

The Department may require additional information that is necessary to make a thorough review of an application. At all times before the Department has made a final decision regarding the application, an applicant has a duty to promptly supplement and correct information the applicant has submitted in an application to the Department. The applicant's duty to supplement and correct the application includes, but is not limited to, relevant information acquired after the applicant has submitted the application and additional information the applicant otherwise determines is relevant to the application and the Department's review and decision. While the Department is processing an application, regardless of whether the Department has determined the application is administratively complete, if the Department determines that additional information is necessary to evaluate or make a final decision regarding the application, the Department may request additional information and the applicant shall provide the requested additional information.

NOTICE REGARDING SCOPE OF A PERMIT: The Department's issuance of an air quality permit only authorizes the use of the specified equipment pursuant to the air quality control laws, regulations and conditions. Permits relate to air quality control only and are issued for the sole purpose of regulating the emission of air contaminants from said equipment. Air quality permits are not a general authorization for the location, construction and/or operation of a facility, nor does a permit authorize any particular land use or other form of land entitlement. It is the applicant's/permittee's responsibility to obtain all other necessary permits from the appropriate agencies, such as the City Planning Department or County Department of Planning and Development Services, including but not limited to site plan approvals, building permits, fire department approvals and the like, as may be required by law for the location, construction and/or operation of a facility. For more information, please visit the City Planning Department website at https://www.cabq.gov/planning and the County Department of Planning and Development Services website at https://www.bernco.gov/planning.

Corporate and Facility Information: This information shall match the information in the permit application**.**

Air Quality Permit Applicant Company Name: **Curia New Mexico, LLC**			
Facility Name: **Curia New Mexico, LLC**			
Facility Physical Address: **4401 Alexander Boulevard NE**	City: **Albuquerque**	State: **NM**	Zip: **87107**
Facility Legal Description:			

General Operation Information: This information shall match the information in the permit application.

Permitting action being requested (please refer to the definitions in 20.11.41 NMAC):
☐ New Permit ☒ Permit Modification, Current Permit #: **1097-M3-2AR**

Attachment Information: The location information provided to the City Planning Department or County Department of Planning and Development Services, as applicable, and reflected in the zoning certification or verifications, as applicable, shall be the same as the Facility location information provided to the Department in the air quality construction permit application.

☐ Zoning Certification Provided by: Choose an item. *This is a use-specific certification.* **City Planning Form**: https://www.cabq.gov/planning/code-enforcement-zoning **County Planning Form**: https://www.bernco.gov/planning/planning-and-land-use/applications-forms/	☒ City Zoning Verification ☐ County Zoning Verification **City Planning Form**: https://www.cabq.gov/planning/code-enforcement-zoning **County Planning Form**: https://www.bernco.gov/planning/planning-and-land-use/applications-forms/

CITY OF ALBUQUERQUE – PLANNING DEPARTMENT
CODE ENFORCEMENT DIVISION

ZONING VERIFICATION REQUEST

OVERVIEW

What is a zoning verification statement?
A zoning verification statement is written confirmation provided by the city to confirm the current zoning designation of a particular piece of property.

What type of information is provided in a zoning verification statement?
Verification statements contain the following information:

- The assigned address of the subject site
- The legal description of the property
- The zoning designation of the property
- The overlay district or sector plan affecting the property, if applicable

Zoning verification statements <u>DO NOT</u> include the following:

- Confirmation of the existing development's compliance with current zoning code requirements*, conformance/non-conformance of existing uses or structures, or reference to building or fire codes
- Copies of site plans, special exceptions, certificates or other approvals
- The zoning designations of abutting or nearby properties
- Reference to existing zoning code violations

**Written confirmation of a property's compliance with current zoning standards, reference to nonconformance/rebuild allowances, and/or types of permitted development on a property are provided through our ZONAL CERTIFICATION process.*

How do I obtain a zoning verification statement?
Complete the form on the reverse side of this brochure and return it to:

City of Albuquerque – Code Enforcement Division
600 2nd St. NW, Suite 500
Albuquerque, New Mexico 87102
(505) 924-3847

THERE IS NO FEE FOR A ZONING VERIFICATION STATEMENT

SELF-HELP RESOURCES

- **Zoning Code**. If you would like to view and/or obtain copies of the Comprehensive City Zoning Code, please visit the following website:
  - http://www.amlegal.com/albuquerque_nm/
- **Recorded Documents**. If you would like copies of official recorded documents such as site plans, special exceptions or certificates of occupancy, please make a Freedom of Information Act (FOIA) request to:
  - cityclerk@cabq.gov
- **GIS Data**. If you would like mapping or geographic information, please visit the following website:
  - www.cabq.gov/gis/advanced-map-viewer
- **Related City Agencies**. If you would like information on City of Albuquerque building codes, fire codes or other development standards, please visit the following website:
  - www.cabq.gov

HELPFUL HINTS

- Make sure the property is located within the Albuquerque city limits prior to requesting a verification statement.
- Provide the legal description of the property and/or the Uniform Property Code (UPC) number. This information helps staff to identify the property and expedite your request.
- Verification statements are processed in the order that they are received. Depending upon division workload and service demands, verification statements may take up to seven (7) days to complete.

For more information, contact:

City of Albuquerque
Planning Department

Phone: (505) 924-3450
(505) 924-3860

www.cabq.gov/planning

Code Compliance Manager:
Andrew Garcia

Revised April 2017

CITY OF ALBUQUERQUE – PLANNING DEPARTMENT
CODE ENFORCEMENT DIVISION

ZONING VERIFICATION REQUEST

DID YOU REMEMBER TO…

- Verify that the property is located within the city limits?
- Provide the legal description of the property and/or the Uniform Property Code (UPC) number?
- Submit your request at least seven (7) days before the verification statement is needed?

City of Albuquerque
PO Box 1293
Albuquerque, New Mexico 87103
www.cabq.gov

FOR STAFF USE ONLY

DATE RECEIVED: ______

RECEIVED BY: ______

ZAP: ______ ZONE: ______

SUBJECT PROPERTY

4401 Alexander Blvd NE
ADDRESS

LOT	BLOCK	SUBDIVISION
B	5	SUNDTS INDUSTRIAL CENTER

101606106405930310
UPC #

Curia New Mexico, LLC
OWNER OF RECORD

APPLICANT INFORMATION

John Gerback, Jr
NAME

Curia New Mexico
COMPANY / ORGANIZATION

4401 Alexander Boulevard NE, Albuquerque, New Mexico 87107
ADDRESS

PHONE	EMAIL
505.340.5989	John.gerbackjr@curia.com

STATEMENT DETAILS

ADDRESS THE STATEMENT TO: ☒ *SAME AS APPLICANT*

NAME

COMPANY / ORGANIZATION

ADDRESS

PHONE FAX EMAIL

CITY OF ALBUQUERQUE

CODE ENFORCEMENT
Plaza Del Sol Building, Suite 500
600 2nd Street NW
Albuquerque, NM 87102
Tel: (505) 924-3850 Fax: (505) 924-3847

Date: November 29, 2022

VIA Email, John.gerbackjr@curia.com
John Gerback, Jr
4401 Alexander Boulevard NE
Albuquerque, NM 87107

RE: 4401 ALEXANDER BLVD NE – the "property".
UPC: 101606106405930310

To Whom It May Concern:

This letter will certify that according to the map on file in this office on November 29, 2022, the property located at: **4401 ALEXANDER BLVD NE**, legally described as: **TR B BLK 5 PLAT OF TRACTS A & B BLK 5 SUNDT'S INDUSTRIALCENTER CONT 11.8662 AC**, Albuquerque, Bernalillo County, New Mexico, is Zoned: NR-GM Non-residential - General Manufacturing Zone District.

If you have any questions regarding this matter please feel free to contact code enforcement by email at codeenforcement@cabq.gov

Sincerely:

Angelo Metzgar
Code Compliance Manager

Attachment 8

Basis of Emission Rates

	UNITED STATES ENVIRONMENTAL PROTECTION AGENCY **2022 MODEL YEAR** **CERTIFICATE OF CONFORMITY** **WITH THE CLEAN AIR ACT**	**OFFICE OF TRANSPORTATION** **AND AIR QUALITY** **ANN ARBOR, MICHIGAN 48105**

Certificate Issued To: Cummins Inc. (U.S. Manufacturer or Importer) **Certificate Number: NCEXL060.AAD-041**	**Effective Date:** **08/19/2021** **Expiration Date:** **12/31/2022**	**Byron J. Bunker, Division Director** **Compliance Division**	**Issue Date:** **08/19/2021** **Revision Date:** **N/A**

Model Year: 2022 **Manufacturer Type:** Original Engine Manufacturer **Engine Family:** NCEXL060.AAD	**Mobile/Stationary Indicator:** Stationary **Emissions Power Category:** kW>560 **Fuel Type:** Diesel **After Treatment Devices:** No After Treatment Devices Installed **Non-after Treatment Devices:** Electronic Control

Pursuant to Section 111 and Section 213 of the Clean Air Act (42 U.S.C. sections 7411 and 7547) and 40 CFR Part 60, and subject to the terms and conditions prescribed in those provisions, this certificate of conformity is hereby issued with respect to the test engines which have been found to conform to applicable requirements and which represent the following engines, by engine family, more fully described in the documentation required by 40 CFR Part 60 and produced in the stated model year.

This certificate of conformity covers only those new compression-ignition engines which conform in all material respects to the design specifications that applied to those engines described in the documentation required by 40 CFR Part 60 and which are produced during the model year stated on this certificate of the said manufacturer, as defined in 40 CFR Part 60.

It is a term of this certificate that the manufacturer shall consent to all inspections described in 40 CFR 1068 and authorized in a warrant or court order. Failure to comply with the requirements of such a warrant or court order may lead to revocation or suspension of this certificate for reasons specified in 40 CFR Part 60. It is also a term of this certificate that this certificate may be revoked or suspended or rendered void *ab initio* for other reasons specified in 40 CFR Part 60.

This certificate does not cover engines sold, offered for sale, or introduced, or delivered for introduction, into commerce in the U.S. prior to the effective date of the certificate.

The actual engine power may lie outside the limits of the Emissions Power Category shown above. See the certificate application for details.

2022 EPA Tier 2 Exhaust Emission Compliance Statement 1750DQKAD Stationary Emergency

60 Hz Diesel generator set

Compliance Information:

The engine used in this generator set complies with Tier 2 emissions limit of U.S. EPA New Source Performance Standards for stationary emergency engines under the provisions of 40 CFR 60 Subpart IIII when tested per ISO8178 D2.

Engine Manufacturer:	Cummins Inc.
EPA Certificate Number:	NCEXL060.AAD-041
Effective Date:	8/19/2021
Date Issued:	8/19/2021
EPA Engine Family (Cummins Emissions Family):	NCEXL060.AAD

Engine information:

Model:	QSK60-G6 NR2	Bore:	6.25 in. (159 mm)
Engine Nameplate HP:	2922	Stroke:	7.48 in. (190 mm)
Type:	4 cycle, 60°V, 16 Cylinder Diesel	Displacement:	3673 cu. in. (60.2 liters)
Aspiration:	Turbocharged and Low Temperature Aftercooled	Compression Ratio:	14.5:1
Emission control device:	Electronic Control		

Diesel Fuel Emissions Limits

D2 Cycle Exhaust Emissions	Grams per BHP-hr			Grams per kW_m-hr		
	NO_X + NMHC	CO	PM	NO_X + NMHC	CO	PM
Test Results	4.5	0.3	0.04	6.0	0.4	0.05
EPA Emissions Limit	4.8	2.6	0.15	6.4	3.5	0.20

Test methods: EPA emissions recorded per 40 CFR Part 60, 89, 1039, 1065 and weighted at load points prescribed in the regulations for constant speed engines.

Diesel fuel specifications: Cetane number: 40-50. Reference: ASTM D975 No. 2-D, 300-500 ppm Sulfur.

Reference conditions: Air inlet temperature: 25°C (77°F), Fuel inlet temperature: 40°C (104°F). Barometric pressure: 100 kPa (29.53 in Hg), Humidity: 10.7 g/kg (75 grains H_2O/lb) of dry air; required for NOx correction, Restrictions: Intake restriction set to a maximum allowable limit for clean filter; Exhaust back pressure set to a maximum allowable limit.

Tests conducted using alternate test methods, instrumentation, fuel or reference conditions can yield different results.
Engine operation with excessive air intake or exhaust restriction beyond published maximum limits, or with improper maintenance, may result in elevated emission levels.

Generator set data sheet

Model: DQKAD
Frequency: 60 Hz
Fuel type: Diesel
kW rating: 1750 Standby
1600 Prime
1450 Continuous
Emissions level: EPA NSPS Stationary Emergency Tier 2

Exhaust emission data sheet:	**EDS-1118**
Exhaust emission compliance sheet:	**EPA-1164**
Sound performance data sheet:	**MSP-1140**
Cooling performance data sheet:	**MCP-206**
Prototype test summary data sheet:	**PTS-308**
Standard set-mounted radiator cooling outline:	**A054M306**
Optional set-mounted radiator cooling outline:	**A054M294**
Optional heat exchanger cooling outline:	**A034T326**
Optional remote radiator cooling outline:	**A054M304**

Fuel consumption

	Standby				**Prime**				**Continuous**			
	kW (kVA)				**kW (kVA)**				**kW (kVA)**			
Ratings	1750 (2187)				1600 (2000)				1450 (1812)			
Load	**1/4**	**1/2**	**3/4**	**Full**	**1/4**	**1/2**	**3/4**	**Full**	**1/4**	**1/2**	**3/4**	**Full**
US gph	43.7	70.5	95	119	40.8	64.9	88.7	109.7	38.5	60.4	82	102.4
L/hr	165.4	265	359.6	450.5	154.4	245.7	335.7	415.2	145.7	228.6	310.4	387.6

Engine

	Standby rating	**Prime rating**	**Continuous rating**
Engine manufacturer	Cummins Inc.		
Engine model	QSK60-G6 NR2		
Configuration	Cast iron, V 16 cylinder		
Aspiration	Turbocharged and low temperature after-cooled		
Gross engine power output, kW_m (bhp)	1871 (2508)	1715 (2299)	1558.4 (2089)
BMEP at set rated load, kPa (psi)	2071.5 (300.4)	1898.9 (275.4)	1725.4 (250.2)
Bore, mm (in.)	159 (6.25)		
Stroke, mm (in.)	190 (7.48)		
Rated speed, rpm	1800		
Piston speed, m/s (ft/min)	11.4 (2243)		
Compression ratio	14.5:1		
Lube oil capacity, L (qt)	261 (276)	378 (400)	378 (400)
Overspeed limit, rpm	2070		
Regenerative power, kW	207		

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Fuel flow

Maximum fuel flow, L/hr (US gph)	1105 (292)
Maximum fuel inlet restriction, kPa (in Hg)	16.9 (5.0)
Maximum fuel inlet temperature, °C (°F)	71 (160)

Air

Air	Standby rating	Prime rating	Continuous rating
Combustion air, m^3/min (scfm)	156 (5525)	150 (5305)	147 (5185)
Maximum air cleaner restriction, kPa (in H_2O)	3.7 (15)		
Alternator cooling air, m^3/min (cfm)	222 (7840)		

Exhaust

Exhaust flow at set rated load, m^3/min (cfm)	371.5 (13119)	348.8 (12319)	331.1 (11691)
Exhaust temperature, °C (°F)	463 (866)	455 (851)	449 (841)
Maximum back pressure, kPa (in H_2O)	6.8 (27)		

Standard set-mounted radiator cooling

Ambient design, °C (°F)	46 (115)		
Fan load, kW_m (HP)	46 (61)		
Coolant capacity (with radiator), L (US gal)	538 (142)		
Cooling system air flow, m^3/min (scfm)	2094 (73937)		
Total heat rejection, MJ/min (Btu/min)	72.3 (68557)	66.6 (63115)	60.2 (57032)
Maximum cooling air flow static restriction, kPa (in H_2O)	0.12 (0.5)		
Maximum fuel return line restriction kPa (in Hg)	34 (10)		

Optional set-mounted radiator cooling

Ambient design, °C (°F)	52 (125.6)		
Fan load, kW_m (HP)	66 (88)		
Coolant capacity (with radiator), L (US gal)	606 (160)		
Cooling system air flow, m^3/min (scfm)	2649 (93550)		
Total heat rejection, MJ/min (Btu/min)	78.6 (74479)	72.1 (68375)	67.6 (64027)
Maximum cooling air flow static restriction, kPa (in H_2O)	0.12 (0.5)		
Maximum fuel return line restriction kPa (in Hg)			

Optional heat exchanger cooling

Set coolant capacity, L (US gal)	
Heat rejected, jacket water circuit, MJ/min (Btu/min)	
Heat rejected, aftercooler circuit, MJ/min (Btu/min)	
Heat rejected, fuel circuit, MJ/min (Btu/min)	
Total heat radiated to room, MJ/min (Btu/min)	
Maximum raw water pressure, jacket water circuit, kPa (psi)	
Maximum raw water pressure, aftercooler circuit, kPa (psi)	
Maximum raw water pressure, fuel circuit, kPa (psi)	
Maximum raw water flow, jacket water circuit, L/min (US gal/min)	
Maximum raw water flow, aftercooler circuit, L/min (US gal/min)	
Maximum raw water flow, fuel circuit, L/min (US gal/min)	
Minimum raw water flow at 27 °C (80 °F) inlet temp, jacket water circuit, L/min (US gal/min)	

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Optional heat exchanger cooling (continued)

Minimum raw water flow at 27 °C (80 °F) inlet temp, aftercooler circuit, L/min (US gal/min)	
Minimum raw water flow at 27 °C (80 °F) inlet temp, fuel circuit, L/min (US gal/min)	
Raw water delta P at min flow, jacket water circuit, kPa (psi)	
Raw water delta P at min flow, aftercooler circuit, kPa (psi)	
Raw water delta P at min flow, fuel circuit, kPa (psi)	
Maximum jacket water outlet temp, °C (°F)	
Maximum aftercooler inlet temp, °C (°F)	
Maximum aftercooler inlet temp at 25 °C (77 °F) ambient, °C (°F)	
Maximum fuel return line restriction, kPa (in Hg)	

Optional remote radiator cooling[1]	Standby rating	Prime rating	Continuous rating
Set coolant capacity, L (US gal)			
Max flow rate at max friction head, jacket water circuit, L/min (US gal/min)	1900 (502)		
Max flow rate at max friction head, aftercooler circuit, L/min (US gal/min)	606 (160)		
Heat rejected, jacket water circuit, MJ/min (Btu/min)	35.1 (33243)	33.3 (31550)	32 (30340)
Heat rejected, aftercooler circuit, MJ/min (Btu/min)	25.8 (24436)	22.6 (21463)	20.4 (19297)
Heat rejected, fuel circuit, MJ/min (Btu/min)			
Total heat radiated to room, MJ/min (Btu/min)	10.9 (10356)	10.1 (9579)	9.4 (8871)
Maximum friction head, jacket water circuit, kPa (psi)	69 (10)		
Maximum friction head, aftercooler circuit, kPa (psi)	48 (7)		
Maximum static head, jacket water circuit, m (ft)	18 (60)		
Maximum static head, aftercooler circuit, m (ft)	18 (60)		
Maximum jacket water outlet temp, °C (°F)	104 (220)	100 (212)	100 (212)
Maximum aftercooler inlet temp at 25 °C (77 °F) ambient, °C (°F)	49 (120)		
Maximum aftercooler inlet temp, °C (°F)	71 (160)	71 (160)	71 (160)
Maximum fuel flow, L/hr (US gph)			
Maximum fuel return line restriction, kPa (in Hg)			

Weights[2]

Unit dry weight kgs (lbs)	13494 (29749)
Unit wet weight kgs (lbs)	13657 (30108)

Notes:

[1] For non-standard remote installations contact your local Cummins representative.

[2] Weights represent a set with standard features. See outline drawing for weights of other configurations.

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Derating factors

Standby	Standard Cooling System: Full rated power available up to 1750 m (5741 ft) at ambient temperatures up to 40°C (104°F). For higher altitudes, derate by 5.7% per 305 m (1000 ft). For temperatures over 40°C, derate by 9.5% per 10°C (18°F). Enhanced Cooling System: Full rated power available up to 990 m (3248 ft) at ambient temperatures up to 40°C (104°F). For higher altitudes, derate by 10.7% per 305 m (1000 ft). For ambient temperatures between 40°C and 50°C, apply altitude derate at 40°C and 50°C and interpolate for ambient temperature derate. At 50°C (122°F) ambient temperatures, full rated power available up to 930 m (3051 ft). For higher altitudes, derate by 11.0% per 305 m (1000 ft). For temperatures over 50°C, derate by 3.5% per 10°C (18°F).
Prime	Standard Cooling System: Full rated power available up to 1040 m (3412 ft) at ambient temperatures up to 40°C (104°F). For higher altitudes, derate by 4.5% per 305 m (1000 ft). For temperatures over 40°C, derate by 12.7% per 10°C (18°F). Enhanced Cooling System: Full rated power available up to 1360 m (4462 ft) at ambient temperatures up to 40°C (104°F). For higher altitudes, derate by 12.0% per 305 m (1000 ft). For ambient temperatures between 40°C and 50°C, apply altitude derate at 40°C and 50°C and interpolate for ambient temperature derate. At 50°C (122°F) ambient temperatures, full rated power available up to 1100 m (3609 ft). For higher altitudes, derate by 11.0% per 305 m (1000 ft). For temperatures over 50°C, derate by 5.0% per 10°C (18°F).
Continuous	Standard Cooling System: Full rated power available up to 700 m (2297 ft) at ambient temperatures up to 40°C (104°F). For higher altitudes, derate by 5.1% per 305 m (1000 ft). For temperatures over 40°C, derate by 13.0% per 10°C (18°F). Enhanced Cooling System: Full rated power available up to 1100 m (3609 ft) at ambient temperatures up to 40°C (104°F). For higher altitudes, derate by 6.0% per 305 m (1000 ft). For ambient temperatures between 40°C and 50°C, apply altitude derate at 40°C and 50°C and interpolate for ambient temperature derate. At 50°C (122°F) ambient temperatures, full rated power available up to 400 m (1312 ft). For higher altitudes, derate by 7.0% per 305 m (1000 ft). For temperatures over 50°C, derate by 13.0% per 10°C (18°F).

Ratings definitions

Emergency Standby Power (ESP):	Limited-Time Running Power (LTP):	Prime Power (PRP):	Base Load (Continuous) Power (COP):
Applicable for supplying power to varying electrical load for the duration of power interruption of a reliable utility source. Emergency Standby Power (ESP) is in accordance with ISO 8528. Fuel stop power in accordance with ISO 3046, AS 2789, DIN 6271 and BS 5514.	Applicable for supplying power to a constant electrical load for limited hours. Limited-Time Running Power (LTP) is in accordance with ISO 8528.	Applicable for supplying power to varying electrical load for unlimited hours. Prime Power (PRP) is in accordance with ISO 8528. Ten percent overload capability is available in accordance with ISO 3046, AS 2789, DIN 6271 and BS 5514.	Applicable for supplying power continuously to a constant electrical load for unlimited hours. Continuous Power (COP) is in accordance with ISO 8528, ISO 3046, AS 2789, DIN 6271 and BS 5514.

Alternator data

Voltage	Connection[1]	Temp rise degrees C	Duty[2]	Single phase factor[3]	Max surge kVA[4]	Winding No.	Alternator data sheet	Frame Size	Feature code
380	Wye, 3-phase	150/125/105	S/P/C		7695	312	ADS-335	P734G	B595-2
380	Wye, 3-phase	125/105/80	S/P/C		7333	13	ADS-515	LVSI804R	B598-2
380	Wye, 3-phase	105/80	S/P		7333	13	ADS-515	LVSI804R	B599-2
380	Wye, 3-phase	80	S		7333	13	ADS-515	LVSI804R	B660-2
416	Wye, 3-phase	105/80	S/P		7695	312	ADS-335	P734G	B715-2
440	Wye, 3-phase	125/105/80	S/P/C		6716	312	ADS-333	P734E	B663-2
440	Wye, 3-phase	105/80	S/P		7361	312	ADS-334	P734F	B664-2
440	Wye, 3-phase	80	S		7695	312	ADS-335	P734G	B668-2
440	Wye, 3-phase	150/125	S/P		6716	312	ADS-333	P734E	B691-2
480	Wye, 3-phase	105/80	S/P		7361	312	ADS-334	P734F	B600-2
480	Wye, 3-phase	80	S		7361	312	ADS-334	P734F	B601-2
480	Wye, 3-phase	125/105/80	S/P/C		6716	312	ADS-333	P734E	B801-2

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480	Wye, 3-phase	150	S		6716	312	ADS-333	P734E	B816-2
480	Wye, 3-phase	80	S/P		7361	312	ADS-334	P734F	B903-2
600	Wye, 3-phase	125/105/80	S/P/C		6716	7	ADS-333	P734E	B602-2
600	Wye, 3-phase	105/80	S/P		7361	7	ADS-334	P734F	B603-2
600	Wye, 3-phase	80	S		7361	7	ADS-334	P734	B604-2
600	Wye, 3-phase	150	S		6716	7	ADS-333	P734E	B817-2
600	Wye, 3-phase	80	S/P		7361	7	ADS-334	P734F	B904-2
4160	Wye, 3-phase	105/80	S/P		7926	51	ADS-324	MV7H	B313-2
4160	Wye, 3-phase	125/105/80	S/P/C		7926	51	ADS-324	MV7H	B467-2
4160	Wye, 3-phase	80	S/P		6335	51	ADS-518	MVSI804R	B905-2
12470	Wye, 3-phase	125/105/80	S/P/C		5948	91	ADS-521	HVSI804R	B448-2
12470	Wye, 3-phase	150/80	S/P		5948	91	ADS-521	HVSI804R	B567-2
12470	Wye, 3-phase	80	S		6800	91	ADS-522	HVSI804S	B607-2
12470	Wye, 3-phase	80	S/P		6800	91	ADS-522	HVSI804S	B906-2
13200	Wye, 3-phase	80	S/P		5948	91	ADS-521	HVSI804R	B907-2
13200	Wye, 3-phase	105/80	S/P		5948	91	ADS-521	HSVI804R	B612-2
13200	Wye, 3-phase	125/105/80	S/P/C		5948	91	ADS-521	HSVI804R	B448-2
13200	Wye, 3-phase	80	S		5948	91	ADS-521	HSVI804R	B628-2
13800	Wye, 3-phase	105/80	S/P		5948	91	ADS-521	HVSI804R	B612-2
13800	Wye, 3-phase	80	S		5948	91	ADS-521	HVSI804R	B628-2
13800	Wye, 3-phase	80	S/P		5948	91	ADS-521	HSVI804R	B909-2
13800	Wye, 3-phase	125/105/80	S/P/C		5948	91	ADS-521	HSVI804R	B448-2

Notes:

1 Limited single phase capability is available from some three phase rated configurations. To obtain single phase rating, multiply the three phase kW rating by the Single Phase Factor[3]. All single phase ratings are at unity power factor.

2 Standby (S), Prime (P) and Continuous ratings (C).

3 Factor for the *Single phase output from Three phase alternator* formula listed below.

4 Maximum rated starting kVA that results in a minimum of 90% of rated sustained voltage during starting.

Formulas for calculating full load currents:

Three phase output

$$\frac{\text{kW x 1000}}{\text{Voltage x 1.73 x 0.8}}$$

Single phase output

$$\frac{\text{kW x SinglePhaseFactor x 1000}}{\text{Voltage}}$$

Warning: Back feed to a utility system can cause electrocution and/or property damage. Do not connect to any building's electrical system except through an approved device or after building main switch is open.

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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.

1.3.3 Emissions[5]

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and noncriteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO_2) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

1.3.3.1 Particulate Matter Emissions[6-15] -

Particulate emissions may be categorized as either filterable or condensable. Filterable emissions are generally considered to be the particules that are trapped by the glass fiber filter in the front half of a Reference Method 5 or Method 17 sampling van. Vapors and particles less than 0.3 microns pass through the filter. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensable particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

Filterable particulate matter emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of No. 4 or No. 5 oil usually produces less PM than does the firing of heavier No. 6 oil.

In general, filterable PM emissions depend on the completeness of combustion as well as on the oil ash content. The PM emitted by distillate oil-fired boilers primarily comprises carbonaceous particles resulting from incomplete combustion of oil and is not correlated to the ash or sulfur content of the oil. However, PM emissions from residual oil burning are related to the oil sulfur content. This is because low-sulfur No. 6 oil, either from naturally low-sulfur crude oil or desulfurized by one of several processes, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur contents, which results in better atomization and more complete combustion.

Boiler load can also affect filterable particulate emissions in units firing No. 6 oil. At low load (50 percent of maximum rating) conditions, particulate emissions from utility boilers may be lowered by 30 to 40 percent and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emission reductions have been noted at low loads from boilers firing any of the lighter grades. At very low load conditions (approximately 30 percent of maximum rating), proper combustion conditions may be difficult to maintain and particulate emissions may increase significantly.

1.3.3.2 Sulfur Oxides Emissions[1-2,6-9,16] -

Sulfur oxides (SO_x) emissions are generated during oil combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominantly in the form of SO_2. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3), and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist.

1.3.3.3 Nitrogen Oxides Emissions[1-2,6-10,15,17-27] -

Oxides of nitrogen (NO_x) formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air ("thermal NO_x"), or to the conversion of chemically bound nitrogen in the fuel ("fuel NO_x"). The term NO_x refers to the composite of nitric oxide (NO) and nitrogen dioxide (NO_2). Test data have shown that for most external fossil fuel combustion systems, over 95 percent of the emitted NO_x is in the form of nitric oxide (NO). Nitrous oxide (N_2O) is not included in NO_x but has recently received increased interest because of atmospheric effects.

Experimental measurements of thermal NO_x formation have shown that NO_x concentration is exponentially dependent on temperature, and proportional to N_2 concentration in the flame, the square root of O_2 concentration in the flame, and the residence time. Thus, the formation of thermal NO_x is affected by four factors: (1) peak temperature, (2) fuel nitrogen concentration, (3) oxygen concentration, and (4) time of exposure at peak temperature. The emission trends due to changes in these factors are generally consistent for all types of boilers: an increase in flame temperature, oxygen availability, and/or residence time at high temperatures leads to an increase in NO_x production.

Fuel nitrogen conversion is the more important NO_x-forming mechanism in residual oil boilers. It can account for 50 percent of the total NO_x emissions from residual oil firing. The percent conversion of fuel nitrogen to NO_x varies greatly, however; typically from 20 to 90 percent of nitrogen in oil is converted to NO_x. Except in certain large units having unusually high peak flame temperatures, or in units firing a low nitrogen content residual oil, fuel NO_x generally accounts for over 50 percent of the total NO_x generated. Thermal fixation, on the other hand, is the dominant NO_x-forming mechanism in units firing distillate oils, primarily because of the negligible nitrogen content in these lighter oils. Because distillate oil-fired boilers are usually smaller and have lower heat release rates, the quantity of thermal NO_x formed in them is less than that of larger units which typically burn residual oil.[28]

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. NO_x emissions from tangentially (corner) fired boilers are, on the average, less than those of horizontally opposed units. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion (SC), reduced air preheat (RAP), low NO_x burners (LNBs), burning oil/water emulsions (OWE), or some combination thereof may result in NO_x reductions of 5 to 60 percent. Load reduction (LR) can likewise decrease NO_x production. Nitrogen oxide emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. It should be noted that most of these variables, with the exception of excess air, only influence the NO_x emissions of large oil-fired boilers. Low excess air-firing is possible in many small boilers, but the resulting NO_x reductions are less significant.

1.3.3.4 Carbon Monoxide Emissions[29-32] -

The rate of carbon monoxide (CO) emissions from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus if a unit is operated improperly or not well maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces tend to emit more of these pollutants than larger combustors. This is because smaller units usually have a higher ratio of heat transfer surface area to flame volume than larger combustors have; this leads to reduced flame temperature and combustion intensity and, therefore, lower combustion efficiency.

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can lead to incomplete combustion, including insufficient oxygen (O_2) availability; poor fuel/air mixing; cold-wall flame quenching; reduced combustion temperature; decreased combustion gas residence time; and load reduction (i. e., reduced combustion intensity). Since various combustion modifications for NO_x reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy efficiency, and operational reasons.

1.3.3.5 Organic Compound Emissions[29-39] -

Small amounts of organic compounds are emitted from combustion. As with CO emissions, the rate at which organic compounds are emitted depends, to some extent, on the combustion efficiency of the boiler. Therefore, any combustion modification which reduces the combustion efficiency will most likely increase the concentrations of organic compounds in the flue gases.

Total organic compounds (TOCs) include VOCs, semi-volatile organic compounds, and condensable organic compounds. Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e. g., benzene, toluene, xylene, and ethyl benzene).

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PAH or PNA). There are also PAH-nitrogen analogs. Information available in the literature on POM compounds generally pertains to these PAH groups.

Formaldehyde is formed and emitted during combustion of hydrocarbon-based fuels including coal and oil. Formaldehyde is present in the vapor phase of the flue gas. Formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion. Thus, larger units with efficient combustion (resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long gas retention times) have lower formaldehyde emission rates than do smaller, less efficient combustion units.

1.3.3.6 Trace Element Emissions[29-32,40-44] -

Trace elements are also emitted from the combustion of oil. For this update of AP-42, trace metals included in the list of 189 hazardous air pollutants under Title III of the 1990 Clean Air Act Amendments are considered. The quantity of trace elements entering the combustion device depends solely on the fuel composition. The quantity of trace metals emitted from the source depends on combustion temperature, fuel feed mechanism, and the composition of the fuel. The temperature determines the degree of volatilization of specific compounds contained in the fuel. The fuel feed mechanism affects the separation of emissions into bottom ash and fly ash. In general, the quantity of any given metal emitted depends on the physical and chemical properties of the element itself; concentration of the metal in the fuel; the combustion conditions; and the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals concentrate in certain waste particle streams from a combustor (bottom ash, collector ash, flue gas particulate), while others do not. Various classification schemes to describe this partitioning have been developed. The classification scheme used by Baig, et al.[44] is as follows:

- Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment.

- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size.

- Class 3: Elements which are emitted in the gas phase.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects of combustion controls on incremental trace metal emissions. For example, several NO_x controls for boilers reduce peak flame temperatures (e. g., SC, FGR, RAP, OWE, and LR). If combustion temperatures are reduced, fewer Class 2 metals will initially volatilize, and fewer will be available for subsequent condensation and enrichment on fine PM. Therefore, for combustors with particulate controls, lower volatile metal emissions should result due to improved particulate removal. Flue gas emissions of Class 1 metals (the non-segregating trace metals) should remain relatively unchanged.

Lower local O_2 concentrations is also expected to affect segregating metal emissions from boilers with particle controls. Lower O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions, Class 2 metals should remain in the vapor phase as they enter the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metal emissions should remain unchanged.

1.3.3.7 Greenhouse Gases[45-50] -

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during fuel oil combustion. Nearly all of the fuel carbon (99 percent) in fuel oil is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion in the fuel stream.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1475^{o}F) and excess air is kept to a minimum (less than 1 percent). Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O formation mechanism. Emissions can vary widely from unit to unit, or even from the same unit at different operating conditions. Average emission factors based on reported test data have been developed for conventional oil combustion systems.

Methane emissions vary with the type of fuel and firing configuration, but are highest during periods of incomplete combustion or low-temperature combustion, such as the start-up or shut-down cycle for oil-fired boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

1.3.4 Controls

Control techniques for criteria pollutants from fuel oil combustion may be classified into three broad categories: fuel substitution/alteration, combustion modification, and postcombustion control. Emissions of noncriteria pollutants such as particulate phase metals have been controlled through the use of post combustion controls designed for criteria pollutants. Fuel substitution reduces SO_2 or NO_x and involves burning a fuel with a lower sulfur or nitrogen content, respectively. Particulate matter will generally be reduced when a lighter grade of fuel oil is burned.[6,8,11] Fuel alteration of heavy oils includes mixing water and heavy oil using emulsifying agents for better atomization and lower combustion temperatures. Under some conditions, emissions of NO_x, CO, and PM may be reduced significantly. Combustion modification includes any physical or operational change in the furnace or boiler and is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Postcombustion control is a device after the combustion of the fuel and is applied to control emissions of PM, SO_2, and NO_x.

1.3.4.1 Particulate Matter Controls[51] -

Control of PM emissions from residential and commercial units is accomplished by improving burner servicing and improving oil atomization and combustion aerodynamics. Optimization of combustion aerodynamics using a flame retention device, swirl, and/or recirculation is considered effective toward achieving the triple goals of low PM emissions, low NO_x emissions, and high thermal efficiency.

Large industrial and utility boilers are generally well-designed and well-maintained so that soot and condensable organic compound emissions are minimized. Particulate matter emissions are more a result of emitted fly ash with a carbon component in such units. Therefore, postcombustion controls (mechanical collectors, ESP, fabric filters, etc.) or fuel substitution/alteration may be used to reduce PM emissions from these sources.

Mechanical collectors, a prevalent type of control device, are primarily useful in controlling particulates generated during soot blowing, during upset conditions, or when a very dirty heavy oil is fired. For these situations, high-efficiency cyclonic collectors can achieve up to 85 percent control of particulate. Under normal firing conditions, or when a clean oil is combusted, cyclonic collectors are not nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

Electrostatic precipitators (ESPs) are commonly used in oil-fired power plants. Older precipitators, usually small, typically remove 40 to 60 percent of the emitted PM. Because of the low ash content of the oil, greater collection efficiency may not be required. Currently, new or rebuilt ESPs can achieve collection efficiencies of up to 90 percent.

In fabric filtration, a number of filtering elements (bags) along with a bag cleaning system are contained in a main shell structure incorporating dust hoppers. The particulate removal efficiency of the fabric filter system is dependent on a variety of particle and operational characteristics including particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleaning, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may be more than 99 percent.

Scrubbing systems have also been installed on oil-fired boilers to control both sulfur oxides and particulate. These systems can achieve SO_2 removal efficiencies of 90 to 95 percent and particulate control efficiencies of 50 to 60 percent.

Fuel alteration of heavy oil by mixing with water and an emulsifying agent has reduced PM emissions significantly in controlled tests.

1.3.4.2 SO_2 Controls[52-53] -

Commercialized postcombustion flue gas desulfurization (FGD) processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. Flue gas desulfurization technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel.

These processes are either regenerable (such that the reagent material can be treated and reused) or nonregenerable (in which case all waste streams are de-watered and discarded).

Wet regenerable FGD processes are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal waste water discharges, and produce a saleable sulfur product. Some of the current nonregenerable calcium-based processes can, however, produce a saleable gypsum product.

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_x absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_x. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. Effectiveness of these devices depends not only on control device design but also on operating variables.

1.3.4.3 NO_x Controls[41,54-55] -

In boilers fired on crude oil or residual oil, the control of fuel NO_x is very important in achieving the desired degree of NO_x reduction since fuel NO_x typically accounts for 60 to 80 percent of the total NO_x formed. Fuel nitrogen conversion to NO_x is highly dependent on the fuel-to-air ratio in the combustion zone and, in contrast to thermal NO_x formation, is relatively insensitive to small changes in combustion zone temperature. In general, increased mixing of fuel and air increases nitrogen conversion which, in turn, increases fuel NO_x. Thus, to reduce fuel NO_x formation, the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. The lack of oxygen creates reducing conditions that, given sufficient time at high temperatures, cause volatile fuel nitrogen to convert to N_2 rather than NO.

Several techniques are used to reduce NO_x emissions from fuel oil combustion. Fuel substitution consists of burning lower nitrogen fuels. Fuel alteration includes burning emulsified heavy oil and water mixtures. In addition to these, the primary techniques can be classified into one of two fundamentally different methods — combustion controls and postcombustion controls. Combustion controls reduce NO_x by suppressing NO_x formation during the combustion process while postcombustion controls reduce NO_x emissions after their formation. Combustion controls are the most widely used method of controlling NO_x formation in all types of boilers and include low excess air, burners out of service, biased-burner firing, flue gas recirculation, overfire air, and low-NO_x burners. Postcombustion control methods include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). These controls can be used separately, or combined to achieve greater NO_x reduction.

Operating at low excess air involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO_x formation is inhibited because less oxygen is available in the combustion zone. Burners out of service involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This method simulates air staging, or overfire air conditions, and limits NO_x formation by lowering the oxygen level in the burner area. Biased-burner firing involves firing the lower rows of burners more fuel-rich than the upper row of burners. This method provides a form of air staging and limits NO_x formation by limiting the amount of oxygen in the firing zone. These methods may change the normal operation of the boiler and the effectiveness is boiler-specific. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NO_x by 10 to 20 percent from uncontrolled levels.

Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce NO_x by as much as 40 to 50 percent in some boilers.

Overfire air is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. Overfire air limits NO_x by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures; (2) a reduced flame temperature that limits thermal NO_x formation, and/or (3) a reduced residence time at peak temperature which also limits thermal NO_x formation.

Low NO_x burners are applicable to tangential and wall-fired boilers of various sizes. They have been used as a retrofit NO_x control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels. They are also used in new boilers to meet NSPS limits. Low NO_x burners can be combined with overfire air to achieve even greater NO_x reduction (40 to 60 percent reduction from uncontrolled levels).

SNCR is a postcombustion technique that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_x in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected; mixing of the reagent in the flue gas; residence time of the reagent within the required temperature window; ratio of reagent to NO_x; and the sulfur content of the fuel that may create sulfur compound that deposit in downstream equipment. There is not as much commercial experience to base effectiveness on a wide range of boiler types; however, in limited applications, NO_x reductions of 25 to 40 percent have been achieved.

SCR is another postcombustion technique that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and water. The SCR reactor can be located at various positions in the process including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia to NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. NO_x emission reductions of 75 to 85 percent have been achieved through the use of SCR on oil-fired boilers operating in the U.S.

Fuel alteration for NO_x reduction includes use of oil/water emulsion fuels. In controlled tests, a mixture of 9 percent water in No. 6 oil with a petroleum based emulsifying agent reduced NO_x emissions by 36 percent on a Btu basis or 41 percent on a volume basis, compared with the same fuel in unaltered form. The reduction appears to be due primarily to improved atomization with a corresponding reduction of excess combustion air, with lower flame temperature contributing slightly to the reduction.[84]

Tables 1.3-1 and 1.3-3 present emission factors for uncontrolled criteria pollutants from fuel oil combustion. Tables in this section present emission factors on a volume basis (lb/10^3gal). To convert to an energy basis (lb/MMBtu), divide by a heating value of 150 MMBtu/10^3gal for Nos. 4, 5, 6, and residual fuel oil, and 140 MMBtu/10^3gal for No. 2 and distillate fuel oil. Table 1.3-2 presents emission factors for condensible particulate matter. Tables 1.3-4, 1.3-5, 1.3-6, and 1.3-7 present cumulative size distribution data and size-specific emission factors for particulate emissions from uncontrolled and controlled fuel oil combustion. Figures 1.3-1, 1.3-2, 1.3-3, and 1.3-4 present size-specific emission factors for particulate emissions from uncontrolled and controlled fuel oil combustion. Emission factors for N_2O, POM, and formaldehyde are presented in Table 1.3-8. Emission factors for speciated organic compounds are presented in Table 1.3-9. Emission factors for trace elements in distillate oil are given in Table 1.3-10. Emission factors for trace metals residual oil are given in Table 1.3-11. Default emission factors for CO_2 are presented in Table 1.3-12. A summary of various SO_2 and NO_x controls for fuel-oil-fired boilers is presented in Table 1.3-13 and 1.3-14, respectively. Emission factors for CO, NO_x, and PM from burning No. 6 oil/water emulsion fuel are presented in Table 1.3-15.

1.3.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the background report for this section. These and other documents can be found on the CHIEF website (http://www.epa.gov/ttn/chief/ap42/).

Supplement A, February 1996

- The formulas presented in the footnotes for filterable PM were moved into the table.

- For SO2 and SO3 emission factors, text was added to the table footnotes to clarify that "S" is a weight percent and not a fraction. A similar clarification was made to the CO and NOx footnotes. SCC A2104004/A2104011 was provided for residential furnaces.

- For industrial boilers firing No. 6 and No. 5 oil, the methane emission factor was changed from 1 to 1.0 to show two significant figures.

- For SO2 and SO3 factors, text was added to the table footnotes to clarify that "S" is a weight percent and not a fraction.

- The N2O, POM, and formaldehyde factors were corrected.

- Table 1.3-10 was incorrectly labeled 1.1-10. This was corrected.

Supplement B, October 1996

- Text was added concerning firing practices.

- Factors for N_2O, POM, and formaldehyde were added.

- New data for filterable PM were used to create a new PM factor for residential oil-fired furnaces.

- Many new factors were added for toxic organics, toxic metals from distillate oil, and toxic metals from residual oil.

- A table was added for new CO_2 emission factors.

Supplement E, September 1998

- Table 1.3-1, the sub-heading for "Industrial Boilers" was added to the first column.

- Table 1.3-3, the emission factor for uncontrolled PM less than 0.625 micron was corrected to 1.7A, the emission factor for scrubber controlled PM less than 10 micron was corrected to 0.50A, and the relationships for each content in various fuel oils was corrected in footnote C.

- Table 1.3-4 and 1.3-6, the relationship for ash content in various fuel oils was corrected in the footnote C of each table.

- Table 1.3-9, the emission factors for trace metals in distillate oil were updated with newer data where available.

- Table 1.3-10, the title of the table was changed to clarify these factors apply to uncontrolled fuel oil boilers.

- Text and emission factors were added pertaining to No. 6 oil/water emulsion fuel.

- Table 1.3-1 was revised to include new NOx emission factors.

- Emission factors for condensable particulate matter were added (Table 1.3-2).

Update May 2010 - updates were originally published as erratas on the CHIEF website on April 28, 2000.

- In Table 1.3-1 corrections to SO2 factors were made for No. 2 oil fired and No.2 oil fired, LNB/FGR boilers. An editorial correction was made to PM filterable factors for boilers < 100 million BTU/hr for No. 5 and No. 6 oil.

- In Table 1.3-8 the correct N2O factor is 0.53 lb/1000 gal for No 6 oil and 0.26 lb/1000 gal for distillate oil.

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)	EMISSIO N 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)	142S[h]	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)	142S[h]	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	9.19(S)+3.22[i]	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	10[i]	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/103 gal to kg/103 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 NO2. Test results indicate that at least 95% by weight of NOx is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 lb/103 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 NO2 /103 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 1b/103 gal.
h The SO2 emission factor for both no. 2 oil fired and for no. 2 oil fired with LNB/FGR, is 142S, not 157S. Errata dated April 28, 2000. Section corrected May 2010.
i The PM factors for No.6 and No. 5 fuel were reversed. Errata dated April 28, 2000. Section corrected May 2010.

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

Firing Configuration[b] (SCC)	Controls	CPM - TOT[c, d] Emission Factor (lb/10^3 gal)	CPM - TOT[c, d] EMISSION FACTOR RATING	CPM - IOR[c, d] Emission Factor (lb/10^3 gal)	CPM - IOR[c, d] EMISSION FACTOR RATING	CPM - ORG[c, d] Emission Factor (lb/10^3 gal)	CPM - ORG[c, d] 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/103 gal to kg/103 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 1.3-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UTILITY BOILERS FIRING RESIDUAL OIL[a]

Particle Size[b] (µm)	Cumulative Mass % . Stated Size			Cumulative Emission Factor lb/10^3 gal)					
		Controlled		Uncontrolled[c]		ESP Controlled[d]		Scrubber Controlled[e]	
	Uncon-trolled	ESP	Scrubber	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	80	75	100	6.7A	C	0.05A	E	0.50A	D
10	71	63	100	5.9A	C	0.042A	E	0.50A	D
6	58	52	100	4.8A	C	0.035A	E	0.50A	D
2.5	52	41	97	4.3A	C	0.028A	E	0.48A	D
1.25	43	31	91	3.6A	C	0.021A	E	0.46A	D
1.00	39	28	84	3.3A	C	0.018A	E	0.42A	D
0.625	20	20	64	1.7A	C	0.007A	E	0.32A	D
TOTAL	100	100	100	8.3A	C	0.067A	E	0.50A	D

a Reference 26. Source Classification Codes 1-01-004-01/04/05/06 and 1-01-005-04/05. To convert from lb/103 gal to kg/m3, multiply by 0.120. ESP = electrostatic precipitator.

b Expressed as aerodynamic equivalent diameter.

c Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.00% sulfur, then S = 1.
No. 6 oil: A = 1.12(S) + 0.37
No. 5 oil: A = 1.2
No. 4 oil: A = 0.84

d Estimated control efficiency for ESP is 99.2%.

e Estimated control efficiency for scrubber is 94%

Table 1.3-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR INDUSTRIAL BOILERS FIRING RESIDUAL OIL[a]

Particle Size[b] (µm)	Cumulative Mass % Stated Size		Cumulative Emission Factor[c] ($lb/10^3$ gal)			
			Uncontrolled		Multiple Cyclone Controlled[d]	
	Uncontrolled	Multiple Cyclone Controlled	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	91	100	7.59A	D	1.67A	E
10	86	95	7.17A	D	1.58A	E
6	77	72	6.42A	D	1.17A	E
2.5	56	22	4.67A	D	0.33A	E
1.25	39	21	3.25A	D	0.33A	E
1.00	36	21	3.00A	D	0.33A	E
0.625	30	—[e]	2.50A	D	—[e]	NA
TOTAL	100	100	8.34A	D	1.67A	E

a Reference 26. Source Classification Codes 1-02-004-01/02/03/04 and 1-02-005-04. To convert lb/103 gal to kg/103 L, multiply by 0.120. NA = not applicable.

b Expressed as aerodynamic equivalent diameter.

c Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.0% sulfur, then S = 1.
No. 6 oil: A = 1.12(S) + 0.37
No. 5 oil: A = 1.2
No. 4 oil: A = 0.84

d Estimated control efficiency for multiple cyclone is 80%.

e Insufficient data.

Table 1.3-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UNCONTROLLED INDUSTRIAL BOILERS FIRING DISTILLATE OIL[a]

EMISSION FACTOR RATING: E

Particle Size[b] (µm)	Cumulative Mass % ≤ Stated Size	Cumulative Emission Factor ($lb/10^3$ gal)
15	68	1.33
10	50	1.00
6	30	0.58
2.5	12	0.25
1.25	9	0.17
1.00	8	0.17
0.625	2	0.04
TOTAL	100	2.00

[a] Reference 26. Source Classification Codes 1-02-005-01/02/03. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.
[b] Expressed as aerodynamic equivalent diameter.

Table 1.3-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS UNCONTROLLED COMMERCIAL BOILERS BURNING RESIDUAL OR DISTILLATE OIL[a]

EMISSION FACTOR RATING: D

Particle Size[b] (µm)	Cumulative Mass % ≤ Stated Size		Cumulative Emission Factor[c] ($lb/10^3$ gal)	
	Residual Oil	Distillate Oil	Residual Oil	Distillate Oil
15	78	60	6.50A	1.17
10	62	55	5.17A	1.08
6	44	49	3.67A	1.00
2.5	23	42	1.92A	0.83
1.25	16	38	1.33A	0.75
1.00	14	37	1.17A	0.75
0.625	13	35	1.08A	0.67
TOTAL	100	100	8.34A	2.00

[a] Reference 26. Source Classification Codes: 1-03-004-01/02/03/04 and 1-03-005-01/02/03/04. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.
[b] Expressed as aerodynamic equivalent diameter.
[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the fuel. For example, if the fuel is 1.0% sulfur, then S = 1.
No. 6 oil: A = 1.12(S) + 0.37
No. 5 oil: A = 1.2
No. 4 oil: A = 0.84
No. 2 oil: A = 0.24

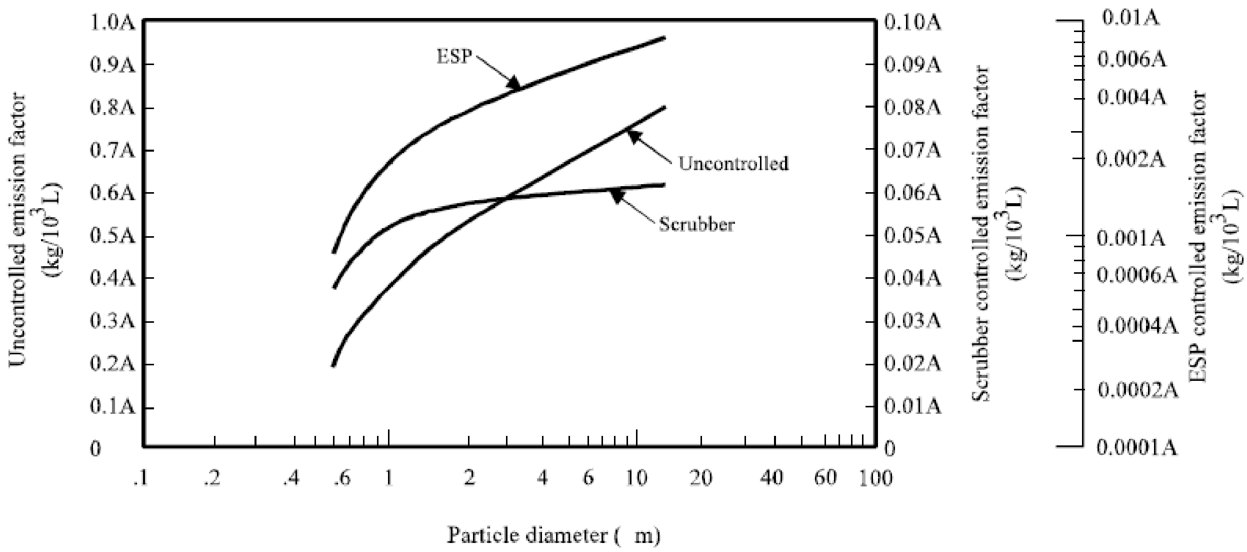

Figure 1.3-1. Cumulative size-specific emission factors for utility boilers firing residual oil.

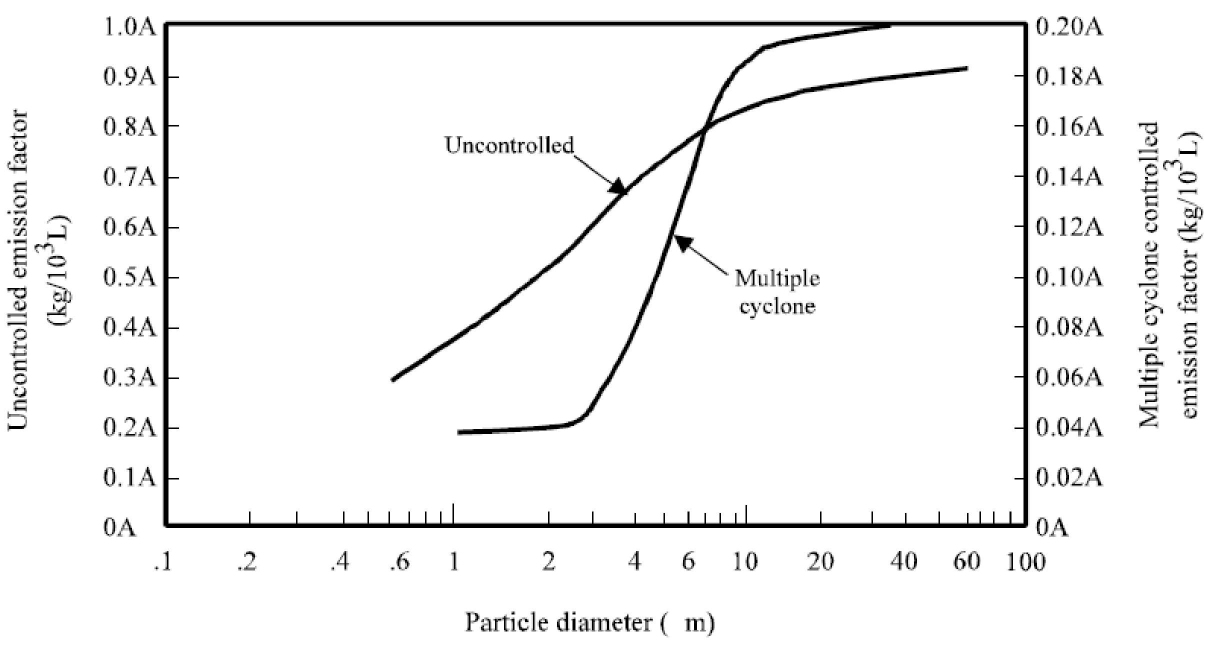

Figure 1.3-2. Cumulative size-specific emission factors for industrial boilers firing residual oil.

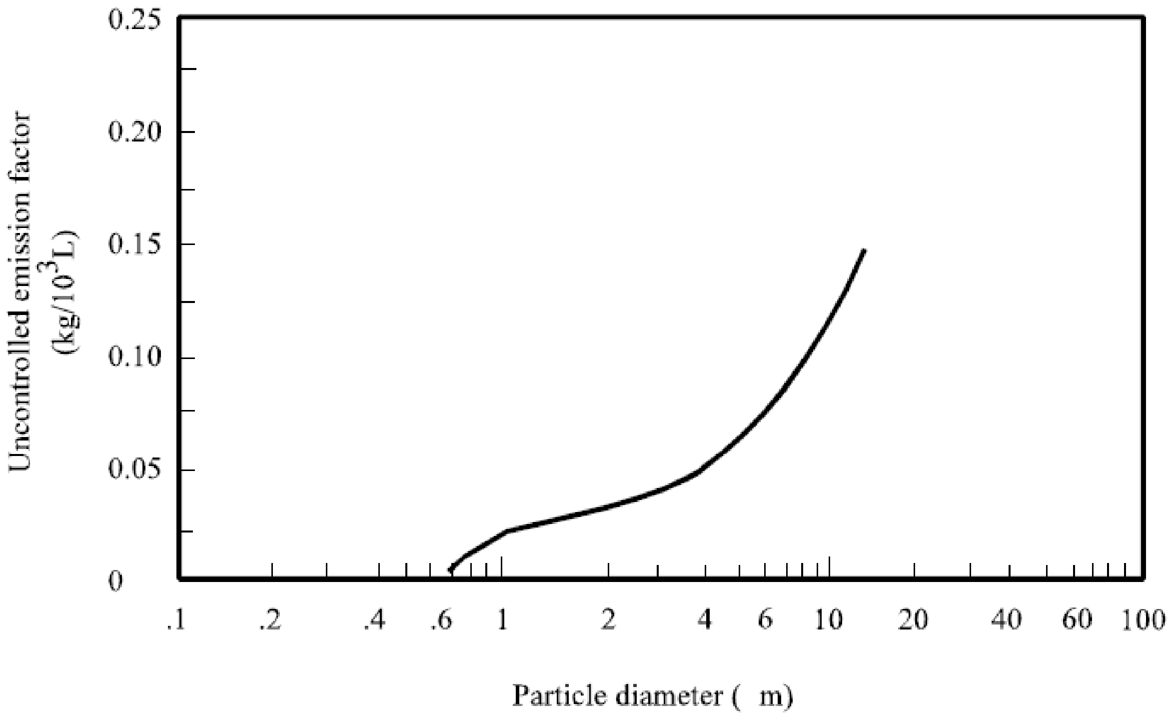

Figure 1.3-3. Cumulative size-specific emission factors for uncontrolled industrial boilers firing distillate oil.

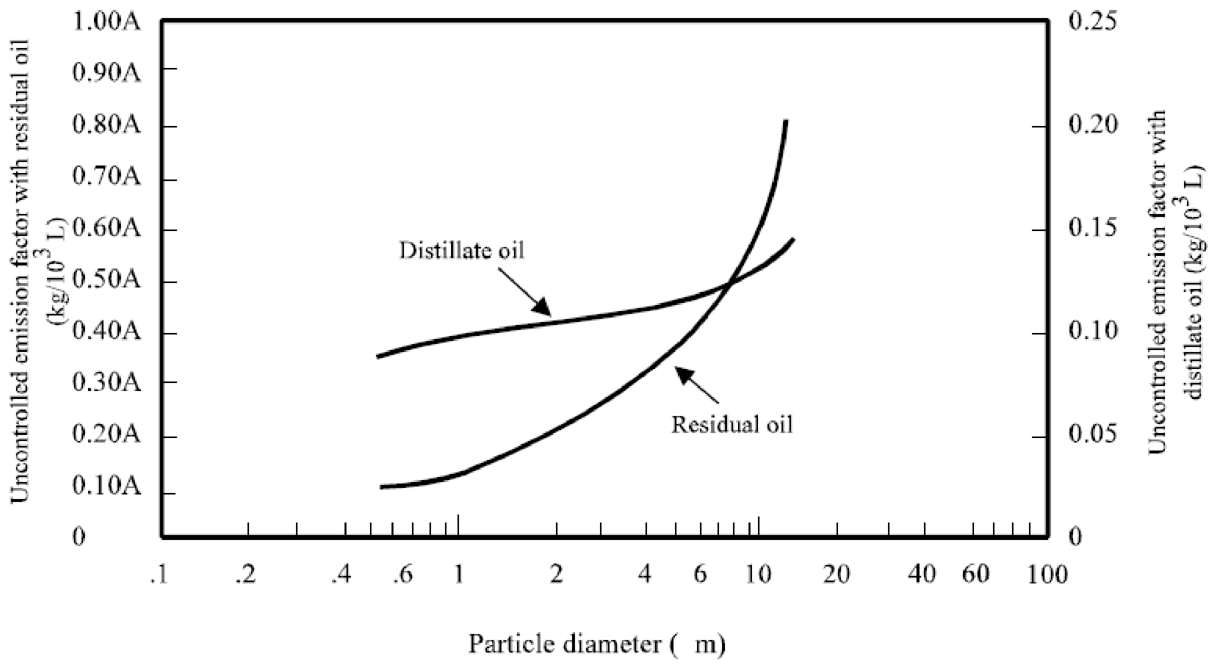

Figure 1.3-4. Cumulative size-specific emission factors for uncontrolled commercial boilers burning residual and distillate oil.

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)	0.53	0.0011 - 0.0013[d]	0.024 - 0.061
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.26	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 1.3-9. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM FUEL OIL COMBUSTION[a]

Organic Compound	Average Emission Factor[b] (lb/10^3 Gal)	EMISSION FACTOR RATING
Benzene	2.14E-04	C
Ethylbenzene	6.36E-05[c]	E
Formaldehyde[d]	3.30E-02	C
Naphthalene	1.13E-03	C
1,1,1-Trichloroethane	2.36E-04[c]	E
Toluene	6.20E-03	D
o-Xylene	1.09E-04[c]	E
Acenaphthene	2.11E-05	C
Acenaphthylene	2.53E-07	D
Anthracene	1.22E-06	C
Benz(a)anthracene	4.01E-06	C
Benzo(b,k)fluoranthene	1.48E-06	C
Benzo(g,h,i)perylene	2.26E-06	C
Chrysene	2.38E-06	C
Dibenzo(a,h) anthracene	1.67E-06	D
Fluoranthene	4.84E-06	C
Fluorene	4.47E-06	C
Indo(1,2,3-cd)pyrene	2.14E-06	C
Phenanthrene	1.05E-05	C
Pyrene	4.25E-06	C
OCDD	3.10E-09[c]	E

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.
[b] References 64-72. To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12.
[c] Based on data from one source test (Reference 67).
[d] The formaldehyde number presented here is based only on data from utilities using No. 6 oil. The number presented in Table 1.3-7 is based on utility, commercial, and industrial boilers.

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 1.3-11. EMISSION FACTORS FOR METALS FROM UNCONTROLLED NO. 6 FUEL OIL COMBUSTION[a]

Metal	Average Emission Factor[b, d] (lb/10^3 Gal)	EMISSION FACTOR RATING
Antimony	5.25E-03[c]	E
Arsenic	1.32E-03	C
Barium	2.57E-03	D
Beryllium	2.78E-05	C
Cadmium	3.98E-04	C
Chloride	3.47E-01	D
Chromium	8.45E-04	C
Chromium VI	2.48E-04	C
Cobalt	6.02E-03	D
Copper	1.76E-03	C
Fluoride	3.73E-02	D
Lead	1.51E-03	C
Manganese	3.00E-03	C
Mercury	1.13E-04	C
Molybdenum	7.87E-04	D
Nickel	8.45E-02	C
Phosphorous	9.46E-03	D
Selenium	6.83E-04	C
Vanadium	3.18E-02	D
Zinc	2.91E-02	D

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.
[b] References 64-72. 18 of 19 sources were uncontrolled and 1 source was controlled with low efficiency ESP. To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12.
[c] References 29-32,40-44.
[d] For oil/water mixture, reduce factors in proportion to water content of the fuel (due to dilution). To adjust the listed values for water content, multiply the listed value by 1-decimal fraction of water (ex: For fuel with 9 percent water by volume, multiply by 1-0.9=.91).

Table 1.3-12. DEFAULT CO_2 EMISSION FACTORS FOR LIQUID FUELS[a]

EMISSION FACTOR RATING: B

Fuel Type	%C[b]	Density[c] (lb/gal)	Emission Factor (lb/10^3 gal)
No. 1 (kerosene)	86.25	6.88	21,500
No. 2	87.25	7.05	22,300
Low Sulfur No. 6	87.26	7.88	25,000
High Sulfur No. 6	85.14	7.88	24,400

[a] Based on 99% conversion of fuel carbon content to CO_2. To convert from lb/gal to gram/cm^3, multiply by 0.12. To convert from lb/10^3 gal to kg/m^3, multiply by 0.12.
[b] Based on an average of fuel carbon contents given in references 73-74.
[c] References 73, 75.

Table 1.3-13. POSTCOMBUSTION SO_2 CONTROLS FOR FUEL OIL COMBUSTION SOURCES

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet scrubber	Lime/limestone	80-95+%	Applicable to high-sulfur fuels, Wet sludge product
	Sodium carbonate	80-98%	5-430 MMBtu/hr typical application range, High reagent costs
	Magnesium oxide/hydroxide	80-95+%	Can be regenerated
	Dual alkali	90-96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying	Calcium hydroxide slurry, vaporizes in spray vessel	70-90%	Applicable to low-and medium-sulfur fuels, Produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25-50%	Commercialized in Europe, Several U.S. demonstration projects underway
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25-50+%	Several R&D and demonstration projects underway, Not yet Commercially available in the U.S.

Table 1.3-14. NO_x CONTROL OPTIONS FOR OIL-FIRED BOILERS[a]

Control Technique	Description Of Technique	NO_x Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Low Excess Air (LEA)	Reduction of combustion air	0 to 28	0 to 24	Generally excess O_2 can be reduced to 2.5% representing a 3% drop from baseline	Available for boilers with sufficient operational flexibility.	Added benefits included increase in boiler efficiency. Limited by increase in CO, HC, and smoke emissions.
Staged Combustion (SC)	Fuel-rich firing burners with secondary combustion air ports	20 to 50	17 to 44	70-90% burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on packaged and field-erected units. However, not commercially available for all design types.	Best implemented on new units. Retrofit is probably not feasible for most units, especially packaged ones.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder of burners firing fuel-rich	10 to 30	ND	Most effective on boilers with 4 or more burners in a square pattern.	Available.	Requires careful selection of BOOS pattern and control of air flow. May result in boiler de-rating unless fuel delivery system is modified.
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	15 to 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on most design types.	Available. Best suited for new units.	Requires extensive modifications to the burner and windbox. Possible flame instability at high FGR rates.
Flue Gas Recirculation Plus Staged Combustion	Combined techniques of FGR and staged combustion	25 to 53	73 to 77	Maximum FGR rates set at 25% for distillate oil and 20% for residual oil.	Available for boilers with sufficient operational flexibility.	May not be feasible on all existing boiler types. Best implemented on new units.

Table 1.3-14 (cont.).

Control Technique	Description Of Technique	NO_x Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	33% decrease to 25% increase in No_x	31% decrease to 17% increase in NO_x	Applicable to all boiler types and sizes. Load can be reduced to 25% of maximum.	Available in retrofit applications.	Technique not effective when it necessitates an increase in excess O_2 levels. LR possibly implemented in new designs as reduced combustion intensity (i. e., enlarged furnace plan area).
Low NO_x Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	20 to 50	20 to 50	New burners described generally applicable to all boilers.	Commercially available.	Specific emissions data from industrial boilers equipped with LNB are lacking.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	5 to 16	ND	Combustion air temperature can be reduced to ambient conditions.	Available.	Application of this technique on new boilers requires installation of alternate heat recovery system (e. g., an economizer).
Selective Noncatalytic Reduction (SNCR)	Injection of NH_3 or urea as a reducing agent in the flue gas	40 to 70	40 to 70	Applicable for large packaged and field-erected watertube boilers. May not be feasible for fire-tube boilers.	Commercially offered but not widely demonstrated on large boilers.	Elaborate reagent injection, monitoring, and control system required. Possible load restrictions on boilers and air preheater fouling when burning high sulfur oil. Must have sufficient residence time at correct temperature.
Conventional Selective Catalytic Reduction (SCR)	Injections of NH_3 in the presence of a catalyst (usually upstream of air heater).	Up to 90% (estimated)	Up to 90% (estimated)	Typically large boiler designs	Commercially offered but not widely demonstrated.	Applicable to most boiler designs as a retrofit technology or for new boilers.

Table 1.3-14 (cont.).

Control Technique	Description Of Technique	NO_x Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Air Heater (SCR)	Catalyst-coated baskets in the air heater.	40-65 (estimated)	40-65 (estimated)	Boilers with rotating-basket air heaters	Available but not widely demonstrated	Design must address pressure drop and maintain heat transfer.
Duct SCR	A smaller version of conventional SCR is placed in existing ductwork	30 (estimated)	30 (estimated)	Typically large boiler designs	Available but not widely demonstrated.	Location of SCR in duct is temperature dependent.
Activated Carbon SCR	Activated carbon catalyst, installed downstream of air heater.	ND	ND	Typically large boiler designs	Available but not widely demonstrated.	High pressure drop.
Oil/Water Emulsified Fuel[a,b]	Oil/water fuel with emulsifying agent	41	ND	Firetube boilers	Available but not widely demonstrated	Thermal efficiency reduced due to water content

[a] ND = no data.

[b] Test conducted by EPA using commercially premixed fuel and water (9 percent water) containing a petroleum based emulsifying agent. Test boiler was a 2400 lb/hr, 15 psig Scotch Marine firetube type, fired at 2 x 10^6 Btu/hr.

Table 1.3-15. EMISSION FACTORS FOR NO. 6 OIL/WATER EMULSION IN INDUSTRIAL/COMMERCIAL/INSTITUTIONAL BOILERS[a]

Pollutant	Emission Factor ($lb/10^3$ gal)	Factor Rating	Comments
CO	1.90	C	33% Reduction from plain oil
NO_x	38.0	C	41% Reduction
PM	14.9	C	45% Reduction

[a] Test conducted by EPA using commercially premixed fuel and water (9 percent water) containing a petroleum based emulsifying agent. Test boiler was a 2400 lb/hr, 15 psig Scotch Marine firetube type, fired at 2×10^6 Btu/hr.

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3.4 Large Stationary Diesel And All Stationary Dual-fuel Engines

3.4.1 General

The primary domestic use of large stationary diesel engines (greater than 600 horsepower [hp]) is in oil and gas exploration and production. These engines, in groups of 3 to 5, supply mechanical power to operate drilling (rotary table), mud pumping, and hoisting equipment, and may also operate pumps or auxiliary power generators. Another frequent application of large stationary diesels is electricity generation for both base and standby service. Smaller uses include irrigation, hoisting, and nuclear power plant emergency cooling water pump operation.

Dual-fuel engines were developed to obtain compression ignition performance and the economy of natural gas, using a minimum of 5 to 6 percent diesel fuel to ignite the natural gas. Large dual-fuel engines have been used almost exclusively for prime electric power generation. This section includes all dual-fuel engines.

3.4.2 Process Description

All reciprocating internal combustion (IC) engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 ignition methods used in stationary reciprocating IC engines, compression ignition (CI) and spark ignition (SI). In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder. Although all diesel- fueled engines are compression ignited and all gasoline- and gas-fueled engines are spark ignited, gas can be used in a CI engine if a small amount of diesel fuel is injected into the compressed gas/air mixture to burn any mixture ratio of gas and diesel oil (hence the name dual fuel), from 6 to 100 percent diesel oil.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

3.4.3 Emissions And Controls

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the atmosphere from the exhaust. Crankcase blowby is minor because TOCs are not present during compression of the charge. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels. In general, evaporative losses are also negligible in engines using gaseous fuels because these engines receive their fuel continuously from a pipe rather than via a fuel storage tank and fuel pump.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x), hydrocarbons and other organic compounds, carbon monoxide (CO), and particulates, which include both visible (smoke) and nonvisible emissions. Nitrogen oxide formation is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The other pollutants, HC, CO, and smoke, are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust. Sulfur oxides also appear in the exhaust from IC engines. The sulfur compounds, mainly sulfur dioxide (SO_2), are directly related to the sulfur content of the fuel.[2]

3.4.3.1 Nitrogen Oxides -

Nitrogen oxide formation occurs by two fundamentally different mechanisms. The predominant mechanism with internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in the high-temperature region of the flame from dissociated molecular nitrogen in the combustion air. Some NO_x, called prompt NO_x, is formed in the early part of the flame from reaction of nitrogen intermediary species, and HC radicals in the flame. The second mechanism, fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Gasoline, and most distillate oils, have no chemically-bound fuel N_2 and essentially all NO_x formed is thermal NO_x.

3.4.3.2 Total Organic Compounds -

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion.

Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.[2]

3.4.3.3 Carbon Monoxide -

Carbon monoxide is a colorless, odorless, relatively inert gas formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.[2-3]

3.4.3.4 Smoke, Particulate Matter, and PM-10 -

White, blue, and black smoke may be emitted from IC engines. Liquid particulates appear as white smoke in the exhaust during an engine cold start, idling, or low load operation. These are formed in the quench layer adjacent to the cylinder walls, where the temperature is not high enough to ignite the fuel. Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines. The primary constituent of black smoke is agglomerated carbon particles (soot).[2]

3.4.3.5 Sulfur Oxides -

Sulfur oxide emissions are a function of only the sulfur content in the fuel rather than any combustion variables. In fact, during the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2. The oxidation of SO_2 gives sulfur trioxide (SO_3), which reacts with water to give sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to give sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.[2,3]

Table 3.4-1 contains gaseous emission factors for the pollutants discussed above, expressed in units of pounds per horsepower-hour (lb/hp-hr), and pounds per million British thermal unit (lb/MMBtu). Table 3.4-2 shows the particulate and particle-sizing emission factors. Table 3.4-3 shows the speciated organic compound emission factors and Table 3.4-4 shows the emission factors for polycyclic aromatic hydrocarbons (PAH). These tables do not provide a complete speciated organic compound and PAH listing because they are based only on a single engine test; they are to be used only for rough order of magnitude comparisons.

Table 3.4-5 shows the NO_x reduction and fuel consumption penalties for diesel and dual-fueled engines based on some of the available control techniques. The emission reductions shown are those that have been demonstrated. The effectiveness of controls on a particular engine will depend on the specific design of each engine, and the effectiveness of each technique could vary considerably. Other NO_x control techniques exist but are not included in Table 3.4-5. These techniques include internal/external exhaust gas recirculation, combustion chamber modification, manifold air cooling, and turbocharging.

3.4.4 Control Technologies

Control measures to date are primarily directed at limiting NO_x and CO emissions since they are the primary pollutants from these engines. From a NO_x control viewpoint, the most important distinction between different engine models and types of reciprocating engines is whether they are rich-burn or lean-burn. Rich-burn engines have an air-to-fuel ratio operating range that is near stoichiometric or fuel-rich of stoichiometric and as a result the exhaust gas has little or no excess oxygen. A lean-burn engine has an air-to-fuel operating range that is fuel-lean of stoichiometric; therefore, the exhaust from these engines is characterized by medium to high levels of O_2. The most common NO_x control technique for diesel and dual fuel engines focuses on modifying the combustion process. However, selective catalytic reduction (SCR) and nonselective catalytic reduction (NSCR) which are post-combustion techniques are becoming available. Control for CO have been partly adapted from mobile sources.[5]

Combustion modifications include injection timing retard (ITR), preignition chamber combustion (PCC), air-to-fuel ratio, and derating. Injection of fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NO_x formation. ITR reduces NO_x from all diesel engines; however, the effectiveness is specific to each engine model. The amount of NO_x reduction with ITR diminishes with increasing levels of retard.[5]

Improved swirl patterns promote thorough air and fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC results in improved mixing and complete combustion of the lean air/fuel mixture which lowers combustion temperature, thereby reducing NO_x emissions.[5]

The air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel that enters each cylinder. At air-to-fuel ratios less than stoichiometric (fuel-rich), combustion occurs under conditions of insufficient oxygen which causes NO_x to decrease because of lower oxygen and lower temperatures. Derating involves restricting engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures thereby lowering NO_x formation rates.[5]

SCR is an add-on NO_x control placed in the exhaust stream following the engine and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with the NO_x in the presence of a catalyst to form water and nitrogen. The effectiveness of SCR depends on fuel quality and engine duty cycle (load fluctuations). Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. Load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.[5]

NSCR is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC and involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios.[5]

3.4.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- The general text was updated.
- Controlled NO_x factors and PM factors were added for diesel units.
- Math errors were corrected in factors for CO from diesel units and for uncontrolled NO_x from dual fueled units.

Table 3.4-1. GASEOUS EMISSION FACTORS FOR LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL-FUEL ENGINES[a]

Pollutant	Diesel Fuel (SCC 2-02-004-01)			Dual Fuel[b] (SCC 2-02-004-02)		
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING
NO_x						
Uncontrolled	0.024	3.2	B	0.018	2.7	D
Controlled	0.013[c]	1.9[c]	B	ND	ND	NA
CO	5.5 E-03	0.85	C	7.5 E-03	1.16	D
SO_x[d]	8.09 E-03S_1	1.01S_1	B	4.06 E-04S_1 + 9.57 E-03S_2	0.05S_1 + 0.895S_2	B
CO_2[e]	1.16	165	B	0.772	110	B
PM	0.0007[c]	0.1[c]	B	ND	ND	NA
TOC (as CH_4)	7.05 E-04	0.09	C	5.29 E-03	0.8	D
Methane	f	f	E	3.97 E-03	0.6	E
Nonmethane	f	f	E	1.32 E-03	0.2[g]	E

[a] Based on uncontrolled levels for each fuel, from References 2,6-7. When necessary, the average heating value of diesel was assumed to be 19,300 Btu/lb with a density of 7.1 lb/gallon. The power output and fuel input values were averaged independently from each other, because of the use of actual brake-specific fuel consumption (BSFC) values for each data point and of the use of data possibly sufficient to calculate only 1 of the 2 emission factors (e. g., enough information to calculate lb/MMBtu, but not lb/hp-hr). Factors are based on averages across all manufacturers and duty cycles. The actual emissions from a particular engine or manufacturer could vary considerably from these levels. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code.

[b] Dual fuel assumes 95% natural gas and 5% diesel fuel.

[c] References 8-26. Controlled NO_x is by ignition timing retard.

[d] Assumes that all sulfur in the fuel is converted to SO_2. S_1 = % sulfur in fuel oil; S_2 = % sulfur in natural gas. For example, if sulfer content is 1.5%, then S = 1.5.

[e] Assumes 100% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 70 weight % carbon in natural gas, dual-fuel mixture of 5% diesel with 95% natural gas, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and natural gas heating value of 1050 Btu/scf.

[f] Based on data from 1 engine, TOC is by weight 9% methane and 91% nonmethane.

[g] Assumes that nonmethane organic compounds are 25% of TOC emissions from dual-fuel engines. Molecular weight of nonmethane gas stream is assumed to be that of methane.

Table 3.4-2. PARTICULATE AND PARTICLE-SIZING EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (lb/MMBtu) (fuel input)
Filterable particulate[b]	
< 1 µm	0.0478
< 3 µm	0.0479
< 10 µm	0.0496
Total filterable particulate	0.0620
Condensable particulate	0.0077
Total PM-10[c]	0.0573
Total particulate[d]	0.0697

[a] Based on 1 uncontrolled diesel engine from Reference 6. Source Classification Code 2-02-004-01. The data for the particulate emissions were collected using Method 5, and the particle size distributions were collected using a Source Assessment Sampling System. To convert from lb/MMBtu to ng/J, multiply by 430. PM-10 = particulate matter ≤ 10 micrometers (µm) aerometric diameter.

[b] Particle size is expressed as aerodynamic diameter.

[c] Total PM-10 is the sum of filterable particulate less than 10 µm aerodynamic diameter and condensable particulate.

[d] Total particulate is the sum of the total filterable particulate and condensable particulate.

Table 3.4-3. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (lb/MMBtu) (fuel input)
Benzene[b]	7.76 E-04
Toluene[b]	2.81 E-04
Xylenes[b]	1.93 E-04
Propylene	2.79 E-03
Formaldehyde[b]	7.89 E-05
Acetaldehyde[b]	2.52 E-05
Acrolein[b]	7.88 E-06

[a]Based on 1 uncontrolled diesel engine from Reference 7. Source Classification Code 2-02-004-01. Not enough information to calculate the output-specific emission factors of lb/hp-hr. To convert from lb/MMBtu to ng/J, multiply by 430.
[b]Hazardous air pollutant listed in the *Clean Air Act*.

Table 3.4-4. PAH EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

PAH	Emission Factor (lb/MMBtu) (fuel input)
Naphthalene[b]	1.30 E-04
Acenaphthylene	9.23 E-06
Acenaphthene	4.68 E-06
Fluorene	1.28 E-05
Phenanthrene	4.08 E-05
Anthracene	1.23 E-06
Fluoranthene	4.03 E-06
Pyrene	3.71 E-06
Benz(a)anthracene	6.22 E-07
Chrysene	1.53 E-06
Benzo(b)fluoranthene	1.11 E-06
Benzo(k)fluoranthene	<2.18 E-07
Benzo(a)pyrene	<2.57 E-07
Indeno(1,2,3-cd)pyrene	<4.14 E-07
Dibenz(a,h)anthracene	<3.46 E-07
Benzo(g,h,l)perylene	<5.56 E-07
TOTAL PAH	<2.12 E-04

[a] Based on 1 uncontrolled diesel engine from Reference 7. Source Classification Code 2-02-004-01. Not enough information to calculate the output-specific emission factors of lb/hp-hr. To convert from lb/MMBtu to ng/J, multiply by 430.

[b] Hazardous air pollutant listed in the *Clean Air Act*.

Table 3.4-5. NO_x REDUCTION AND FUEL CONSUMPTION PENALTIES FOR LARGE STATIONARY DIESEL AND DUAL-FUEL ENGINES[a]

Control Approach		Diesel (SCC 2-02-004-01) NO_x Reduction (%)	Diesel (SCC 2-02-004-01) ΔBSFC[b] (%)	Dual Fuel (SCC 2-02-004-02) NO_x Reduction (%)	Dual Fuel (SCC 2-02-004-02) ΔBSFC (%)
Derate	10%	ND	ND	<20	4
	20%	<20	4	ND	ND
	25%	5 - 23	1 - 5	1 - 33	1 - 7
Retard	2°	<20	4	<20	3
	4°	<40	4	<40	1
	8°	28 - 45	2 - 8	50 - 73	3 - 5
Air-to-fuel	3%	ND	ND	<20	0
	±10%	7 - 8	3	25 - 40	1 - 3
Water injection (H_2O/fuel ratio)	50%	25 - 35	2 - 4	ND	ND
SCR		80 - 95	0	80 - 95	0

[a] References 1,27-28. The reductions shown are typical and will vary depending on the engine and duty cycle. SCC = Source Classification Code. ΔBSFC = change in brake-specific fuel consumption. ND = no data.

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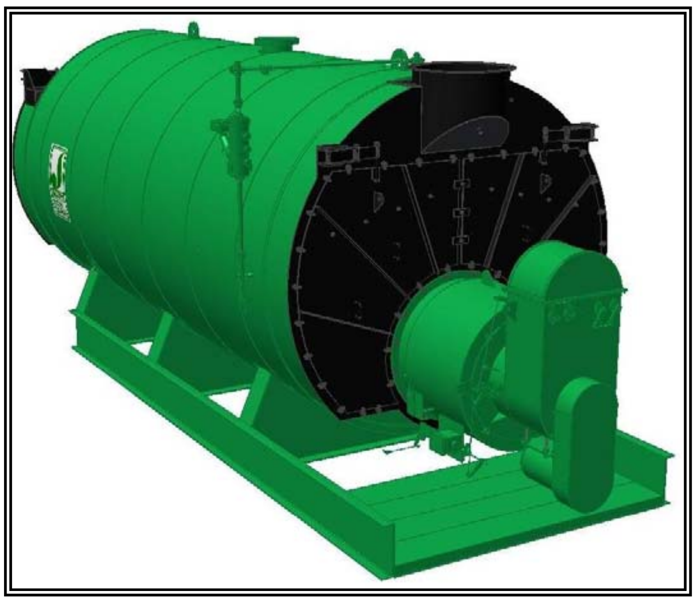
MODEL: PFTA 400-4

4-Pass Steam Packaged Firetube Boiler



Ratings & Performance Data

Horsepower 400			
Steam Storage, ft^3	74.8	Natural Gas Flow, SCFH (1,000 Btu/ft^3)**	16,305
Steam Disengaging Area, ft^2	82.2	Combustion Air (15% Excess), SCFM***	2,984
Total Heating Surface, ft^2	2,026	Flue Gas Flow Rate, lb/hr***	14,219
Furnace Outside Diameter, in	42.0	Stack Flue Gas Velocity, ft/min***	2,017
Furnace Heat Release Rate, Btu/ft^3 hr**	161,000	#2 Oil Flow, gal/hr (140,000 BTU/gal)**	112.3
Total Combustion Volume, ft^3	148.0	#6 Oil Flow, gal/hr (150,000 BTU/gal)**	104.2
Total Heat Release Rate, Btu/ft^3 hr**	110,000	Flue Gas Side Pressure Drop, in. H_2O	3.9
Water Content N.W.L., gal	2,435	Water Content Flooded, gal.	2,995
Approx. Dry Weight 15#, lb	27,400	Approx. Operating Weight 15#, lb.	48,000
Approx. Dry Weight 150#, lb	31,400	Approx. Operating Weight 150#, lb.	52,000
Approx. Dry Weight 200#, lb	35,100	Approx. Operating Weight 200#, lb.	55,700
Approx. Dry Weight 250#, lb	39,600	Approx. Operating Weight 250#, lb.	60,200
Approx. Dry Weight 300#, lb	44,200	Approx. Operating Weight 300#, lb.	64,800

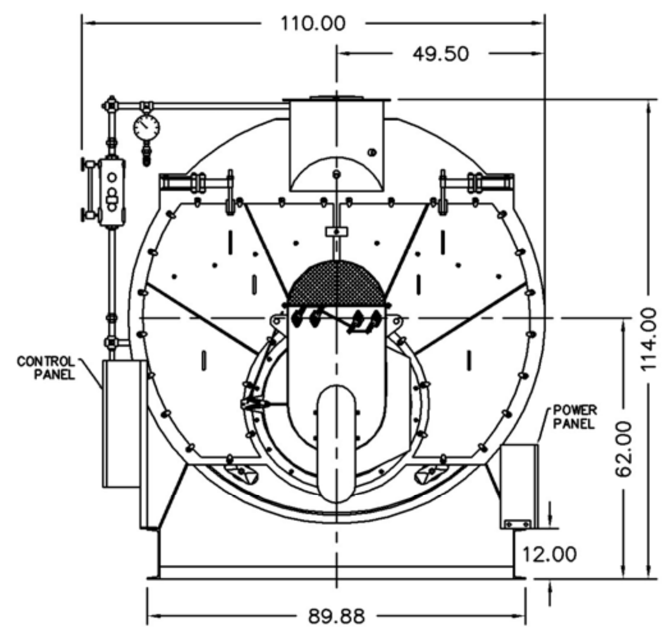
Performance Data

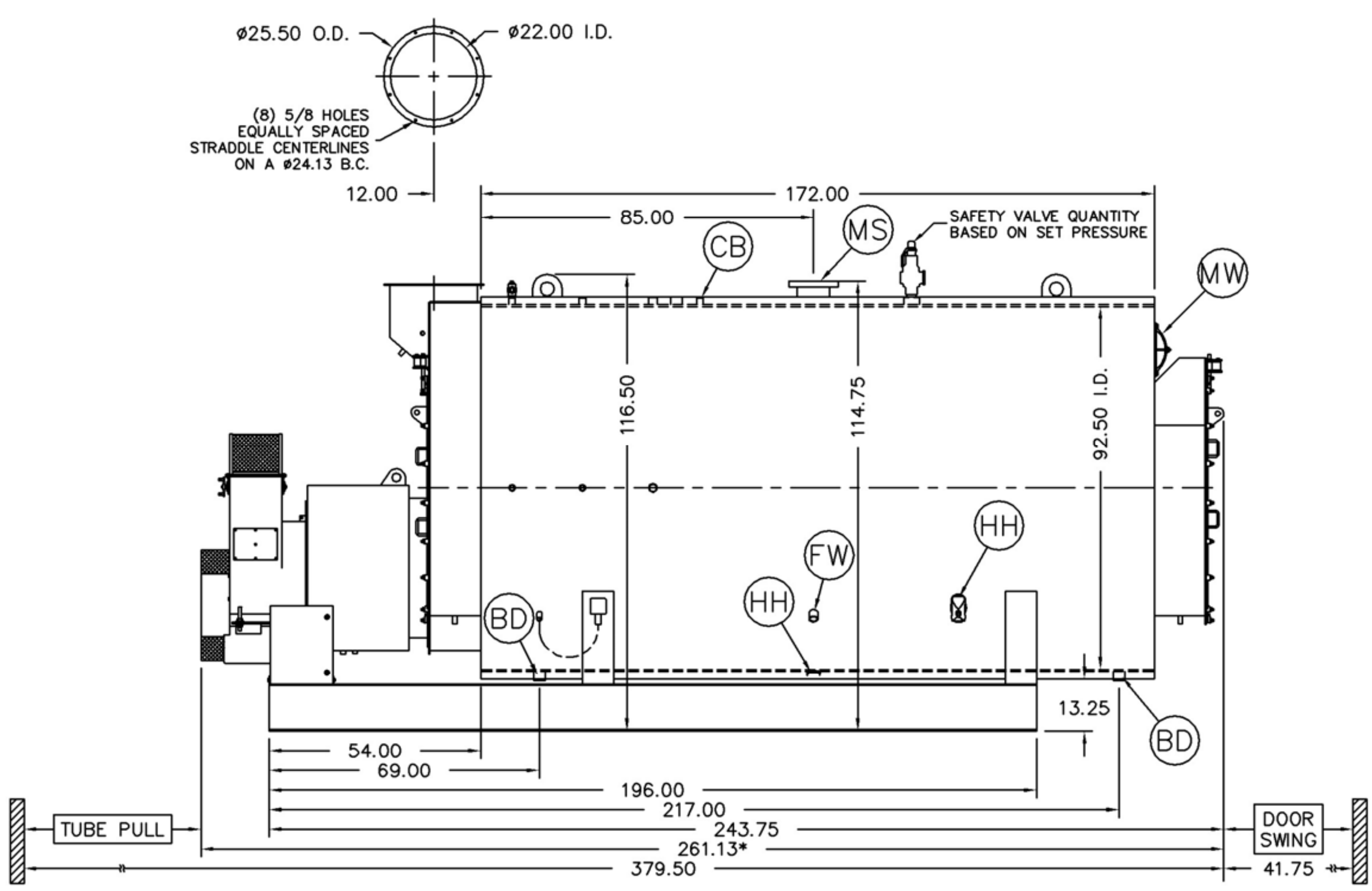
Operating Pressure (psig)	Steam Rate (lb/hr)	Natural Gas		#2 Oil		#6 Oil	
		Stack Temp (F)	%Eff	Stack Temp (F)	%Eff	Stack Temp (F)	%Eff
10	13,891	308	84.6	320	87.7	335	88.2
50	13,622	366	83.2	379	86.2	394	86.7
100	13,476	407	82.1	419	85.2	436	85.7
150	13,395	435	81.4	448	84.4	466	84.9
200	13,344	458	80.8	470	83.8	489	84.3
250	13,312	476	80.4	489	83.4	508	83.8
300	13,291	492	79.9	505	82.9	525	83.4

*Based on 228°F feedwater and 3% O_2, ** Values calculated at 100 psi operating pressure, ***Calculated Firing Natural Gas

Drawings - 4-Pass Steam Packaged Firetube Boiler

Connection & Opening Schedule			
Conn.	**Description**	**Type**	**Qty**
FW	Feedwater Inlet	2.00 FNPT	2
MS*	Main Steam	6.00 300# RF	1
CB	Continuous Blowoff	1.00 FNPT	1
BD	Blowdown Outlet	2.00 FNPT	2
MW	Manway	12 X 16	1
HH	Hand Hole	4 X 6	7
*10.00 150#RF Flange on 15 psig Design			

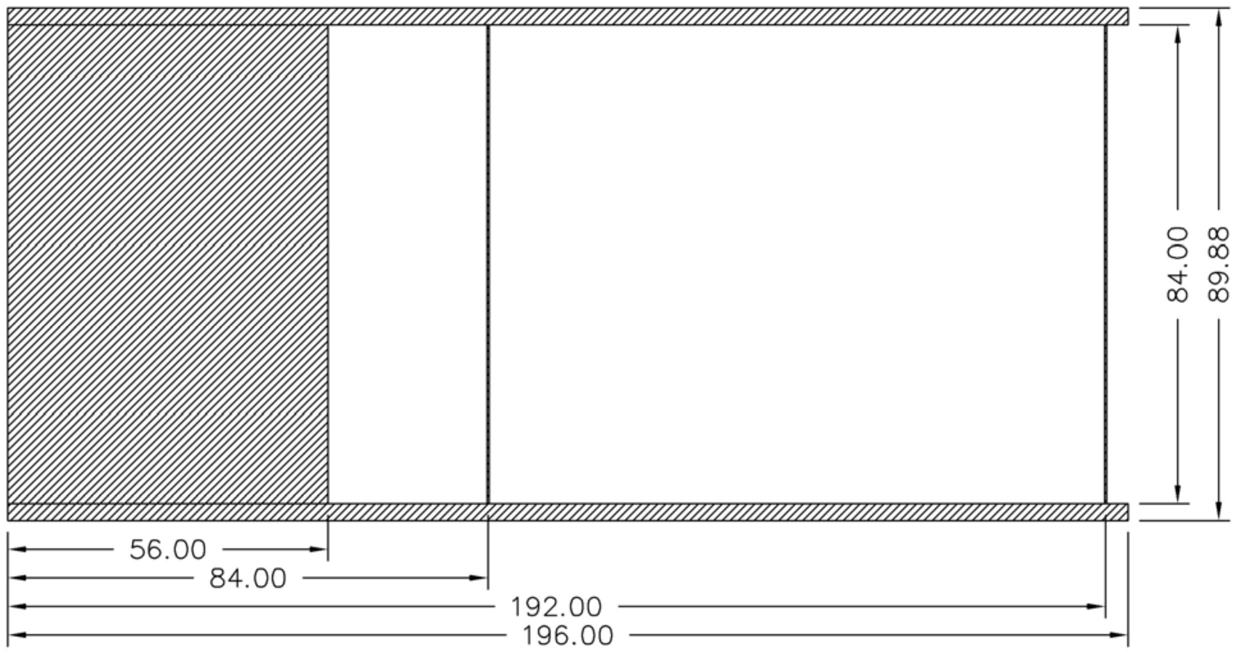


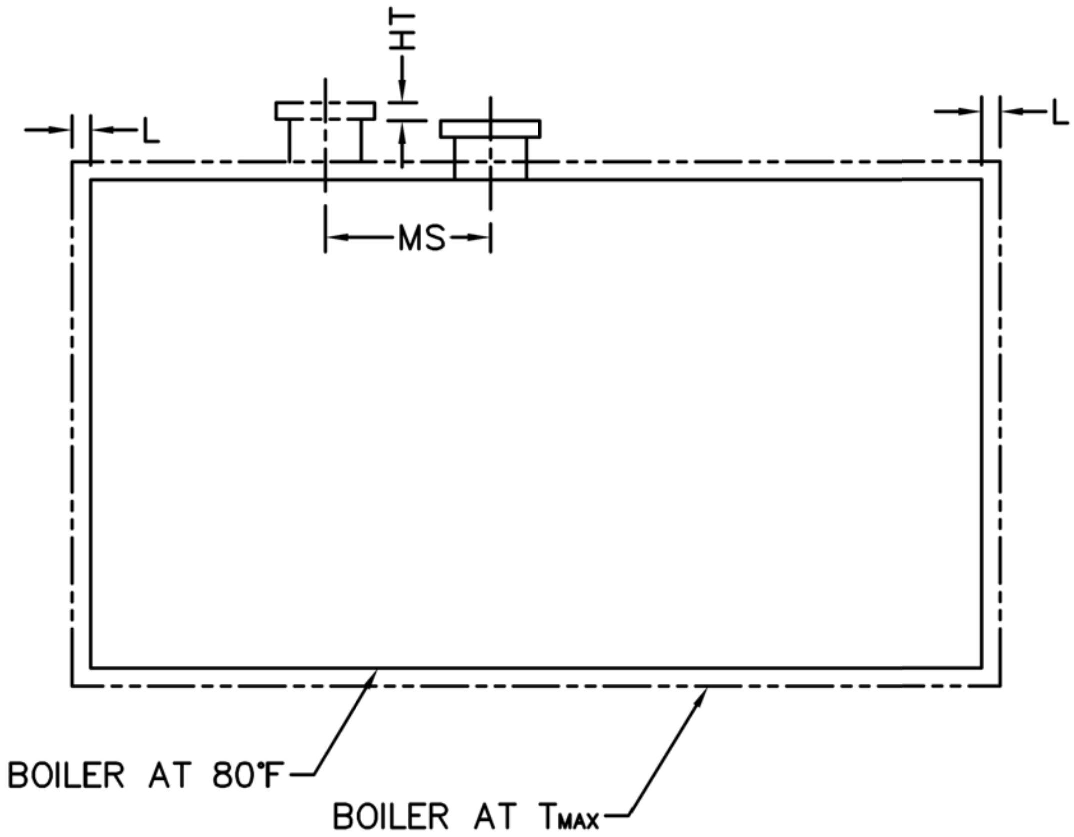


Notes:
150# Steam design shown, all dimensions given in inches.
Fuel piping and/or optional boiler trim may increase overall width.
Specifications subject to change to incorporate engineering advances.
***May vary on low-NO_x designs**

MODEL: PFTA 400-4

Base Diagram



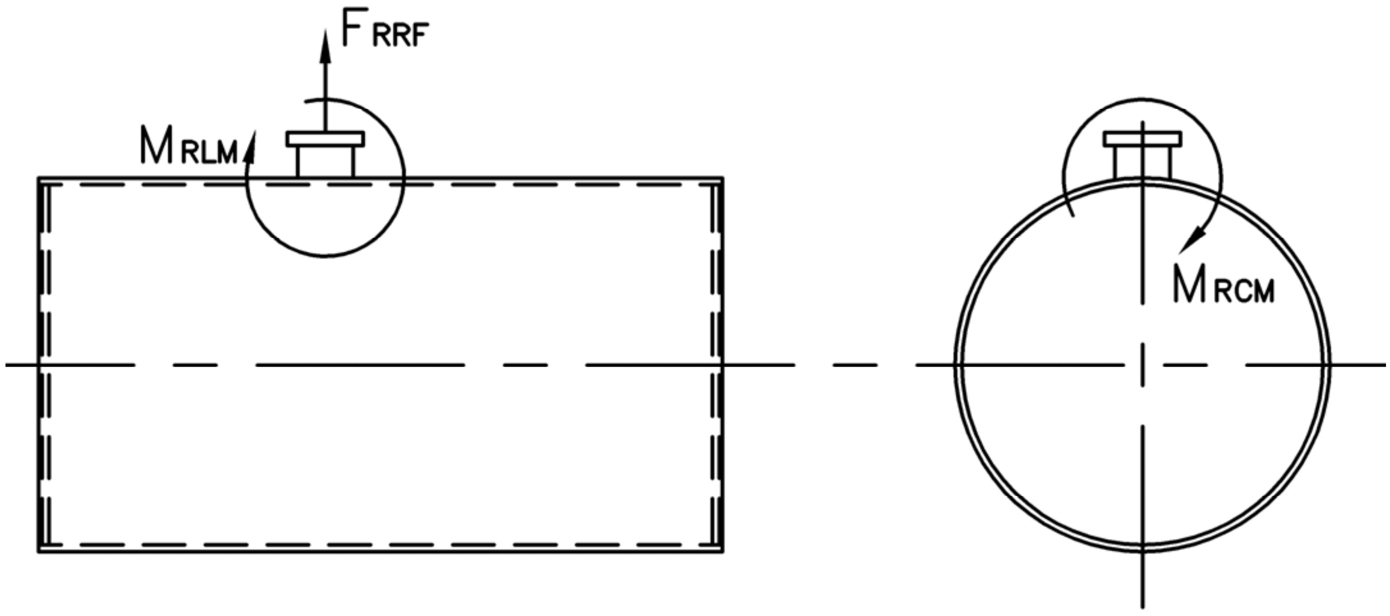


Thermal Expansion					
psig	15	150	200	250	300
Metal T_{MAX} (F)	240	366	388	406	421
L (in)	0.088	0.147	0.159	0.168	0.176
MS (in)	0.001	0.002	0.002	0.002	0.002
HT (in)	0.095	0.160	0.172	0.182	0.191

MODEL: PFTA 400-4

Nozzle Loadings

Maximum Allowable Load on Boiler Steam Nozzle					
	15# Design	150# Design	200# Design	250# Design	300# Design
F_{RRF}, lb	8,980	2,775	4,335	5,495	4,920
M_{RCM}, in-lb	60,810	28,745	46,625	61,140	56,770
M_{RLM}, in-lb	117,350	24,765	36,950	46,030	47,465



Stack Emissions-Natural Gas (1,000 Btu/CF)				
	PPMv (Corr to 3% O_2)	lb/MBtu	lb/hr @ Full Rate	Ton/Yr @ Full Rate
NO_x *	110	0.131	2.135	9.352
	30	0.036	0.582	2.551
	9	0.011	0.175	0.765
CO	50	0.037	0.60	2.624
CO_2	2.55 lb/lb fuel	119.76	1,953	8,553
H_20	2.03 lb/lb fuel	106.16	1,731	7,582
Stack Emissions-#2 Oil** (140,000 Btu/gal)				
NO_x	128	0.174	2.738	11.992
CO	50	0.037	0.578	2.530
CO_2	3.20 lb/lb fuel	168.53	2,650	11,608
H_20	1.12 lb/lb fuel	71.20	1,120	4,904
* 110 ppm "A" Burner, 30 ppm A-FGR Burner, 9 ppm FIR Burner				
**0.02% fuel bound Nitrogen				

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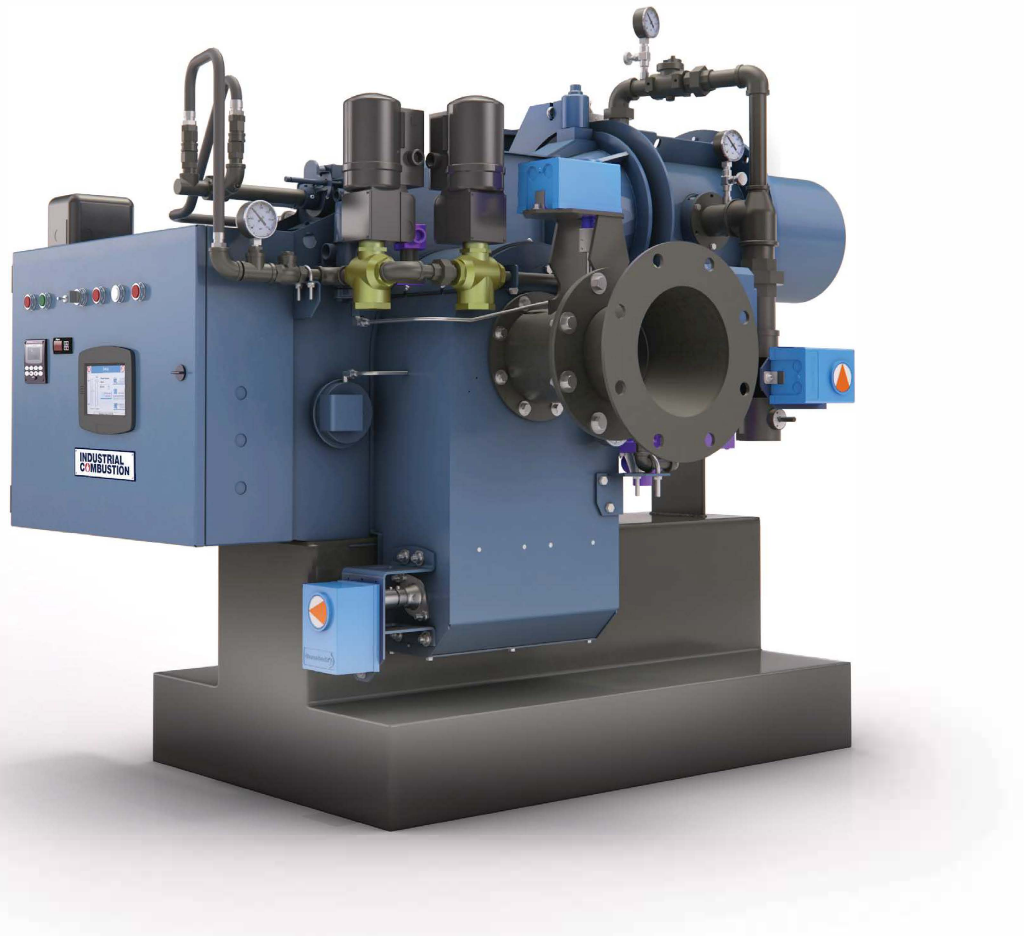

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1.5 TO 92.4 MMBTU/HR

High-efficiency burner technology for the most stringent emissions requirements.

Developed to meet and exceed the California emission standards.

Designed and developed with a flue gas recirculation (FGR) system proven to be the benchmark in the industry, firing up to 2200 HP boilers. With over 500 units in the field nationwide, our commitment to engineering excellence and the environment has not changed. Air pollution reduction, fuel savings, performance, and reliability, make the Industrial Combustion NT Series an outstanding choice – for the end user and the air we breathe.

NT Series features ultra-low NOx emissions:

On natural gas @ 3% 0_2:

< 9 PPM NOx

< 12 PPM NOx

< 15 PPM NOx

NTD Series

The NT Series features an advanced design impeller with backwards-inclined vanes. Unlike ordinary forward-curved impellers, the backward-incline design does not allow for dust to collect on the vanes, thus allowing the impeller to maintain its original balance while supplying combustion air. Our special air intake box with a rotary air damper (NTH, NTD) and FGR modulating valve, allows a precise amount of induced FGR and fuel/air ratio control throughout the firing range. This system provides the right amount of air and FGR for combustion. Excellent flame retention is assured at all firing rates.

NT Series features the unique Industrial Combustion technology for a stable, controlled flame front throughout the entire firing range.

The center core stabilizer acts as a fuel-rich zone, while the multiple gas lances are a fuel-lean zone. Each zone is controlled by a butterfly gas valve with actuators. Excellent flame retention is assured at all firing rates.

The gas lances feature a unique nozzle configuration with backflow orifices for staged gas zone.

NT Series was designed using Industrial Combustions' advanced computational fluid dynamics (CFO) for a burner concept that matches the geometry and aerodynamic parameters of the furnace.

Industrial Combustion center core technology is offered on the NT Series to enhance the performance and operation of the system.

Design Components

Industrial Combustion Technology
Adaptable to most types of combustion chamber configurations

Center Core Gas STABILIZER
Multiple staged gas injectors

Industrial Combustion Center Core Technology
Hammerhead injectors with backflow orifices

Rotary Air Damper (NTH, NTD)
Backward-curved impeller

Induced FGR
FGR modulating valve and shutoff valve

Oil Back-up
Parallel positioning for precise air-fuel metering

Hinged
For easy access of internal components

NT Fuel Applications for Firing:

- Natural Gas
- Light Fuel Oil (#2, Amber Oil)
- Propane – Air Mix

NT Fuel and Air Flows

The NT burner head's unique core and radially variable pitch swirl blades provide absolute flame stability at all loads for excess air from 20 to 60%.

The NT burner head is mounted inside the blast tube. Gas is directed to the various gas paths via connecting piping.

The high fuel-to-air mixing efficiency is obtained from the axial, radial and tangential turbulent air flow field generated at the burner outlet. This is combined with high velocity fuel jets, resulting in an optimized and well defined mixing pattern for maximum local mixture uniformity.

Ultra-Low-NOx Configuration

The NTXL Series was designed and developed with a flue gas recirculation (FGR) system which has been proven to be the benchmark in the industry. Emissions reduction, fuel savings, performance and reliability make the NTXL an excellent choice. The Industrial Combustion NTXL Series burner offers natural gas, propane air mix, air atomized #2 oil and combination gas and oil fuel options from 37.8 to 92.4 MMBTU per hour, with full modulation operation and parallel positioning for greater efficiency and cost savings. The NTXL is an ultra-low-NOx burner capable of less than 9 PPM NOx emissions.

NTXL Burner

1800/3600 RPM Combustion Fan motor horsepower is based on NOx and capacity requirement

Air-Atomizing, low-pressure oil nozzle (steam atomization optional)

V-Port Oil Flow Control Valve is used for maximum capacity and precise oil flow control

Parallel Positioning required for optimal control throughout the firing range

Hinged Rear Door and Access Panels for easy access to internal components

Gas Manifold on oil burners standard for easy upgrade to combination units

Combustion Air Fan efficient airfoil blade design smoothly lifts airflow over the entire blade, resulting in less motor horsepower requirement and significant noise reduction when compared to standard forced-draft fans

Available to less than 9 PPM NOx

No. 2 Oil capability for back-up fuel

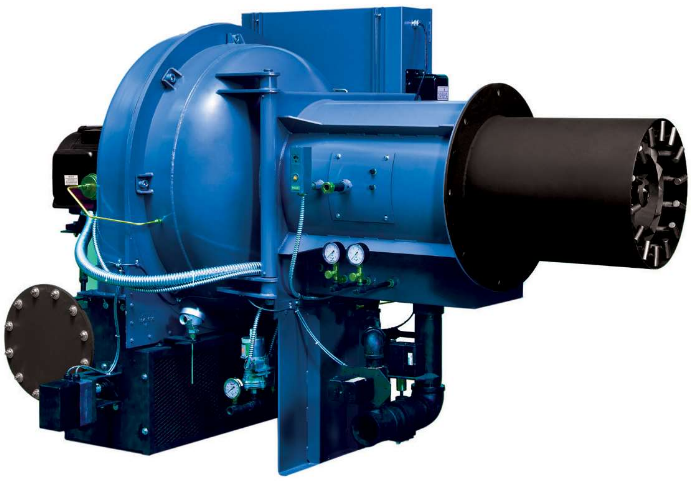
Frame	Model range	Boiler HP	Capacities		Mode of operation	Fuel	Parallel positioning
			MBH	GPH			
Size 1–3	378–924	900–2,200	37,800–92,400	270–660	Full modulation	Gas/Comb.	Required

Note: A parallel positioning system is required for burner management and combustion control. Consult factory for options.

Ultra-Low-NOx Configuration

The NTD Series was designed and developed with a flue gas recirculation (FGR) system which has been proven to be the benchmark in the industry. The Industrial Combustion NTD Series burner offers natural gas, propane air mix, air atomized #2 oil, and combination gas and oil fuel options from 12.6 to 33.5 MMBTU per hour, with full modulation operation and parallel positioning for greater efficiency and cost savings. The NTD is an ultra-low-NOx burner capable of less than 9 PPM NOx emissions.

NTD Burner



Available to less than 9 PPM NOx

Induced FGR modulating valve and shutoff valve

Parallel Positioning is standard for optimal control throughout the firing range

No. 2 Oil capability for back-up fuel

Rotary Air Damper for precise fuel-to-air ratios

Hinged Air Housing for easy access to internal components

Gas Injectors are a low-NOx, lance-style, hammerhead design, with all gas injectors mounted to an internal gas manifold assembly

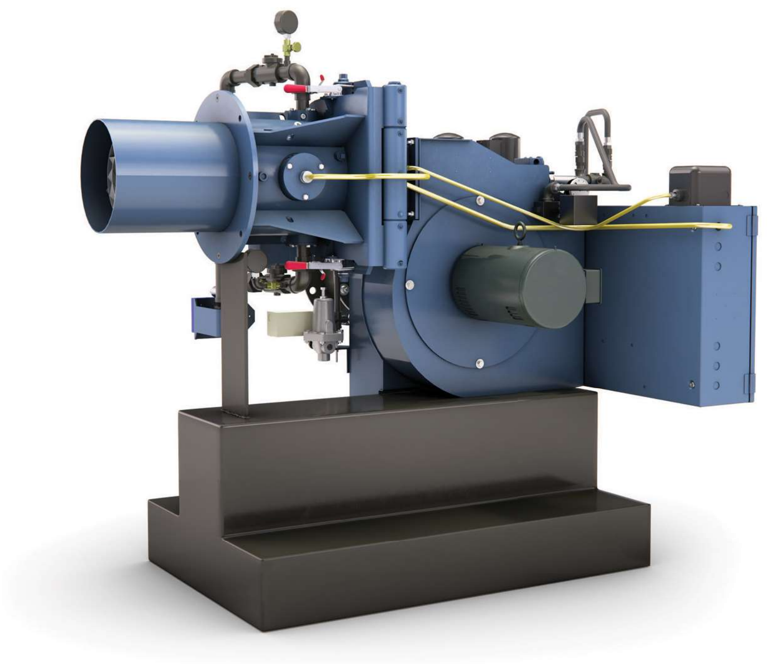
Backward-Curved Impeller provides adequate combustion air for various furnace pressure and high altitude applications

Frame	Model range	Boiler HP	Capacities		Mode of operation	Fuel	Parallel positioning
			MBH	GPH			
Size 5–8	126–336	300–800	12,600–33,500	90–239	Full modulation	Gas, Oil, Comb.	Standard

Ultra-Low-NOx Configuration

The NTH Series was designed and developed with a flue gas recirculation (FGR) system which has proven to be the benchmark in the industry, the Industrial Combustion NTH burner is capable of firing up to 300 HP firetube and watertube boilers. The NTH features an advanced design impeller with backwards-inclined vanes. Unlike ordinary forward-curved impellers, the backward incline design does not allow for dust to collect on the vanes, thus allowing the impeller to maintain its original balance while supplying combustion air. A special air intake box with a rotary air damper and FGR modulating valve, allows a precise amount of induced FGR and fuel-to-air ratio control throughout the firing range.

NTH Burner



Available to less than 9 PPM NOx

Induced FGR modulating valve and shutoff valve

Parallel Positioning is standard for optimal control throughout the firing range

Fuel Options gas, #2 oil and combination fuel capabilities

Rotary Air Damper precise fuel-to-air ratios

Hinged Air Housing for easy access to internal components

Gas Injectors are a low-NOx, lance-style, hammerhead design, with all gas injectors mounted to an internal gas manifold assembly

Backward-Curved Impeller provides adequate combustion air for various furnace pressure and high altitude applications

Panel Options top or rear mount available

Frame	Model range	Boiler HP	Capacities		Mode of operation	Fuel	Parallel positioning
			MBH	GPH			
Size 2–4	32–86	36–299	1,500–12,500	90–239	Full modulation	Gas, Oil, Comb.	Standard

Capacities and Ratings

Less than 15 PPM and less than 9 PPM Ultra-Low-NOx Configuration (NTXLG, NTXLLG)

Burner model no. & frame size	378-1	420-1	462-1	504-1	546-2	588-2	630-2	672-3	756-3	840-3	924-3
Gas input (MBTU/hr)	37,800	42,000	46,200	50,400	54,600	58,800	63,000	67,200	75,600	84,000	92,400
Oil input (US gal/hr)	270	300	330	360	390	420	450	480	540	600	660
Boiler HP @ 80% efficiency	900	1,000	1,100	1,200	1,300	1,400	1,500	1,600	1,800	2,000	2,200
Blower motor HP	50	50	75	100	100	100	125	150	150	200	200
Separate compressor motor HP	15	15	15	15	15	15	15	15	15	15	15
Furnace pressure (" w.c.)	6.8	8.3	8.7	8.9	9.3	9.6	11.1	9.5	9.5	10	10.1
Standard gas train pipe size (in.)	3	3	3	3	3	4	4	4	4	4	4
Gas pressure required (psi)	10	10	10	10	10	10	10	10	10	10	10
FGR line piping (in.)	14	14	14	16	16	16	16	18	18	20	20

Input is based on fuel BTU content and altitude of 2,000 feet or less. If altitude > 2,000 feet and < 8,000 feet, derate capacity 4% per 1,000 feet over 2,000 feet. Consult factory for higher altitudes. Gas input is based on natural gas with 1,000 BTU/cu.ft., 0.60 gravity, 0" w.c. furnace pressure and the aforementioned conditions. Oil input based on 140,000 BTU/gal and the aforementioned conditions. Consult factory for 50 Hz. applications. Contact the factory for shipping weight estimation.

Less than 15 ppm and less than 9 ppm Ultra-Low-NOx Configuration (NTDG, NTDLG)

Burner sizes		126	147	168	210	252	294	315	336
Gas input (MBTU/hr)		12600	14600	16700	20900	25100	29300	31400	33500
Oil input (US gal/hr)		90	105	120	149	179	209	224	239
Boiler HP @ 80% efficiency		300	350	400	500	600	700	750	800
Remote oil pump motor HP		1/2	1/2	3/4	3/4	3/4	3/4	3/4	3/4
Compressor motor HP: IC shower head oil nozzle		5	5	5	5	7 1/2	7 1/2	7 1/2	7 1/2
Compressor motor HP: oil nozzle		15	15	20	20	20	25	25	30
Minimum gas pressure required (psi)		6	6	6	6	8	8	8	8
<15 PPM	Frame size	5	5	6	6	7	7	8	8
	Blower motor HP	20	25	25	40	50	60	75	75
	FGR line piping (in)	6	8	8	8	8	10	10	10
	Furnace pressure (" w.c.)	3.3	4.6	5.2	3	4.6	6.2	7.1	8
<9 PPM	Frame size	5	6	6	6	8	8	-	-
	Blower motor HP	25	40	50	50	75	75	-	-
	FGR line piping (in)	8	10	10	10	12	12	-	-
	Furnace pressure (" w.c.)	4.1	5.7	6.4	3.7	5.7	7.7	-	-

Input is based on fuel BTU content and altitude of 2,000 feet or less. If altitude > 2,000 feet and < 8,000 feet, derate capacity 4% per 1,000 feet over 2,000 feet. Consult factory for higher altitudes. Gas input is based on natural gas with 1,000 BTU/cu.ft., 0.60 gravity, 0" w.c. furnace pressure and the aforementioned conditions. Oil input based on 140,000 BTU/gal and the aforementioned conditions. Consult factory for 50 Hz. applications.

Capacities and Ratings

Less than 15 ppm and less than 9 ppm Ultra-Low-NOx Configuration (NTH)

Burner sizes		15	20	25	30	35	40	42	45	50	52	55
Gas input (MBTU/hr)		1500	2000	2500	3000	3500	4000	4200	4500	5000	5200	5500
Oil input (US gal/hr)		-	-	-	-	-	-	-	32	36	37	39
Boiler HP @ 80% efficiency		36	48	60	72	84	96	100	108	120	125	131
Oil pump motor HP		-	-	-	-	-	-	-	$\frac{3}{4}$	$\frac{3}{4}$	$\frac{3}{4}$	$\frac{3}{4}$
Compressor motor HP		-	-	-	-	-	-	-	3	3	3	3
Min. gas pressure required (psi)		4	4	4	4	4	4	4	4	4	4	4
< 20 PPM	Frame size	2	2	2	2	2	2	2	3	3	3	3
	Blower motor HP	$\frac{3}{4}$	$\frac{3}{4}$	1	1	$1\frac{1}{2}$	2	2	3	5	5	5
	Furnace pressure (" w.c.)	0.5	0.8	1.3	1.1	$1\frac{1}{2}$	1.6	0.7	2.1	$2\frac{1}{2}$	1	3.1
< 15 PPM	Frame size	2	2	2	2	2	3	3	3	3	3	3
	Blower motor HP	$\frac{3}{4}$	$\frac{3}{4}$	1	$1\frac{1}{2}$	2	3	3	3	5	5	5
	Furnace pressure (" w.c.)	0.5	0.9	1.4	1.2	1.6	1.7	0.7	2.2	2.7	1.1	3.3
< 12 PPM	Frame size	2	2	2	2	2	3	3	3	3	3	3
	Blower motor HP	$\frac{3}{4}$	$\frac{3}{4}$	1	1.5	2	3	3	5	5	5	$7\frac{1}{2}$
	Furnace pressure (" w.c.)	0.6	1	1.6	1.3	1.7	1.9	0.8	2.4	3	1.2	3.7
< 9 PPM	Frame size	2	2	2	2	2	3	3	3	3	3	3
	Blower motor HP	$\frac{3}{4}$	1	$1\frac{1}{2}$	2	3	5	3	5	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$
	Furnace pressure (" w.c.)	0.6	1.1	1.8	1.4	2	2.2	0.9	2.7	3.4	1.4	4.1

Burner sizes		60	63	70	80	84	90	100	105	110	120	125
Gas input (MBTU/hr)		6,000	6,300	7,000	8,000	8,400	9,000	10,000	10,500	11,000	12,000	12,500
Oil input (US gal/hr)		43	45	50	57	60	64	71	75	79	86	89
Boiler HP @ 80% efficiency		143	150	167	191	200	215	239	250	263	287	299
Oil pump motor HP		1	1	1	$1\frac{1}{2}$	$1\frac{1}{2}$	$1\frac{1}{2}$	$1\frac{1}{2}$	$1\frac{1}{2}$	$1\frac{1}{2}$	$1\frac{1}{2}$	$1\frac{1}{2}$
Compressor motor HP		3	3	3	3	3	3	3	3	3	3	3
Min. gas pressure required (psi)		4	4	4	4	4	4	5	5	5	6	6
< 20 PPM	Frame size	3	3	3	3	3	4	4	4	4	4	4
	Blower motor HP	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$	10	10	10	15	15
	Furnace pressure (" w.c.)	3.6	1.7	2.6	3.5	2.4	4.4	4.1	2.1	4.9	5.8	6.3
< 15 PPM	Frame size	3	3	3	4	4	4	4	4	4	4	-
	Blower motor HP	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$	10	10	10	15	15	-
	Furnace pressure (" w.c.)	3.9	1.8	2.8	3.7	2.5	4.7	4.4	2.3	5.3	6.3	-
< 12 PPM	Frame size	3	3	4	4	4	4	4	4	4	4	-
	Blower motor HP	$7\frac{1}{2}$	$7\frac{1}{2}$	$7\frac{1}{2}$	10	10	10	15	15	15	15	-
	Furnace pressure (" w.c.)	4.4	2	3.2	4.1	2.8	5.2	4.8	2.5	2	1.5	-
< 9 PPM	Frame size	3	3	4	4	4	4	4	4	-	-	-
	Blower motor HP	$7\frac{1}{2}$	$7\frac{1}{2}$	10	10	10	15	15	15	-	-	-
	Furnace pressure (" w.c.)	4.9	2.3	3.5	4.6	3.2	5.9	5.4	2.9	-	-	-

For firetube, firebox and commercial watertube boilers only. Turndown on tangent tube commercial watertube boilers may be restricted, consult factory. Consult factory for oil applications for burner models 15 through 42. Input is based on fuel BTU content, list furnace pressure and altitude of 2,000 feet or less. If altitude > 2,000 feet and < 8,000 feet, derate capacity 4% per 1,000 feet over 2,000 ft. Consult factory for higher altitudes. If furnance pressure exceeds listed value, derate capacity 5% for every 1/2" w.c. of pressure in excess of stated. Consult factory if derate exceeds 20%. Gas input is based on natural gas with 1,000 BTU/cu.ft., 0.60 gravity, 0 furnace pressure and the aforementioned conditions. Gas pressure based on zero furance pressure. For total pressure at manifold, add furnace pressure. Oil input based on 140,000 BTU/gal and the aforementioned conditions. Consult factory for 50Hz. applications.

Burner and Control Upgrades Are Easier Than Ever.

Industrial Combustion has the engineering team to design a turnkey solution for any boiler and any application. Contact an Industrial Combustion authorized distributor to determine what upgrade is right for you.

Evaluate your burner and controls for an upgrade if:

- Existing burners do not offer high turndown for maximum efficiency
- Your burner or boiler controls are more than 10 years old
- Burner controls are not fully integrated with boiler loads
- You must reduce emissions while maintaining efficiency
- Alternate fuels could provide energy savings and/or reduced emissions

Lower Fuel Costs

Following initial installation, fuel costs will become your biggest operating expense. Industrial Combustion works with you to custom-tailor burner and control solutions that help you increase efficiency and decrease fuel costs in virtually any boiler room environment. By installing the right burners, controls and heat recovery equipment, you can realize substantial savings immediately.

Lower Emissions

Lowering boiler room emissions can be challenging, regardless of the fuel type you are using. Whether for a sustainability effort or the result of a government-mandated emissions program, you can look to Industrial Combustion to help you reach your goals. We have long been a leader in offering low-emission solutions that are right for any application. Our team will work with you to design a retrofit solution utilizing our burners to achieve the low emissions you need.

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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.

1.4.3 Emissions[3-4]

The emissions from natural gas-fired boilers and furnaces include nitrogen oxides (NO_x), carbon monoxide (CO), and carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOCs), trace amounts of sulfur dioxide (SO_2), and particulate matter (PM).

Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism of NO_x formation in natural gas combustion is thermal NO_x. The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NO_x is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO_x emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_x formation, called prompt NO_x, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of NO_x formed through the thermal NO_x mechanism. However, prompt NO_x levels may become significant with ultra-low-NO_x burners.

The third mechanism of NO_x formation, called fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_x formation through the fuel NO_x mechanism is insignificant.

Carbon Monoxide -

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. In some cases, the addition of NO_x control systems such as low NO_x burners and flue gas recirculation (FGR) may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.

Volatile Organic Compounds -

The rate of VOC emissions from boilers and furnaces also depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

Sulfur Oxides -

Emissions of SO_2 from natural gas-fired boilers are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO_2 emissions. Boilers combusting unprocessed natural gas may have higher SO_2 emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO_2 emissions.

Particulate Matter -

Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

Greenhouse Gases -[6-9]

CO_2, CH_4, and N_2O emissions are all produced during natural gas combustion. In properly tuned boilers, nearly all of the fuel carbon (99.9 percent) in natural gas is converted to CO_2 during the combustion process. This conversion is relatively independent of boiler or combustor type. Fuel carbon not converted to CO_2 results in CH_4, CO, and/or VOC emissions and is due to incomplete combustion. Even in boilers operating with poor combustion efficiency, the amount of CH_4, CO, and VOC produced is insignificant compared to CO_2 levels.

Formation of N_2O during the combustion process is affected by two furnace-zone factors. N_2O emissions are minimized when combustion temperatures are kept high (above 1475°F) and excess oxygen is kept to a minimum (less than 1 percent).

Methane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of methane.

1.4.4 Controls[4,10]

NO_x Controls -

Currently, the two most prevalent combustion control techniques used to reduce NO_x emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NO_x burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the recirculated gas acts as a dilutent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_x emission rates for these systems. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners.

Other combustion control techniques used to reduce NO_x emissions include staged combustion and gas reburning. In staged combustion (e.g., burners-out-of-service and overfire air), the degree of staging is a key operating parameter influencing NO_x emission rates. Gas reburning is similar to the use of overfire in the use of combustion staging. However, gas reburning injects additional amounts of natural gas in the upper furnace, just before the overfire air ports, to provide increased reduction of NO_x to NO_2.

Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). The SNCR system injects ammonia (NH_3) or urea into combustion flue gases (in a specific temperature zone) to reduce NO_x emission. The Alternative Control Techniques (ACT) document for NO_x emissions from utility boilers, maximum SNCR performance was estimated to range from 25 to 40 percent for natural gas-fired boilers.[12] Performance data available from several natural gas fired utility boilers with SNCR show a 24 percent reduction in NO_x for applications on wall-fired boilers and a 13 percent reduction in NO_x for applications on tangential-fired boilers.[11] In many situations, a boiler may have an SNCR system installed to trim NO_x emissions to meet permitted levels. In these cases, the SNCR system may not be operated to achieve maximum NO_x reduction. The SCR system involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x emissions. No data were available on SCR performance on natural gas fired boilers at the time of this publication. However, the ACT Document for utility boilers estimates NO_x reduction efficiencies for SCR control ranging from 80 to 90 percent.[12]

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4.[11] Tables in this section present emission factors on a volume basis (lb/10^6 scf). To convert to an energy basis (lb/MMBtu), divide by a heating value of 1,020 MMBtu/10^6 scf. For the purposes of developing emission factors, natural gas combustors have been organized into three general categories: large wall-fired boilers with greater than 100 MMBtu/hr of heat input, boilers and residential furnaces with less than 100 MMBtu/hr of heat input, and tangential-fired boilers. Boilers within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas.

Emission factors are rated from A to E to provide the user with an indication of how "good" the factor is, with "A" being excellent and "E" being poor. The criteria that are used to determine a rating for an emission factor can be found in the Emission Factor Documentation for AP-42 Section 1.4 and in the introduction to the AP-42 document.

1.4.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section are summarized below. For further detail, consult the Emission Factor Documentation for this section. These and other documents can be found on the Emission Factor and Inventory Group (EFIG) home page (http://www.epa.gov/ttn/chief).

Supplement D, March 1998

- Text was revised concerning Firing Practices, Emissions, and Controls.
- All emission factors were updated based on 482 data points taken from 151 source tests. Many new emission factors have been added for speciated organic compounds, including hazardous air pollutants.

July 1998 - minor changes

- Footnote D was added to table 1.4-3 to explain why the sum of individual HAP may exceed VOC or TOC, the web address was updated, and the references were reordered.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $1b/10^6$ scf to lb/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. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

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. $CO_2[lb/10^6 \text{ scf}] = (3.67)\text{ (CON) (C)(D)}$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ 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-Methylcholanthrene[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
207-08-9	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
74-98-6	Propane	1.6E+00	E

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
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 $1b/10^6$ 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 l6. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020.

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

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12. *Alternate Control Techniques Document - NO_x Emissions from Utility Boilers*, EPA-453/R-94-023, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1994.

3.3 Gasoline And Diesel Industrial Engines

3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion (IC) engines such as aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The three primary fuels for reciprocating IC engines are gasoline, diesel fuel oil (No.2), and natural gas. Gasoline is used primarily for mobile and portable engines. Diesel fuel oil is the most versatile fuel and is used in IC engines of all sizes. The rated power of these engines covers a rather substantial range, up to 250 horsepower (hp) for gasoline engines and up to 600 hp for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines".) Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

3.3.2 Process Description

All reciprocating IC engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). This section deals with both types of reciprocating IC engines. All diesel-fueled engines are compression ignited, and all gasoline-fueled engines are spark ignited.

In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

3.3.3 Emissions

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the atmosphere from the exhaust. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x), total organic compounds (TOC), carbon monoxide (CO), and particulates, which include both visible (smoke) and nonvisible emissions. Nitrogen oxide formation is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The other pollutants, HC, CO, and smoke, are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust. Sulfur oxides (SO_x) also appear in the exhaust from IC engines. The sulfur compounds, mainly sulfur dioxide (SO_2), are directly related to the sulfur content of the fuel.[2]

3.3.3.1 Nitrogen Oxides -

Nitrogen oxide formation occurs by two fundamentally different mechanisms. The predominant mechanism with internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in the high-temperature region of the flame from dissociated molecular nitrogen in the combustion air. Some NO_x, called prompt NO_x, is formed in the early part of the flame from reaction of nitrogen intermediary species, and HC radicals in the flame. The second mechanism, fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Gasoline, and most distillate oils have no chemically-bound fuel N_2 and essentially all NO_x formed is thermal NO_x.

3.3.3.2 Total Organic Compounds -

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion.

Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.[2]

3.3.3.3 Carbon Monoxide -

Carbon monoxide is a colorless, odorless, relatively inert gas formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.[2-3]

3.3.3.4 Smoke and Particulate Matter -

White, blue, and black smoke may be emitted from IC engines. Liquid particulates appear as white smoke in the exhaust during an engine cold start, idling, or low load operation. These are formed in the quench layer adjacent to the cylinder walls, where the temperature is not high enough to ignite the fuel. Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion mixtures that are oxygen deficient.[2]

3.3.3.5 Sulfur Oxides -

Sulfur oxides emissions are a function of only the sulfur content in the fuel rather than any combustion variables. In fact, during the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2. The oxidation of SO_2 gives sulfur trioxide (SO_3), which reacts with water to give sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to give sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.[2-3]

3.3.4 Control Technologies

Control measures to date are primarily directed at limiting NO_x and CO emissions since they are the primary pollutants from these engines. From a NO_x control viewpoint, the most important distinction between different engine models and types of reciprocating engines is whether they are rich-burn or lean-burn. Rich-burn engines have an air-to-fuel ratio operating range that is near stoichiometric or fuel-rich of stoichiometric and as a result the exhaust gas has little or no excess oxygen. A lean-burn engine has an air-to-fuel operating range that is fuel-lean of stoichiometric; therefore, the exhaust from these engines is characterized by medium to high levels of O_2. The most common NO_x control technique for diesel and dual-fuel engines focuses on modifying the combustion process. However, selective catalytic reduction (SCR) and nonselective catalytic reduction (NSCR) which are post-combustion techniques are becoming available. Controls for CO have been partly adapted from mobile sources.[4]

Combustion modifications include injection timing retard (ITR), preignition chamber combustion (PCC), air-to-fuel ratio adjustments, and derating. Injection of fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NO_x formation. ITR reduces NO_x from all diesel engines; however, the effectiveness is specific to each engine model. The amount of NO_x reduction with ITR diminishes with increasing levels of retard.[4]

Improved swirl patterns promote thorough air and fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC results in improved mixing and complete combustion of the lean air/fuel mixture which lowers combustion temperature, thereby reducing NO_x emissions.[4]

The air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel that enters each cylinder. At air-to-fuel ratios less than stoichiometric (fuel-rich), combustion occurs under conditions of insufficient oxygen which causes NO_x to decrease because of lower oxygen and lower temperatures. Derating involves restricting the engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures, thereby lowering NO_x formation rates.[4]

SCR is an add-on NO_x control placed in the exhaust stream following the engine and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form water and nitrogen. The effectiveness of SCR depends on fuel quality and engine duty cycle (load fluctuations). Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. Load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.[4]

NSCR is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC and involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios.[4]

The most accurate method for calculating such emissions is on the basis of "brake-specific" emission factors (pounds per horsepower-hour [lb/hp-hr]). Emissions are the product of the brake-specific emission factor, the usage in hours, the rated power available, and the load factor (the power actually used divided by the power available). However, for emission inventory purposes, it is often easier to assess this activity on the basis of fuel used.

Once reasonable usage and duty cycles for this category were ascertained, emission values were aggregated to arrive at the factors for criteria and organic pollutants presented. Factors in Table 3.3-1 are in pounds per million British thermal unit (lb/MMBtu). Emission data for a specific design type were weighted according to estimated material share for industrial engines. The emission factors in these tables, because of their aggregate nature, are most appropriately applied to a population of industrial engines rather than to an individual power plant. Table 3.3-2 shows unweighted speciated organic compound and air toxic emission factors based upon only 2 engines. Their inclusion in this section is intended for rough order-of-magnitude estimates only.

Table 3.3-3 summarizes whether the various diesel emission reduction technologies (some of which may be applicable to gasoline engines) will generally increase or decrease the selected parameter. These technologies are categorized into fuel modifications, engine modifications, and exhaust after-treatments. Current data are insufficient to quantify the results of the modifications. Table 3.3-3 provides general information on the trends of changes on selected parameters.

3.3.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- Text was revised concerning emissions and controls.
- The CO_2 emission factor was adjusted to reflect 98.5 percent conversion efficiency.

Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01) Emission Factor (lb/hp-hr) (power output)	Gasoline Fuel Emission Factor (lb/MMBtu) (fuel input)	Diesel Fuel (SCC 2-02-001-02, 2-03-001-01) Emission Factor (lb/hp-hr) (power output)	Diesel Fuel Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING
NO_x	0.011	1.63	0.031	4.41	D
CO	6.96 E-03[d]	0.99[d]	6.68 E-03	0.95	D
SO_x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10[b]	7.21 E-04	0.10	2.20 E-03	0.31	D
CO_2[c]	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

[a] References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.

[b] PM-10 = particulate matter less than or equal to 10 µm aerodynamic diameter. All particulate is assumed to be $\leq$ 1 µm in size.

[c] Assumes 99% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

[d] Instead of 0.439 lb/hp-hr (power output) and 62.7 lb/mmBtu (fuel input), the correct emissions factors values are 6.96 E-03 lb/hp-hr (power output) and 0.99 lb/mmBtu (fuel input), respectively. This is an editorial correction. March 24, 2009

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

Table 3.3-3. EFFECT OF VARIOUS EMISSION CONTROL TECHNOLOGIES ON DIESEL ENGINES[a]

Technology	Affected Parameter	
	Increase	Decrease
Fuel modifications		
Sulfur content increase	PM, wear	
Aromatic content increase	PM, NO_x	
Cetane number		PM, NO_x
10% and 90% boiling point		PM
Fuel additives		PM, NO_x
Water/Fuel emulsions		NO_x
Engine modifications		
Injection timing retard	PM, BSFC	NO_x, power
Fuel injection pressure	PM, NO_x	
Injection rate control		NO_x, PM
Rapid spill nozzles		PM
Electronic timing & metering		NO_x, PM
Injector nozzle geometry		PM
Combustion chamber modifications		NO_x, PM
Turbocharging	PM, power	NO_x
Charge cooling		NO_x
Exhaust gas recirculation	PM, power, wear	NO_x
Oil consumption control		PM, wear
Exhaust after-treatment		
Particulate traps		PM
Selective catalytic reduction		NO_x
Oxidation catalysts		TOC, CO, PM

[a] Reference 8. PM = particulate matter. BSFC = brake-specific fuel consumption.

References For Section 3.3

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11. *Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992* (1994) DOE/PO-0028, Volume 2 of 3, U.S. Department of Energy.

12. G. Marland and R. M. Rotty, *Carbon Dioxide Emissions From Fossil Fuels: A Procedure For Estimation And Results For 1950-1982*, Tellus 36B:232-261, 1984.

13. *Inventory Of U. S. Greenhouse Gas Emissions And Sinks: 1990-1991*, EPA-230-R-96-006, U. S. Environmental Protection Agency, Washington, DC, November 1995.

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Power Generation

Exhaust Emission Data Sheet
275DQDAB
60 Hz Diesel Generator Set
EPA NSPS Stationary Emergency

Engine Information:

Model:	Cummins Inc. QSL9-G7 NR3	Bore:	4.49 in. (114 mm)
Type:	4 Cycle, In-line, 6 Cylinder Diesel	Stroke:	5.69 in. (145 mm)
Aspiration:	Turbocharged and CAC	Displacement:	543 cu. in. (8.9 liters)
Compression Ratio:	16.1:1		
Emission Control Device:	Turbocharger and CAC		

PERFORMANCE DATA	**1/4 Standby**	**1/2 Standby**	**3/4 Standby**	**Full Standby**	**Full Prime**
Engine HP @ Stated Load (1800 RPM)	104.5	209	313.5	418	378
Fuel Consumption (gal/hr)	6.38	11.35	16.33	21.31	19.40
Exhaust Gas Flow (CFM)	N/A	N/A	N/A	N/A	N/A
Exhaust Gas Temperature (°F)	654	770	880	958	930
EXHAUST EMISSION DATA					
HC (Total Unburned Hydrocarbons)	0.289	0.148	0.071	0.042	0.047
NOx (Oxides of Nitrogen as NO2)	1.6	1.70	2.42	4.26	3.39
CO (Carbon Monoxide)	N/A	N/A	N/A	N/A	N/A
PM (particular Matter)	N/A	N/A	N/A	N/A	N/A
SO2 (Sulfur Dioxide)	0.14	0.13	0.12	0.11	0.115
Smoke (Bosch)	0.458	0.455	0.348	0.181	0.22

All values are Grams per HP-Hour

TEST CONDITIONS

Data was recorded during steady-state rated engine speed (± 25 RPM) with full load (±2%). Pressures, temperatures, and emission rates were stabilized.

Fuel Specification:	46.5 Cetane Number, 0.035 Wt.% Sulfur; Reference ISO8178-5, 40 CFR86.1313-98 Type 2-D and ASTM D975 No. 2-D.
Fuel Temperature:	99 ± 9 °F (at fuel pump inlet)
Intake Air Temperature:	77 ± 9 °F
Barometric Pressure:	29.6 ± 1 in. Hg
Humidity:	NOx measurement corrected to 75 grains H2O/lb dry air
Reference Standard:	ISO 8178

The NOx, HC, CO and PM emission data tabulated here were taken from a single engine under the test conditions shown above. Data for the other components are estimated. These data are subjected to instrumentation and engine-to-engine variability. Field emission test data are not guaranteed to these levels. Actual field test results may vary due to test site conditions, installation, fuel specification, test procedures and instrumentation. Engine operation with excessive air intake or exhaust restriction beyond published maximum limits, or with improper maintenance, may results in elevated emission levels.

Model No. / Modele: DQDAB – 1216217

Serial No. / Serie: L120426818 | Spec. E

IMPORTANT!
Model & Serial No. Required When Ordering Parts.
Modele & No. Serie Requis Pour Commander Des Pieces. 99-2433

CUMMINS POWER GENERATION
1400 73RD AVE. N.E.
MINNEAPOLIS, MN 55432 U.S.A.

MADE IN U.S.A.

FREQUENCY	60 HZ			
SERVICE RATING	STANDBY		PRIME	
PHASE	1PH	3PH	1PH	3PH
RATED KW	0.0	275.0	0.0	0.0
POWER FACTOR	0.0	0.8	0.0	0.0
RATED KVA	0.0	343.7	0.0	0.0
I2 CAPABILITY	8pct			
CONNECTION	WYE			

BATTERY	VOLTS	AMPS	AMPS
24 VDC	120/ 240	827	
	139/ 240	827	
	277/ 480	413.5	

ROTATING
SPEED
1800RPM

NOMINAL
RATED

INSUL:
CLASS H
AMB 40C

FUEL: Diesel — MAX FLOW 163 L/hr (43 gal/hr)

WIRING DIAGRAM

RAD

For Electrical Equipment Only
Pour Material Electrique Seulement

Model No. / Modele: DQDAB - 1216217

Serial No. / Serie: L120426818 | Spec.

IMPORTANT!
Model & Serial No. Required When Ordering Parts.
Modele & No. Serie Requis Pour Commander Des Pieces. 99-2433

Serial No.
Serie L120426818

Spec.

IMPORTANT!
Model & Serial No. Required When Ordering Parts.
Modele & No. Serie Requis Pour Commander Des Pieces. 99-2433

12/05/2012 MMDDYYYY Build Date
0326-6967 Calibration P/N

Feature P/N	Feature P/N	Feature P/N
0326-5483	0326-5484	0326-5488
0326-5490	0326-5566	0326-5579
0326-5597	0326-5653	0326-5745
0326-6780	0326-6965	


Cummins
Cummins Inc.
Columbus, Indiana
47202-3005
Assembled in U.S.A.
WARNING: INJURY MAY RESULT AND WARRANTY IS VOID-
ED IF FUEL RATE RPM OR ALTITUDES EXCEED PUBLISHED
MAXIMUM VALUES FOR THIS MODEL AND APPLICATION.
Date of Mfg. 20121115
Cummins Engine Co. Ltd.
5272639
CID/ L. 540 / 8.9
Family CCEXL0540AAB
Valve lash cold
Inch 0.012
MM 0.305
Int.
Int.
Fuel rate at rated HP/Kw 275
Timing - TDC ELECTRONIC
EMISSION CONTROL INFORMATION: THIS ENGINE
2012 STATIONARY EMERGENCY DIESEL ENGINE
APPLICATIONS ONLY


CID/ L. 540 / 8.9
Family CCEXL0540AAB
CPL 3301
Engine Serial No. 73472926
Cust. Spec. A029L220
Model QSL9-G7
Prime HP/Kw 422
Prime HP/Kw 365
Standby HP/Kw 464
Standby HP/Kw 402
Valve lash cold
Inch 0.012 Int. 0.022 Exh.
MM 0.305 Int. 0.559 Exh.
Fuel rate at rated HP/Kw 275 mm3/st
Timing - TDC ELECTRONIC
MISSION CONTROL INFORMATION: THIS ENGINE COMPLIES WITH U.S. EPA
STATIONARY EMERGENCY DIESEL ENGINES. USE IN A EMER
CATIONS ONLY

Attachment 9

Emission Calculations

Curia New Mexico, LLC

Facility Emissions Summary

Proposed Emission Unit #6 - Cummins Emergency Generator
Proposed Emission Unit #7 - Johnston Boiler
Add HAP calculations for existing emission units
Minor corrections/adjustments to emission limits for existing units #3 and #4

Current Permit Emissions Summary (Reflects October 5, 2022 Revision to Air Quality Construction Permit #1097-M3-2AR)

Unit #	#1 Diesel Emergency Generator		#2[1] Diesel Emergency Generator		#3[2] Diesel Emergency Generator		#4[2] Diesel Emergency Generator		#5 Superior Natural Gas Boiler		Solvent and Chemical Usage		Total Current Permit Emissions	
	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year
CO	1.560	0.390			2.66	0.66	5.564	1.391	0.160	0.700	-	-	9.944	3.141
NOx+NMHC					3.07	0.77	10.230	2.560						
NOx	7.250	1.810			3.03	0.76	9.666	2.416	0.130	0.570	-	-	20.076	5.554
VOC[2]	0.580	0.140			0.04	0.01	0.509	0.127	0.034	0.150	1.280	4.000	2.443	4.427
SO2	0.480	0.120			0.11	0.03	1.17E-02	2.93E-03	0.004	0.020	-	-	0.606	0.173
TSP/PM	0.510	0.130			0.15	0.04	0.318	0.079	0.020	0.090	-	-	0.998	0.339
PM10	0.510	0.130			0.15	0.04	0.318	0.079	0.020	0.090	-	-	0.998	0.339
PM2.5	0.510	0.130			0.15	0.04	0.318	0.079	0.020	0.090	-	-	0.998	0.339
Total HAP													0.000	0.000

Proposed Emission Unit Permit Limits / **Proposed Construction Permit (New EG and Boiler plus Permit Corrections)**

Unit #	Existing #1 Diesel Emergency Generator Add HAPs (Criteria Pollutants do not change)		Existing #3 Diesel Emergency Generator Permit Corrections		Existing #4 Diesel Emergency Generator Permit Corrections		Existing #5 Superior Natural Gas Boiler Add HAPs (Criteria Pollutants do not change)		Existing Solvent and Chemical Usage		New #6 Diesel Emergency Generator		New #7 Johnston Natural Gas Boiler		Net Changes (for permit modification with new emergency generator and boiler)		Proposed Construction Permit (#6 - New Emergency Generator and #7 - New Boiler and Permit Corrections)	
	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year	pounds per hour	tons per year
CO	1.560	0.390	2.670	0.667	5.564	1.391	0.160	0.700			14.431	3.608	1.375	6.024	15.816	9.639	25.760	12.780
NOx+NMHC																		
NOx	7.250	1.810	2.899	0.725	9.666	2.416	0.130	0.570			25.069	6.267	0.524	2.295	25.461	8.529	45.537	14.083
VOC[2]	0.580	0.140	0.153	0.038	0.509	0.127	0.034	0.150	1.280	4.000	1.319	0.330	0.090	0.394	1.522	0.752	3.965	5.180
SO2	0.480	0.120	0.113	0.028	0.012	0.003	0.004	0.020			0.030	0.008	0.010	0.043	0.043	0.049	0.649	0.222
TSP/PM	0.510	0.130	0.153	0.038	0.318	0.079	0.020	0.090			0.825	0.206	0.124	0.545	0.952	0.749	1.950	1.089
PM10	0.510	0.130	0.153	0.038	0.318	0.079	0.020	0.090			0.825	0.206	0.124	0.545	0.952	0.749	1.950	1.089
PM2.5	0.510	0.130	0.153	0.038	0.318	0.079	0.020	0.090			0.825	0.206	0.124	0.545	0.952	0.749	1.950	1.089
Total HAP	5.68E-09	1.42E-09	2.29E-08	5.72E-09	2.78E-08	6.95E-09	4.65E-02	2.04E-01			2.65E-08	6.61E-09	0.185	0.810	0.231	1.013	0.231	1.013

Notes:

1. Unit #2 (Emergency Generator) was removed from the permit per October 5, 2022 Administrative Revision to Permit No. 1097-M3-1TR.
2. Unit #3 and Unit #4 limits are established in the current permit as NOx+NMHC in Permit Condition 2 - Unit Emission Limits. Emissions represented in this summary are based the split of NOx/VOC specified in Permit condition 5h) and 5i).
3. Limit on VOC emission from solvent and chemical usage in the existing permit is 4.0 tpy. Annual hours of operations are assumed to be 6,240 hours/year to estimate the lb/hr emissions.

Estimated Emissions

Existing Emission Unit #1
Onan Generator Set - 125QSEA-71410B
Cummins Engine - 6CT 8 3G

Nameplate Provided Specifications:			Source:	Calculation Basis/Conversion Factors:
Site Rated Standby kW Generator	125	kW	Genset Nameplate (3 Phase)	Gross Heat Content of Diesel Assumption from AP-42 Appendix A.
Engine Brake Horsepower	207	bhp	Engine Nameplate	137,000 Btu/gal
Engine Brake Horsepower	154	kW		
Standby Fuel Consumption	11	gal/hr		Convert Grams to lbs:
Standby Heat Input Capacity	1.449	MMBTU/hr		0.00220462 lb= 1 g
Brake Specific Fuel Consumption	7000	Btu/hp-hr	AP-42, Fifth Edition, Volume 1, Chapter 3, Section 3.3, Table 3.3-1, Footnote C, for Gasoline and Diesel Industrial Engines (up to 600 hp)	
Manufacture Date:	Unknown			2544.43 BTU/HP-hr
				0.7457 kW/hp
Annual Operating Hours:	500	hrs/yr		

Emission Estimates- HAPs

	Emission Factor		Emission Factor Source	Estimated Emissions	
HAPs	**Lb/MMBTU (fuel input)**			**pounds per hour**	**tons per year**
1,3-Butadiene	3.90E-05		AP-42, Fifth Edition, Volume 1, Chapter 3, Section 3.3, Tables 3.3-2 for Gasoline and Diesel Industrial Engines (up to 600 hp)	5.65E-11	1.41E-11
Acenaphthene	1.42E-06			2.06E-12	5.14E-13
Acenaphthylene	5.06E-06			7.33E-12	1.83E-12
Acetaldehyde	7.67E-04			1.11E-09	2.78E-10
Acrolein	9.25E-05			1.34E-10	3.35E-11
Anthracene	1.87E-06			2.71E-12	6.77E-13
Benz(a)anthracene	1.68E-06			2.43E-12	6.09E-13
Benzene	9.33E-04			1.35E-09	3.38E-10
Benzo(a)pyrene	1.88E-07			2.72E-13	6.81E-14
Benzo(b)fluoranthene	9.91E-08			1.44E-13	3.59E-14
Benzo(g,h,l)pyrene	4.89E-07			7.09E-13	1.77E-13
Benzo(k)fluoranthene	1.55E-07			2.25E-13	5.61E-14
Chrysene	3.53E-07			5.11E-13	1.28E-13
Dibenz(a,h)anthracene	5.83E-07			8.45E-13	2.11E-13
Flouranthene	7.61E-06			1.10E-11	2.76E-12
Flourene	2.92E-05			4.23E-11	1.06E-11
Formaldehyde	1.18E-03			1.71E-09	4.27E-10
Indeno(1,2,3-cd)pyrene	3.75E-07			5.43E-13	1.36E-13
Naphthalene	8.48E-05			1.23E-10	3.07E-11
Phenanthrene	2.94E-05			4.26E-11	1.07E-11
Pyrene	4.78E-06			6.93E-12	1.73E-12
Toluene	4.09E-04			5.93E-10	1.48E-10
Xylenes	2.85E-04			4.13E-10	1.03E-10
Arsenic	4.00E-06		EPA AP-42, Table 1.3-10	5.80E-12	1.45E-12
Beryllium	3.00E-06			4.35E-12	1.09E-12
Cadmium	3.00E-06			4.35E-12	1.09E-12
Chromium	3.00E-06			4.35E-12	1.09E-12
Lead	9.00E-06			1.30E-11	3.26E-12
Mercury	3.00E-06			4.35E-12	1.09E-12
Manganese	6.00E-06			8.69E-12	2.17E-12
Nickel	3.00E-06			4.35E-12	1.09E-12
Selenium	1.50E-05			2.17E-11	5.43E-12
Total HAPs				5.68E-09	1.42E-09

Estimated Emissions

Existing Emission Unit #3

Onan Diesel Emergency Generator - DQKAB-1216217

Cummins Engine - QSL9-G7/Sn 73472926

Nameplate Provided Specifications:			Source:
Site Rated Standby kW Generator	275	kW	Genset Nameplate
Standby Horsepower (Brake HP)	464	bhp	Engine Nameplate
Standby Fuel Consumption	43	gal/hr	Genset Nameplate
Standby Heat Input Capacity	5.891	MMBTU/hr	
Gen Set Manufacture Date	12/5/2012		Genset Nameplate
Engine Manufacture Date	11/15/2012		Engine Nameplate
Displacement	8.3	L	Engine Nameplate
Manufacter SO2 Emission Factor:	0.11	g/hp-hr	Manufacture Data Sheet
SO2 Emission Factor:	2.43E-04	lb/hp-hr	
Annual Operating Hours:	500	hrs/yr	

Calculation Basis/Conversion Factors:

Gross Heat Content of Diesel Assumption from AP-42 Appendix A.

137,000 Btu/gal

Convert Grams to lbs:

0.00220462 lb= 1 g

2544.43 BTU/HP-hr

0.7457 kW/hp

Emission Estimates

Air Contaminant	Emission Factor g/kW-hr	Emission Factor lb/hp-hr (power output)	Emission Factor Source	Estimated Emissions pounds per hour	Estimated Emissions tons per year	Permit Limits pounds per hour[4]	Permit Limits tons per year[5]	Δ Calculated and Permitted pounds per hour	Δ Calculated and Permitted tons per year
CO	3.5		EPA-420-B-16-022 (March 2016), Nonroad CI EPA Tier 3 Standards for 130<kW>560 per 40 CFR 1039, Appendix I	2.67	0.67	2.66	0.66	0.01	0.01
NOx+NMHC	4.0			3.05	0.76	3.07	0.77	-0.02	-0.01
NOx[1]	3.8			2.90	0.72	3.03	0.76	-0.13	-0.03
VOC[1]	0.2			0.15	0.04	0.04	0.01	0.11	0.03
SO_2[2]		2.43E-04	Manufacturer SOx EF	0.11	0.028	0.11	0.03	0.00	0.00
PM/TSP	0.2		EPA-420-B-16-022 (March 2016), Nonroad CI EPA Tier 3 Standards for 130<kW>560 per 40 CFR 1039, Appendix I	0.15	0.04	0.15	0.04	0.00	0.00
PM10[3]	0.2			0.15	0.04	0.15	0.04	0.00	0.00
PM2.5[3]	0.2			0.15	0.04	0.15	0.04	0.00	0.00

HAPs	Lb/MMBTU (fuel input)			pounds per hour	tons per year
Acenaphthene	1.42E-06		AP-42, Fifth Edition, Volume 1, Chapter 3, Section 3.3, Tables 3.3-2 for Gasoline and Diesel Industrial Engines (up to 600 hp)	8.37E-12	2.09E-12
Acenaphthylene	5.06E-06			2.98E-11	7.45E-12
Acetaldehyde	7.67E-04			4.52E-09	1.13E-09
Acrolein	9.25E-05			5.45E-10	1.36E-10
Anthracene	1.87E-06			1.10E-11	2.75E-12
Benz(a)anthracene	1.68E-06			9.90E-12	2.47E-12
Benzene	9.33E-04			5.50E-09	1.37E-09
Benzo(a)pyrene	1.88E-07			1.11E-12	2.77E-13
Benzo(b)fluoranthene	9.91E-08			5.84E-13	1.46E-13
Benzo(g,h,l)pyrene	4.89E-07			2.88E-12	7.20E-13
Benzo(k)fluoranthene	1.55E-07			9.13E-13	2.28E-13
Chrysene	3.53E-07			2.08E-12	5.20E-13
Dibenz(a,h)anthracene	5.83E-07			3.43E-12	8.59E-13
Flouranthene	7.61E-06			4.48E-11	1.12E-11
Flourene	2.92E-05			1.72E-10	4.30E-11
Formaldehyde	1.18E-03			6.95E-09	1.74E-09
Indeno(1,2,3-cd)pyrene	3.75E-07			2.21E-12	5.52E-13
Naphthalene	8.48E-05			5.00E-10	1.25E-10
Phenanthrene	2.94E-05			1.73E-10	4.33E-11
Pyrene	4.78E-06			2.82E-11	7.04E-12
Toluene	4.09E-04			2.41E-09	6.02E-10
Xylenes	2.85E-04			1.68E-09	4.20E-10
Arsenic	4.00E-06		EPA AP-42, Table 1.3-10	2.36E-11	5.89E-12
Beryllium	3.00E-06			1.77E-11	4.42E-12
Cadmium	3.00E-06			1.77E-11	4.42E-12
Chromium	3.00E-06			1.77E-11	4.42E-12
Lead	9.00E-06			5.30E-11	1.33E-11
Mercury	3.00E-06			1.77E-11	4.42E-12
Manganese	6.00E-06			3.53E-11	8.84E-12
Nickel	3.00E-06			1.77E-11	4.42E-12
Selenium	1.50E-05			8.84E-11	2.21E-11
Total HAPs				2.29E-08	5.72E-09

Notes:

1. EPA Tier 3 NOx+NMHC emission standard for engine 130<kW>560 is 4.0 g/kW-hr. A 95%/5% split of NOx/VOC was used based on the 2004 California Air Resources Board (CARB) policy "CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NOx."
2. SOx emission factor is from the Manufacturer (0.11 g/hp-hr) converted to lb/hp-hr.
3. For the purposes of these calculations, it was assumed PM = PM10 = PM2.5 as a conservative estimate of PM10 and PM2.5.
4. Permit Condition 2 - Unit Emission Limits specifies a combined NOx+NMHC limit for Emergency Engines #3 for Nox and NMHCs and #4. Pound per hour emission limits for NOx and NMHC are specified in Conditions 5h) and 5i).
5. Ton per year limits for individual NOx and VOC are not specified in the permit. They are calculated from the lb/hr values specified in Permit Conditions 5h) and 5i).

Estimated Emissions

Existing Emission Unit #4

Cummins Diesel Emergency Generator - DQPAA-1755965

Cummins Engine - QSK19-G8

Nameplate Provided Specifications:			Source:
Site Rated Standby kW Generator	600	kW	Genset Nameplate
Advrt. Power (Brake HP)	967	bhp	Engine Nameplate
Standby Fuel Consumption	125	gal/hr	Genset Nameplate
Standby Heat Input Capacity	17.125	MMBTU/hr	
Genset Manufacture Date:	Feb-18		Engine Nameplate
Engine Manufacture Date:	Feb-18		
Displacement	19	L	Engine Nameplate
Annual Operating Hours:	500	hrs/yr	

Calculation Basis/Conversion Factors:

Gross Heat Content of Diesel Assumption from AP-42 Appendix A.
137,000 Btu/gal

Diesel Fuel Sulfur Content:
15 ppm
0.0015 percent

Convert Grams to lbs:
0.00220462 lb= 1 g

2544.43 BTU/HP-hr

0.7457 kW/hp

Emission Estimates

	Emission Factor		Emission Factor Source	Estimated Emissions		Permit Limits		Δ Calculated and Permitted	
Air Contaminant	**g/kW-hr**	**lb/hp-hr (power output)**		**pounds per hour**	**tons per year**	**pounds per hour[4]**	**tons per year[5]**	**pounds per hour**	**tons per year**
CO	3.5		EPA-420-B-16-022 (March 2016), Nonroad CI EPA Tier 2 Standards for kW>560 per 40 CFR 1039, Appendix I	5.56	1.39	5.44	1.39	0.12	0.00
NOx+NMHC	6.4			10.17	2.54	10.23	2.56	-0.06	-0.02
NOx[1]	6.08			9.67	2.42	9.72	2.43	-0.05	-0.01
VOC[1]	0.32			0.51	0.13	0.51	0.13	0.00	0.00
SO_2[2]		1.214E-05	AP-42 Chapter 3.4, Table 3.4-1 for Large Stationary Diesel (greater than 600 hp)	0.012	0.003	0.23	0.06	-0.22	-0.06
PM/TSP	0.2		EPA-420-B-16-022 (March 2016), Nonroad CI EPA Tier 2 Standards for kW>560 per 40 CFR 1039, Appendix I	0.32	0.08	0.32	0.008	0.00	0.07
PM10[3]	0.2			0.32	0.08	0.32	0.008	0.00	0.07
PM2.5[3]	0.2			0.32	0.08	0.32	0.008	0.00	0.07

HAPs	**Lb/MMBTU (fuel input)**			**pounds per hour**	**tons per year**
Acenaphthene	4.68E-06		AP-42, Fifth Edition, Volume 1, Chapter 3, Section 3.4, Tables 3.4-3 and 3.4-4 (10/96) for Large Stationary Diesel (greater than 600 hp)	8.01E-11	2.00E-11
Acenaphthylene	9.23E-06			1.58E-10	3.95E-11
Acetaldehyde	2.52E-05			4.32E-10	1.08E-10
Acrolein	7.88E-06			1.35E-10	3.37E-11
Anthracene	1.23E-06			2.11E-11	5.27E-12
Benz(a)anthracene	6.22E-07			1.07E-11	2.66E-12
Benzene	7.76E-04			1.33E-08	3.32E-09
Benzo(b)fluoranthene	1.11E-06			1.90E-11	4.75E-12
Benzo(g,h,l)pyrene	5.56E-07			9.52E-12	2.38E-12
Benzo(k)fluoranthene	2.18E-07			3.73E-12	9.33E-13
Chrysene	1.53E-06			2.62E-11	6.55E-12
Dibenz(a,h)anthracene	3.46E-07			5.93E-12	1.48E-12
Flouranthene	4.03E-06			6.90E-11	1.73E-11
Flourene	1.28E-05			2.19E-10	5.48E-11
Formaldehyde	7.89E-05			1.35E-09	3.38E-10
Indeno(1,2,3-cd)pyrene	4.14E-07			7.09E-12	1.77E-12
Naphthalene	1.30E-04			2.23E-09	5.57E-10
Phenanthrene	4.08E-05			6.99E-10	1.75E-10
Pyrene	3.71E-06			6.35E-11	1.59E-11
Toluene	2.81E-04			4.81E-09	1.20E-09
Xylenes	1.93E-04			3.31E-09	8.26E-10
Arsenic	4.00E-06		EPA AP-42, Table 1.3-10	6.85E-11	1.71E-11
Beryllium	3.00E-06			5.14E-11	1.28E-11
Cadmium	3.00E-06			5.14E-11	1.28E-11
Chromium	3.00E-06			5.14E-11	1.28E-11
Lead	9.00E-06			1.54E-10	3.85E-11
Mercury	3.00E-06			5.14E-11	1.28E-11
Manganese	6.00E-06			1.03E-10	2.57E-11
Nickel	3.00E-06			5.14E-11	1.28E-11
Selenium	1.50E-05			2.57E-10	6.42E-11
Total HAPs				2.78E-08	6.95E-09

Notes:

1. EPA Tier 2 NOx+NMHC emission standard for engine kW > 560 is 6.4 g/kW-hr. A 95%/5% split of NOx/VOC was used based on the 2004 California Air Resources Board (CARB) policy "CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NOx."
2. SOx emission factor assumes low-sulfur diesel maximum sulfur content of 15 ppm (8.09E-03S lb/hp-hr from AP-42, Table 3.4-1).
3. For the purposes of these calculations, it was assumed PM = PM10 = PM2.5 as a conservative estimate of PM10 and PM2.5.
4. Permit Condition 2 - Unit Emission Limits specifies a combined NOx+NMHC limit for Emergency Engines #3 for Nox and NMHCs and #4. Pound per hour emission limits for NOx and NMHC are specified in Conditions 5h) and 5i).
5. Ton per year limits for individual NOx and VOC are not specified in the permit. They are calculated from the lb/hr values specified in Permit Conditions 5h) and 5i).

Estimated Emissions

Existing Emission Unit #5

4.2 MMBTU/hr Natural Gas Boiler - Superior

Manufacturer Provided Specifications:

Model JBX Burner		
Gas Input	4,200	MBTU/hr
	4.2	MMBtu/hr
Fuel Heat Content (Natural Gas)	1,020	BTU/CF
Burner Max Rate (Gas Input)	4,118	SCFH

Manufacturer Specified Emission Rate:

NOx	9	< ppm

Operating Hours (Hr/yr) 8760

Emission Estimates- HAPs

	Emission Factor		Emission Factor Source	Estimated Emissions	
HAPs		**Emission Factor (lb/MMcf)**		**pounds per hour**	**tons per year**
2-Methylnaphthalene	91-57-6	2.40E-05	EPA AP-42, Table 1.4-3	9.88E-08	4.33E-07
3-Methylcholanthrene	56-49-5	1.80E-06		7.41E-09	3.25E-08
7,12-Dimethylbenz(a)anthracene	No CAS	1.60E-05		6.59E-08	2.89E-07
Acenaphthene	83-32-9	1.80E-06		7.41E-09	3.25E-08
Acenaphthylene	203-96-8	1.80E-06		7.41E-09	3.25E-08
Anthracene	120-12-7	2.40E-06		9.88E-09	4.33E-08
Benz(a)anthracene	56-55-3	1.80E-06		7.41E-09	3.25E-08
Benzene	71-43-2	2.10E-03		8.65E-06	3.79E-05
Benzo(a)pyrene	50-32-8	1.20E-06		4.94E-09	2.16E-08
Benzo(b)fluoranthene	205-99-2	1.80E-06		7.41E-09	3.25E-08
Benzo(g,h,i)perylene	191-24-2	1.20E-06		4.94E-09	2.16E-08
Benzo(k)fluoranthene	207-08-9	1.80E-06		7.41E-09	3.25E-08
Butane	106-97-8	2.10E+00		8.65E-03	3.79E-02
Chrysene	218-01-9	1.80E-06		7.41E-09	3.25E-08
Dibenzo(a,h)anthracene	53-70-3	1.20E-06		4.94E-09	2.16E-08
Dichlorobenzene	25321-22-6	1.20E-03		4.94E-06	2.16E-05
Ethane	74-84-0	3.10E+00		1.28E-02	5.59E-02
Fluoranthene	206-44-0	3.00E-06		1.24E-08	5.41E-08
Fluorene	86-73-7	2.80E-06		1.15E-08	5.05E-08
Formaldehyde	50-00-0	7.50E-02		3.09E-04	1.35E-03
Hexane	110-54-3	1.80E+00		7.41E-03	3.25E-02
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06		7.41E-09	3.25E-08
Naphthalene	91-20-3	6.10E-04		2.51E-06	1.10E-05
Pentane	109-66-0	2.60E+00		1.07E-02	4.69E-02
Phenanathrene	85-01-8	1.70E-05		7.00E-08	3.07E-07
Propane	74-98-6	1.60E+00		6.59E-03	2.89E-02
Pyrene	129-00-0	5.00E-06		2.06E-08	9.02E-08
Toluene	108-88-3	3.40E-03		1.40E-05	6.13E-05
Lead	7439-92-1	0.0005	EPA AP-42, Table 1.4-2	2.06E-06	9.02E-06
Arsenic	7440-38-2	2.00E-04	EPA AP-42, Table 1.4-4	8.24E-07	3.61E-06
Beryllium	7440-41-7	1.20E-05		4.94E-08	2.16E-07
Cadmium	7440-43-9	1.10E-03		4.53E-06	1.98E-05
Chromium	7440-47-3	1.40E-03		5.76E-06	2.52E-05
Cobalt	7440-48-4	8.40E-05		3.46E-07	1.51E-06
Manganese	7439-96-5	3.80E-04		1.56E-06	6.85E-06
Mercury	7439-97-6	2.60E-04		1.07E-06	4.69E-06
Nickel	7440-02-0	2.10E-03		8.65E-06	3.79E-05
Selenium	7782-49-2	2.40E-05		9.88E-08	4.33E-07
Total HAPS:				4.65E-02	2.04E-01

Estimated Emissions

Proposed Emission Unit #6

Cummins Diesel Emergency Generator - DQKAD

Manufacturer Provided Specifications:			Source:
Site Rated Standby kW Generator	1750	kW	
Gross Engine Power Output	2508	bhp	Cummins Generator Set Data Sheet
Gross Engine Power Output	1871	kW	
Standby Fuel Consumption	119	gal/hr	
Standby Heat Input Capacity	16.303	MMBTU/hr	
Annual Operating Hours:	500	hrs/yr	

Calculation Basis/Conversion Factors:

Gross Heat Content of Diesel Assumption from AP-42 Appendix A.
137,000 Btu/gal

Diesel Fuel Sulfur Content:
15 ppm
0.0015 percent

Convert Grams to lbs:
0.00220462 lb= 1 g

2544.43 BTU/HP-hr

0.7457 kW/hp

Emission Estimates

Air Contaminant	Emission Factor: g/kW-hr	Emission Factor: lb/hp-hr (power output)	Emission Factor Source	Estimated Emissions: pounds per hour	Estimated Emissions: tons per year
CO	3.5		EPA-420-B-16-022 (March 2016), Nonroad CI EPA Tier 2 Standards for kW>560 per 40 CFR 1039, Appendix I	14.431	3.608
NOx+NMHC	6.4				
NOx[1]	6.08			25.069	6.267
VOC[1]	0.32			1.319	0.330
SO_2[2]		1.214E-05	AP-42 Chapter 3.4, Table 3.4-1 for Large Stationary Diesel (greater than 600 hp)	0.03	0.01
PM/TSP	0.2		EPA-420-B-16-022 (March 2016), Nonroad CI EPA Tier 2 Standards for kW>560 per 40 CFR 1039, Appendix I	0.825	0.206
PM10[3]	0.2			0.825	0.206
PM2.5[3]	0.2			0.825	0.206
HAPs	**Lb/MMBTU (fuel input)**			**pounds per hour**	**tons per year**
Acenaphthene	4.68E-06		AP-42, Fifth Edition, Volume 1, Chapter 3, Section 3.4, Tables 3.4-3 and 3.4-4 (10/96) for Large Stationary Diesel (greater than 600 hp)	7.63E-11	1.91E-11
Acenaphthylene	9.23E-06			1.50E-10	3.76E-11
Acetaldehyde	2.52E-05			4.11E-10	1.03E-10
Acrolein	7.88E-06			1.28E-10	3.21E-11
Anthracene	1.23E-06			2.01E-11	5.01E-12
Benz(a)anthracene	6.22E-07			1.01E-11	2.54E-12
Benzene	7.76E-04			1.27E-08	3.16E-09
Benzo(a)pyrene	2.57E-07			4.19E-12	1.05E-12
Benzo(b)fluoranthene	1.11E-06			1.81E-11	4.52E-12
Benzo(g,h,l)pyrene	5.56E-07			9.06E-12	2.27E-12
Benzo(k)fluoranthene	2.18E-07			3.55E-12	8.89E-13
Chrysene	1.53E-06			2.49E-11	6.24E-12
Dibenz(a,h)anthracene	3.46E-07			5.64E-12	1.41E-12
Flouranthene	4.03E-06			6.57E-11	1.64E-11
Flourene	1.28E-05			2.09E-10	5.22E-11
Formaldehyde	7.89E-05			1.29E-09	3.22E-10
Indeno(1,2,3-cd)pyrene	4.14E-07			6.75E-12	1.69E-12
Naphthalene	1.30E-04			2.12E-09	5.30E-10
Phenanthrene	4.08E-05			6.65E-10	1.66E-10
Pyrene	3.71E-06			6.05E-11	1.51E-11
Toluene	2.81E-04			4.58E-09	1.15E-09
Xylenes	1.93E-04			3.15E-09	7.87E-10
Arsenic	4.00E-06		EPA AP-42, Table 1.3-10	6.52E-11	1.63E-11
Beryllium	3.00E-06			4.89E-11	1.22E-11
Cadmium	3.00E-06			4.89E-11	1.22E-11
Chromium	3.00E-06			4.89E-11	1.22E-11
Lead	9.00E-06			1.47E-10	3.67E-11
Mercury	3.00E-06			4.89E-11	1.22E-11
Manganese	6.00E-06			9.78E-11	2.45E-11
Nickel	3.00E-06			4.89E-11	1.22E-11
Selenium	1.50E-05			2.45E-10	6.11E-11
Total HAPs				2.65E-08	6.61E-09

Notes:

1. EPA Tier 2 NOx+NMHC emission standard for engine kW > 560 is 6.4 g/kW-hr. A 95%/5% split of NOx/VOC was used based on the 2004 California Air Resources Board (CARB) policy "CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NOx."
2. SOx emission factor assumes low-sulfur diesel maximum sulfur content of 15 ppm (8.09E-03S lb/hp-hr from AP-42, Table 3.4-1).
3. For the purposes of these calculations, it was assumed PM = PM10 = PM2.5 as a conservative estimate of PM10 and PM2.5.

Estimated Emissions

Proposed Emission Unit #7

16.7 MMBTU/hr Natural Gas Boiler - Johnston MODEL: PFTA 400-4

Ultra-Low-NOx Configuration

Manufacturer Provided Specifications:

4-Pass Steam Packaged Firetube Boiler		
w/ IC-SA-1755 NT Series Burner		
Gas Input	16,700	MBTU/hr
Fuel Heat Content (Natural Gas)	1,020	BTU/CF
Burner Max Rate (Gas Input)	16,373	SCFH

Manufacturer Specified Emission Rate:

NOx	9	< ppm

Operating Hours (Hr/yr) 8760

Boiler Stack Emissions - Natural Gas (Uncontrolled)

Pollutant	CAS	Emission Factor (lb/MMcf)	Emission Factor Source	pounds per hour	tons per year
CO		84	EPA AP-42, Table 1.4-1	1.38	6.02
NOx		32	EPA AP-42, Table 1.4-1 Controlled Low NOx Burners /Flue Gas Recirculation (Manufacturer <9 ppm)	0.52	2.29
VOC		5.5	EPA AP-42, Table 1.4-2	0.09	0.39
SO_2		0.6	EPA AP-42, Table 1.4-2	0.01	0.04
$PM/PM_{10}/PM_{2.5}$		7.6	EPA AP-42, Table 1.4-2	0.12	0.55
HAPs					
2-Methylnaphthalene	91-57-6	2.40E-05	EPA AP-42, Table 1.4-3	3.93E-07	1.72E-06
3-Methylcholanthrene	56-49-5	1.80E-06		2.95E-08	1.29E-07
7,12-Dimethylbenz(a)anthracene	No CAS	1.60E-05		2.62E-07	1.15E-06
Acenaphthene	83-32-9	1.80E-06		2.95E-08	1.29E-07
Acenaphthylene	203-96-8	1.80E-06		2.95E-08	1.29E-07
Anthracene	120-12-7	2.40E-06		3.93E-08	1.72E-07
Benz(a)anthracene	56-55-3	1.80E-06		2.95E-08	1.29E-07
Benzene	71-43-2	2.10E-03		3.44E-05	1.51E-04
Benzo(a)pyrene	50-32-8	1.20E-06		1.96E-08	8.61E-08
Benzo(b)fluoranthene	205-99-2	1.80E-06		2.95E-08	1.29E-07
Benzo(g,h,i)perylene	191-24-2	1.20E-06		1.96E-08	8.61E-08
Benzo(k)fluoranthene	207-08-9	1.80E-06		2.95E-08	1.29E-07
Butane	106-97-8	2.10E+00		3.44E-02	1.51E-01
Chrysene	218-01-9	1.80E-06		2.95E-08	1.29E-07
Dibenzo(a,h)anthracene	53-70-3	1.20E-06		1.96E-08	8.61E-08
Dichlorobenzene	25321-22-6	1.20E-03		1.96E-05	8.61E-05
Ethane	74-84-0	3.10E+00		5.08E-02	2.22E-01
Fluoranthene	206-44-0	3.00E-06		4.91E-08	2.15E-07
Fluorene	86-73-7	2.80E-06		4.58E-08	2.01E-07
Formaldehyde	50-00-0	7.50E-02		1.23E-03	5.38E-03
Hexane	110-54-3	1.80E+00		2.95E-02	1.29E-01
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06		2.95E-08	1.29E-07
Naphthalene	91-20-3	6.10E-04		9.99E-06	4.37E-05
Pentane	109-66-0	2.60E+00		4.26E-02	1.86E-01
Phenanathrene	85-01-8	1.70E-05		2.78E-07	1.22E-06
Propane	74-98-6	1.60E+00		2.62E-02	1.15E-01
Pyrene	129-00-0	5.00E-06		8.19E-08	3.59E-07
Toluene	108-88-3	3.40E-03		5.57E-05	2.44E-04
Lead	7439-92-1	0.0005	EPA AP-42, Table 1.4-2	8.19E-06	3.59E-05
Arsenic	7440-38-2	2.00E-04	EPA AP-42, Table 1.4-4	3.27E-06	1.43E-05
Beryllium	7440-41-7	1.20E-05		1.96E-07	8.61E-07
Cadmium	7440-43-9	1.10E-03		1.80E-05	7.89E-05
Chromium	7440-47-3	1.40E-03		2.29E-05	1.00E-04
Cobalt	7440-48-4	8.40E-05		1.38E-06	6.02E-06
Manganese	7439-96-5	3.80E-04		6.22E-06	2.73E-05
Mercury	7439-97-6	2.60E-04		4.26E-06	1.86E-05
Nickel	7440-02-0	2.10E-03		3.44E-05	1.51E-04
Selenium	7782-49-2	2.40E-05		3.93E-07	1.72E-06
Total HAPS:				1.85E-01	8.10E-01

Attachment 10

Operational and Maintenance Strategy

Curia New Mexico, LLC
Permit 1097-M3-2AR Modification Application
Operational and Maintenance Strategy

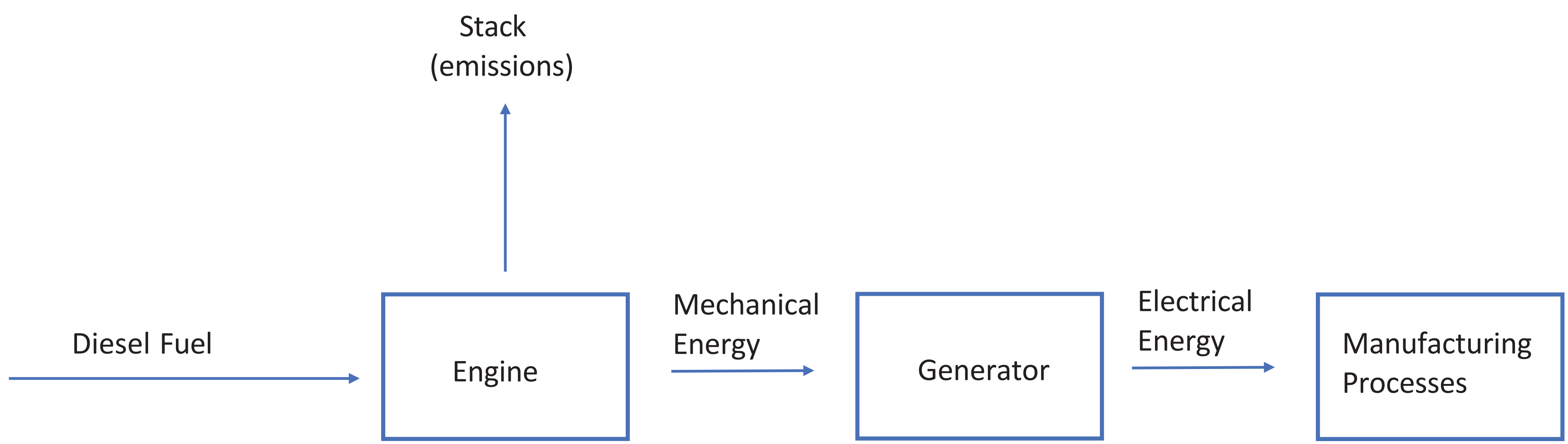
1. The engineering and maintenance (E&M) departments performs routine daily, weekly, monthly, semi-annual, and annual maintenance on the boilers and emergency generators. If they are not operating within specification and the issue cannot be resolved internally, the E&M Department will schedule an emergency service call with a qualified contractor who specializes in the service of boilers or emergency generators. The equipment will be shut down until such service occurs.

2. The boilers operate continuously. The site may shutdown the boilers, only one at a time, due to: 1) routine maintenance (as specified by the manufacturer); 2) site emergency; or 3) equipment malfunction. This proposed boiler has an integrated flue gas recirculation (FGR). The site emergency generators are tested monthly and are inspected annually. The emergency generator's pollution control is limited operating hours (not to exceed 500 hours per year and the site has averaged about 10 hours per year of use).

3. The site uses routine daily, weekly, monthly, semi-annual, and annual maintenance on the boilers and emergency generators to ensure the equipment is operating according to manufacturer's specifications.

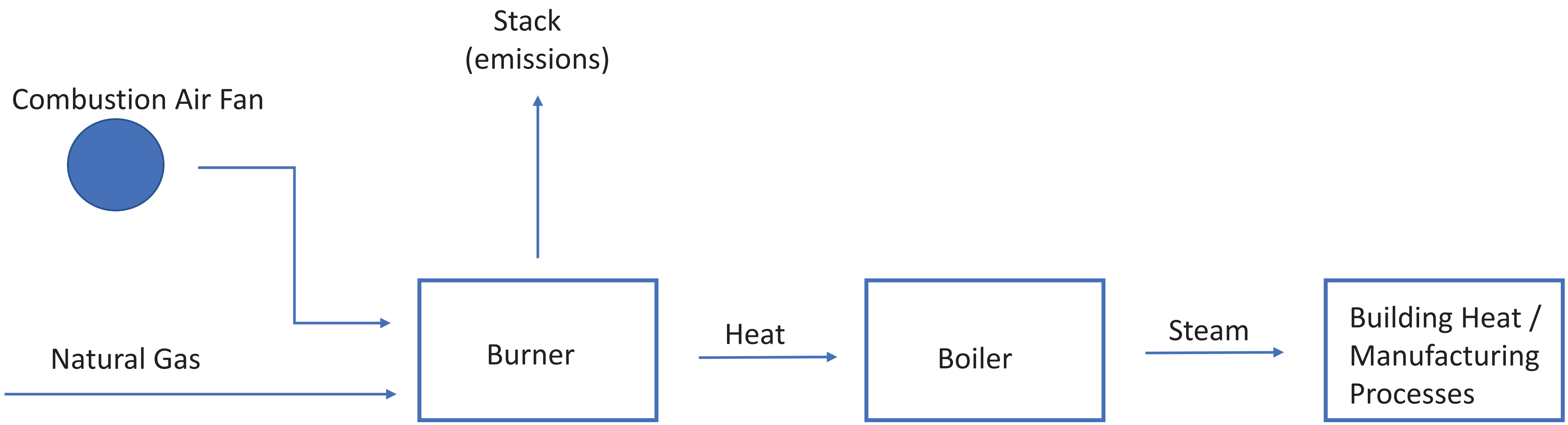
Attachment 11

Process Flow Diagram: Emergency Generator and Boiler



Curia New Mexico, LLC
Permit 1097-M3-2AR Modification Application
November 21, 2022

Process Flow Diagram
Unit 6
Emergency Generator

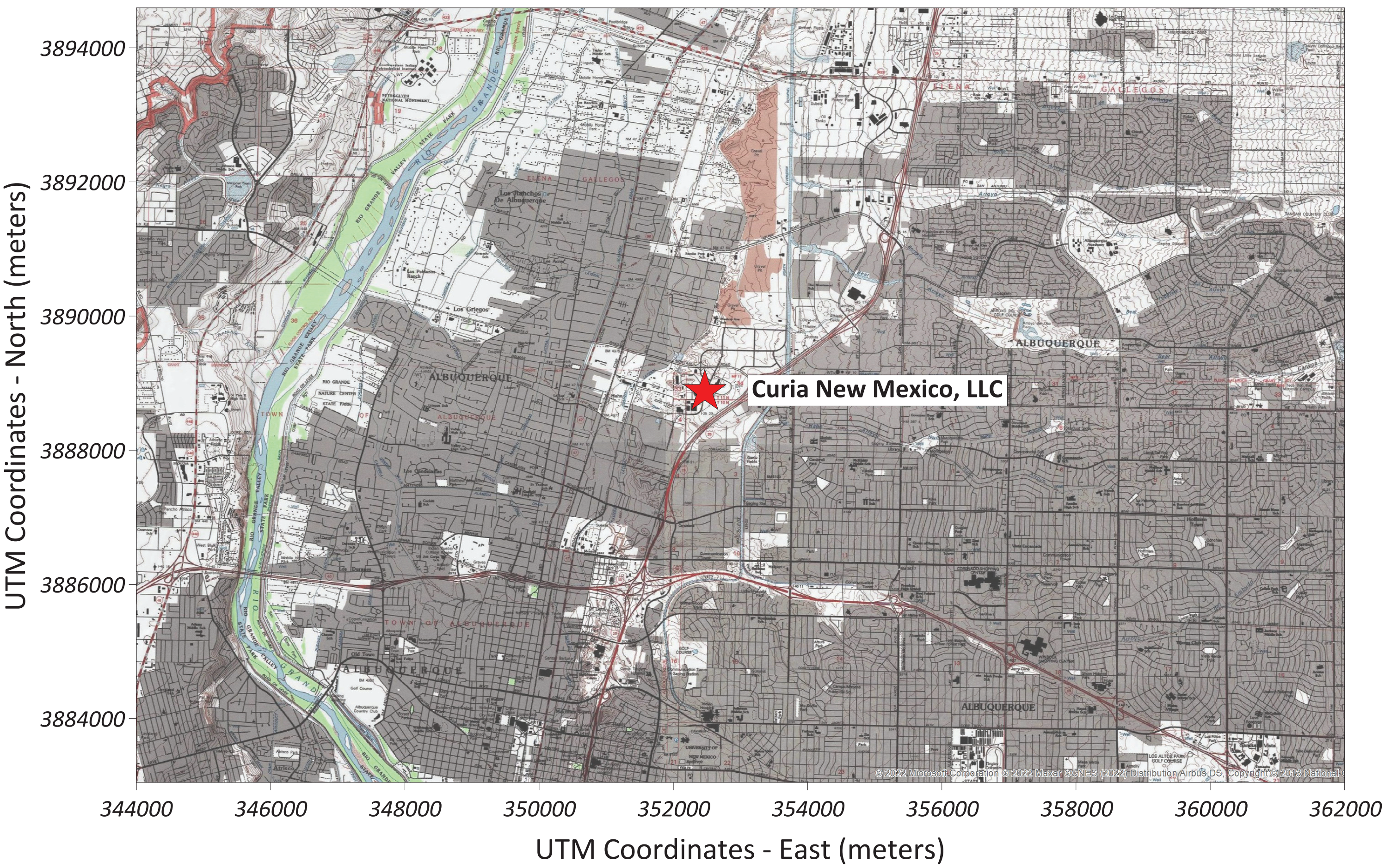


Curia New Mexico, LLC
Permit 1097-M3-2AR Modification Application
November 28, 2022

Process Flow Diagram
Unit 7
Boiler

Attachment 12

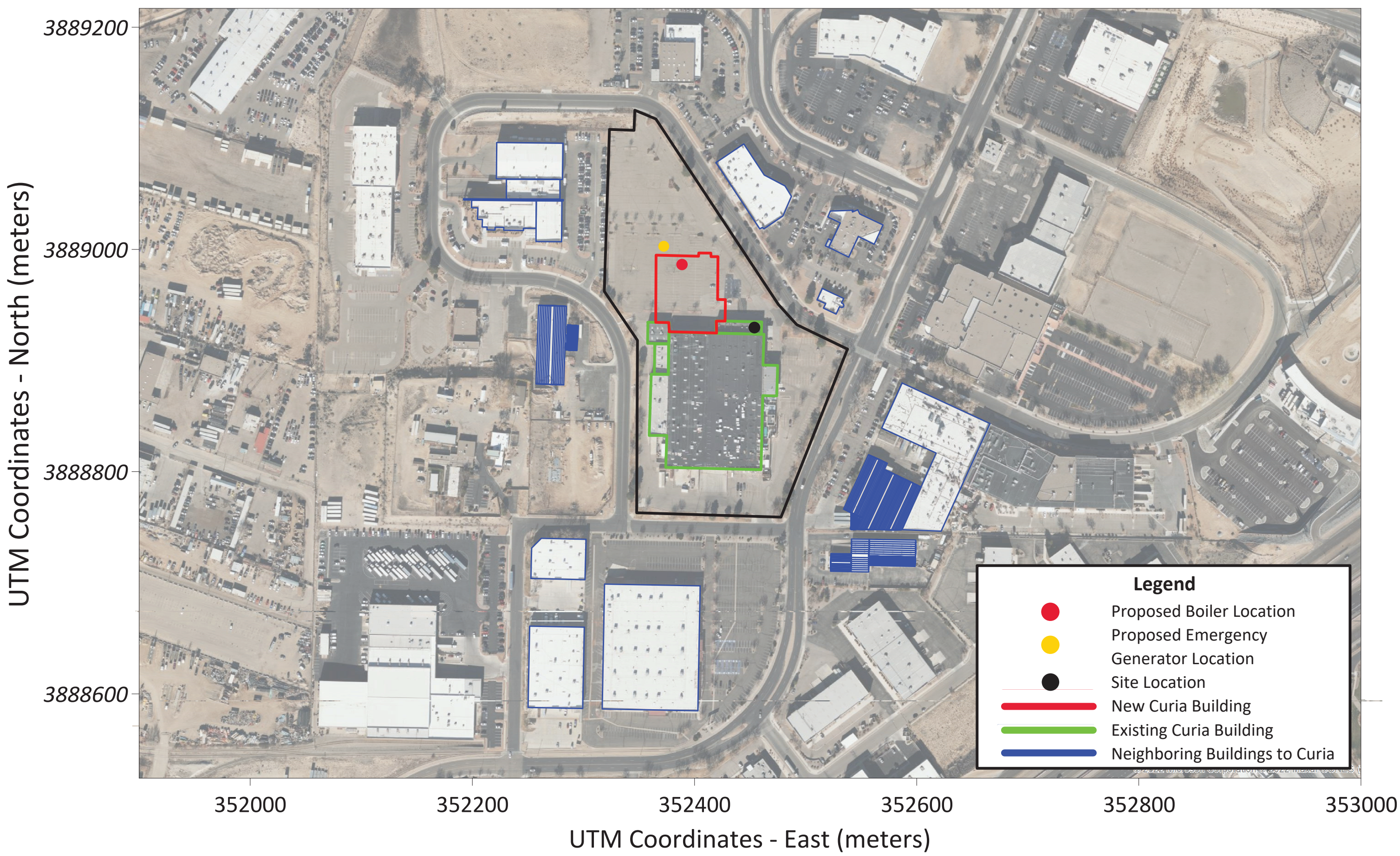
Site Location Map and Aerial Photograph



Site Location Map

Environmental Resources Management
www.erm.com

Curia New Mexico, LLC
Albuquerque, NM



Aerial Photograph

Environmental Resources Management
www.erm.com

Curia New Mexico, LLC
Albuquerque, NM

Attachment 13

Permit Application Review Fee Checklist

City of Albuquerque

Environmental Health Department
Air Quality Program

Permit Application Review Fee Instructions

All source registration, authority-to-construct, and operating permit applications for stationary or portable sources shall be charged an application review fee according to the fee schedule in 20.11.2 NMAC. These filing fees are required for both new construction, reconstruction, and permit modifications applications. Qualified small businesses as defined in 20.11.2 NMAC may be eligible to pay one-half of the application review fees and 100% of all applicable federal program review fees.

Please fill out the permit application review fee checklist and submit with a check or money order payable to the "City of Albuquerque Fund 242" and either:

1. be delivered in person to the Albuquerque Environmental Health Department, 3rd floor, Suite 3023 or Suite 3027, Albuquerque-Bernalillo County Government Center, south building, One Civic Plaza NW, Albuquerque, NM or,

2. mailed to Attn: Air Quality Program, Albuquerque Environmental Health Department, P.O. Box 1293, Albuquerque, NM 87103.

The department will provide a receipt of payment to the applicant. The person delivering or filing a submittal shall attach a copy of the receipt of payment to the submittal as proof of payment Application review fees shall not be refunded without the written approval of the manager. If a refund is requested, a reasonable professional service fee to cover the costs of staff time involved in processing such requests shall be assessed. Please refer to 20.11.2 NMAC (effective January 10, 2011) for more detail concerning the "Fees" regulation as this checklist does not relieve the applicant from any applicable requirement of the regulation.

City of Albuquerque

Environmental Health Department
Air Quality Program

Permit Application Review Fee Checklist Effective January 1, 2023 – December 31, 2023

Please completely fill out the information in each section. Incompleteness of this checklist may result in the Albuquerque Environmental Health Department not accepting the application review fees. If you should have any questions concerning this checklist, please call 768-1972.

I. COMPANY INFORMATION:

Company Name	Curia New Mexico, LLC	
Company Address	4401 Alexander Blvd. NE, Albuquerque, New Mexico, 87107	
Facility Name	Curia New Mexico, LLC	
Facility Address	4401 Alexander Blvd. NE, Albuquerque, New Mexico, 87107	
Contact Person	John Gerback, Jr.	
Contact Person Phone Number	505-340-5989	
Are these application review fees for an existing permitted source located within the City of Albuquerque or Bernalillo County?	**Yes**	**No**
If yes, what is the permit number associated with this modification?	**Permit # 1097-M3-2AR**	
Is this application review fee for a Qualified Small Business as defined in 20.11.2 NMAC? (See Definition of Qualified Small Business on Page 4)	**Yes**	**No**

II. STATIONARY SOURCE APPLICATION REVIEW FEES:

If the application is for a new stationary source facility, please check all that apply. If this application is for a modification to an existing permit please see Section III.

Check All That Apply	Stationary Sources	Review Fee	Program Element
	Air Quality Notifications		
	AQN New Application	$641.00	2801
	AQN Technical Amendment	$352.00	2802
	AQN Transfer of a Prior Authorization	$352.00	2803
	Not Applicable	*See Sections Below*	
	Stationary Source Review Fees (Not Based on Proposed Allowable Emission Rate)		
	Source Registration required by 20.11.40 NMAC	$ 657.00	2401
	A Stationary Source that requires a permit pursuant to 20.11.41 NMAC or other board regulations and are not subject to the below proposed allowable emission rates	$1,314.00	2301
	Not Applicable	*See Sections Below*	
	Stationary Source Review Fees (Based on the Proposed Allowable Emission Rate for the single highest fee pollutant)		
	Proposed Allowable Emission Rate Equal to or greater than 1 tpy and less than 5 tpy	$986.00	2302
	Proposed Allowable Emission Rate Equal to or greater than 5 tpy and less than 25 tpy	$1,971.00	2303
	Proposed Allowable Emission Rate Equal to or greater than 25 tpy and less than 50 tpy	$3,942.00	2304
	Proposed Allowable Emission Rate Equal to or greater than 50 tpy and less than 75 tpy	$5,913.00	2305
	Proposed Allowable Emission Rate Equal to or greater than 75 tpy and less than 100 tpy	$7,884.00	2306
	Proposed Allowable Emission Rate Equal to or greater than 100 tpy	$9,855.00	2307
	Not Applicable	*See Section Above*	

	Federal Program Review Fees (In addition to the Stationary Source Application Review Fees above)		
	40 CFR 60 - "New Source Performance Standards" (NSPS)	$1,314.00	2308
	40 CFR 61 - "Emission Standards for Hazardous Air Pollutants (NESHAPs)	$1,314.00	2309
	40 CFR 63 - (NESHAPs) Promulgated Standards	$1,314.00	2310
	40 CFR 63 - (NESHAPs) Case-by-Case MACT Review	$13,140.00	2311
	20.11.61 NMAC, Prevention of Significant Deterioration (PSD) Permit	$6,570.00	2312
	20.11.60 NMAC, Non-Attainment Area Permit	$6,570.00	2313
	Not Applicable	*Not Applicable*	

III. MODIFICATION TO EXISTING PERMIT APPLICATION REVIEW FEES:

If the permit application is for a modification to an existing permit, please check all that apply. If this application is for a new stationary source facility, please see Section II.

Check All That Apply	Modifications	Review Fee	Program Element
	Modification Application Review Fees (Not Based on Proposed Allowable Emission Rate)		
	Proposed modification to an existing stationary source that requires a permit pursuant to 20.11.41 NMAC or other board regulations and are not subject to the below proposed allowable emission rates	$1,314	2321
	Not Applicable	*See Sections Below*	
	Modification Application Review Fees (Based on the Proposed Allowable Emission Rate for the single highest fee pollutant)		
	Proposed Allowable Emission Rate Equal to or greater than 1 tpy and less than 5 tpy	$986.00	2322
X	Proposed Allowable Emission Rate Equal to or greater than 5 tpy and less than 25 tpy	$1,971.00	2323
	Proposed Allowable Emission Rate Equal to or greater than 25 tpy and less than 50 tpy	$3,942.00	2324
	Proposed Allowable Emission Rate Equal to or greater than 50 tpy and less than 75 tpy	$5,913.00	2325
	Proposed Allowable Emission Rate Equal to or greater than 75 tpy and less than 100 tpy	$7,884.00	2326
	Proposed Allowable Emission Rate Equal to or greater than 100 tpy	$9,855.00	2327
	Not Applicable	*See Section Above*	
	Major Modifications Review Fees (In addition to the Modification Application Review Fees above)		
	20.11.60 NMAC, Permitting in Non-Attainment Areas	$6,570	2333
	20.11.61 NMAC, Prevention of Significant Deterioration	$6,570	2334
	Not Applicable	*Not Applicable*	
	Federal Program Review Fees (This section applies only if a Federal Program Review is triggered by the proposed modification) (These fees are in addition to the Modification and Major Modification Application Review Fees above)		
X	40 CFR 60 - "New Source Performance Standards" (NSPS)	$1,314.00	2328
	40 CFR 61 - "Emission Standards for Hazardous Air Pollutants (NESHAPs)	$1,314.00	2329
	40 CFR 63 - (NESHAPs) Promulgated Standards	$1,314.00	2330
	40 CFR 63 - (NESHAPs) Case-by-Case MACT Review	$13,140.00	2331
	20.11.61 NMAC, Prevention of Significant Deterioration (PSD) Permit	$6,570.00	2332
	20.11.60 NMAC, Non-Attainment Area Permit	$6,570.00	2333
	Not Applicable	*Not Applicable*	

IV. ADMINISTRATIVE AND TECHNICAL REVISION APPLICATION REVIEW FEES:

If the permit application is for an administrative or technical revision of an existing permit issued pursuant to 20.11.41 NMAC, please check one that applies.

Check One	Revision Type	Review Fee	Program Element
	Administrative Revisions	$ 250.00	2340
	Technical Revisions	$ 500.00	2341
	Not Applicable	*See Sections II, III or V*	

V. PORTABLE STATIONARY SOURCE RELOCATION FEES:

If the permit application is for a portable stationary source relocation of an existing permit, please check one that applies.

Check One	Portable Stationary Source Relocation Type	Review Fee	Program Element
	No New Air Dispersion Modeling Required	$ 500.00	2501
	New Air Dispersion Modeling Required	$ 750.00	2502
	Not Applicable	*See Sections II, III or V*	

VI. Please submit a check or money order in the amount shown for the total application review fee.

Section Totals	Review Fee Amount
Section II Total	$
Section III Total	$3285.00
Section IV Total	$
Section V Total	$
Total Application Review Fee	**$3285.00**

I, the undersigned, a responsible official of the applicant company, certify that to the best of my knowledge, the information stated on this checklist, give a true and complete representation of the permit application review fees which are being submitted. I also understand that an incorrect submittal of permit application reviews may cause an incompleteness determination of the submitted permit application and that the balance of the appropriate permit application review fees shall be paid in full prior to further processing of the application.

Signed this 22 **day of** March **20**23

John Gerbasi — **Print Name**

Sr. Manager of EHS — **Print Title**

[signature] — **Signature**

Definition of Qualified Small Business as defined in 20.11.2 NMAC:

"Qualified small business" means a business that meets all of the following requirements:

(1) a business that has 100 or fewer employees;
(2) a small business concern as defined by the federal Small Business Act;
(3) a source that emits less than 50 tons per year of any individual regulated air pollutant, or less than 75 tons per year of all regulated air pollutants combined; and
(4) a source that is not a major source or major stationary source.

Note: Beginning January 1, 2011, and every January 1 thereafter, an increase based on the consumer price index shall be added to the application review fees. The application review fees established in Subsection A through D of 20.11.2.18 NMAC shall be adjusted by an amount equal to the increase in the consumer price index for the immediately-preceding year. Application review fee adjustments equal to or greater than fifty cents ($0.50) shall be rounded up to the next highest whole dollar. Application review fee adjustments totaling less than fifty cents ($0.50) shall be rounded down to the next lowest whole dollar. The department shall post the application review fees on the city of Albuquerque environmental health department air quality program website.