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January 24, 2003

1290001-007-AV

Hand-Delivered

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JAN 24 2003
BUREAU OF AIR REGULATION

Scott M. Sheplak
Administrator - Title V Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS# 5505
Tallahassee, Florida 32399-2400

Re: Alternate Fee Calculation Method
Annual Title V Emission Fees
Sam O. Purdom Generating Station (Facility I.D. No. 1290001)

Dear Mr. Sheplak:

I wanted to take this opportunity to thank you for meeting with the City of Tallahassee (City) on January 14, 2003, to discuss the Alternate Title V Emission Fee Calculation Method for the Sam O. Purdom Generating Station (Purdom).

As per your request, and pursuant to Rule 62-213.205(1)(e)(3), Florida Administrative Code (F.A.C.), the City is pleased to submit the following alternate Title V fee calculation method and supporting documentation for emissions of sulfur dioxide and oxides of nitrogen from Combustion Turbine No. 1 (EU-008), Combustion Turbine No. 2 (EU-009), and the Auxiliary Boiler (EU-011), at the Purdom facility for calendar year 2002 and thereafter.

As you are aware, Combustion Turbine Nos. 1 and 2 are very small peaking units which began commercial operation in 1963 and each run a nominal 12.3 megawatt generator. The Auxiliary Boiler produces only steam and is rated at a maximum heat input of 16.74 million British thermal units per hour (mmBtu/hr). The City investigated the possibility of conducting field-testing on these units, but due to their size, age, and design, this was not deemed practicable.

The fee calculation method for Purdom Boiler No. 7 (EU-007) and Combustion Turbine No. 8 (EU-014) remains in accordance with the rule and an alternate fee calculation method is not being requested for these units at this time.

This alternate fee calculation method is based on scientifically accurate and verifiable procedures, and will more accurately reflect actual emissions from the Purdom facility.

I. COMBUSTION TURBINE NO'S. 1 AND 2

Pollutant:	Sulfur Dioxide
Fuel:	Fuel Oil No. 2

Sulfur dioxide emissions from the combustion of No. 2 fuel oil in Combustion Turbine No. 1 and Combustion Turbine No. 2 for each calendar year will be calculated from the product of the following:

- The quantity of fuel oil combusted during the calendar year determined from fuel flow meters, tank drop measurements, and/or fuel invoice data supplied by the fuel vendor.
- The maximum allowable fuel oil sulfur content specified in the current Title V Air Operating Permit (e.g. 0.05% by weight)
- Ratio of the molecular weight of sulfur dioxide to the molecular weight of sulfur
- Sulfur conversion factor of 1 (i.e. assume 100% conversion).
- The highest fuel oil density as determined from fuel oil analysis provided by the fuel supplier each time fuel is delivered during the calendar year.
- Unit conversion and/or correction factors as necessary to convert to units of tons of pollutant emitted per calendar year.

Pollutant:	Sulfur Dioxide
Fuel:	Natural Gas

Sulfur dioxide emissions from the combustion of natural gas in Combustion Turbine No. 1 and Combustion Turbine No. 2 for each calendar year will be calculated from the product of the following:

- Total volume of natural gas combusted during the calendar year determined from fuel flow meters and/or fuel invoice data supplied by the vendor.
- Highest non-anomalous quality-assured daily sulfur content of the natural gas combusted as recorded by the fuel vendor using a Florida Department of Environmental Protection (DEP) or U.S. Environmental Protection Agency (EPA)-approved ASTM reference method, or equivalent, during the calendar year.
- Highest quality-assured daily gross calorific heating value of the natural gas as recorded by the fuel vendor using a DEP or EPA-approved ASTM reference method, or equivalent, for the calendar year.
- Molecular weight of sulfur dioxide

- Unit conversion and/or correction factors as necessary to convert to units of tons of pollutant emitted per calendar year.

Pollutant:	**Oxides of Nitrogen**
Fuel:	**Fuel Oil No. 2**

Emissions of oxides of nitrogen from the combustion of No. 2 fuel oil in Combustion Turbine No. 1 and Combustion Turbine No. 2 for each calendar year will be calculated from the product of the following:

- The quantity of fuel oil combusted during the calendar year determined from fuel flow meters, tank drop measurements, and/or fuel invoice data supplied by the fuel vendor.
- Highest NOx emission factor available from *Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I, Stationary Point and Area Sources* for combustion turbines (e.g. 1.08E+00 lb/mmBtu).
- Highest quality-assured daily gross calorific heating value of the fuel oil as recorded by the fuel vendor using a DEP or EPA-approved ASTM reference method, or equivalent, for the calendar year.
- Highest density of No. 2 fuel oil combusted as determined by the fuel supplier for each fuel shipment for the calendar year.
- Unit conversion and/or correction factors as necessary to convert to units of tons of pollutant emitted per calendar year.

Pollutant:	**Oxides of Nitrogen**
Fuel:	**Natural Gas**

Emissions of oxides of nitrogen from the combustion of natural gas in Combustion Turbine No. 1 and Combustion Turbine No. 2 for each calendar year will be calculated from the product of the following:

- Total volume of natural gas combusted during the calendar year determined from fuel flow meters and/or fuel invoice data supplied by the vendor.
- Highest NOx emission factor available from *Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I, Stationary Point and Area Sources* for combustion turbines (e.g. 9.68E-01 lb/mmBtu).
- Highest quality-assured daily gross calorific heating value of the natural gas as recorded by the fuel vendor using a DEP or EPA-approved ASTM reference method, or equivalent, for the calendar year.
-

- Unit conversion and/or correction factors as necessary to convert to units of tons of pollutant emitted per calendar year.

II. AUXILIARY BOILER

Pollutant:	Sulfur Dioxide
Fuel:	Natural Gas

Sulfur dioxide emissions from the combustion of natural gas in the Auxiliary Boiler for each calendar year will be calculated from the product of the following:

- Total volume of natural gas combusted during the calendar year deterrnined from fuel flow meters and/or fuel invoice data supplied by the vendor.
- Highest non-anomalous quality-assured daily sulfur content of the natural gas combusted as recorded by the fuel vendor using a DEP or EPA-approved ASTM reference method, or equivalent, during the calendar year.
- Highest quality-assured daily gross calorific heating value of the natural gas as recorded by the fuel vendor using a DEP or EPA-approved ASTM reference method, or equivalent, for the calendar year.
- Molecular weight of sulfur dioxide.
- Unit conversion and/or correction factors as necessary to convert to units of tons of pollutant emitted per calendar year.

Pollutant:	Oxides of Nitrogen
Fuel:	Natural Gas

Emissions of oxides of nitrogen from the combustion of natural gas in the Auxiliary Boiler for each calendar year will be calculated from the product of the following:

- Total volume of natural gas combusted during the calendar year determined from fuel flow meters and/or fuel invoice data supplied by the vendor.
- Highest NOx emission factor available from *Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I, Stationary Point and Area Sources* for small boilers (e.g. 1.945E+02 lb/mmscf).
- Highest quality-assured daily gross calorific heating value of the natural gas as recorded by the fuel vendor using a DEP or EPA-approved ASTM reference method, or equivalent, for the calendar year.
- Unit conversion and/or correction factors as necessary to convert to units of tons of pollutant emitted per calendar year.

III. CONCLUSION

This alternate fee calculation method meets the requirements of Rule 62-213.205, F.A.C., and more accurately reflects emissions from the Purdom facility. The City reserves the right, however, to calculate Title V emission fees based on the maximum allowable limits and/or the facility-wide emissions cap as specified in the Title V Air Operation Permit and as authorized by Rule 62-213.205, F.A.C.

Thank you again for your attention to this matter. Please do not hesitate to contact me at (850) 891-5534, or Jennette Curtis, Environmental Director, at (850) 891-8850, if you have any questions or require additional information.

Sincerely,

Robert E. McGarrah
Manager of Power Production
Responsible Official

Attachment A – Title V Air Operation Permit No. 1290001-007-AV Subsection D
Attachment B – Title V Air Operation Permit No. 1290001-007-AV Subsection E
Attachment C – AP-42, Fifth Edition, Volume I, Section 1.3, Fuel Oil Combustion
- Final Section
- Background Document
- Related Information – Zip File

Attachment D - AP-42, Fifth Edition, Volume I, Section 1.3, Natural Gas Combustion
- Final Section
- Background
- Related Information – Zip File

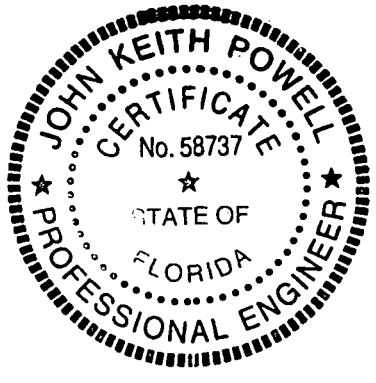
Attachment E - AP-42, Fifth Edition, Volume I, Section 3.1, Stationary Gas Turbines
- Final Section
- Background Document
- Related Information – Zip File

cc: Howard Rhodes, FDEP, w/o attachment
Trina Vielhauer, FDEP, w/o attachments
Jonathan Holtom, FDEP, w/ attachments
Kevin Wailes, COT, w/o attachments
Gordon King, COT, w/o attachments
Ben Cowart, COT, w/o attachment
Jennette Curtis, COT, w/o attachment
John Powell, COT w/o attachments

I, the undersigned, hereby certify that to the best of my knowledge, the alternate fee calculation method is based on scientifically accurate and verifiable procedures. I further certify that there exists reasonable assurance that the alternate fee calculation method will more accurately quantify actual pollutant emissions and corresponding annual Title V emissions fees.

John K. Powell
Profession Engineer
Registration No. 58737

1/29/03
Date



TV PERMIT
SECTION E

Section III. Emissions Units.

Subsection D. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-008	Combustion Turbine Number 1
-009	Combustion Turbine Number 2

These emissions units are simple cycle combustion turbines manufactured by Westinghouse (model number W171G) and are designated as "Combustion Turbine Number 1" and "Combustion Turbine Number 2". They are each rated at a maximum heat input of 228 million Btu per hour (MMBtu/hour) while being fueled by natural gas and/or No. 2 fuel oil. Each of these combustion turbines run a nominal 12.3 MW generator. Emissions from the combustion turbines are uncontrolled.

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. Combustion Turbine Number 1 began commercial operation in 1963. Combustion Turbine Number 2 began commercial operation in 1963. Each combustion turbine has its own stack. Stack height = 38 feet, exit diameter = 10 feet, exit temperature = 880 °F, actual volumetric flow rate = 395,080 acfm.}

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
8	228 (LHV @ 80 degrees Fahrenheit)	Natural Gas
	228 (LHV @ 80 degrees Fahrenheit)	No. 2 Fuel Oil
9	228 (LHV @ 80 degrees Fahrenheit)	Natural Gas
	228 (LHV @ 80 degrees Fahrenheit)	No. 2 Fuel Oil

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop

measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific conditions **C.11.** & **D.13.**
[Rule 62-297.310(2), F.A.C.]

{Permitting Note: Based on the information submitted with the Title V Air Operation Permit renewal application received on July 1, 2002, the operating capacities of CT 1 and CT 2 are limited to 216.7 and 184.8 MMBtu/hr, respectively, until such time that future tests are conducted to regain the authority to operate at the permitted capacity. Pursuant to Rule 62-297.310(2), F.A.C., operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.}

D.3. Methods of Operation.
a. Fuels. Only natural gas and/or new No. 2 fuel oil shall be fired in these turbines.
b. Other. Fuel additives typically of a magnesium oxide, hydroxide, sulfonate, or calcium nitrate origin may be used when burning fuel oil.

[Rule 62-213.410, F.A.C.; and, Applicant's request in Title V Air Operation Permit renewal application dated July 1, 2002.]

D.4. Hours of Operation. The hours of operation are not limited, but these units are subject to the NO_X and SO_2 facility-wide emissions caps (see specific conditions **D.19.** & **D.20.**). The permittee shall maintain an operation log available for Department inspection that documents the total hours of annual operation, including a detailed account of the hours operated on each of the allowable fuels.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, PSD-FL-239/PA97-36.]

Emission Limitations and Standards

{Permitting Note: The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

[Note: These emissions units are subject to the facility-wide emissions caps for SO_2 and NO_X.]

{Permitting note: Unless otherwise specified, the averaging times for conditions D.5. & D.6. are based on the specified averaging time of the applicable test method.}

D.5. Visible Emissions. Visible emissions from each turbine shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AO65-242827.]

D.6. Sulfur Dioxide – Fuel Oil Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.05%, by weight. See specific condition **D.12.**
[AO65-242827; applicant request on initial Title V application received June 14, 1996; PSD-FL-239/PA97-36; and, BACT.]

Excess Emissions

D.7. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.8. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

D.9. Sulfur Dioxide. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor upon each fuel delivery. See specific conditions **D.6.** & **D.12.**
[Rule 62-213.440, F.A.C.]

D.10. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.11. Visible emissions. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

D.12. Sulfur Content. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions.
[Rules 62-213.440 and 62-297.440, F.A.C.]

D.13. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operating at permitted capacity, which is defined as 90-100 percent of the manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test. If it is impracticable to test at capacity, then sources may be tested at less than capacity. In such cases, the entire heat input vs. inlet temperature curve will be adjusted by the increment equal to the difference between the design heat input value and 110 percent of the value reached during the test. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.
[Rule 62-297.310(2), F.A.C.]

D.14. Applicable Test Procedures.
(a) Required Sampling Time.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
    c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2., F.A.C.]

D.15. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a. Did not operate; or
    b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard (see specific condition **D.16.**);
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

[Rule 62-297.310(7), F.A.C.; AO65-242827, Specific Condition #5 (frequency); and, SIP approved.]

D.16. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuels; or
b. gaseous fuels in combination with any amount of liquid fuels for less than 400 hours per year; or
c. only liquid fuels for less than 400 hours per year.

[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

Recordkeeping and Reporting Requirements

{Permitting Note: The reports that are required by the following conditions are to be sent to the Department of Environmental Protection's Northwest District Office, 160 Governmental Center, Pensacola, Florida 322501-5794}

D.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

D.18. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.]

D.19. These emissions units are subject to the facility-wide SO_2 emissions cap listed in facility-wide condition **13.** Sufficient records shall be maintained to ensure that the total facility-wide SO_2 emissions do not exceed 80 tons per year **(see facility-wide conditions 13. & 14.)**.
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

D.20. These emissions units are subject to the facility-wide NO_X emissions cap listed in facility-wide condition **15.** Sufficient records shall be maintained to ensure that the total facility-wide NO_X emissions do not exceed 467 tons per year **(see facility-wide conditions 15. & 16.)**.
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

Section III. Emissions Units.

Subsection E. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-011	Auxiliary Boiler

This is a Kewanee model H3S-400-G steam generator rated at a maximum heat input of 16.74 MMBtu/hour while being fueled with natural gas.

{Permitting notes: This emissions unit is regulated under 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. However, since it is only permitted to combust natural gas, the standards, the monitoring and the associated reporting requirements contained in Subpart Dc do not apply, with the exception that the reporting requirements pertaining to "start-up", as referenced in 40 CFR 60.7, do apply. Except for compliance testing, this boiler may only operate when Unit 7 or Unit 8 is not operating; therefore, there will be no significant increase in emissions for PSD purposes. Stack height = 30 feet, exit diameter = 2.0 feet, exit temperature = 420 °F, actual volumetric flow rate = 4,000 acfm (exit temperature and flow rate estimated by manufacturer service representative). Emissions from this boiler are uncontrolled.}

The following specific conditions apply to the emissions unit listed above:

E.1. *(Reserved)*

Essential Potential to Emit (PTE) Parameters

E.2. Permitted Capacity. The maximum operation heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
11	16.74	Natural Gas

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

E.3. Emissions Unit Operating Rate Limitation After Testing. See common condition **C.11.**
[Rule 62-297.310(2), F.A.C.]

E.4. Methods of Operation - Fuels. Only natural gas shall be fired in this boiler.
[Rules 62-4.160(2) and 62-213.440(1), F.A.C.]

E.5. Hours of Operation. This emissions unit may operate 2,000 hours/year as an auxiliary source of steam; however, except for compliance testing, it may only operate when either Unit 7 or Unit 8 is not operating. The Permittee shall maintain an operation log available for Department inspection certifying the total hours of operation and fuel consumption annually.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; 1290001-002-AC & 1290001-005-AC.]

Emission Limitations and Standards

{Permitting Note: The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

[Note: This emissions unit is subject to the facility-wide emissions caps for SO_2 and NO_X.]

{Permitting note: Unless otherwise specified, the averaging times for conditions E.6. – E.8. are based on the specified averaging time of the applicable test method.}

E.6. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one six-minute period per hour during which opacity shall not exceed 27 percent.
[Rule 62-296.406(1), F.A.C.]

E.7. Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas.
[Rule 62-296.406(2), F.A.C.; and, BACT determination dated October 8, 1996.]

E.8. Sulfur Dioxide. Sulfur dioxide emissions shall be controlled by the firing of natural gas.
[Rule 62-296.406(3), F.A.C.; and, BACT determination dated October 8, 1996.]

Excess Emissions

{Permitting Note: The excess emissions rule at 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

E.9. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

E.10. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

E.11. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

E.12. This emissions unit is also subject to the conditions contained in **Subsection C. Common Conditions**, as specified below.

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.13. Visible Emissions. See common conditions **C.5. & C.6.**

E.14. Operating Rate During Testing. See common condition **C.11.**

E.15. Applicable Test Procedures. See common condition **C.13.(a)2.**

E.16. Frequency of Compliance Tests. See common condition **C.15. except (a)5. & 8.**

E.17. Visible Emissions - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit.
[Rules 62-297.310(7)(a)4., F.A.C.]

Recordkeeping and Reporting Requirements

E.18. The permittee shall record and maintain records of the amount of natural gas combusted during each day the auxiliary boiler is operated.
[40 CFR 60.48c(g)]

E.19. See common conditions **C.18.** and **C.20.(a) & (b).**

E.20. Sufficient records shall be maintained to ensure that the total facility-wide SO_2 emissions do not exceed 80 tons per year (**see facility-wide conditions 13. & 14.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

E.21. Sufficient records shall be maintained to ensure that the total facility-wide NO_X emissions do not exceed 467 tons per year (**see facility-wide conditions 15. & 16.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

SECTION 1.3

U.S. Environmental Protection Agency

Technology Transfer Network Clearinghouse for Inventories & Emission Factors

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Emission Inventory Improvement Program
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Related Sites
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AP-42, Fifth Edition, Volume I Chapter 1: External Combustion Sources

Explanation of File Formats

NOTE: Many AP-42 files contain equation fonts that may not be readable on some computers. If you encounter problems with viewing AP-42 documents contact the Info CHIEF Help Desk, (919) 541-1000.

1.0 Introduction to External Combustion Sources

1.1 Bituminous and Subbituminous Coal Combustion

- Final Section - Supplement E, September 1998 (PDF 515K)
- Background Document (PDF 8M)
- Related EIIP Documents (PDF 232K)

1.2 Anthracite Coal Combustion

- Final Section - Supplement B, October 1996 (PDF 59K)
- Background Document (PDF 249K)
- Related EIIP Documents (PDF 232K)

1.3 Fuel Oil Combustion

- Final Section - Supplement E , September 1998 (PDF 293K)
- Errata
- Background Document (PDF 716K)
- Related Info.
- Related EIIP Documents (PDF 232K)

1.4 Natural Gas Combustion

- Final Section - Supplement D , July 1998 (PDF 230K)
- Background Document (PDF 225K)
- Related Info.
- Related EIIP Documents (PDF 232K)

1.5 Liquified Petroleum Gas Combustion

- Final Section - Supplement B , October 1996 (PDF 18K)
- Background Document (PDF 129K)
- Related EIIP Documents (PDF 232K)

1.6 Wood Residue Combustion in Boilers

- Final Section - Update 2001, July 2001 (PDF 480K) Revised March 2002.
- Revision Information
- Background Document (PDF 72K)
- Related Information

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°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 memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF web site (http://www.epa.gov/ttn/chief/).

Supplement A, February 1996

- The formulas presented in the footnotes for filterable PM were moved into the table.
- For SO_2 and SO_3 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 NO_x 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 SO_2 and SO_3 factors, text was added to the table footnotes to clarify that "S" is a weight percent and not a fraction.
- The N_2O, 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.
- 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 NO_x emission factors.
- Emission factors for condensable particulate matter were added (Table 1.3-2).

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

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

Table 1.3-1. (cont.)

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

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

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

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

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

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

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

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

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

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

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.

[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.

[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.

[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10^3 gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10^3 gal.

[e] References: 76-78.

[f] References: 79-82.

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

EMISSION FACTOR RATING: A

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

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

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

Table 1.3-4. 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]	
	Uncontrolled	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/10^3 gal to kg/m^3, 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 Factof (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/10^3 gal to kg/10^3 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

	Cumulative Mass % ≤ Stated Size		Cumulative Emission Factor[c] (lb/10^3 gal)	
Particle Size[b] (μm)	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

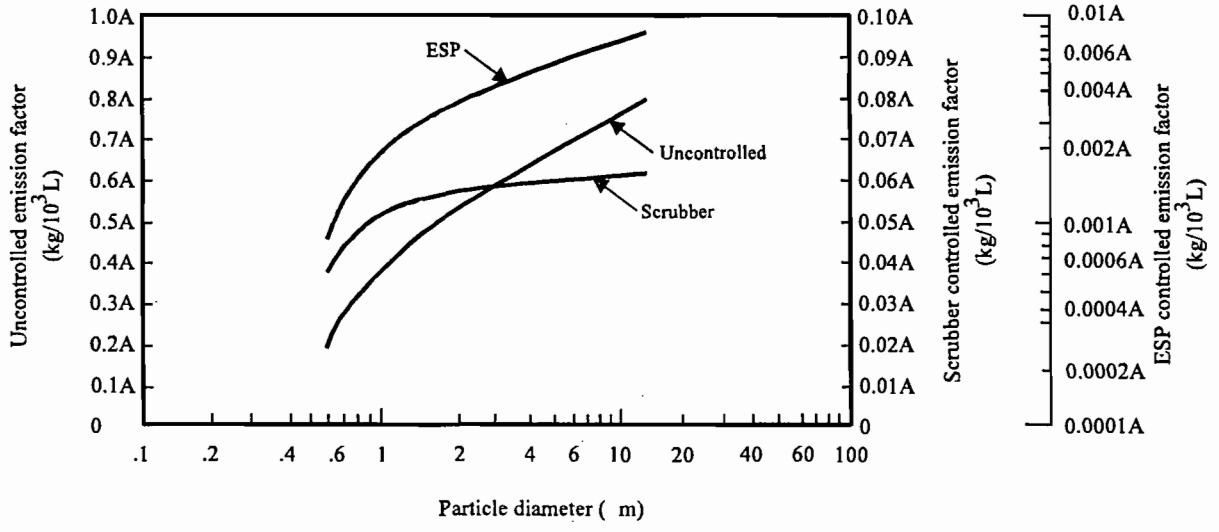


Figure 1.3-1. Cumulative size-specific emission factors for utility boilers firing residual oil.

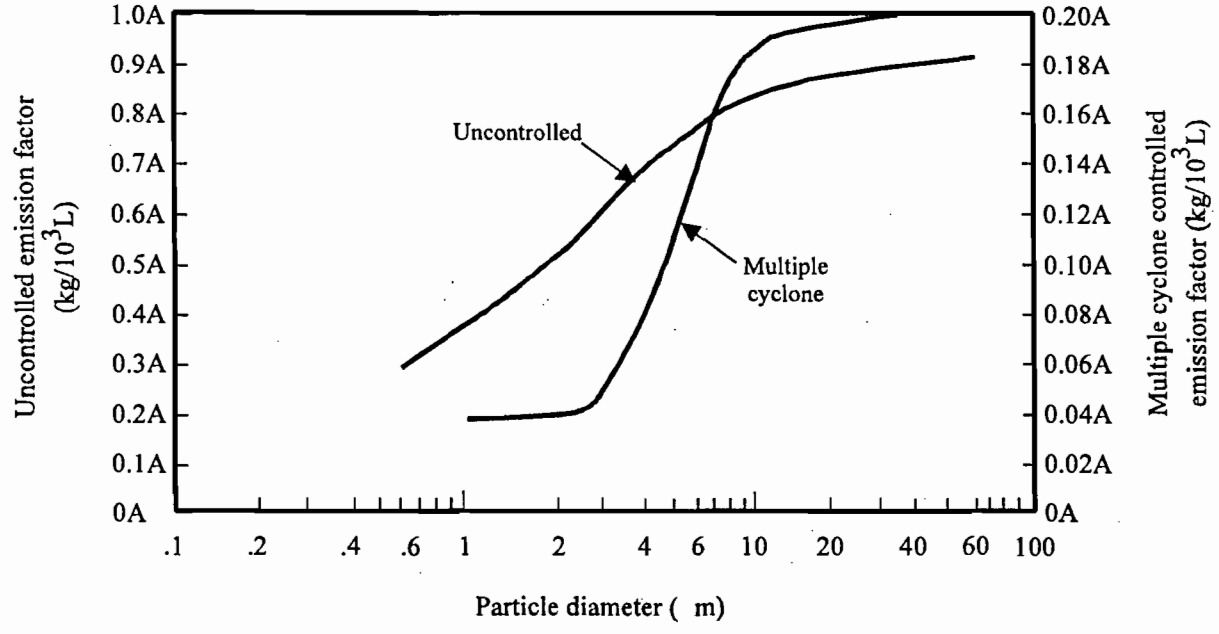


Figure 1.3-2. Cumulative size-specific emission factors for industrial boilers firing residual oil.

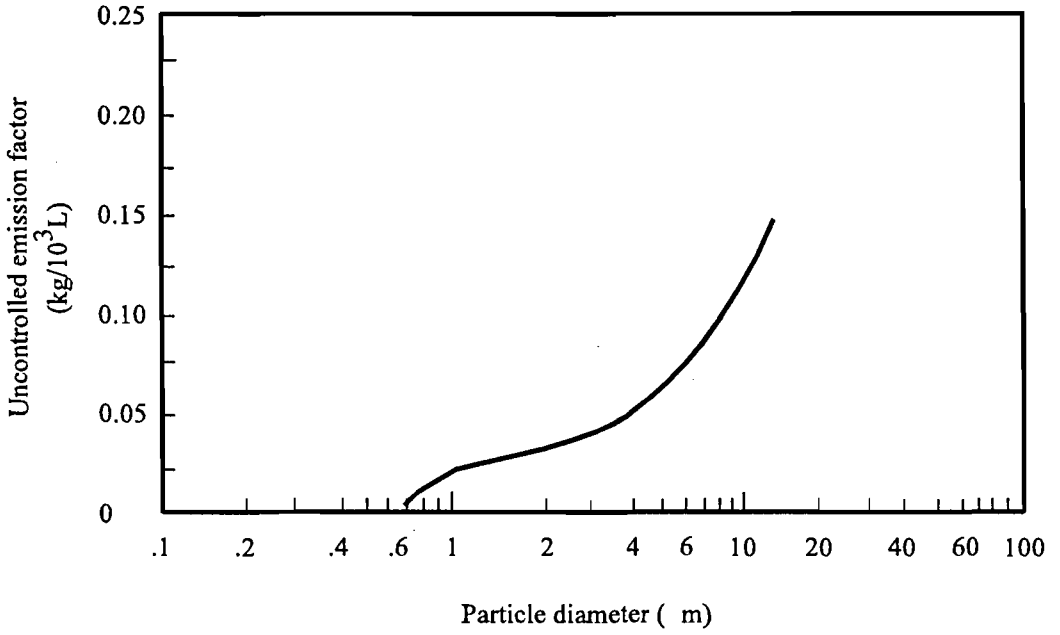


Figure 1.3-3. Cumulative size-specific emission factors for uncontrolled industrial boilers firing distillate oil.

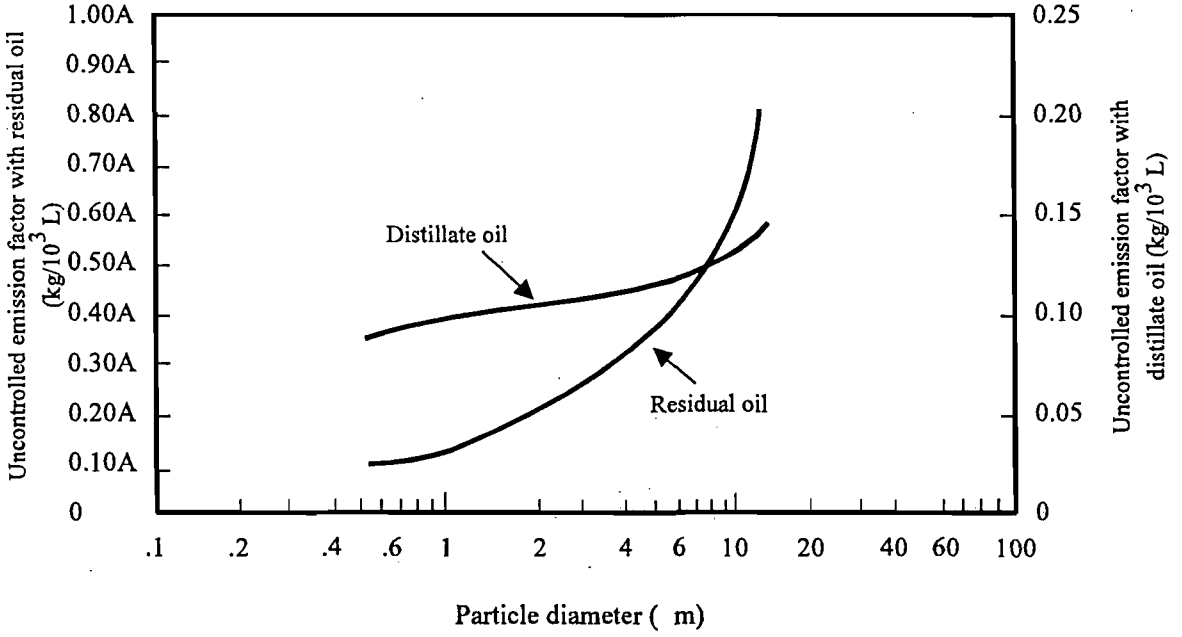


Figure 1.3-4. Cumulative size-specific emission factors for uncontrolled commercial boilers burning residual and distillate oil.

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)	0.11	0.0011 - 0.0013[d]	0.024 - 0.061
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.11	0.0033[e]	0.035 - 0.061
Residential furnaces (A2104004/A2104011)	0.05	ND	ND

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

Table 1.3-9. 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 2×10^6 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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EMISSION FACTOR DOCUMENTATION FOR

AP-42 SECTION 1.3,

FUEL OIL COMBUSTION

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TABLE OF CONTENTS

Page

LIST OF TABLES vi

CHAPTER 1. INTRODUCTION 1-1

CHAPTER 2. SOURCE DESCRIPTION 2-1

2.1 CHARACTERIZATION OF FUEL OIL APPLICATIONS 2-1
2.2 PROCESS DESCRIPTIONS 2-2
2.2.1 Watertube Boilers 2-2
2.2.2 Firetube Boilers 2-3
2.2.3 Cast Iron Boilers 2-3
2.2.4 Other Boilers 2-3
2.3 EMISSIONS 2-4
2.3.1 Particulate Matter Emissions 2-5
2.3.2 Sulfur Oxide Emissions 2-5
2.3.3 Nitrogen Oxides Emissions 2-6
2.3.4 Carbon Monoxide Emissions 2-8
2.3.5 Organic Compound Emissions 2-8
2.3.6 Trace Element Emissions 2-10

2.4 CONTROL TECHNOLOGIES 2-12
2.4.1 Fuel Substitution 2-12
2.4.2 Combustion Modification 2-13
2.4.2.1 Particulate Matter Control 2-13
2.4.2.2 NO_x Control 2-13

2.4.3 Post Combustion Control..... 2-15
2.4.3.1 Particulate Control..... 2-15
2.4.3.2 NO_x Control..... 2-16
2.4.3.3 SO_2 Control..... 2-16
REFERENCES..... 2-29

CHAPTER 3. GENERAL EMISSION DATA REVIEW AND ANALYSIS PROCEDURES..... 3-1

3.1 CRITERIA POLLUTANTS..... 3-1
3.1.1 Literature Search..... 3-1
3.1.2 Literature Evaluation..... 3-1
3.1.3 Emission Factor Quality Rating..... 3-3

3.2 SPECIATED VOCs..... 3-4
3.2.1 Literature Search..... 3-4

TABLE OF CONTENTS (continued)

Page

3.2.2 Literature Evaluation..... 3-5
3.2.3 Data and Emission Factor Quality Rating..... 3-5

3.3 AIR TOXICS..... 3-5
3.3.1 Literature Search..... 3-5
3.3.2 Literature Evaluation..... 3-6
3.3.3 Data and Emission Factor Quality Rating Criteria..... 3-6

3.4 Nitrous Oxide..... 3-8

3.4.1 Literature Search..... 3-8
3.4.2 Literature Evaluation..... 3-8
3.4.3 Data and Emission Factor Quality Rating..... 3-8

3.5 FUGITIVE EMISSIONS..... 3-9

3.6 PARTICLE SIZE DISTRIBUTION..... 3-10
3.6.1 Literature Search..... 3-10
3.6.2 Literature Evaluation..... 3-11
3.6.3 Data Quality Ranking..... 3-12
REFERENCES..... 3-16

CHAPTER 4. EMISSION FACTOR DEVELOPMENT..... 4-1

4.1 CRITERIA POLLUTANTS..... 4-1
4.1.1 Review of Previous AP-42 Data..... 4-1
4.1.2 Review of New Baseline Data..... 4-1
4.1.3 Compilation of Baseline Emission Factors..... 4-4
4.1.4 Compilation of Controlled Emission Factors..... 4-7

4.2 SPECIATED VOCs..... 4-8

4.3 HAZARDOUS AIR POLLUTANTS..... 4-8
4.3.1 Review of New Data..... 4-8
4.3.2 Baseline Emission Factors..... 4-12
4.3.3 Controlled Emission Factors..... 4-14

4.4 Nitrous Oxide..... 4-14
4.4.1 Review of Specific Data Sets..... 4-14

TABLE OF CONTENTS (continued)

Page

4.5 FUGITIVE EMISSIONS..... 4-15
4.5.1 Review of Specific Data..... 4-16
4.5.2 Compilation of Emission Factors..... 4-16

4.6 PARTICULATE SIZE DISTRIBUTION..... 4-16
4.6.1 Review of 1986 Section 1.3 Data..... 4-16
4.6.2 Review of New Data..... 4-17
4.6.3 Compilation of Uncontrolled Emission Factors..... 4-18
4.6.4 Control Technology Emission

Factors..... 4-18
REFERENCES..... 4-51

CHAPTER 5. AP-42 SECTION 1.3: FUEL OIL COMBUSTION..... 5-1

APPENDIX A: CONVERSION FACTORS..... A-1

APPENDIX B: MARKED-UP 1986 AP-42 SECTION 1.3..... B-1

LIST OF TABLES

Table		Page
2-1	U.S. Oil Consumption by Sector in 1990	2-19
2-2	Boiler Usage by Sector	2-20
2-3	Total U.S. Anthropogenic Emissions by Category for SO_2, NO_x, VOC, and TSP in 1989	2-21
2-4	NSPS Summary for Fossil Fuel-fired Boilers	2-22
2-5	Combustion Modification NO_x Controls Evaluated for Oil-fired Boilers	2-24
2-6	Post Combustion NO_x Reduction Technologies	2-27
2-7	Commercial Post Combustion SO_2 Controls for Coal Combustion Sources	2-28
3-1	Literature Search/Consultation Record	3-14
3-2	Evaluation of References	3-15
4-1	Results of 1986 Section 1.3 Data Spot Checks	4-21
4-2	PM Emission Factor Update	4-25
4-3	SO_2 Emission Factor Update	4-27
4-4	SO_3 Emission Factor Update	4-29
4-5	CO Emission Factor Update	4-31
4-6	NO_x Emission Factor Update	4-32
4-7	VOC Emission Factor Update	4-34
4-8	Controlled PM Emissions	4-35
4-9	Controlled SO_2 Emissions	4-37
4-10	Controlled NO_x Emissions	4-40
4-11	Metals Enrichment Behavior	4-44
4-12	HAP Emission Factors (Metric Units) for Residual and Distillate Oil Combustion	4-45
4-13	HAP Emission Factors (English Units) for Residual and Distillate Oil Combustion	4-46
4-14	Summary of N_20 Emission Factors for Fuel Oil Combustion	4-47
4-15	Comparison of Fugitive Emissions of VOCs from Equipment Types	4-47
4-16	Oil-Fired Particulate Sizing Data for the Current AP-42 Sections: Number of A- and B-Rated Data Sets	4-48
4-17	Comparison of Organic and Inorganic CPM Emissions from a 5 Million Btu/Hr Scotch Dry-back Boiler	4-48
4-18	Comparison of Organic and Inorganic CPM Emissions from a Type-H Stirling Boiler Firing No. 2 Fuel Oil	4-49

4-19 Comparison of Organic and Inorganic CPM Emissions from a Face-fired Supercritical 480 MW Steam Generator 4-49

LIST OF TABLES (continued)

Table Page

4-20 Comparison of Organic and Inorganic CPM Emissions from a Face-fired, Balanced Draft Utility Boiler 4-50

4-21 Comparison of Organic and Inorganic CPM Emissions from an Oil-fired Boiler Equipped with a Mechanical Collector 4-50

1. INTRODUCTION

An emission factor is an average value which relates the quantity (weight) of a pollutant released to the atmosphere with the activity associated with the release of that pollutant. Emission factors for many activities are listed in the document "Compilation of Air Pollutant Emission Factors" (AP-42) published by the U.S. Environmental Protection Agency (EPA) since 1972. The uses for the emission factors reported in AP-42 include:

- Estimates of area-wide emissions,
- Emission estimates for a specific facility,
- Evaluation of emissions relative to ambient air quality.

The EPA routinely updates AP-42 in order to respond to the needs of State and local air pollution control programs, industry, as well as the Agency itself. Section 1.3 in AP-42, the subject of this Emission Factor Documentation (EFD) report, pertains to fuel oil combustion in stationary, external equipment.

The prior revisions of AP-42 Section 1.3 focused primarily on the criteria pollutants, together with particle sizing. The purpose of this revision is to update the data base for the earlier revisions and extend the section's scope to other pollutant species. Specifically, the scope of the current update includes the following:

- Updating of emission factors for criteria pollutants during baseline, uncontrolled operation using data that has become available since the prior revision (i.e., 1986).

- Inclusion of several non-criteria emission species for which data are available: organics speciation, air toxics, and greenhouse or ozone depletion gases [e.g., nitrous oxide (N_2O) and carbon dioxide (CO_2)].

- Expand and update the technical discussion and control efficiency data for boilers operating with nitrogen oxides (NO_x), carbon monoxide (CO), or particulate matter (PM) control systems.

The update of Section 1.3 of AP-42 began with a review of the existing version of Section 1.3. Spot checks were made on the quality of existing emission factors by selecting primary data references from the background files and recalculating emission factors.

An extensive literature review was undertaken to improve technology descriptions, update usage trends, and collect new test reports for criteria and non-criteria emissions. The new test reports were subjected to data quality review as outlined in the draft EPA document, "Technical Procedures For Developing AP-42 Emission Factors And Preparing AP-42 Sections" (March 6, 1992). The data points obtained from test reports receiving sufficiently high quality ratings were then combined with existing data, wherever possible, and used to produce new emission factors.

In this revision, several new emission factors pertaining to non-criteria pollutants have been added. These new emission factors pertain to speciated volatile organic compounds (VOCs), air toxics, N_2O, CO_2, and fugitive emissions. Additionally, in this revision, the information on control technologies for particulate, sulfur oxides (SO_x), and NO_x emissions has been updated. Finally, this revision has resulted in the addition of several new references.

Chapter 2 of this report gives a description of the fuel oil combustion industry. It includes a characterization of fuel oil applications, an overview of the different process types, a description of emissions, and a description of the technology used to control emissions resulting from fuel oil combustion. Chapter 3 is a review of emissions data collection and analysis procedures. It describes the literature search, the screening of emissions data reports, and the quality rating system for both emission data and emission factors. Chapter 4 details pollutant emission factor development. It includes reviews of specific data sets and details of emission factor compilations. Chapter 5 presents the revised AP-42 Section 1.3.

2. SOURCE DESCRIPTION

The amount and type of oil consumed, design of combustion equipment, and application of emission control technology have a direct bearing on emissions from oil-fired combustion equipment. This chapter characterizes oil applications, fuel oil combustion processes, and emission control technologies pertaining to the United States.

2.1 CHARACTERIZATION OF FUEL OIL APPLICATIONS

Annual consumption of fuel oil in boilers in the United States totalled about 4200 kJ (4400 x 10^{12} Btu) in 1990.[1] This consumption in boilers was divided into four sectors: (1) utility boilers producing steam for the generation of electricity; (2) industrial boilers generating steam or hot water for process heat, electricity generation, or space heat; (3) boilers used for space heating of commercial facilities; and (4) residential furnaces used for space heating purposes.

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 numbers 1 and 2 being distillate oils; numbers 5 and 6 being residual oils; and number 4 being either distillate oil or a mixture of distillate and residual oils. Grade 6 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 0.5 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications.

Being more viscous and less volatile than distillate oils, the heavier residual oils (grades 5 and 6) must be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue left over after the lighter fractions (e.g., 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. Table 2-1 summarizes the Department of Energy data on oil use by combustion sector in 1990.[1]

2.2 PROCESS DESCRIPTIONS

The three major boiler configurations for fuel oil-fired combustors (i.e., watertube, firetube, and cast iron) are described below. 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.

2.2.1 Watertube Boilers

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.

Industrial watertube boilers are available as packaged or field erected units, in capacities ranging from less than 2.9 to over 200 MW [10 to over 700 million Btu per hour (MMBtu/hr)].[1] Utility oil-fired boilers are field erected and have thermal heat input ratings up to about 2,300 MW (8,000 MMBtu/hr). New industrial oil-fired boilers as large as 70 MW (250 MMBtu/hr) input capacity are typically shop assembled and shipped as packaged units. Larger oil-fired boilers are field-erected units assembled on-site. In general, field-erected watertube boilers are much more common than packaged units in the boiler size category above 58 MW (200 MMBtu/hr) input capacity whereas, below this capacity, watertube boilers are usually packaged. There are, however, packaged watertube units as large as 102 MW (350 MMBtu/hr) input capacity.

2.2.2 Firetube Boilers

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.[3] As a consequence, firetube boilers are typically small, with heat input capacities limited to less than 15 MW (50 MMBtu/hr) and steam pressures limited to 150 kPa (300 psig), although high-end steam pressures of 76 kPa (150 psig) are more common.[4] Firetubes are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size. Firetube boilers are generally available as packaged units in capacities ranging from 0.1 MW (0.4 MMBtu/hr) to 15 MW (50 MMBtu/hr).

2.2.3 Cast Iron Boilers

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 and have input capacities up to 4 MW (14 MMBtu/hr).[4]

2.2.4 Other Boilers

A fourth 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. This type of boiler is packaged and is available in heat input capacities ranging from 0.07 to 1.2 MW (0.25 to 4.2 MMBtu/hr).[5]

Boilers used in thermally enhanced oil recovery (TEOR) operations are referred to as oil field steam generators. These units are typically packaged watertube boilers with heat input capacities from about 5.8 to 18 MW (20 to 63 MMBtu/hr). Steam

generators are typically cylindrical in shape and horizontally oriented, with watertubes arranged in a coil-like design. For a given size, there is little variability in the design or configuration of oil field steam generators.[6] Table 2-2 summarizes the use of the three major types of boilers in various sectors.[7]

2.3 EMISSIONS

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing practices used, and the level of equipment maintenance. The term "baseline emissions" of criteria and non-criteria pollutants refer to emissions from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment, low-NO_x burners, or other modifications for emission control. Baseline emissions for sulfur dioxide (SO_2) and PM can be obtained from controlled sources if measurements are taken upstream of APC equipment. This may not be possible with combustion modification controls for NO_x, where the controls are an intrinsic part of the boiler design.

For this update of AP-42, point source emissions of NO_x, SO_2, PM, and CO are being evaluated as criteria pollutants (those emissions which have established National Primary and Secondary Ambient Air Quality Standards).[34] Particulate matter emissions are sometimes reported as total suspended particulate (TSP). The portion of inhalable particulate matter which is less than 10 microns in aerodynamic diameter (PM-10) has been redesignated as a criteria pollutant. In addition to the criteria pollutants, this update includes point source emissions of some non-criteria pollutants (e.g., N_2O, VOCs, and hazardous air pollutants) as well as data on particle size distribution to support PM-10 emission inventory efforts. Emissions of CO_2 are also being considered because of its possible participation in global climatic change and the corresponding interest in including this gas in emission inventories. Most of the carbon in fossil fuels, including fuel oil, is emitted as CO_2 during combustion. Minor amounts of carbon are emitted as CO, much of which ultimately oxidizes to CO_2, or as carbon in the ash. Finally, fugitive emissions associated with the use of fuel oil at the combustion source are being included in this update of AP-42.

A general discussion of emissions of criteria and non-criteria pollutants from coal combustion is given in the following paragraphs.

2.3.1 Particulate Matter Emissions[10-14,19-20,28,30-31]

The PM emissions from fuel oil-firing under normal non-sooting conditions depend primarily on the grade of oil fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of Nos. 4 and 5 usually produces less PM than does the firing of heavier No. 6.

In general, PM emissions depend on the completeness of combustion as well as the oil ash content. The PM emitted by distillate oil-fired boilers is primarily carbonaceous particles resulting from incomplete combustion of oil and does not correlate with the ash or sulfur content of the oil. This is because lower sulfur (distillate) oil has substantially lower viscosity and reduced asphaltene and ash contents. Consequently, lower sulfur oils atomize better and burn easier. The level of PM emissions from residual oil combustion, however, is related to the oil sulfur content. This applies regardless of whether the fuel oil is refined from naturally occurring low sulfur crudes or is desulfurized by current refinery practice.

Boiler load can also affect particulate emissions in units firing No. 6 oil. At low load conditions, particulate emissions may be lowered by 30 to 40 percent from utility boilers and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emissions have been noted at low loads from boilers firing any of the lighter oil grades. At very low load conditions, proper combustion conditions typically cannot be maintained and particulate emissions may increase drastically.

2.3.2 Sulfur Oxide Emissions[8-12,29]

Sulfur oxide 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.[13] On average, more than 95 percent of the fuel sulfur is converted to SO_2; about 1 to 5 percent further oxidized to sulfur trioxide (SO_3); and about 1 to 3 percent is emitted as sulfate particulate. The SO_3 readily reacts with water vapor (both in air and in flue gases) to form a sulfuric acid mist.

2.3.3 Nitrogen Oxides Emissions [8-18,21-22,27,31]

Oxides of nitrogen 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"). Although five oxides of nitrogen exist, the term NO_x is customarily used to describe the composite of nitric oxide (NO) and nitrogen dioxide (NO_2). Nitrous oxide is of increasing interest as an upper atmosphere gas, but is not included in NO_x. Test data have shown that for most stationary fossil fuel combustion systems, over 95 percent of the emitted NO_x is in the form of NO.[13]

On a global basis, thermal NO_x formation rates in flames is exponentially dependent on temperature and proportional to the nitrogen (N_2) concentration in the flame, the square root of the oxygen (O_2) concentration in the flame, and the residence time.[27] These relationships are corroborated by experimental data which show that thermal NO_x formation is most strongly dependant on three factors: (1) peak temperature, (2) O_2 concentration (or stoichiometric ratio), and (3) time of exposure at peak temperature. The emission trends due to changes in these factors are fairly 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 regardless of the boiler type.

Fuel nitrogen conversion is an important NO_x-forming mechanism in residual oil-fired boilers. It can account for 50 percent of the total NO_x emissions from residual oil firing.[32] The percent conversion of fuel nitrogen to NO_x, however, varies greatly. Anywhere 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 residual oil, fuel NO_x will generally account 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.

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. The NO_x emissions from tangentially (or corner)-fired boilers are, on the average, less than those with

horizontally opposed burners. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion (SC), or some combination thereof may result in NO_x reductions of 5 to 60 percent (see Section 2.4.1 for a discussion of these techniques). Load reduction can likewise decrease NO_x production. Emissions of NO_x may be reduced from 0.5 to 1 percent for each percentage reduction in load below full load operation. It should be noted that most of these variables, with the exception of excess air, influence the NO_x emissions only of large oil-fired boilers. Low excess air firing is possible in many small boilers, but the resulting NO_x reductions may not be significant.

Nitrous oxide emissions for most oil-fired boilers are only a small fraction of the NO_x levels. Earlier data (prior to 1988) had suggested much higher levels of N_2O. However, these data are thought to be erroneous due to a sampling artifiact introduced as a result of the time lapse between sampling and analysis. New methods have been proposed to circumvent this problem. Recent N_2O emissions data, indicate that direct N_2O emissions from oil combustion units are considerably below the measurements made prior to 1988.[35] Nevertheless, the N_2O formation and reaction mechanisms are still not well understood nor well characterized. Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O mechanism. Emissions can vary widely from unit to unit, or even from the same unit under different operating conditions. It has been shown in some cases that N_2O increases with decreasing boiler temperature.[36] For this AP-42 update, an average emission factor based on reported test data was developed for conventional oil combustion systems.

The nationwide inventory of PM, SO_2, and NO_x emissions resulting from fuel oil combustion in 1985 are summarized in Table 2-3. Table 2-4 summarizes the new source performance standards (NSPS) pertinent to PM, SO_2, and NO_x emissions from fossil fuel-fired boilers.[48]

2.3.4 Carbon Monoxide Emissions [23-26]

The rate of 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 leading to reduced flame temperature and combustion intensity and, therefore, lower combustion efficiency than large combustors. Larger combustors also have more complex combustion control systems to trim O_2 to a level which gives low CO emissions but high 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. These include:

- Insufficient O_2 availability;
- Extremely high levels of excess air (which leads to quenching);
- 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.

2.3.5 Organic Compound Emissions [23-26]

Small amounts of organic compounds are emitted from combustion. As with CO emissions, the rate at which organic compounds are emitted depends 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 which remain in a gaseous state in ambient air, semi-volatile organic compounds, and condensible organic compounds. According to the Federal Register definition (57 FR 3945), VOC has been defined as any organic compound excluding CO, CO_2, carbonic acid, metallic carbides or carbonates, and ammonium carbonate which participates in atmospheric photochemical

reactions. The following additional compounds have been deemed to be of "negligible photochemical reactivity" and also are exempt from the definition of VOC: methane, ethane, methyl chloroform, methylene chloride, and most chlorinated-fluorinated compounds (commonly referred to as CFCs). Although these compounds are considered "exempt" from most ozone control programs due to their low photochemical reactivity rates, they are of concern when developing complete emission inventories which are necessary for the design of effective ozone control strategies. The term TOC will refer to all organic compounds: VOCs plus the "exempt" compounds, including methane and ethane, toxic compounds, aldehydes, perchloroethylene, semi-volatiles, and condensibles (as measured by EPA Reference Methods).

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, ethyl benzene, etc.).[37,38]

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 (PNA or PAH). Information available in the literature on POM compounds generally pertains to these PAH groups. Because of the dominance of PAH information (as opposed to other POM categories) in the literature, many reference sources have inaccurately used the terms POM and PAH interchangeably.

A few comments are in order concerning an extremely toxic subclass of PNA -- the polychlorinated and polybrominated biphenyls (PCBs and PBBs). A theoretical assessment of PCB formation in combustion sources concluded that, although PCB formation is thermodynamically possible for combustion of fuels containing some chlorine (e.g., some coals and residual oil), it is unlikely due to low chlorine concentrations and to short residence times at conditions favoring PCBs.[39] Also, with

efficient mixing, O_2 availability, and adequate residence time at temperatures in the 800-1000° C (1500-1800° F) range, PCBs (together with polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans) will be efficiently destroyed.[40] Other research has shown, however, that chlorinated PNAs can be formed via catalyzed reactions on fly ash particles at low temperatures in equipment downstream of the combustion device.[60]

Formaldehyde is formed and emitted during the combustion of hydrocarbon-based fuels, including coal and oil. Formaldehyde is present in the vapor phase of the flue gas. Since formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion, large units with efficient combustion resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long residence times should have lower formaldehyde emission rates relative to small, less efficient combustion units.[41,42]

2.3.6 Trace Element Emissions [23-26]

Trace elements are also emitted from oil combustion with the emission rate largely dependant on the metals concentration of the 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 (CAAA-90) are considered.[43] The quantity of trace metals emitted 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 partitioning of ash into heavier material which deposits on boiler surfaces and lighter, smaller ash which is emitted with the flue gas.

The quantity of any given metal emitted, in general, depends on:

- Its concentration in the fuel;
- The combustion conditions;
- The type of particulate control device used, and its collection efficiency as a function of particle size; and
- The physical and chemical properties of the element affecting transformation and fate.

It has become widely recognized that some trace metals concentrate in certain waste particle streams from a combustor (e.g., bottom ash, collector ash, flue gas particulate), while others do not.[44] Various classification schemes to describe this partitioning have been developed.[45-47] The schemes have been derived for solid fuel-firing, but are also relevant to oil-firing. The classification scheme used by Baig, et al. is as follows:[47]

- 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 intermediate between Classes 1 and 2.
- Class 4: 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.[44] For example, several boiler NO_x control techniques reduce peak flame temperatures (e.g., staged combustion, FGR, reduced air preheat, and load reduction). If combustion temperatures are reduced, fewer Class 2 metals will initially volatilize, and fewer will be available for subsequent condensation and enrichment in the fine particle fractions. 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.

Local O_2 concentration is also expected to affect metal emissions from boilers with particulate 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 in the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metals emissions should remain unchanged.

Other combustion NO_x controls which decrease local O_2 concentrations (such as staged combustion and FGR) also reduce peak flame temperatures. Under these conditions, the effect of reduced combustion temperature is expected to be stronger than that of lower O_2 concentrations.

2.4 CONTROL TECHNOLOGIES

The various control techniques and/or devices employed with oil combustion sources depend on the source category and the pollutant being controlled. Only controls for criteria pollutants are discussed here because controls designed specifically for non-criteria emissions have not been demonstrated nor commercialized for oil combustion sources.

Control techniques may be classified into three broad categories: fuel substitution, combustion modification, and post combustion control. Fuel substitution involves using "cleaner" fuels to reduce emissions. Combustion modification and post combustion control are both applicable and widely commercialized for oil combustion sources. Combustion modification is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Post combustion control is applied to emissions of PM, SO_2, and, to some extent, NO_x from oil combustion.

2.4.1 Fuel Substitution[10,12,15,51]

Fuel substitution, or the firing of "cleaner" fuel oils, can substantially reduce emissions of a number of pollutants. Lower sulfur oils, for instance, will reduce SO_x emissions in all boilers, regardless of size or type of unit or grade of oil fired. Particulate loading generally will be reduced when a lighter grade of oil is fired. Nitrogen oxide emissions will be reduced by switching to either a distillate oil or a residual oil with less nitrogen. The practice of fuel substitution, however, may be limited by the ability of a given operation to fire a better grade of oil and by the cost and availability of that fuel.

2.4.2 Combustion Modification[8-11,15-16,20-21,27]

Combustion modification includes any physical change in the boiler/burner hardware or in boiler operation. Maintenance of the burner system, for example, is important to assure proper atomization and subsequent minimization of any unburned

combustibles. Periodic tuning is important in small units for maximum operating efficiency and emission control, particularly of smoke and CO. Combustion modifications, such as limited excess air firing, FGR, staged combustion and reduced load operation, result in lowered NO_x emissions in large facilities.

2.4.2.1 Particulate Matter Control.[51] Control of PM emissions from residential and commercial units is accomplished by improved burner servicing and by incorporating appropriate equipment design changes to improve oil atomization and combustion aerodynamics. Optimization of combustion aerodynamics using a flame retention device, swirl, and/or recirculation is considered to be the best approach toward achieving the triple goals of low PM, low NO_x, and high thermal efficiency.

Large industrial and utility boilers are generally well-designed and well-maintained so that soot and condensible organic compound emissions are minimized. Particulate matter emissions are more a result of entrained fly ash in such units. Therefore, post- combustion controls are necessary to reduce PM emissions from these sources.

2.4.2.2 NO_x Control. The formation of thermal NO_x occurs in part through the Zeldovich mechanism:

(2-1) $N_2 + O \leftrightarrow NO + N$
(2-2) $N + O_2 \leftrightarrow NO + O$
(2-3) $N + OH \leftrightarrow NO + H$

Reaction (2-1) is generally believed to be the rate-determining step due to its large activation energy.[44] Kinetically, thermal NO_x formation is related to nitrogen (N_2) concentration, combustion temperature, and O_2 concentration by the following equation:[44]

(2-4) $[NO] = k_1 \exp(-k_2/T) [N_2] [O_2]^{1/2} t$

where:

[ ] = mole fraction

T = temperature (°K)

t = residence time

k_1, k_2 = reaction rate coefficient constants

From this relationship and the Zeldovich mechanism, it can be seen that thermal NO_x formation can be controlled by four approaches: (1) reduction of peak temperature of reaction, (2) reduction of N_2 concentration, (3) reduction of O_2 level, and (4) reduction of the residence time of exposure. Typically, the N_2 mole fraction in hydrocarbon-air flames is on the order of 0.7 and is difficult to modify.[44] Therefore, combustion modification techniques to control thermal NO_x in boilers have focused on reducing O_2 level, peak temperature, and time of exposure at peak temperature in the primary flame zones of the furnaces. Equation 2-4 also shows that thermal NO_x formation depends exponentially on temperature, parabolically on O_2 concentration, and linearly on residence time. Hence, temperature has a dominant effect on production of thermal NO_x.

In boilers fired on coal, crude oil, or residual oil, the control of fuel NO_x is very important in achieving the desired degree of NO_x reduction since typically fuel NO_x accounts for 50 to 80 percent of the total NO_x formed.[52-53] 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.[54] 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 O_2 creates reducing conditions that, given sufficient time at high temperatures, cause volatile fuel nitrogen to convert to N_2 rather than NO.

In the formation of both thermal and fuel NO_x, all of the above reactions and conversions do not take place at the same time, temperature, or rate. The actual mechanisms for NO_x formation in a specific situation are dependent on the quantity of fuel bound nitrogen, if any, and the temperature and stoichiometry of the flame zone. Although the NO_x formation mechanisms are different, both thermal NO_x and fuel NO_x are promoted by rapid mixing of fuel and combustion air. This rate of mixing may itself depend on fuel characteristics such as the atomization quality of liquid fuels.[55] Additionally, thermal NO_x is greatly increased by increased residence time at high

temperatures, as mentioned earlier. Thus, primary combustion modification controls for both thermal and fuel NO_x typically rely on the following control approaches:

- ! Decrease primary flame zone O_2 level:
  - Decrease overall O_2 level
  - Control (delay) mixing of fuel and air
  - Use of fuel-rich primary flame zone
- ! Decrease residence time at high temperatures:
  - Decrease adiabatic flame temperature through dilution
  - Decrease combustion intensity
  - Increase flame cooling
  - Decrease primary flame zone residence time

Table 2-5 shows the relationship between these control strategies and combustion modification NO_x control techniques currently in use on boilers firing fuel oil.[44]

2.4.3 Post Combustion Control[49-51]

Post combustion control refers to removal of pollutants from combustion flue gases. Its use is relatively rare with oil-fired boilers due to relatively high cost per mass of pollutant removed. Some larger installations have, however, been equipped with controls for PM, NO_x, or SO_x.

2.4.3.1 Particulate Control.[51] Industrial and utility boilers are, generally, well-designed and well-maintained. Hence, particulate collectors are usually needed only in special circumstances. The use of particulate collectors with oil-firing is described below.

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. During 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 will not be nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

Electrostatic precipitators (ESPs) are used in a few oil-fired power plants. Older ESPs, usually small, remove generally 40 to 60 percent of the PM. Because of the low ash content of the oil, greater collection efficiency may not be required. Today, new or rebuilt ESPs have collection efficiencies of 99 percent or greater.

Scrubbing systems have been installed on oil-fired boilers, especially of late, to control both SO_x and PM. These systems can achieve SO_2 removal efficiencies of 90 to 95 percent and particulate control efficiencies of 50 to 60 percent.

2.4.3.2 NO_x Control. The variety of flue gas treatment NO_x control technologies is nearly as great as combustion-based technologies. Although these technologies differ greatly in cost, complexity, and effectiveness, they all involve the same basic chemical reaction:

(2-5) $NH_3 + NO_x \leftrightarrow N_2 + H_2O$

In selective catalytic reduction (SCR), the reaction takes place in the presence of a catalyst, improving performance. Non-catalytic systems rely on a direct reaction, usually at higher temperatures, to remove NO_x. Although removal efficiencies are lower, non-catalytic systems are typically less complex and often significantly less costly. Table 2-6 presents various catalytic and non-catalytic technologies.[56]

2.4.3.3 SO_2 Control. Commercialized post combustion flue gas desulfurization (FGD) uses an alkaline reagent to absorb SO_2 in the flue gas to produce sodium or calcium sulfate or sodium or calcium sulfite compounds. 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 are nonregenerable, in which all waste streams are de-watered and discarded. Table 2-7 summarizes commercially available post-combustion SO_2 control technologies.

Wet regenerable FGD processes are attractive because they have the potential for greater than 95 percent sulfur removal efficiency, have minimal waste-water discharges, and produce saleable sulfur product.[57] 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 scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables.

The lime and limestone scrubbing process uses a slurry of calcium oxide (CaO) or limestone ($CaCO_3$) to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods have been demonstrated.[58] The process produces a calcium sulfite and calcium sulfate mixture.

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) to absorb SO_2 from the flue gas. Sodium scrubbers are generally applied to smaller sources because of high reagent costs, however these systems have been installed on industrial boilers up to 125 MW (430 million Btu/hr) thermal input.[1] Demonstrated SO_2 removal efficiencies of up to 96.2 percent have been demonstrated.[58] Because the SO_2 removal efficiency can vary during load swings and process upsets, a long term mean efficiency of at least 91 percent is necessary to comply with the 90 percent NSPS reduction requirement based on a 30-day rolling average. The operation of the scrubber is characterized by a low liquid-to-gas ratio [1.3 to 3.4 l/m^3 (10 to 25 gal/ft^3)] and a sodium alkali sorbent which has a high reactivity relative to lime or limestone sorbents. The scrubbing liquid is a solution rather than a slurry because of the high solubility of sodium salts.

The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. Most of the effluent from the sodium scrubber is recycled back to the scrubber, but a slipstream is withdrawn and reacts with lime or limestone in a regeneration reactor. Performance data indicate average SO_2 removal efficiencies of 90 to 96 percent.[1] However, initial reports of long-term operating histories with dual alkali scrubbing have indicated SO_2 control system reliability averages of only slightly higher than 90 percent.[59]

TABLE 2-1. U.S. OIL CONSUMPTION BY SECTOR IN 1990[a]

Sector	Oil consumption, 10^{12} kJ (10^{12} Btu)		
	Residual	Distillate[b]	Sum of Residual and Distillate
Utility	1201.6 (1139.4)	91.0 (86.3)	1292.6 (1225.7)
Industrial	437.1 (414.5)	1245.4 (1180.9)	1682.5 (1595.4)
Commercial	255.6 (242.4)	513.6 (487.0)	769.2 (729.4)
Residential	0.0 (0.0)	883.1 (837.4)	883.1 (837.4)
Total for all Sectors	1894.4 (1796.3)	2733.1 (2591.6)	4627.5 (4387.9)

[a]Reference 1

[b]For the utility sector this value includes distillate oil (No. 2), kerosene, and jet fuel. For the other three sectors it includes distillate oil only.

TABLE 2-2. BOILER USAGE BY SECTOR

Sector	Capacity, MW (MMBtu/hr)	Boiler type	Application
Utility	> 29 (>100)	Watertube	Electricity generation
Industrial	0.29 - 29 (10 - 100)	Watertube	Electricity generation
		Watertube	Process steam
		Watertube	Space heat
		Firetube	Process steam
		Firetube	Space heat
Commercial	0.1 - 2.9 (0.5 - 10)	Watertube	Space heat
		Firetube	Space heat
		Cast iron	Space heat
Residential	<0.1 (< 0.5)	Cast iron	Space heat

TABLE 2-3. TOTAL U.S. ANTHROPOGENIC EMISSIONS BY CATEGORY FOR SO_2, NO_x, AND TSP IN 1989[33]

Oil type	Sector	Emissions inventory, MT (tons)		
		SO_2	NO_x	TSP
Distillate	Residential	116 (128)	68 (75)	9 (10)
	Commercial/ Institutional	83 (91)	50 (55)	5 (5)
	Industrial	92 (101)	79 (87)	7 (8)
	Electric Generation	15 (17)	18 (20)	0.9 (1)
Residual	Residential	0.9 (1)	0 (0)	0 (0)
	Commercial/ Institutional	132 (146)	43 (47)	14 (15)
	Industrial	582 (641)	169 (186)	48 (53)
	Electric Generation	538 (593)	153 (169)	26 (29)

TABLE 2-5. COMBUSTION MODIFICATION NO_x CONTROLS EVALUATED FOR OIL-FIRED BOILERS

Control technique	Description of technique	No. of boilers	Effectiveness of control (% NO_x reduction)		Range of application	Commercial availability/ R&D status	Comments
			Residual oil	Distillate oil			
Low Excess Air (LEA)	Reduction of combustion air	22 residual oil boilers, 7 distillate oil boilers	0 to 28	0 to 24	Generally excess O_2 can be reduced to 2.5 % representing a 3 % drop from baseline	Available	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	3 residual oil boilers, 1 distillate oil boiler	20 to 50	17 to 44	70-90 % burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on package 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 firing fuel rich.	8 boilers	10 to 30	N/A	Applicable only for boilers with minimum of 4 burners. Best suited for square burner pattern with top burner or burners out of service. Only for retrofit application.	Available. Retrofit requires careful selection of BOOS pattern and control of air flow.	Retrofit often requires boiler de-rating unless fuel delivery system is modified.
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	1 distillate oil boiler, 2 residual oil boilers	15 to 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on all design types.	Available. Requires extensive modifications to the burner and windbox.	Best suited for new units. Costly to retrofit. Possible flame instability at high FGR rates.

TABLE 2-5. COMBUSTION MODIFICATION NO_x CONTROLS EVALUATED FOR OIL-FIRED BOILERS

Control technique	Description of technique	No. of boilers	Effectiveness of control (% NO_x reduction)		Range of application	Commercial availability/ R&D status	Comments
			Residual oil	Distillate oil			
Flue Gas Recirculation Plus Staged Combustion	Combined techniques of FGR and staged combustion	Only one packaged watertube boiler	25 to 53	73 to 77	Max. FGR rates set at 25% for distillate oil and 20% for residual oil	Combined techniques are still at experimental stage. Needs more R&D.	Retrofit may not be feasible. Best implemented on new units.
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	17 residual oil-fired boilers, 7 distillate oil-fired boilers	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 now as a retrofit application. Better implemented with improved firebox design.	Technique not effective when it necessitates an increase in excess O_2 levels. LR possibly implemented in new designs as reduced combustion intensity (enlarged furnace plan area).
Low NO_x Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	Large number tested in Japan	20 to 50	20 to 50	New burners described generally applicable to all boilers. More specific information needed.	Commercially offered but not demonstrated	Specific emissions data from industrial boilers equipped with LNB are lacking

TABLE 2-5. COMBUSTION MODIFICATION NO_x CONTROLS EVALUATED FOR OIL-FIRED BOILERS

Control technique	Description of technique	No. of boilers	Effectiveness of control (% NO_x reduction)		Range of application	Commercial availability/ R&D status	Comments
			Residual oil	Distillate oil			
Ammonia/ urea Injection	Injection of urea or NH_3 as a reducing agent in the flue gas	5 (4 Japanese installations, 1 domestic)	40 to 70	40 to 70	Applicable for large package and field-erected watertube boilers. May not be feasible for fire-tube boilers.	Commercially offered but not demonstrated	Elaborate NH_3 injection, monitoring and control system required. Possible load restrictions on boiler and air preheater fouling when burning high sulfur oil.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	2 residual oil-fired boilers	5 to 16	N/A	Combustion air temperature can be reduced to ambient conditions (340K)	Available. Not implemented because of significant loss in thermal efficiency.	Application of this technique on new boilers requires installation of alternate heat recovery system (e.g., an economizer)

TABLE 2-6. POST COMBUSTION NO_x REDUCTION TECHNOLOGIES[56]

Technique	Description	Advantages	Disadvantages
1. Urea Injection	Injection of urea into furnace to react with NO_x to form N_2 and water.	- Low capital cost - Relatively simple system - Moderate NO_x removal (30-60%) - Non-toxic chemical - Typically, low energy injection is sufficient	- Temperature dependent - Design must consider boiler operating conditions and configuration - Reduction may decline at lower loads
2. Ammonia Injection (Thermal-DeNO_x)	Injection of ammonia into furnace to react with NO_x to form N_2 and water.	- Low operating cost - Moderate NO_x removal (30-60%)	- Moderately high capital costs - Ammonia handling, storage, vaporization, and injection systems required - Ammonia is a toxic chemical
3. Air Heater SCR (AH-SCR)	Air heater baskets replaced with catalyst-coated baskets. Catalyst promotes reaction of ammonia with NO_x.	- Moderate NO_x removal (40-65%) - Moderate capital cost - No additional ductwork or reactor required - Low pressure drop - Can use urea or ammonia - Rotating air heater assists mixing and contact with catalyst	- Design must address pressure drop, maintain heat transfer - Due to rotation of air heater, only 50% of catalyst is active at any time
4. Duct SCR	A smaller version of conventional SCR is placed in existing ductwork.	- Moderate capital cost - Moderate NO_x removal (30%) - No additional ductwork required	- Duct location unit specific - Some pressure drop must be accommodated
5. Activated Carbon SCR	Activated carbon catalyst, installed downstream of air heater, promotes reaction of ammonia with NO_x at low temperature.	- Active at low temperature - High surface area reduces reactor size - Low cost of catalyst - Can use urea or ammonia - Activated carbon is a non-hazardous material - SO_x removal as well as NO_x removal	- High pressure drop - Not a fully commercial technology
6. Conventional SCR	Catalyst located in flue gas stream (usually upstream of air heater) promotes reaction of ammonia with NO_x.	- High NO_x removal (90%)	- Very high capital cost - High operating cost - Extensive ductwork to/from reactor - Large volume reactor - Increased pressure drop may require ID fan or larger FD fan - Reduced efficiency - Ammonia sulfate removal equipment for air heater - Water treatment of air heater wash

TABLE 2-7. COMMERCIAL POST-COMBUSTION SO_2 CONTROLS FOR COAL COMBUSTION SOURCES

Control technology	Process	Available control efficiencies	Remarks
Wet Scrubber	Lime/Limestone	80 - 95+%	Applicable to high sulfur fuel, 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.

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3. GENERAL EMISSION DATA REVIEW AND ANALYSIS PROCEDURES

3.1 CRITERIA POLLUTANTS

3.1.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of criteria and non-criteria pollutant emission data associated with fuel oil-fired boilers. This search included a broad range of relevant EPA reports as well as the archive files from prior AP-42 revisions, and numerous additional reports and contacts with testing groups, regulatory agencies, and trade groups. On-line computerized databases were also accessed to gather information on sources of emissions data. The details of the literature search are summarized in Table 3-1.

3.1.2 Literature Evaluation

A large number of references were identified and compiled through the literature search. Subsequently, each item in this large body of literature was screened for data on criteria pollutant emissions and/or information on control technology pertaining to NO_x, SO_2, and PM emissions. Checklists were developed to document this scanning procedure. These checklists can be found in the background files for this update to AP-42. Thereafter, references with data on criteria pollutants were subjected to a rigorous data evaluation to determine if they contained candidate data for use in developing uncontrolled emission factors. References relating only to control technology information were used in characterizing control efficiencies and, as such, were not subjected to any data evaluation procedure.

The following general criteria were used in evaluating literature with criteria pollutant data:

1. Emissions data must be from a well-documented reference; and

2. The report must contain sufficient data to evaluate the testing procedures and source operating conditions.

These criteria were used in a thorough review of the reports, documents, and information to produce a final set of reference materials. The data contained in this final set of references were then subjected to a thorough quality and quantity evaluation to determine their suitability for use for developing emission factors. Checklists were employed to facilitate and document this evaluation. The completed checklists were placed in the background files for this update to AP-42.

Data with the following characteristics were always excluded from further consideration:

1. Test series averages reported in units that cannot be converted to the selected reporting units;

2. Test series representing incompatible test methods (e.g., comparison of EPA Method 5 front-half with EPA Method 5 front- and back-half);

3. Test series of controlled emissions for which the control device was not specified;

4. Test series in which the source process was not clearly identified and described; and

5. Test series in which it is not clear whether the emissions were measured before or after the control device.

Data sets that were not excluded were assigned a quality rating. The rating system used was that specified in "Technical Procedures for Developing AP-42 Emission Factors and Preparing AP-42 Sections".[8] The data were rated as follows:

A - Multiple tests performed on the same source using sound methodology and reported in enough detail for adequate validation. These tests are not necessarily EPA reference method tests, although such reference methods are preferred and are certainly to be used as a guide.

B - Tests that were performed by a generally sound methodology but lacked enough detail for adequate validation.

C - Tests that were based on an untested or new methodology or that lacked a significant amount of background data.

D - Tests that were based on a generally unacceptable method but may provide an order-of-magnitude value for the source.

The following criteria were used to evaluate source test reports for sound methodology and adequate detail:

1. Source operation. The manner in which the source was operated is well documented in the report. The source was operating within typical parameters during the test.

2. Sampling procedures. The sampling procedures conformed to generally acceptable methodology. If actual procedures deviated from accepted methods, the deviations are well documented. When this occurred, an evaluation was made of the extent such alternative procedures could influence the test results.

3. Sampling and process data. Adequate sampling and process data are documented in the report. Many variations can occur unnoticed and without warning during testing. Such variations can induce wide deviations in sampling results. If a large spread between test results could not be explained by information contained in the test report, the data were considered suspect and were given a lower rating.

4. Analysis and calculations. The test reports contain original raw data sheets. The nomenclature and equations used were compared to those (if any) specified by EPA to establish equivalency. The depth of review of the calculations was dictated by the reviewer's confidence in the ability and conscientiousness of the tester, which in turn was based on factors such as consistency of results and completeness of other areas of the test report.

3.1.3 Emission Factor Quality Rating

In each AP-42 section, tables of emission factors are presented for each pollutant emitted from each of the emission points associated with the source. The reliability or quality of each of these emission factors is indicated in the tables by an overall Emission Factor Quality Rating ranging from A (excellent) to E (poor). These ratings incorporate the results of the above quality and quantity evaluations on the data

sets used to calculate the final emission factors. The overall Emission Factor Quality Ratings are described as follows:

A--Excellent: Developed only from A-rated test data taken from many randomly chosen facilities in the industry population. The source category is specific enough so that variability within the source category population may be minimized.

B--Above average: Developed only from A-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industries. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.

C--Average: Developed only from A- and B-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.

D--Below average: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Any limitations on the use of the emission factor are footnoted in the emissions factor table.

E--Poor: The emission factor was developed from C- and D-rated test data, and there is reason to suspect that the facilities tested do not represent a random sample of the industry.. There also may be evidence of variability within the source category population. Any limitations on the use of these factors are always clearly noted.

The use of these criteria is somewhat subjective and depends to an extent on the individual reviewer. Details of the rating of each candidate emission factor are provided in Chapter 4 of this report.

3.2 SPECIATED VOCs

3.2.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of speciated VOC emissions data associated with fuel oil-fired boilers. Some

specific areas of search include Tennessee Valley Authority, Electric Power Research Institute (EPRI)/PISCES, EPA/Air and Waste Management (A&WMA) Air Toxic Symposiums, and Toxic Air Pollutants: State and Local Regulatory Strategies 1989.

3.2.2 Literature Evaluation

Until recently, little concern existed for VOC speciation on stationary external combustion sources. Therefore, available data for VOC speciation were very sparse and inadequate, limiting this data evaluation to EPA's Office of Air Quality Planning and Standards (OAQPS) databases: the VOC/PM Speciation Data System (SPECIATE) and the Crosswalk Air Toxic Emission Factor Database (XATEF), and their references.

3.2.3 Data and Emission Factor Quality Rating

The ratings of emission factors in SPECIATE and XATEF should not be used without first reviewing primary sources of numerical data against the criteria presented in Chapter 3.1. The quality of the data is insufficient to satisfy the requirements for assignment of an emission factor; therefore, the data is unratable or, at best, E-rated.

3.3 AIR TOXICS

3.3.1 Literature Search

A separate literature search was conducted for hazardous air pollutants (HAPs) since this category was not included in prior AP-42 revisions. The HAPs data base is expanding rapidly as a result of recent regulations. The prior data base is very sparse and largely based on obsolete protocols. Many of the data identified and evaluated were not of suitable quality for developing emission factors and were, therefore, elirninated for use in this update following the criteria outlined in Section 3.1.

A literature search was conducted using the Dialog Information Retrieval Service. This is a broad-based data retrieval system that has access to over 400 data bases. Specifically for the air toxics search, six data bases were queried by key words relating to the processes and chemicals of concern. The data bases accessed were: National Technical Information Service (NTIS), COMPENDEX PLUS, POLLUTION ABSTRACT, CONFERENCE PAPERS, ENERGY SCIENCE & TECHNOLOGY, and EPRI. The list of literature generated from the search was evaluated for applicability and the relevant documents were obtained.

Searches of the EPA's air toxics data bases were also performed. These data bases include the XATEF and the SPECIATE databases, and the Air Clearing House for Inventory and Emission Factors (CHIEF) CD ROM which contains additional data in conjunction with XATEF and SPECIATE. The computer searches were performed by source classification code (SCC) for all boiler sizes and types that combust oil. The reference numbers were recorded for each of the "hits" and these references were obtained for review.

Various air pollution control districts (APCDs) located in California were contacted to obtain air toxics data collected under the California Assembly Bill 2588, the Air Toxics "Hot Spots" Information and Assessment Act of 1987. This bill requires reporting of emissions of a specified list of air toxic compounds. The following APCDs were contacted by phone and with a written information request: Bay Area, South Coast, Fresno County, North Coast Unified, Sacramento Metropolitan, San Joaquin County, Ventura County, Calaveras County, Lake County, Lassen County, Santa Barbara, San Diego, Kern County, and the California Air Resources Board.

Several industry and non-agency sources were also contacted in order to obtain source test data for development of emission factors. These include the Western States Petroleum Association (WSPA), the Canadian Electrical Association (CEA), and the Ontario Ministry of the Environment.

3.3.2 Literature Evaluation

The references obtained from the literature search were evaluated for their applicability for generating emission factors. Table 3-2 summarizes the data sources and indicates which sources were used in generating the emission factors. The table contains a reference number which corresponds to the list of references provided at the end of this section. The references are evaluated and discussed in greater detail in Section 4.3.1. The criteria used to perform this evaluation are discussed in detail in Section 3.3.3.

3.3.3 Data and Emission Factor Quality Rating Criteria

Emissions data used to calculate emission factors were obtained from many sources, such as published technical papers and reports, documented emissions test results, and regulatory agencies (such as local APCDs). The quality of these data must

be evaluated in order to determine how well the calculated emission factors represent the emissions of an entire source category. Data sources may vary from single source test runs to ranges of minimum and maximum values for a particular source. Some data must be eliminated all together due to their format or lack of documentation. Factors such as the precision and accuracy of the sampling and analytical methods and the operating and design specifications of the unit being tested are key in the evaluation of data viability. The key factors for data evaluation and rating were essentially the same as detailed for criteria pollutants in Section 3.1.

The first step in evaluating a data report was to determine whether the source is a primary or secondary source. A primary source is that which reports the actual source test results while a secondary source is one that references a data report. Many of the sources referenced by XATEF, SPECIATE, and the CD ROM are secondary, tertiary, etc. sources. Preferably, only primary sources are used in the development of emission factors.

The primary source reports are evaluated to determine if sufficient information is included on the device of interest and on any abatement equipment associated with the device. General design parameters such as boiler size, firing configuration, atypical design parameters, fuel type, operating parameters during the test, (e.g., load), are all required in order to evaluate the quality of the data. Data on the type and number of samples, sampling and analytical methods used, sampling locations, quality control samples and procedures, modifications to methods, fuel composition and feed rates, etc. are also needed. Sufficient documentation to determine how the data were reduced and how emissions estimates were made are required. This documentation should include sample calculations, assumptions, correction factors, etc. Equivalent information for the emission control device(s) must also be included.

When primary data could not be obtained in the time frame of this initial update, secondary sources were evaluated to determine the representativeness of the emission factors to a source category. A judgement of the quality of the primary data analysis was made in this case, which automatically warrants a lower quality rating for the emission factor. The secondary sources can potentially provide at least an order of magnitude estimate of emissions.

3.4 N_2O

3.4.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of N_2O emissions data associated with fuel oil-fired boilers. Some specific resources searched included the European N_2O Workshop, EPA/Air and Energy Engineering Research Laboratory, AWMA, and the journals Combustion and Flame and Journal of Geophysical Research.

3.4.2 Literature Evaluation

The literature evaluation criteria were lowered for N_2O to allow the inclusion of sufficient data to calculate emission factors. Data were evaluated even if they failed one or more questions on the test report exclusion criteria checklist described in Section 3.1.2. This treatment was necessitated by the sparseness of the data base resulting from the development of a protocol only since 1988.

3.4.3 Data and Emission Factor Quality Rating

Data obtained through the literature search, except that derived from on-line N_2O analysis with gas chromatography/electron capture detection (GC/ECD), were rated C or poorer because the data were based on untested or new methodology that lacked sufficient background data. A problem has been identified with previous grab sampling techniques to measure N_2O emissions from fuel oil combustion. Storing combustion products in grab samples containing SO_2, NO_x, and water for periods as short as one hour can lead to the formation of several hundred parts per million of N_2O where none originally existed. Some improved methodologies for N_2O sampling and analysis and their relative effects on data quality ratings are as follows:

1. On-line N_2O analysis with GC/ECD (the preferred method);
2. Grab samples;
    a. Removing H_2O: drying the sample reduces the most important reactant, but may not entirely eliminate N_2O formation;

b. Removing SO_2: scrubbing the sample through NaOH solution;

c. A combination of a and b above (the second method preference).

The N_2O emission data for residual oil-fired utility boilers came from full-scale facilities and were rated B quality. The data obtained for distillate oil-fired boilers came from two small pilot-scale systems and were assigned a B quality rating. These data were obtained with on-line GC/ECD N_2O analysis. The emission factors for residual and distillate oil were assigned a D rating, because the data were taken from small pilot scale systems or because the test data were from a small number of facilities and do not represent a cross-section of the industry.

3.5 FUGITIVE EMISSIONS

Fugitive emissions have not historically been covered in Chapter 1 of AP-42. Chapter 4 of AP-42 contains emission factors for evaporative losses from petroleum storage facilities and will continue to be the source of such data. Fugitive particulate emissions are very low from oil-fired boilers and only result from ash liberated during maintenance activities. These ash deposits are usually removed during a boiler wash (in which most of the deposits are removed in a liquid stream). Therefore, fugitive particulate emissions from these facilities are minimal. Particulate matter fugitive emission factors from these operations can be developed using the procedures in AP-42 Chapter 11.

A literature search was conducted to quantify fugitive emissions from leaking seals and fittings that would be present in the fuel feed system for oil-fired boilers. These sources include valves, pumps, flanges, sampling connections, and open-end lines. The literature evaluation verified the conclusions of previous attempts at determining emission factors for VOCs in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). During the establishment of proposed standards for fugitive VOC emissions from SOCMI, EPA determined that (1) the only quality emission factor data were generated during a study of 13 petroleum refineries for EPA and (2)

the best data for percent leaking of each equipment type resulted from an EPA study of leak frequency in the SOCMI.

Data from the primary reference above were subjectively rated B quality per the general guidelines previously described. Because of the complexity of calculating new emission factors for fugitive emissions, the remainder of the references were not used.

3.6 PARTICLE SIZE DISTRIBUTION

3.6.1 Literature Search[8]

The literature search emphasized filling the perceived gaps in the previous updates. Future updates to AP-42 are expected to report PM-10 emissions as the sum of the in-stack filterable particulate and the organic and inorganic condensible particulate matter (CPM). Upon review of the previous AP-42 update of particulate sizing emission data, the largest gap appeared to be the lack of CPM data.

The background files for the previous AP-42 update were reviewed. A Dialog Information Retreival System search was conducted, focussing on reports since 1980. Based on the results of the Dialog search, NTIS documents, EPA reports, and conference proceedings were ordered and journal articles were collected. Conference symposia that were searched included the Eighth and Ninth Particulate Control Symposia and the AWMA annual conferences for 1988 through 1991.

The following PM-10 "gap filling" documents were examined:

- "PM-10 Emission Factor Listing Developed by Technology Transfer" (EPA-450/4-89-022): The factors applicable to sections 1.1, 1.3, and 1.7 all came from AP-42. The factor for a bituminous coal commercial facility assumes that 52% of particulate is < 10 um.

- "Gap Filling PM-10 Emission Factors for Selected Open Area Dust Sources" (EPA-450/88-003): Not applicable to stationary source combustion.

- "Generalized Particle Size Distributions for Use in Preparing Size Specific Particulate Emission Inventories" (EPA-450/4-86-013): Lists the average collection efficiencies of various particulate control devices for different size fractions. This was the source of the overall collection efficiency estimates for the 1986 PM-10 update of AP-42 Chapter 1.

The following regional EPA offices and State and regional air pollution control boards were contacted:

- EPA Region 2
- EPA Region 3
- EPA Region 4
- EPA Region 5
- California Air Resources Board: Stationary Sources Division, Monitoring and Laboratory Division, and the Compliance Division
- Illinois Air Pollution Control
- New York Air Pollution Control
- New Jersey Air Pollution Control
- Bay Area Air Quality Management District (CA)
- Kern County Air Pollution Control District (CA)
- Stanislaus County Air Pollution Control District (CA)
- San Joaquin County Air Pollution Control District (CA)

The primary source of the particulate size distribution data for the 1986 AP-42 update was the Fine Particulate Emissions Information System (FPEIS). The FPEIS has not been updated since the printouts obtained during the 1986 AP-42 update. The printouts used for the previous update were available in the background files.

The EPA/OAQPS Emissions Monitoring Branch was contacted for test data from method development studies for EPA Method 202.

Contacts were also made with EPRI, Wheelabrator Air Pollution Control, Southern Research Institute, and Entropy Environmentalists, Inc.

3.6.2 Literature Evaluation

The previous update was reviewed and evaluated. The size distribution data were evaluated by spot-checking the tabulated results against the original FPEIS

printouts. If, during the literature search, the original test report was obtained that corresponded to a particular FPEIS printout, the data were compared. The objective of the review was to ensure that the data collected in the 1986 update were ranked and used appropriately.

The 1986 update was also evaluated with respect to the development of emission factors from the particle size distribution data.

The original FPEIS printouts were also examined. There were two objectives in the reevaluation of the FPEIS printouts:

(1) To ensure that only filterable particulate matter was included in the cumulative percent mass results; and

(2) To search for impinger results to provide CPM emission data.

New literature was evaluated based on the use of appropriate sampling methods and documentation of sufficient process information.

3.6.3 Data Quality Ranking

Data were reviewed and ranked according to the criteria described in Section 3.1 and the data evaluation criteria presented for the previous update. Data quality was assessed based on the particle sizing and/or PM-10 measurement method used and the availability of sampling and process data.

For particulate sizing and filterable PM-10 data, the following criteria were used:

A - Particle sizing tests performed by cascade impactors or PM-10 measurements performed via Method 201 or 201A. The test information must provide enough detail for adequate validation and the isokinetics must fall between 90 and 110 percent.

B - Particle sizing tests performed via SASS trains if the sampling flow rate isokinetic value was reported and sufficient operating data was used. Cascade impactor data or Method 201 or 201A data if isokinetics not reported or if isokinetics not within the 90 to 110 percent range.

C - SASS train data if the isokinetics were not reported or if the isokinetics did not fall within the 90 to 110 percent range.

D - Test results based on a generally unaccepted particulate sizing method, such as polarized light microscopy.

Although cascade impactors are generally considered the best available method for measuring particulate size distributions, errors in segregating specific sizes of combustion particles arise from the following:

- Particle bounce and re-entrainment
- Diffusive deposition of fine particles
- Deposition of condensible/adsorbable gases
- Losses to the impactor walls

The effects of such errors are described in Reference 10.

The ranking of data for CPM was based primarily on the methodology employed in the testing. Most CPM source tests have been conducted using the back-half of an EPA Method 5, EPA Method 17 or South Coast Methods 5.2 or 5.3 trains. However, these test methods do not require an N_2 purge of the impingers. Without the N_2 purge, dissolved SO_2 remains in the impingers and is included in the inorganic CPM results. This type of CPM data is considered very low-quality.[9] In contrast, Method 202 includes a one-hour N_2 purge of the impingers immediately after sampling to remove dissolved SO_2. Therefore, Method 202 CPM data should be ranked higher than Method 5 or Method 17 CPM data, even though Method 202 is a relatively new method. The following rankings were selected for CPM data:

A - CPM tests performed via Method 202. The test information must provide enough detail for adequate validation and the isokinetics must fall between 90 and 110 percent.

B - CPM tests performed via Method 202 but isokinetics not reported or isokinetics not within the 90 to 110 percent range. CPM tests performed via Method 5 or Method 17 or another acceptable EPA Method that does not include an impinger N_2 purge, if the isokinetics were within the 90 to 110 percent range.

C - CPM tests performed via Method 5 or Method 17 or another acceptable EPA method that does not include an impinger N_2 purge, if the isokinetics were not reported or not within the 90 to 110 percent range.

D - Test results based on a generally unaccepted CPM method.

TABLE 3-1. LITERATURE SEARCH/CONSULTATION RECORD

Literature type	New baseline data	NO_x control information	Particulate control information	SO_x control information
(A) "Minimum" list given in the task order				
1. AP-42 files	✓	✓	✓	✓
2. ESD Files/NSPS Background Information Documents	✓	✓	✓	✓
3. CTC publications	none	✓	none	none
4. ORD reports	✓	✓	✓	✓
5. NTIS	✓	✓	✓	✓
(B) Other sources				
1. EPRI	none	✓	none	none
2. Contractor in-house documents	✓	✓	✓	✓
3. American Petroleum Institute	✓	none	none	none

TABLE 3-2. EVALUATION OF REFERENCES

Reference	Evaluation	Parameter of Interest
1	Not a primary reference; however, data quality is sufficient to determine emission estimates.	POM
2	Emission factors presented are of sufficient quality.	Metals
3	Not a primary reference, however, data of sufficient quality.	Cr
4	Not a primary reference, however, data of sufficient quality.	HCOH
5	Not a primary reference; however, data are of sufficient quality.	Metals, POM, HCOH
6	Not a primary reference; however, some data presented of sufficient quality.	Metals
7	Not a primary reference; however, data of sufficient quality.	Mn

CHAPTER 3 REFERENCES

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2. Leavitt, C., K. Arledge, C. Shih, R. Orsini, W. Hamersma, R. Maddalone, R. Beimer, G. Richard, M. Yamada, Environmental Assessment of Coal- and Oil-Firing in a Controlled Industrial Boiler; Volume I, II, III. Comprehensive Assessment and Appendices, EPA-600/7-78-164abc, U.S. Environmental Protection Agency, Research Triangle Park, NC, August 1978.

3. Locating and Estimating Air Emissions from Sources of Chromium, EPA-450/4-84-007g, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1984.

4. Locating and Estimating Air Emissions From Sources of Formaldehyde (Revised), EPA-450/4-91-012, Emission Inventory Branch Technical Support Division, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1991.

5. Estimating Air Toxic Emissions from Coal and Oil Combustion Sources, EPA-450/2-89-001, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1989.

6. Surprenant, N.F., et. al., Emissions Assessment of conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources, EPA-600/7-81-003c, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1981.

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8. Technical Procedures for Developing AP-42 Emission Factors and Preparing AP-42 Sections, Draft Report, U.S. Environmental Protection Agency, Research Triangle Park, NC, March 1992.

9. Private communication with Ron Meyers, U.S. Environmental Protection Agency, March 24, 1992.

10. Ondov, John M., "Cascade Impactors in the Chemical and Physical Characterization of Coal-Combustion Aerosol Particles", Chapter 25 of Fossil Fuels Utilization: Environmental Concerns, 1986.

4. EMISSION FACTOR DEVELOPMENT

This chapter describes the test data and methodology used to develop pollutant emission factors for the fuel oil combustion category.

4.1 CRITERIA POLLUTANTS

4.1.1 Review of Previous AP-42 Data

A review of the 1986 version of Section 1.3 was conducted by spot checking the quality of existing emission factors. This was done by selecting primary data references from the section Background File and recalculating emission factors. The results of these spot checks are summarized in Table 4-1.

In almost all cases, the results of spot checks indicated that existing emission factors were accurate. Spot checks also revealed that, in general, ample A-rated data were available for the criteria pollutants. However, the SO_3 emission factor in the 1986 Section 1.3 was found to be incorrect and was changed as described in Section 4.1.3.

4.1.2 Review of New Baseline Data

A total of 60 references were documented and reviewed during the literature search. These references are listed in the checklists added to the Background File for this update to AP-42. The original group of 60 documents was reduced to a set of rated references utilizing the criteria outlined in Chapter 3. The following is a discussion of the data contained in each of the rated references.

References 1-3

These references document the multi-media emission tests conducted on Boiler No. 4 of the Firestone Tire and Rubber Co. plant located in Pottstown, Pennsylvania. Flue gas sampling was conducted before and after a pilot flue gas desulfurization unit to establish which pollutants were removed, modified, or produced by the control device. In these tests, continuous monitors were used to measure CO, NO_x, SO_2, and total hydrocarbons (THC) while a Source Assessment Sampling System (SASS) was used to collect gaseous and particulate samples. Adequate source descriptions were

provided in the reports. A rating of A was assigned to criteria pollutant data in these reports.

References 4-5

These reports describe tests performed on two industrial watertube boilers to characterize the effects of combustion modifications and operating variable changes on thermal efficiency and pollutant emissions. In these tests, gaseous emissions were measured by standard gas analyzer methods while EPA Method 5 was used to measure PM emissions. Adequate source descriptions were provided in the reports. A rating of A was assigned to criteria pollutant data in these reports.

Reference 6

This report details results of a comprehensive emissions assessment performed on the Haynes No. 5 utility boiler in Long Beach, California. Adequate details on tests including source operation and sampling and analysis of pollutants are provided in the report. A rating of A was assigned to criteria pollutant data in this report. This report was cited as Reference 26 in the 1986 AP-42 Section 1.3 but data contained in it had not been used. Hence, these data have been included in current emission factor calculations.

Reference 7

This report describes results of tests conducted on a 26.4 MW residual oil-fired boiler using SC and LEA as the NO_x emission control technology. Tests were conducted to determine whether combustion modification techniques which demonstrated reductions in air pollutant emissions during short-term tests are feasible for longer periods. Adequate details on tests including source operation and sampling and analysis of pollutants are provided in the report. A rating of A was assigned to criteria pollutant data in this report. This report was cited as Reference 27 in the 1986 AP-42 Section 1.3 but data contained in it had not been used. Hence these data have been included in current emission factor calculations.

Reference 8

This report describes the results of tests conducted on Boiler No. 7 at the Boston Edison Company's Mystic River Station located at Everett, Massachusetts. The purpose of the sampling program was to determine the effect of raising the temperature of the filter and probe of an EPA Method 5 train from 120°C to 160°C and of baking the filter at 160°C on the amounts of particulate, sulfate, and sulfuric acid emissions. However, baseline data were obtained using EPA Method 5 procedures, including a filter termperature of 120°C. A data rating of A was assigned to PM emissions data.

Reference 9

This report describes the second phase of an investigation into ways to improve the air pollutant emission and thermal efficiency characteristics of residential oil furnaces. Detailed description of source operation and sampling methodology are provided in the report. The data were assigned a rating of A.

Reference 10

This report presents the results of a field testing effort to characterize particulate emissions from refinery combustion sources. The major objective of this program was to determine emission factors, size distribution, and chemical composition of particulates from refinery combustion sources. EPA Method 5 was used for PM emissions measurements. Adequate details on source operation are provided in this report. The data were assigned a rating of A.

Reference 11

This symposium paper describes a series of tests conducted on a 100 horsepower (HP) firetube boiler. In these tests, shale oil and two types of residual oil - No. 6 oil and a coal-oil mixture were fired. The paper does not provide enough details on emission measurement methodology and, hence, data in this paper are rated B.

Reference 12

This report provides an overview of the regulatory baseline, technical basis, and alternative control levels available for developing NSPS for SO_2 emissions from small steam generating units (i.e., boilers). The report includes data from various sources but does not provide details of source operation and emission sampling. Hence, the data in this report are rated B.

Reference 13

This report provides an overview of the emissions data and technical basis for NO_x NSPS for small boilers. The report includes data from various sources but does not provide details of source operation and emission sampling. Hence, the data in this report are rated B.

Reference 14

This report provides an overview of the regulatory baseline, technical basis, and alternative control levels available for developing NSPS limiting PM emissions from small steam generating units (i.e., boilers). The report includes data from various sources but does not provide details of source operation and emission sampling. Hence, the data in this report are rated B.

4.1.3 Compilation of Baseline Emission Factors

The references described above were used in updating the uncontrolled (baseline) emission factors for criteria pollutants. A computer spreadsheet was created to calculate emission factors from the data contained in the above references. The formulae and conversion factors used in this spreadsheet are shown in Appendix A. Relevant parts of this spreadsheet, pertaining to specific pollutants, are discussed in the corresponding sections below.

As previously mentioned, spot check results revealed that criteria pollutant emission factors are supported by ample A- rated data points. Hence, only new A-rated data points were used in the emission factor determinations described below.

PM Emission Factors

The PM emission factors for various sources are summarized in Table 4-2. As seen in this table, the following new data points have been added to the PM emission factors database:

- Utility boilers firing No. 6 oil: 5 points
- Industrial boilers firing No. 6 oil: 4 points
- Industrial boilers firing No. 2 oil: 1 point

No new data points were found for commercial boilers or residential furnaces. Also, no new data were found for No. 4 and No. 5 oil firing. Spot checks revealed that PM data from References 26 and 27 in the 1986 AP-42 Section 1.3 were not included in previous PM emission factor determinations. These data have been included in this effort.

For No. 6 oil-firing, PM emissions can be correlated with the percent sulfur content of the fuel (designated as S). This correlation, published in the 1986 AP-42 Section 1.3, has been updated in this effort. The steps involved in updating this correlation are detailed in Table 4-2. The proposed new correlation has a correlation coefficient, or r-value, of 0.96 as opposed to the previously published correlation with r-value of 0.65.

SO_2 Emission Factors

The SO_2 emission factors for various sources are summarized in Table 4-3. As seen in this table, the following new data points have been added to the SO_2 emission

factors database:

- Utility boilers firing No. 6 oil: 1 point
- Industrial boilers firing No. 6 oil: 3 points
- Industrial boilers firing No. 2 oil: 1 point

No new A-rated data points were found for commercial boilers or residential furnaces. Also, no new data could be found for No. 4 and No. 5 oil-firing. Spot checks revealed that SO_2 data from Reference 26 in the 1986 AP-42 Section 1.3 were not included in previous SO_2 emission factor determinations. These data have been included in this effort.

As discussed in Section 2.3.2, SO_2 emissions are almost entirely dependent on the sulfur content of the fuel. Hence, correlations between fuel sulfur content and SO_2 emission factors are derived in Table 4.1-3. These correlations are then compared with emission factors developed from measured emissions. Sulfur dioxide emission factor updates are based on such comparisons; results are shown in Table 4-3.

SO_3 Emission Factors

The SO_3 emission factors for various sources are summarized in Table 4-4. As seen in this table, the following new data points have been added to the SO_3 emission factors database:

- Industrial boilers firing No. 6 oil: 2 points
- Industrial boilers firing No. 2 oil: 1 point

No new A-rated data points were found for utility and commercial boilers or residential furnaces. Also, no new data could be found for No. 4 and No. 5 oil-firing.

For utility boilers firing No. 6 oil, the previous emission factor was based on information provided in Reference 25 as cited in the 1986 section. Spot checks revealed this emission factor to be incorrect. The development of a new emission factor is shown in Table 4-4. This table also contains new data for industrial boilers; new calculations have been made for the SO_3 emission factors for residual and distillate oil.[4-5]

Because of the limited amount of test data available, engineering estimates were considered based on published conversion factors of fuel sulfur to SO_3. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel. About 1

to 5 percent of the sulfur is oxidized to SO_3. The 1986 Section 1.3 used a factor of 2.86 percent for conversion of fuel sulfur to SO_3. This factor agrees well with the median value of the published range of 1 to 5 percent.

CO Emission Factors

The CO emission factors for various sources are summarized in Table 4.1-5. As seen in this table, the following new data points have been added to the CO emission factors database:

- Utility boilers firing No. 6 oil: 1 point
- Industrial boilers firing No. 6 oil: 3 points
- Industrial boilers firing No. 2 oil: 1 point
- Residential furnace firing No. 2 oil: 1 point

No new A-rated data points were found for commercial boilers. Also, no new data were found for No. 4 and No. 5 oil-firing. Spot checks revealed that CO data from Reference 26 in the 1986 AP-42 Section 1.3 were not included in previous CO emission factor determinations. These data have been included in this effort.

As per spot checks, CO emissions typically range between 0.1 to 120 kg/10^3 liters of oil (1 to 10 lb/10^3 gal oil). Based on this information, an emission factor of 0.6 kg/10^3 liters of oil (5 lb/10^3 gal) was adopted in 1986, along with a qualifying footnote about the sensitivity of CO emission to combustion conditions. This emission factor has been retained as explained in Table 4-5.

NO_x Emission Factors

The NO_x emission factors for various sources are summarized in Table 4.1-6. As seen in this table, the following new data points have been added to the NO_x emission factors database:

- Utility boilers firing No. 6 oil: 2 points
- Industrial boilers firing No. 6 oil: 4 points
- Industrial boilers firing No. 2 oil: 1 point
- Residential furnace firing No. 2 oil: 1 point

No new A-rated data points were found for commercial boilers. Also, no new data were found for No. 4 and No. 5 oil firing. Spot checks revealed that NO_x data from Reference 27 in the 1986 AP-42 Section 1.3 were not included in previous NO_x emission factor

determinations. These data have been included in this effort.

Results regarding NO_x emission factors are shown in Table 4-6. The correlation between the NO_x (as NO_2) emission factor and the fuel nitrogen content, for industrial/commercial boilers firing residual oil, was based on 36 points as indicated in the 1986 Emission Factor Documentation (EFD).[19] However, these points were not documented adequately in the previous. Hence, well-documented data points, given in Reference 15, were used to develop a new correlation and to compare this correlation with the 1986 correlation. This new correlation is based on least squares fitting of data. A comparison of means and standard deviations of error sets pertaining to the new correlation and the 1986 correlation indicates that the new correlation is more accurate in the data range covered. Hence, this new correlation has been adopted in place of the previously published one.

It is generally known that NO_x emissions depend on boiler heat release rate (HRR), where HRR is a function of boiler size and design.[16] Using data from Reference 15, efforts were made to correlate NO_x emissions with capacity and then with load-to-capacity ratio. However, these efforts did not meet with success as correlation coefficients were near 0 for the correlations developed. This is probably because the effects of boiler design and excess air could not be excluded from the data under consideration.

VOC Emission Factors

Only one data point providing a TOC emission factor was found in this update. This data point is shown in Table 4-7. As seen in spot checks, 1986 emission factors were based on multiple data points and, therefore, have been retained. The results of the emission factor development efforts, described above, are summarized in Tables 1.3-1 through 1.3-4 in Chapter 5.

4.1.4 Compilation of Controlled Emission Factors

A compilation of controlled emissions and control efficiencies, attained on application of some of the control technologies discussed in Section 2.4, is given in Tables 4-8 through 4-10.

4.2 SPECIATED VOCs

As discussed in Section 3.2, there were insufficient data to develop emission

factors for speciated VOC. Some isolated data were identified in the general air toxics literature search summarized in Section 4.3.

4.3 HAZARDOUS AIR POLLUTANTS

4.3.1 Review of New Data

The screening of identified HAP data sources discussed in Section 3.3 yielded a smaller data base which was evaluated in more detail. These data were subjected to the quality ranking criteria discussed in sections 3.1 and 3.3. The overall evaluation of the key references follows. In general, the data base is very sparse, with older data taken with questionable protocols, and generally insufficient sensitivity to the importance of equipment operation and control system operation on emission rates. The data that are available indicate a high degree of variability of HAP emission with fuel content, combustion conditions, and control system settings. To adequately characterize such variability will require a comprehensive testing data base, much more comprehensive than was developed for criteria species.

Reference 20

This article summarizes the emissions of certain trace metals and hazardous pollutants from oil combustion. The data presented are a summary of a literature review. Emission factors are presented in the units of mass emitted per heat unit combusted and are presented for boilers of different sizes and configurations. The emission factors are the same for all oil-fired boilers. The article references several primary references which were evaluated and determined to be of insufficient quality.

Reference 21

This document is a compilation of the available information on sources and emission of POM and is not a primary reference. The document cautions against the use of these data for development of an exact assessment of emissions from any particular facility; however, the data are useful for comparing with other sources to verify the validity of calculated emission factors. The data are based primarily on utility boiler test data.

Reference 22

The emission factors for oil combustion are of sufficient quality for one of the tests presented in the report.

Metals: Metals emission factors for an oil test were used.

Organics: It was stated in the report that the organics recovered were not combustion products but were components in the sample collection media and in the analytical laboratory.

POM: POM data were below the detection limit. Malfunctioning multicyclones would also impact the quality of these data.

Reference 23

The data quality and documentation in this report are of unacceptable quality to generate emission factors.

Metals: Level I sampling and analysis program which is semiquantiative (a factor of $\pm$ 3) data quality. A SASS train and spark source mass spectroscopy (SSMS) analyses were used. These data are not suited for calculation of enrichment factors or mass balances, as stated in the reference.

No analytical data are presented for fuels used for the testing nor for measured control efficiencies on the abatement devices.

The emission factors presented are calculated using average concentrations obtained from reference sources.

The raw emissions data (in units of $\mu g/m^3$) are never presented. Only pg/J units are presented for the results and there is no documentation on how these were calculated.

POM: The sampling and analytical methods are also of lower quality, e.g. SASS and GC/MS.

The documentation for the analytical results is not clear as to why only portions of the samples were analyzed; therefore, one cannot determine if the entire sample was accounted for.

Reference 24

The purpose of this document is to provide a preliminary emission assessment of conventional stationary combustion sources. The data presented deal with national averages or ranges based on the best available information. Emission factors in mass emitted per heat unit input are not provided.

Reference 25

The emission factors for oil combustion that were summarized in this document came from Reference 23. These data were eliminated from use in this update due to their poor quality.

Reference 26

This report summarizes a study that was performed to determine organic compounds emitted from stationary sources which contribute to the formation of smog in the atmosphere. The report provides a summary of organic concentrations from the exhaust from a utility boiler and provides data on families of organics but does not clearly indicate emissions of specific compounds.

Reference 27

This report summarizes testing performed on several sizes and types of boilers; however, only criteria pollutant testing was performed.

Reference 28

Measured and calculated emission factors for distillate and residual oil are presented in this document. The emission factors are rated with a low quality because the document is not a primary source and the quality of the data cannot be verified.

Reference 29

This document presents a summary of emission factors for different types of processes which emit formaldehyde. The emission factors are presented in mass per heat unit input. A factor is provided for residual and for distillate oil; however, the factors are based on one test only. The emission factor is, therefore, rated with a low rating.

Reference 30

This document provides a summary of the emissions factors for metals, POM, and formaldehyde for oil-fired boilers. The emission factors for metals were based on the contents of typical residual and distillate oil compositions with the assumption that all metals in the oil are emitted. The existing source test data are used to demonstrate that the metal emission factors are within reason. The emission factors for oil-fired boilers do not differentiate between residual and distillate oils nor by boiler configuration or size because the number of data points is not high enough to do so.
The document cautions that relatively limited data are available on toxic air pollutants resulting from these types of processes and that emissions data in the document should not be used to develop an exact assessment of emissions from any particular facility. Emission factors for the processes outlined in the document are summarized and provided for use in determining order of magnitude emissions. The emission factors are rated with a lower quality because this document is not a primary source of information and, therefore, data acquisition and manipulation could not be verified.

Reference 31

Source testing was performed on three utility boilers in southern California. Testing was performed for the following parameters: PAH with California Air Resources Board (CARB) Method 429; benzene, toluene, xylenes with CARB Method 410; formaldehyde, acetaldehyde, and acrolein with CARB Method 430; metals with CARB draft multiple metals. The QA/QC data, sampling points, number of test runs, etc. were reviewed by the South Coast Air Quality Management District (SCAQMD) for conformance with the applicable CARB test methods. These data were used by the SCAQMD to generate emission factors and are considered to be of sufficient quality for this update. It is not clear from the data, however, whether the samples were taken prior to or after the control device. Therefore, these data will not be used in this update until the request for clarification is received.

Reference 32

This report summarizes the results of the source testing of three distillate oil-fired boilers, and five residual oil-fired boilers. The samples were taken using a SASS train. The metals were analyzed using SSMS which is a semiquantitative method for determining metals. The report does present an average fuel analysis of metals for residual oil. These data are used in the presentation of emission factors for residual oil emissions.

Reference 33

This document presents emission factors for sources of chromium. A literature survey was used to compile emission estimates from residual oil-fired boilers. The emission factor for utility boilers is used for generating the emission factor.

Reference 52

This article focused on mechanisms which control the emissions of trace metals from waste combustion systems. A model was developed based on phenomena including particle entrainment, chemical interactions, vaporization, condensation, particle coagulation, and particle collection by gas cleaning system. The model was tested against the results from metals spiking in a pilot scale rotary kiln incinerator. The emissions data collected were not considered to be applicable for development of trace metal emission factors for oil-fired boilers.

Reference 53

In this article thermodynamic methods were used to calculate the volatility of chromium in the offgas for a decontamination and waste treatment facility incinerator and molten

salt processor. The results were not considered to be applicable for development of trace metal emission factors for oil-fired boilers.

4.3.2 Baseline Emission Factors

Emission factors for metals, or trace elements, are quite often presented in the units of mass emitted per unit thermal heat input and are not specific to a particular boiler configuration. Ideally, emission factors for metals should be developed as a function of the boiler firing configuration, boiler size, trace element content in the fuel, fuel heating value, enrichment factor, and the collection efficiency of the control device.

The concepts of partitioning and enrichment are often used to characterize the behavior of trace metals in the combustion process. These concepts are used to describe the distribution of trace elements among the boiler outlet streams and particle sizes. Outlet streams for oil-firing include soot deposits, and particulate or vapor in the flue gas. Enrichment refers to the preferential concentration of trace metals in a specific particle size fraction or outlet stream. The process of enrichment is usually facilitated by the action of a control device.

The physical and chemical properties of a trace metal govern how that metal will distribute in the outlet streams. For example, mercury is a highly volatile metal and, therefore, the majority of the mass of mercury in the fuel oil tends to be emitted from the boiler in the flue gas and not deposited as bottom ash or convective section deposits.

A method for describing partitioning behavior is to report the fraction of the total elemental mass input that has left the boiler in an outlet stream. Another method for quantifying the distribution of a metal is to calculate an enrichment factor by comparing the trace element concentration of an outlet stream to the trace element concentration in the inlet fuel stream. The enrichment ratio calculation that is outlined in Reference 1 is performed using the following equation:

$$ER_{ij} = (C_{ij}/C_{Rj})/(C_{ic}/C_{Rc})$$

where:

ER_{ij} = enrichment ratio for element i in stream j

C_{ij} = concentration of element i in stream j

C_{Rj} = concentration of reference element R in stream j

C_{ic} = concentration of element i in fuel

C_{Rc} = concentration of reference element R in fuel

Enrichment ratios greater than 1 indicate that an element is enriched in a given stream, (e.g. stream j), or that it partitions to a given stream. A reference element is used because its partitioning and enrichment behavior is often comparable to that for the total mass. In other words, the reference element partitions with consistent concentrations in all streams and normalizes the calculation. Typical reference elements are aluminum (Al), iron (Fe), scandium (Sc), and titanium (Ti). The enrichment behavior of elements is somewhat consistent in different types of boilers and can be explained by a volatilization-condensation or adsorption mechanism. A summary of the enrichment behavior for the HAPs metals and the reference metals is presented in Table 4-11.

Insufficient data were available to develop enrichment ratios for different sizes and configurations of oil-fired boilers. As stated in Reference 33, it is reasonable to estimate metals emissions based on the assumption that the entire metal content in the fuel is emitted. This approach results in an emission factor that is theoretically the maximum for the fuel under analysis. The only means by which actual emissions could be greater than the calculated value is if a metal is added to the emission stream from metal erosion in the boiler or control device, or if the metal is present in combustion air at a significant level. The most significant factor influencing the uncontrolled emission is the content of the metal in the fuel. The metals content in the fuel were used in conjunction with source test data to develop uncontrolled emission factors.

As stated in Reference 28, residual oils appear to have higher chromium contents than crude oils as a result of the refining process. A heavy metal such as chromium has a very low vapor pressure and exists distillation operations as a low pressure organo-metallic complex along with the higher molecular weight hydrocarbons in the crude oil. The metal concentrates in the residual part of the crude oil as it is distilled. This concentration phenomenon explains why the chromium content of distillate oils is generally lower than that of residual and crude oils. This phenomenon holds true for similar metals.

Unlike metals emissions, POM emissions are a direct product of inefficiency in the combustion process as described in Reference 6. The primary constituents of the POM emissions are naphthalene, biphenyl, phenanthrene, anthracene, and fluoranthene. Based on very limited data, POM emissions from distillate oil combustion appear to be slightly higher than emissions from residual oil combustion. This trend may be due to the fact that smaller distillate oil boilers have less efficient combustion systems than larger residual oil boilers.

Tables 4-12 and 4-13 present emission factors for metals, POM, and formaldehyde in metric and English units, respectively. Limited data are available on other HAPs compounds and could not be obtained for this update. The metals data were more abundant while data for formaldehyde were very limited. The POM data were also relatively limited. The data are presented in the units of mass emitted per unit thermal heat input as reported in most of the references. Insufficient documentation was available to convert the factors to mass emitted per volume of fuel combusted.

4.3.4 Controlled Emission Factors

Insufficient data were available to generate emission factors for controlled HAPs emissions. It is clear that control devices for criteria pollutants will impact emissions of HAPs. For example, PM control devices will control nonvolatile metals and some semivolatile organic compounds that are associated with PM. Additional testing of these sources for HAPs and further data acquisition from agencies and industries which have performed these tests will need to occur for future updates of AP-42. 4.4 Nitrous Oxide

4.4.1 Review of Specific Data Sets

A total of 29 references were identified and reviewed during the literature search. Of these, 27 references proved to be unusable for developing N_2O emission factors. The primary reasons for rejection were:

- Data were taken with a pre-1988 protocol which has subsequently proven to give erroneously high measurements due to artifacts resulting from reactions in the sampling container;

- Insufficient documentation of source or sampling/analysis methods;
- Pilot scale data.

The screening results showed two of the 29 reports to be useable. The treatment in the current update is summarized below.

Reference 36

This reference contained N_2O emissions data from eight full-scale utility boilers. All test reports were rejected except for the test report from the Italian power plant. The Italian power plant had two sources: one source ran on fuel oil and the other source ran on bituminous coal. The data from the fuel oil source were used in this update. The report provided adequate detail for validation and the sampling and analysis methodology appeared sound. A B quality rating was assigned to the data.

Reference 37

This test report contained data for N_2O emissions from two sub-scale boilers. Both of the boiler units were run with natural gas, No. 2 fuel oil, and No. 5 fuel oil. The N_2O data were measured with an on-line GC/ECD N_2O analysis. Because the test report was from a small pilot scale system, a rating of D was assigned to the data for both boilers.

For the useable data contained in these reports, emission factor calculations were made in terms of mass of pollutant per mass of fuel. It should be noted that the terms "controlled" and "uncontrolled" in this discussion are indicative only of the location at which the measurements were made.

A summary of the N_2O emission data is contained in Table 4-14.

4.5 FUGITIVE EMISSIONS

There were no previous data on fugitive emissions in Chapter 1 of AP-42 and therefore, no existing data were available for validation. Most fugitive emissions from fuel oil handling or ash handling can be estimated from AP-42 Chapters 4 and 11. The data added to Section 1-3 for this update were for fugitive emissions from valves and flanges.

4.5.1 Review of Specific Data

A total of 10 references were documented and reviewed during the literature search. Nine of the ten were rejected using the criteria summarized in Chapter 3.1. The most common reason for rejection was lack of quantified process conditions.

4.5.2 Compilation of Emission Factors

Emission factors for fuel and fly ash handling and storage are found in Chapters 4 and 11 of AP-42, respectively. The VOC emission factors for the fuel feed system selected for inclusion in AP-42 were taken directly from the Petroleum Refineries study and the 24-unit SOCMI study.[38] The factors specified for fuel oil-fired boilers are the EPA-approved values for valves, pumps, flanges, and open-ended lines handling heavy liquids, which are defined as liquids with a vapor pressure less than kerosene. These values were derived through a well-described emission factor development approach derived as part of the SOCMI fugitive emissions standards proposed by EPA in January 1981. The procedure called for a determination of leaking and non-leaking source emission factors from the refinery data set and applying these factors to the leak frequencies found in the SOCMI 24-unit screening study to yield emission factors for average SOCMI units. The resultant "average" SOCMI factors evolved from a comprehensive and thorough study and were considered valid for this update. Table 4-15 presents the developed VOC emission factors for fuel oil feed systems.

4.6 PARTICULATE SIZE DISTRIBUTION

The revised AP-42 scope is intended to include particulate size distribution emission factors as well as filterable and condensible PM-10 emission factors. The 1986 AP-42 Section 1.3 includes detailed analysis of particulate size distribution data. Filterable PM-10 data are included in this analysis by default, because they are among the cumulative size fractions considered. Condensible PM-10 data are not in the 1986 Section 1.3; they should be added to future revisions of the section.

4.6.1 Review of 1986 Section 1.3 Data

The 1986 database was evaluated with respect to sources of data, data analysis, and calculations. Only filterable particulate data were retrieved and analyzed for that update.

Table 4-16 lists the sets of A-and B-rated data used to develop the current AP-42 emission factors for oil-fired particulate. The FPEIS printouts were the primary sources of emission data for the 1986 update. The original printouts were spot-checked to ensure that the data were used appropriately in the 1986 update. The spot-checking did not uncover any inaccuracies in the previous analysis. During the FPEIS

evaluation, several FPEIS printouts were obtained that contained inorganic and organic impinger data. The data were evaluated for development of condensible PM-10 emission factors. The results of this analysis are discussed below.

4.6.2 Review of New Data

A search for additional data was conducted. Of primary interest were CPM data collected via EPA Method 202, because this particulate fraction has not been addressed in previous AP-42 updates. Unfortunately, only method-development quality source test data were found.

Although a variety of sources were contacted regarding particulate sizing and PM-10 data, very little additional data were obtained. State and district offices that were contacted either had no PM-10 data available or were unable to process such a request in a timely fashion due to other staff commitments. Several divisions within the CARB were contacted because CARB considers condensible particulate as a portion of total particulate. However, the personnel contacted did not have any reportable data. An official at the Stanislaus County Air Pollution Control District in California stated that they assume that all particulate from fuel-oil-fired boilers is PM-10, therefore, they do not require specific PM-10 testing.

Thirty source tests were performed on five boilers fueled with fuel oil.[41] Condensible particulate matter was one of the parameters measured during this test phase. None of the boilers was equipped with an abatement device for particulate emissions. Two different test trains were employed in the program: an EPA SASS and a modified EPA Method 5 train. Both trains consisted of a heated probe; three calibrated cyclones with nominal cut sizes of 10, 3, and 1 um contained in an oven capable of being heated to 400°F; a millipore filter also in the oven; two impingers containing distilled water; one dry impinger; one impinger containing desiccant; vacuum pump; and a dry gas meter. The primary difference in the two trains was size. The SASS was the larger of the two trains. It had a sampling rate of 4.0 standard dry cubic feet per minute (SDCFM) whereas the Method 5 sampling train had a sampling rate of 1.0 SDCFM. Condensible particulate matter data from this report are shown in Table 4-17 to 4-20.

One Method 202 test report was obtained that contained CPM emission data for an oil-fired boiler equipped with a mechanical collector.[42] The test objectives were to document the precision and sampling train collection efficiency of Draft Method 202, as well as to assess the general performance of the method at a source category expected to have significant CPM emissions. The boiler was fired on moderately high-sulfur oil and was expected to emit significant quantities of inorganic CPM.

The data are presented as mg emitted/m^3. The test matrix included the volumetric flow rates in the stacks but the process data, such as the size of the boiler or the oil-firing rate, were not recovered. Therefore, it is not possible to prepare emission factors from the results. However, conclusions may be drawn regarding the relative size of the organic and inorganic portions of the CPM. These results are presented in Table 4-21. The results indicate that CPM originating from high-sulfur oil-fired boilers are at least 90 percent inorganic matter.

4.6.3 Compilation of Uncontrolled Emission Factors

The previous update was reviewed with respect to the procedure used to develop emission factors from the particle size distribution data. The uncontrolled emission factors were calculated for each size fraction by multiplying the total particulate emission factor by the cumulative percent mass for the given size interval. Therefore, all uncontrolled emission factors will change simply by updating the overall particulate emission factors.

It is apparent that the level of uncertainty increases as one moves from the cumulative percent mass to the uncontrolled emission factors. The uncontrolled emission factors are functions of two numbers estimated generally from different sets of data: the cumulative percent mass, and the total particulate emission factor.

4.6.4 Control Technology Emission Factors

There were two calculation steps in the development of controlled emission factors in the previous AP-42 particulate sizing update. First, a controlled emission factor was developed for total particulate by multiplying the uncontrolled total particulate emission factor from the criteria pollutant table by one of the following control efficiency factors:

- Multiple cyclone - 80 percent,

- Baghouse - 99.8 percent,
- ESP - 99.2 percent, and
- Scrubber - 94 percent.

Nest, a controlled emission factor was developed for each of the cumulative size ranges by multiplying the controlled emission factor for total particulate by the cumulative percent mass for the size range. Thus, the quality of the right-hand side of each size distribution table in the 1986 Section 1.3 is directly related to the quality of three other numbers: (1) the control efficiency factors, (2) the total particulate emission factor (taken from the criteria pollutant table), and (3) the cumulative percent mass data. This, in part, explains the low ratings generally listed the section for the controlled emission factors for the particulate size fractions.

The disadvantage of this procedure is the loss of emission factor quality. The advantage of the procedure is that it allows the determination of process-specific controlled emission factors rather than using generalized control efficiency results. Process-specific controlled emission factors are better than generalized control efficiencies results because control efficiency is dependent on particulate parameters, such as the resistivity, not just the particle size distribution.

It is useful to note that the procedure does not assume a single control efficiency for each particle size. Rather, it assumes a single overall efficiency and applies this to the total particulate emission factor. The size-based emission factors depend on the total controlled emission factor and the percent of the total mass within a particular size range.

Although different methods could be used to develop controlled emission estimates, the procedure used in the 1986 document is logical. The process appears to generate conservatively high values for the controlled emission factors, as there are occasionally controlled emission factors in the tables that are larger than the uncontrolled factors.

With respect to the appropriateness of the four particulate control efficiencies used throughout the previous update, the values for the ESP and scrubbers appear to be high. The text of the 1986 AP-42 Section 1.3 indicates that the particulate removal efficiency of older ESPs is only 40 to 60 percent and that new or rebuilt ESPs remove

up to 80 percent. This varies significantly from the efficiency of 99.2 percent assumed for the calculation of the controlled emission factors. The NSPS for small steam generating units confirms the discussion in AP-42. It lists source test data from two different oil-fired boilers that shows particulate control efficiencies ranging from 40 to 83 percent, with an average value of 64 percent. The boiler sizes were 28 MW (94 MMBtu/hr) and 1610 MW (5500 MMBtu/hr).

The 1986 AP-42 controlled emission factor calculations assume a scrubber efficiency of 94 percent. However, the AP-42 text notes that scrubbers remove only 50 to 60 percent of the particulate generated from oil-fired boilers. The NSPS document lists design particulate removal efficiencies for several wet scrubbers applied to oil-fired boilers. The efficiencies range from 40 to 92 percent with an average of 72 percent.

It is suggested that the control efficiencies used in the fuel oil tables be changed to 50 percent for old ESPs, 80 percent for new or rebuilt ESPs, and 80 percent for scrubbers.

TABLE 4-1. RESULTS OF 1986 SECTION 1.3 DATA SPOT CHECKS

Pollutant	Boiler	Fuel	1986 Section 1.3 reference	Total data points	Spot checked data points	Observations
Particulate[a]	Utility	#6	7, pp. 68-74	53	2	A data point from a controlled facility;
			24, printouts	10	2	
	Industrial/ Commercial	#6	3, Table VI-4		1	
			4, Table F-3	21	1	
			5, Table 4-1		1	
	Industrial/ Commercial	#5	3, Table VI-4			Average emission factor (10 lb/1000 gal) adopted in footnote g.
			4, Table F-3	9		
			5, Table 4-1		1	
	Industrial/ Commercial	#4	3, Table VI-4	3	1	Average emission factor (7 lb/1000 gal) adopted in footnote g.
			4, Table F-3			
	Industrial/ Commercial	#2	3, Table VI-4		1	Average emission factor (2 lb/1000 gal) adopted in footnote g.
			4, Table F-3	15		
			5, Table 4-1		1	
	Residential	#2	4, Table I-3	33	-	Emission factor suggested in the table has been adopted.
SO_2[b]	Utility	Residual	5, pp. 16-17	-	-	States that SOx emissions are proportional to fuel S% and are not affected by boiler size, burner design, or fuel.
	Industrial	Residual	5, pp. 16-17	-	-	States that SOx emissions are proportional to fuel S% and are not affected by boiler size, burner design, or fuel.
	Commercial	Residual	3, pp. I-14, 16	5	-	Generally agrees with the EPA value (159S vs. 157S).
			4, p. I-20, 21	11	-	Suggest using a range (154S - 162S: #4 - #6).
	Industrial	Distillate	5, pp. 16-17	-	-	States that SOx emissions are proportional to fuel S% and are not affected by boiler size, burner design, or fuel.

TABLE 4-1. RESULTS OF 1986 SECTION 1.3 DATA SPOT CHECKS

Pollutant	Boiler	Fuel	1986 Section 1.3 reference	Total data points	Spot checked data points	Observations
	Commercial	Distillate	3, pp. I-14, 16	1	-	Generally agrees with the EPA value (140S vs. 142S).
			4, p. I-20, 21	8	-	Suggest using the EPA value of 142S.
	Residential	Distillate	3, pp. I-13, 15	18	-	Lower than the EPA value (127S vs. 142S).
SO_3[c]	Utility	Residual	25, p. 20	-	-	Calculations based on Ref. 25 do not yield the EPA value.
	Industrial/ Commercial	Residual	-	-	-	Emission factor seems to be based on a simple mass balance indicated in ref. 1.
	Industrial/ Commercial/ Residential	Distillate	-	-	-	Appears that the result for Industrial/Commercial-Residualhas been used.
CO[d]	Utility	Residual	8, Table 2-13	9	-	CO ranged in 1-8 lb/1000 gal oil for all utility boilers.
			9, pp. 114-142	5	-	CO for all utility boilers, under normal baseline conditions, was in the range 5-10 lb/1000 gal oil.
	Industrial	Residual	5, p. 73	-	-	CO, typically, was less than 100 ppm (12.5 lb/1000 gal).
	Commercial	Residual	3, pp. I-14, 16	5	-	Average CO emission factor was 3.8 lb/1000 gal oil.
			4, p. I-20, 21	11	-	Suggest using a range (0.9 - 1.2 lb/1000 gal oil : #4 - #6).
	Industrial	Distillate	5, p. 73	-	-	CO, typically, was less than 100 ppm (12.5 lb/1000 gal).
	Commercial	Distillate	3, pp. I-14, 16	2	-	Average CO emission factor was 2.7 lb/1000 gal oil.
			4, p. I-20, 21	8	-	Suggest using 0.5 lb/1000 gal oil.
	Residential	Distillate	3, pp. I-13	18	-	Average CO emission factor was 5.1 lb/1000 gal oil.

TABLE 4-1. RESULTS OF 1986 SECTION 1.3 DATA SPOT CHECKS

Pollutant	Boiler	Fuel	1986 Section 1.3 reference	Total data points	Spot checked data points	Observations
			10, p. 25	38	-	Average CO emission factor was 0.12 lb/1000 lb oil (.86 lb/1000 gal oil).
NO_x[e]	Utility	Residual/ tangential	17, Table 2-1	2	-	New (16% lower) emission factor adopted.
		Residual/ vertical		-	-	Old emission factor retained.
		Residual/other		49	-	New (lower) emission factor adopted.
	Industrial/	Residual	17, Tables 3-1 & 4-1	28	-	Average emission factor adopted by EPA.
	Industrial/ Commercial	Distillate	17, Tables 3-1 & 4-1	19	-	Average emission factor adopted by EPA.
	Residential	Distillate	3, p. I-8;	19	-	Verified the notes in EFD.
			4, p. I-9, 11;	33	-	
			& 10, p. 25	38	-	
	1986 Footnote j		3, 4, 5	36	-	
VOC[f]	Utility	Residual	19, pp. 201 & 207	10	1	Verified the details in EFD.
	Industrial	Residual	21, pp. 102 & 106	4	-	
		Distillate	21, pp. 102 & 106	4	-	
	Commercial	Residual	20, pp. 75 & 79	4	-	
		Distillate	20, pp. 75 & 79	3	-	
	Residential	Distillate	18, pp. 58 & 62	5	-	

[a]Insufficient number of data points for #5 firing. Hence, emission factors for these cases should be rated B.
Adequate number of data points for #6 and #2 firing. Hence, a rating of A for corresponding emission factors.
[b]General comments for SO_2:

1. EFD does not provide sufficient information.
2. Emission factor for residual oil seems to be based on a simple mass balance indicated in Ref. 1 (see Table 4.1-3).
3. Emission factor for distillate oil (#2), calculated as per the simple mass balance indicated in Ref. 1, seems to be somehwat lower than the EPA value (137S vs. 142 S, where S = % sulfur - see Table 4.1.-3).
4. Ref. 2 is quite non-specific and probably should be purged.

5. Ref. 27 does not apply.
6. Emission factor rating:

   Since emission factor estimates based on a mass balance assuming ~98% conversion of fuel S to SO_2, are very close to AP-42 values, emission factor ratings of A are assigned.

[c]General comments for SO_3:

1. EFD does not provide enough information.
2. Ref. 2 is quite non-specific and probably should be purged.
3. Ref. 27 does not apply.
4. Utility emission factor, based on Ref. 25, seems to be incorrect (see Section 4.1.3).
5. Emission factor rating:

   For rating boiler firing residual oil, Ref. 25 does not provide adequate information. Hence, emission factors for this case should be rated C.

   For cases other than utility boiers firing residual oil, emission factor estimates based on 1% fuel S to SO_3, are very close to AP-42 value of 2S. Hence, a rating of A was assigned.

[d]General comments for CO:

1. EFD does no provide adequate information.
2. An emission factor of 5 lb/1000 gal seems to have been adopted for all cases and published with a qualifying footnote.
3. Emission factor rating:

   In general, as shown above, CO emission factors are between 1-10lb/1000 gal. Hence, a median valuee of 5 lb/1000 gal, with a qualifying footnote about CO emissions on combustion conditions, should be rated A.

[e]General comments for NO_x:

1. EFD is reasonably explicit but does not address footnote j adequately. No information available on specific pages in references used in connection with footnote j.
2. Emission factor rating:

   Since NO_x emission factors are based on ample A-rated data points, corresponding emission factor rating of A is assigned.

[i]General comments for VOC:

1. EFD is quite explicit and, therefore, only utility/residual case was spot checked.
2. Emission factor rating: Since emission factors are based on ample A-rated data points, ratings of A are assigned.

TABLE 4-2. PM EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Fuel			Density, lb/gal	Load/ capacity	Sample O_2,	PM, lb/MBtu	PM, lb/Kgal
					HHV, Btu/lb	S, %	Ash, %			%		
6	Utility	Low S Oil	A	Haynes #5	18958	0.18	0.01	7.59	0.92	3-4	0.0153	2.202
8	Utility	6	A	Boiler No. 7	18477	1.99	0.08	8.14	1	5		16.690
					18451	1.9	0.09	8.17	1	6.1		22.606
					18466	1.91	0.1	8.16	1	5.5		23.600
											Average	20.965
					18477	1.99	0.08	8.14	1			29.5
					18451	1.9	0.09	8.17	1			15.2
					18466	1.91	0.1	8.16	1			15.823
											Average	20.178
10	Utility	6	A	Refinery B, Source 2	18750	0.73	0.03	7.951	0.97	4.9	0.035	5.218
					18750	0.73	0.03	7.951	0.98	6.6	0.035	5.218
											Average	5.218
	Utility	6	A	Refinery C, Source 1	18610	1.19	0.02	8.027	1.02	7.3	0.054	8.067
					18610	1.19	0.02	8.027	0.775	9.6	0.088	13.146
											Average	10.606
1-3	Industrial	6	A		17515	1.96	0.02	7.88	0.7-1		0.14	19.323
4,5	Industrial	2	A	Location 19	19680	0.16	0.00	6.97	0.8	3.2	0.0564	7.736
					19680	0.16	0.00	6.97		2.95		0.000
											Average	7.736
	Industrial	6	A	Location 19	19000	0.54	0.01	7.75	0.8	3	0.084	12.369
					19000	0.54	0.01	7.75		3.1		0.000
											Average	12.369

TABLE 4-2. PM EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Fuel			Density, lb/gal	Load/ capacity	Sample O_2, %	PM, lb/MBtu	PM, lb/Kgal
					HHV, Btu/lb	S, %	Ash, %					
	Industrial	6	A	Location 38	18467	1.88	0.05	8.04	0.89	2.9	0.1543	22.910
7	Industrial	6	A	Site 2	18950	0.97	0.02	7.71	1	8.9	0.0475	6.940
					19020	0.88	0.02	7.69	1.02	7.6	0.0757	11.077
											Average	9.008

Results:

1. Industrial boilers firing distillate oil:

The average emission factor from one data point, shown above, is 7.74 lb/1000 gal.
AP-42 emission factor, based on 15 points, is 2 lb/1000 gal.
AP-42 factor is retained.

2. Utility/Industrial/Commercial boilers firing No. 6 oil:

A. Original 71 points reduced to 3 average points in the sulfur brackets shown below

S range (%)	# of points	S%	PM, lb/1000 gal
1.5 - 2.5	19	2.063	23
0.625 - 1.25	33	0.937	13
0.10 - 0.625	19	0.5	8.6

B. 10 Additional points (added in last EFD from reference 24):

Point	S%	PM, lb/MMB	HHV, Btu/gal	PM, lb/1000 gal
1	0.41	0.05	145551	7.27755
2	0.46	0.06	143156	8.58936
3	0.33	0.03	147184	4.41552
4	0.34	0.019	153192	2.94112864
5	0.39	0.106	149152	15.914518
6	0.37	0.09	142540	12.28286
7	0.44	0.006	142700	0.8562
8	0.34	0.05	142790	7.3645
9	0.37	0.03	147700	4.431
10	0.45	0.03	149289	4.47867

Points from B reduced to 1 average point:

---Average---

S range, %	# of points	S%	PM, lb/1000 gal
0.25 - 0.625	8	0.38	6.7

Note that points 1 and 2 have not been averaged in as these were taken after an ESP

C. 9 additional points added in this effort:

Point	S %	PM, lb/1000 gal
1	0.18	2.2
2	1.93	21
3	1.93	20
4	0.73	5.2
5	1.19	11
6	1.96	19
7	0.54	12.37
8	1.88	23
9	0.925	9

Above 9 points are reduced to 3 average points shown below

-----Average---------

S range, %	# of points	S, %	PM, lb/1000 gal
1.5 - 2.5	4	1.9	21
0.625 - 1.25	3	0.9	8.3
0.10 - 0.625	2	0.4	7.29

D. Linear regression using average points from A, B, and C.

---------Average----------

S ,	PM lb/1000 gal
2.1	23
0.94	13
0.5	8.6
0.38	6.7
1.9	21
0.95	8.3
0.36	7.3

Regression Output:

Constant	3.22
Std Err of Y Est	2.109
R Squared	0.94
No. Of Observations	7
Degrees of Freedom	5
X Coefficient(s)	9.19

In view of above, the algorithm given in previous AP-42 is changed to:

PM, lb/1000 gal = 9.19*S% + 3.22
This has a correlation coefficient of r = 0.97

TABLE 4-3. SO_2 EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Density, lb/gal	Load/ capacity	O_2, %	SO_2, lb/MMBtu	SO_2, lb/Kgal.	SO_2/S% Residual	SO2/S% Distillate
6	Utility	Low S oil	B	Haynes #5	143	18958	0.18	7.59	0.92	3-4	0.209	30.07	167.07	
1-3	Industrial	6	B		202-3 & 4	17515	1.96	7.88	0.7-1		2.28	314.68	160.55	
4,5	Industrial	2	B	Location 19	19-5	19680	0.16	6.97	0.8	3.2	0.146	20.03		
					19-7	19680	0.16	6.97		2.95	0.223	30.59		
												25.31		158.17
	Industrial	6	B	Location 19	19-97	19000	0.54	7.75	0.8	3	0.596	87.76		
					19-99	19000	0.54	7.75		3.1	0.644	94.83		
												91.30	169.06	
	Industrial	6	B	Location 38	200-24	18467	1.88	8.04	0.89	2.9	1.713	254.34	135.29	
												Average	157.99	158.17

TABLE 4-3. SO_2 EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Density, lb/gal	Load/ capacity	O_2, %	SO_2, lb/MMBtu	SO_2, lb/Kgal.	SO_2/S% Residual	SO2/S% Distillate

Results:

1. Residual Oil Firing:

SO_2 emission factor based on fuel oil S weight percent can be estimated as follows:

$$0.98 \times 64/32 \times \%S/100 \times 8 \times 1000 = 156.8S$$

assuming 98% conversion of S to SO_2 and oil density of 8 lb/gal.

1986 AP-42 emission factor is identical to the above estimated value.
The average emission factor, shown above, is also very close to the AP-42 value.

Hence, 1986 emission factor is retained.

2. Distillate Oil Firing:

SO_2 emission factor based on fuel oil S weight percent can be estimated as follows:

$$0.98 \times 64/32 \times \%S/100 \times 7 \times 1000 = 137.2S$$

assuming 98% conversion of S to SO_2 and oil density of 7 lb/gal.

1986 AP-42 emission factor is very close to the above estimated value.
The average emission factor, based on one data point, is higher than the above estimated value.

In light of paucity of new data and above estimate, 1986 emission factor is retained.

3. No. 4 Oil firing:

No. 4 oil properties can be approximated by averaging residual & distillate oils properties.
Hence, emission factor is also an average.

TABLE 4-4. SO_3 EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Fuel density, lb/gal	Load/ capacity	O_2, %	SO_3, lb/MMBtu	SO_3, lb/Kgal	SO_3/S%
4,5	Industrial	2	A	Location 19	19-5	19680	0.16	6.97	0.8	3.2	0.0023	0.315	2.0
	Industrial	6	A	Location 19	19-97	19000	0.54	7.75	0.8	3	0.0093	1.369	2.5
	Industrial	6	A	Location 38	200-24	18467	1.88	8.04	0.89	2.9	0.0509	7.557	4.0

TABLE 4-4. SO_3 EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Fuel density, lb/gal	Load/ capacity	O_2, %	SO_3, lb/MMBtu	SO_3, lb/Kgal	SO_3/S%

Results:

1. Utility boilers firing No. 6 oil:

An emission factor for utility boilers firing No. 6 oil, based on information in 1986 Section 1.3 Reference 25, can be estimated as follows:

$$0.0286 \times 80/32 \times S\%/100 \times 8 \times 1000 = 5.72S$$

assuming a mean conversion of 2.86% for S to SO_3 and oil density of 8 lb/gal.

Above estimate suggests that for utility boilers firing No. 6 oil the 1986 AP-42 value of 2.9S lb/Kgal is incorrect.

The above estimated value is accepted as the emission factor for this case, with a C rating as data in 1986 Reference 25 are rated B due to lack of adequate information.

2. Other hardware/fuel combinations:

An emission factor, for residual oil firing, can be estimated as follow:

$$0.01 \times 80/32 \times S\%/100 \times 8 \times 1000 = 2S$$

assuming a mean conversion of 1% for S to SO_3 (as per Ref.1) and oil density of 8 lb/gal.

Since there is a wide variability in conversion of S to SO_3, the emission factor of 2S (lb $SO_3/10^3$ gal oil) is also valid for distillate oil firing.

The averaged emission factor for industrial boilers is close to the 1986 AP-42 value of 2S.

In view of paucity of new data, and above result, 1986 AP-42 value is retained.

TABLE 4-5. CO EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Fuel density, lb/gal	Load/ capacity	O_2	CO, lb/MBtu	CO, lb/Kgal.
6	Utility	Low S oil	A	Haynes #5	143	18958	0.18	7.59	0.92	3-4	0.013	1.87
1-3	Industrial	6	A		202-3 & 4	17515	1.96	7.88	0.7-1		0.01	1.38
						17515	1.96	7.88	0.7-1		0.01	1.38
												1.38
4,5	Industrial	2	A	Location 19	19-5	19680	0.16	6.97	0.8	3.2	0.003	0.45
					19-7	19680	0.16	6.97		2.95	0.01	1.30
												0.88
	Industrial	6	A	Location 19	19-97	19000	0.54	7.75	0.8	3	0.003	0.49
					19-99	19000	0.54	7.75		3.1	0.003	0.49
												0.49
	Industrial	6	A	Location 38	200-24	18467	1.88	8.04	0.89	2.9	0.017	2.58
9	Residential	2	A		43					8.5	0.37 g/kg	2.59
					44					8.5	0.33 g/kg	2.31
												2.45
											Average	1.61

Results:

As shown above, the average emission factor for CO is less than the 1986 AP-42 value of 5 lb/1000 gal. However, the 1986 AP-42 value is based on many more observations; therefor it is retained.

TABLE 4-6. NO_x EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel N, %	Fuel density, lb/gal	Load/ capacity	Sample O_2, %	NO_2, lb/MMBtu	NO_2, lb/Kgal
10	Utility (Horizontal fired)	6	A	Refinery B, Source 2	10,11,12	18750	0.22	7.951	0.97	4.9	0.22	32.80
					7,8,9	18750	0.22	7.951	0.98	6.6	0.23	34.29
												33.54
	Utility (Horizonal fired)	6	A	Refinery C, Source 1	1,2,3	18610	0.18	8.027	1.02	7.3	0.27	40.33
					4,5,6	18610	0.18	8.027	0.775	9.6	0.34	50.79
												45.56
1-3	Industrial	6	A		202-3 & 4	17515	0.36	7.88	0.7-1		0.38	52.45
						17515	0.36	7.88	0.7-1		0.365	50.38
												51.41
4,5	Industrial	2	A	Location 19	19-5	19680	0.00	6.97	0.8	3.2	0.241	33.06
					19-7	19680	1	6.97		2.95	0.2301	31.56
							0.00 1					
												32.31
	Industrial	6	A	Location 19	19-97	19000	0.2	7.75	0.8	3	0.428	63.02
					19-99	19000	0.2	7.75		3.1	0.438	64.50
												63.76
	Industrial	6	A	Location 38	200-24	18467	0.31	8.04	0.89	2.9	0.52	77.21
7	Industrial	6	A	Site 2	1-1 & 1-2	18950	0.27	7.71	1	8.9	0.506	73.93
					1-3	19020	0.24	7.69	1.02	7.6	0.4487	65.65
												69.79
9	Residential	2	A		43					8.5	2.602 g/kg	27.92
					44					8.5	2.577 g/kg	27.66
												27.79

TABLE 4-6. NO_x EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel N, %	Fuel density, lb/gal	Load/ capacity	Sample O_2, %	NO_2, lb/MMBtu	NO_2, lb/Kgal

Results:

1. Utility boilers firing No. 6 oil:

Since no new data was uncovered for tangentially fired and vertical fired boilers, old emission factors are retained for these cases. However two data points, uncovered above, are used in determining emission factor for other firing configurations.

Average (lb/Kgal)	n	n x average	
67	49	3283	1986 data described in EFD and 1986 Ref. 17
33.54	1	34	New data point
45.56	1	46	New data point
	51	3362	

New emission factor (EF) = 65.92 (lb/1000 gal)
% change in EF = -1.49

Since % change in EF is small, 1986 EF (67 lb/Kgal) is retained.

2. Industrial/Commercial boilers firing residual oil:

Average (lb/Kgal)	n	n x average	
53	20	1060	1986 data described in EFD and 1986 Ref. 17
60	8	480	1986 data described in EFD and 1986 Ref. 17
51.41	1	51	New data point
63.76	1	64	New data point
77.21	1	77	New data point
69.79	1	70	New data point
	32	1802	

New emission factor (EF) = 56.32 lb/1000 gal
% change in EF = -2.4

Since % change in EF is small, 1986 EF (55 lb/Kgal) is retained.

3. Industrial/Commercial boilers firing distillate oil

Average (lb/Kgal)	n	n x average	
20	12	240	1986 data was described in EFD and Ref. 17
19	7	133	1986 data was described in EFD and Ref. 17
32.31	1	32.31	New data point
	20	405.3	

New emission factor (EF) = 20.27 lb/1000 gal
% change in EF = 1.35

Since % change in EF is small, 1986 EF (20 lb/Kgal) is retained.

4. Residential units firing distillate oil:

Since only one data point was obtained for this case, 1986 emission factor of 18lb/1000 gal, based on multiple data points, has been retained.

TABLE 4-7. VOC EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Run	Sample O_2, %	TOC, g/kg	TOC, lb/Kgal
9	Residential	2	A	43	8.5	0.04	0.28
				44	8.5	0.04	0.28
							0.28

Results:

The average emission factor for TOC is less than the 1986 AP-42 value of 2.49 lb/1000 gal.

The 1986 value is retained as it is derived from multiple data points.

TABLE 4-8. CONTROLLED PM EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Fuel HHV, Btu/lb	Control technology	Emissions uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
NR/15 MW (NR/52 MMBtu/h)	Residual oil	1.10		Venturi scrubber	0.94[a]/0.03	96.8[a]	14
14.5 MW/17 MW (49 MMBtu/h/57 MMBtu/h)	Residual oil	1.10		Steam Venturi/ spray tower	0.94[a]/0.052	94.5[a]	14
13 MW/17 MW (59.3 MMBtu/h/57 MMBtu/h)	Residual oil	2.80		Steam Venturi/ spray tower	2.08[a]/0.095	95.4[a]	14
13.7 MW/15 MW (52.4 MMBtu/h/50 MMBtu/h)	Residual oil	1.65		Heat. Tech. caustic scrubber	1.31[a]/0.08	93.9[a]	14
6.4 MW/7 MW (22.8 MMBtu/h/25 MMBtu/h)	Residual oil	1.46		Koch caustic scrubber	1.18[a]/0.07	94.1[a]	14
12.9 MW/15 MW (42.5 MMBtu/h/50MMBtu/h)	Residual oil	1.46		And. 2000 caustic scrubber	1.18[a]/0.08	93.2[a]	14
13.7 MW/15 MW (45.5 MMBtu/h/50 MMBtu/h)	Residual oil	1.34		Heat. Tech. caustic scrubber	1.10[a]/0.09	91.8[a]	14
13.5 MW/15 MW (45.0 MMBtu/h/50 MMBtu/h)	Residual oil	1.14		Koch caustic scrubber	0.96[a]/0.06	93.8[a]	14
NR/28 MW (NR/94 MMBtu/h)	Oil fired	0.7		ESP	0.063/0.035	45	14
1630 MW/1610 MW (5580 MMBtu/h 5500 MMBtu/h)	Oil fired	2	0.08	ESP	0.041/0.007	83	14
1640 MW/1610 MW (5590 MMBtu/h/5500 MMBtu/h)	Oil fired	2	0.09	ESP	0.045/0.012	69	14
1610 MW/1610 MW (5490 MMBtu/h/5500 MMBtu/h)	Oil fired	2	0.10	ESP	0.049/0.011	78	14
NR/10 MW	Oil fired	0.7	NR	ESP	0.092/0.056[a]	40	18
NR/10 MW	Oil fired	0.7	NR	ESP	0.14/0.07[a]	51	18
NR/48 MW	Oil fired	2.4	NR	ESP	0.18/0.113[a]	38.0	18
NR/48 MW	Oil fired	2.4	NR	ESP	0.35/0.15[a]	57.0	18

TABLE 4-8. CONTROLLED PM EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Fuel HHV, Btu/lb	Control technology	Emissions uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
NR/48 MW	Oil fired	2.4	NR	ESP	0.11/0.033[a]	71.0	18
NR/593 MW	Oil fired	2.2	NR	ESP	0.38/0.065[a]	83.0	18
NR/595 MW	Oil fired	2.2	NR	ESP	0.33/0.102[a]	69.0	18
NR/589 MW	Oil fired	2.2	NR	ESP	0.32/0.07[a]	78.0	18
NR/119 MW	Oil fired	1.95	0.09	ESP	NR/0.07	NR	18
NR/600 MW	Oil fired	0.3	0.02	ESP	0.02/0.017[a]	16	18
NR/350 MW	Oil fired	0.37	NR	ESP	0.026/0.012[a]	54	18
5.3 MW/6.4 MW (17.6 MMBtu/h/22 MMBtu/h)	Distillate oil/ WT packaged	NR		LEA	0.06/0.04	33.3	13
5.4 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Distillate oil/ WT packaged	NR		LEA	0.06/0.01	83.3	13
5.4 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Distillate oil/ WT packaged	NR		OFA	0.06/0.03	50.0	13
5.2 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Residual oil/ WT packaged	NR		LEA	0.08/0.07	12.5	13
13.6 MW/16 MW (47.6 MMBtu/h 56 MMBtu/h)	Residual oil/ WT packaged			LEA	0.15/0.11	26.7	13
NR/6.5 MW	Residual oil/ WT packaged			OFA	0.08/0.07	12.5	13

[a]Calculated value.
ESP = Electrostatic precipitator.
LEA = Low excess air.
OFA = Overfired air.
NR = Not reported.
WT = Watertube.

TABLE 4-9. CONTROLLED SO_2 EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Control technology	Emissions, uncontrolled/ controlled	Removal efficiency, %	Ref.
6.2 MW/6.7 MW (21.2 MMBtu/h/23 MMBtu/h)	Oil-fired units	1.0	Sodium scrubbing	425 ng/J/38 ng/J	91	12
6.1 MW/8.1 MW (20.6 MMBtu/h/27.5 MMBtu/h)	Oil-fired units	1.0	Sodium scrubbing	390 ng/J/43.0 ng/J	89	12
13.5 MW/14.7 MW (46 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.65	Sodium scrubbing	700 ng/J/21.5 ng/J	96.9	12
14.1 MW/14.7 MW (48 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.34	Sodium scrubbing	700 ng/J/25.8 ng/J	96.3	12
11.8 MW/16.2 MW (40.3 MMBtu/h/55.2 MMBtu/h)	Oil-fired units	.60	Sodium scrubbing	345 ng/J/17.2 ng/J	95.0	12
6.9 MW/7.3 MW (23.8 MMBtu/h/25 MMBtu/h)	Oil-fired units	1.00	Sodium scrubbing	350 ng/J/1.7 ng/J	99.5	12
12.9 MW/14.7 MW (44 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.46	Sodium scrubbing	700 ng/J/12.9 ng/J	98.1	12
4.5 MW/6.4 MW (15.6 MMBtu/h/22 MMBtu/h)	Oil-fired units	1.56	Sodium scrubbing	825 ng/J/103 ng/J	87.5	12
4.3 MW/6.4 MW (14.7 MMBtu/h/22 MMBtu/h)	Oil-fired units	1.61	Sodium scrubbing	690 ng/J/38.7 ng/J	94.4	12
15.4 MW/14.7 MW (52.5 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.58	Sodium scrubbing	750 ng/J/77.4 ng/J	89.7	12
14.8 MW/14.7 MW (50.5 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.66	Sodium scrubbing	825 ng/J/34.4 ng/J	95.8	12
15.7 MW/18.3 MW (53.8 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	.85	Sodium scrubbing	575 ng/J/17.2 ng/J	97.0	12
16.6 MW/18.3 MW (56.9 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.15	Sodium scrubbing	500 ng/J/12.9 ng/J	97.4	12
15.4 MW/18.3 MW (52.5 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.00	Sodium scrubbing	545 ng/J/21.5 ng/J	96.0	12
15.0 MW/18.3 MW (51.3 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.10	Sodium scrubbing	425 ng/J/17.2 ng/J	96.0	12

TABLE 4-9. CONTROLLED SO_2 EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Control technology	Emissions, uncontrolled/ controlled	Removal efficiency, %	Ref.
6.2 MW/6.7 MW (21.2 MMBtu/h/23 MMBtu/h)	Oil-fired units	1.0	Sodium scrubbing	425 ng/J/38 ng/J	91	12
15.0 MW/18.3 MW (51.3 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.10	Sodium scrubbing	530 ng/J/215 ng/J	96.0	12
19.8 MW/18.3 MW (67.5 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.01	Sodium scrubbing	975 ng/J/19.2 ng/J	98.0	12
17.2 MW/18.3 MW (58.8 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	.80	Sodium scrubbing	550 ng/J/4.3 ng/J	99.2	12
6.7 MW/8.8 MW (22.8 MMBtu/h/30 MMBtu/h)	Oil-fired units	1.20	Sodium scrubbing	465 ng/J/30.1 ng/J	93.5	12
6.7 MW/7.3 MW (23 MMBtu/h/25 MMBtu/h)	Oil-fired units	1.46	Sodium scrubbing	695 ng/J/12.9 ng/J	98.1	12
15 MW/15 MW (52 MMBtu/h/52 MMBtu/h)	Residual oil fired	1.10	Venturi scrubber	NR	92	14
14.5 MW/17 MW (473 MMBtu/h/57 MMBtu/h)	Residual oil fired	1.10	Steam venturi/spray tower	NR	99	14
13 MW/17 MW (40 MMBtu/h/57 MMBtu/h)	Residual oil fired	2.80	Steam venturi/spray tower	NR	99.9	14
13.7 MW/15 MW (40 MMBtu/h/50 MMBtu/h)	Residual oil fired	1.65	Heater tech, Caustic scrubber	NR	95.0	14
6.4 MW/7 MW (22.8 MMBtu/h/25 MMBtu/h)	Residual oil fired	1.46	Koch Caustic scrubber	NR	98	14
12.9 MW/15 MW (42.5 MMBtu/h/50 MMBtu/h)	Residual oil fired	1.46	And. 2000 Caustic scrubber	NR	96.0	14
13.7 MW/15 MW (45.5 MMBtu/h/50 MMBtu/h)	Residual oil fired	1.34	Heater tech scrubber	NR	92.0	14
13.5 MW/15 MW (45 MMBtu/h/50 MMBtu/h)	Residual oil fired	1.14	Koch Caustic scrubber	NR	99.0	14
89 MW (310 MMBtu/h)	Oil	1.5	Dual alkali scrubber	1.1 lb/MMBtu/0.091 lb/MMBtu	91.7	12

TABLE 4-9. CONTROLLED SO_2 EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Control technology	Emissions, uncontrolled/ controlled	Removal efficiency, %	Ref.
6.2 MW/6.7 MW (21.2 MMBtu/h/23 MMBtu/h)	Oil-fired units	1.0	Sodium scrubbing	425 ng/J/38 ng/J	91	12
70,000 SCFM	Industrial oil	1.5	Double Alkali System	17,750/710 ppm	96	8

TABLE 4-10. CONTROLLED NO_x EMISSIONS

Boiler load, actual/design	Boiler type	Fuel N, %	Control technology	Emissions, uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
2.5 MW/2.6 MW (8.6 MMBtu/h/9 MMBtu/h)	Firetube/residual oil	0.27	LEA	(0.389/0.328)	16	13
4.0 MW/3.8 MW (13.5 MMBtu/h/13 MMBtu/h)	Firetube/residual oil	1.30	LEA	(0.239/0.227)	5	13
6.3 MW/6.7 MW (21.6 MMBtu/h/23 MMBtu/h)	Firetube/residual oil	0.03	LEA	(0.213/0.201)	6	13
19.2 MW/24 MW (65 MMBtu/h/81 MMBtu/h)	Field erected water tube/ residual oil	0.38	LEA	(0.641/0.572)	11	13
20 MW/24 MW (67 MMBtu/h/81 MMBtu/h)	Packaged water tube/residual oil	0.29	LEA	(0.256/0.236)	8	13
5.2 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/residual oil	0.25	LEA	(0.278/0.193)	31	13
5.4 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/residual oil	0.44	LEA	(0.459/0.438)	5	13
5.4 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/residual oil	0.44	LEA	(0.436/0.368)	16	13
18.6 MW/29 MW (64 MMBtu/h/100 MMBtu/h)	Packaged water tube/residual oil	0.37	LEA	(0.398/0.356)	11	13
5.3 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/residual oil	0.14	LEA	(0.217/0.159)	27	13
7.1 MW/9.1 MW (24.2 MMBtu/h/31 MMBtu/h)	Packaged water tube/residual oil	0.19	LEA	(0.200/0.145)	28	13
10.7 MW/26 MW (36.1 MMBtu/h/88 MMBtu/h)	Packaged water tube/residual oil	NR	LEA	(0.263/0.231)	12	13
12.2 MW/15 MW 40.5 MMBtu/h/50 MMBtu/h)	Packaged water tube/residual oil	0.30	LEA	(0.251/0.230)	8	13
13.6 MW/16 MW (47 MMBtu/h/56 MMBtu/h)	Packaged water tube/residual oil	0.14	LEA	(0.386/0.305)	21	13

TABLE 4-10. CONTROLLED NO_x EMISSIONS

Boiler load, actual/design	Boiler type	Fuel N, %	Control technology	Emissions, uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
13.0 MW/16 MW (45.4 MMBtu/h/56 MMBtu/h)	Packaged water tube/residual oil	0.49	LEA	(0.419/0.312)	26	13
1.9 MW/3.8 MW (65 MMBtu/h/13 MMBtu/h)	Firetube/distillate oil	NR	LEA	(0.221/0.197)	11	13
3.4 MW/7.3 MW (11.8 MMBtu/h/25 MMBtu/h)	Firetube/distillate oil	NR	LEA	(0.224/0.186)	17	13
5.5 MW/11 MW (18 MMBtu/h/36 MMBtu/h)	Packaged water tube/distillate oil	0.045	LEA	(0.136/0.118)	13	13
5.1 MW/6.4 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.006	LEA	(0.096/0.088)	10	13
5.1 MW/6.4 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.006	LEA	(0.134/0.125)	7	13
4.2 MW/6.4 MW (14.5 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.006	LEA	(0.107/0.105	2	13
5.3 MW/6.4 MW (18.3 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.004	LEA	(0.154/0.125)	19	13
8.7 MW/11 MW (28.4 MMBtu/h/36 MMBtu/h)	Packaged water tube/distillate oil	0.045	LEA	(0.158/0.134)	15	13
16 MW/16 MW (56 MMBtu/h/56 MMBtu/h)	Packaged water tube/distillate oil	NR	FGR-10 %	(0.185/0.152)	18	13
5.4 MW/6.5 MW (18.3 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.004	FGR-28 %	(0.154/0.041)	73	13
5.4 MW/6.5 MW (18.3 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.004	OFA	(0.154/0.125)	19	13
18.5 MW/22 MW (63 MMBtu/h/75 MMBtu/h)	Packaged water tube/distillate oil	NR	SCB	(NR/0.110)	NR	13
6.1 MW/9.1 MW (20.8 MMBtu/h/31 MMBtu/h)	Packaged water tube/distillate oil	0.19	FGR-7 %	(0.161/0.157)	3	13

TABLE 4-10. CONTROLLED NO_x EMISSIONS

Boiler load, actual/design	Boiler type	Fuel N, %	Control technology	Emissions, uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
6.1 MW/9.1 MW (20.8 MMBtu/h/31 MMBtu/h)	Packaged water tube/distillate oil	0.19	FGR-19 %	(0.161/0.112)	30	13
5.3 MW/6.5 MW (17.8 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.25	FGR-25 %	(0.278/0.193)	31	13
5.2 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Residual oil packaged watertube	0.14	OFA	(0.217/0.166)	24	13
5.2 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Residual oil packaged watertube	0.44	OFA	(0.217/0.141)	35	13
5.1 MW/6.5 MW (17.4 MMBtu/h/22 MMBtu/h)	Residual oil packaged watertube	0.44	OFA	(0.278/0.194)	30	13
12.8 MW/16 MW (44.8 MMBtu/h/56 MMBtu/h)	Residual oil packaged watertube	0.49	OFA	(0.419/0.222)	47	13
13.6 MW/16 MW (47.6 MMBtu/h/56 MMBtu/h)	Residual oil packaged watertube	0.31	OFA	(0.386/0.245)	37	13
40-80%-170 MW	O/G wall fired		BOOS	(0.42/0.25)	40	17
40-80%-170 MW	O/G wall fired		FGR	(0.42/0.20)	52	17
40-80%-170 MW	O/G wall fired		LNB + OFA	(0.42/0.20)	52	17
40-80%-170 MW	O/G wall fired		LNB + OFA + FGR	(0.42/0.12)	71	17
40-80%-170 MW	O/G wall fired		SNCR	(0.15/0.08)	47	17
40-80%-170 MW	O/G wall fired		NCR	(0.15/0.04)	73	17
40-80%-170 MW	O/G tangentially fired		SNCR	(0.37/0.18)	51	17
40-80%-170 MW	O/G tangentially fired		NCR	(0.37/0.07)	81	17
60-123 MW/150 MW	Oil/wall fired		BOOS	(O.42/0.25)	40	17
60-123 MW/150 MW	Oil/wall fired		FGR	(O.42/0.20)	52	17
60-123 MW/150 MW	Oil/wall fired		LNB + OFA	(O.42/0.20)	52	17

TABLE 4-10. CONTROLLED NO_x EMISSIONS

Boiler load, actual/design	Boiler type	Fuel N, %	Control technology	Emissions, uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
60-123 MW/150 MWO	Oil/wall fired		LNB + OFA + FGR	(O.42/0.12)	71	17
60-123 MW/150 MW	Oil/tangential		FGR	(O.32/0.15)	71	17
60-123 MW/150 MW	Oil/tangential		LNB + OFA	(O.32/0.12)	78	17
60-123 MW/150 MW	Oil/wall tangential		SCR	(O.15/0.04)	73	17
60-123 MW/150 MW	Oil/wall tangential		SCR	(O.37/0.07)	81	17
60-123 MW/150 MW	Oil/wall tangential		SNCR	(O.15/0.08)	47	17
60-123 MW/150 MW	Oil/wall tangential		SNCR	(O.37/0.18)	51	17

LEA = Low excess air.
NR = Not reported.
FGR = Flue gas recirculation.
OFA = Overfired air ports.
O/G = Oil/gas.
BOOS = Burners out of service.
LNB = Low NO_x burner.
SCR = Selective catalytic reduction.
SNCR = Selective non-catalytic reduction.

TABLE 4-11. METALS ENRICHMENT BEHAVIOR

Class	Description	Reference 30	Reference 22	Reference 34
I	Equal distribution between fly ash and soot		Al, Co, Fe, Mn, Sc, Ti	Al, Co, Cr, Fe Mn, Sc, Ti
II	Enriched in fly ash relative to soot	As, Cd	As, Cd, Pb, Sb	As, Cd, Pb, Sb
III	Somewhere in between Class I and II, multiple behavior	Be, Cr, Ni, Mn	Cr, Ni	Ni
IV	Emitted in gas phase	Hg	Hg	Hg

TABLE 4-12. HAP EMISSION FACTORS (METRIC UNITS) FOR RESIDUAL AND DISTILLATE OIL COMBUSTION[a]

Firing configuration (SCC)	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	POM	HCOH[b]
Residual, Grade 6, Normal Firing (10100401)	10-20	8.2-49	1.8	6.8-91	9.0-55	33-50	12-80	10-30	0.6-14	360-964	16	3.2-3.6[c]	69-174
Residual, Grade 6, Normal Firing (10100404)	10-20	8.2-49	1.8	6.8-91	9.0-55	33-50	12-80	10-30	0.6-14	360-964	16	3.2-3.6[c]	69-174
Residual, Grade 6, Normal Firing (10200401)	10-20	8.2-49	1.8	6.8-91	9.0-55	33-50	12-80	10-30	0.6-14	360-964	16	3.2-3.6[c]	69-174
Residual, Grade 6, Normal Firing (10300401)	10-20	8.2-49	1.8	6.8	9.0-55	33-50	12-80	10-30	0.6-14	360-964	16	3.2-3.6[c]	69-174
Distillate, Grade 2, (10100501)	-	1.8	1.1	4.5	21-29	-	3.8	6.0	1.3	7.3	-	9.7[d]	100-174
Distillate, Grade 2, (10200501)	-	1.8	1.1	4.5	21-29	-	3.8	6.0	1.3	7.3	-	9.7[d]	100-174
Distillate, Grade 2, (10300501)	-	1.8	1.1	4.5	21-29	-	3.8	6.0	1.3	7.3	-	9.7[d]	100-174

[a]All emission factors in pg/J. All emission factors rated as E quality.
[b]Based on 1964 data, only four data points.
[c]Particulate and gaseous POM.
[d]Particulate POM only.

TABLE 4-13. HAP EMISSION FACTORS (ENGLISH UNITS) FOR RESIDUAL AND DISTILLATE OIL COMBUSTION[a]

Firing configuration (SCC)	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	POM	HCOH[b]
Residual, Grade 6, Normal Firing (10100401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4[c]	161-405
Residual, Grade 6, Normal Firing (10100404)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4[c]	161-405
Residual, Grade 6, Normal Firing (10200401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4[c]	161-405
Residual, Grade 6, Normal Firing (10300401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4[c]	161-405
Distillate, Grade 2, (10100501)	-	4.2	2.5	11	48-67	-	8.9	14	3.0	170	-	22[d]	233-405
Distillate, Grade 2, (10200501)	-	4.2	2.5	11	48-67	-	8.9	14	3.0	170	-	22[d]	233-405
Distillate, Grade 2, (10300501)	-	4.2	2.5	11	48-67	-	8.9	14	3.0	170	-	22[d]	233-405

[a]All emission factors in lb/10^{12} Btu. All emission factors rated as E quality.
[b]Based on 1986 and limited new data.
[c]Particulate and gaseous POM.
[d]Particulate POM only.

TABLE 4-14. SUMMARY OF N_2O EMISSION FACTORS FOR FUEL OIL COMBUSTION

Boiler type	Emission factor rating	Nitrous oxide emissions,	
		lb/10^3gal	kg/10^3l
Utility boilers			
Residual oil-fired	D	0.11	0.013
Industrial boilers			
Residual oil-fired	E	0.11[a]	0.013[a]
Distillate oil-fired	E	0.11[a]	0.013[a]
Commercial boilers			
Residual oil-fired	E	0.11[a]	0.013[a]
Distillate oil-fired	E	0.11[a]	0.013[a]
Residential furnaces			
Distillate oil-fired	D	0.05	0.006

[a]No data were available, therefore the value for utility boilers was extrapolated.

TABLE 4-15. COMPARISON OF FUGITIVE EMISSIONS OF VOCs FROM EQUIPMENT TYPES

Equipment type	Emission factor, kg/h/source[a]	Sources leaking, %
Valve - light liquid	0.0071	11.5[b]
Valve - heavy liquid	0.00023	0.2[b]
Pump - light liquid	0.0494	24.0[b]
Pump - heavy liquid	0.0214	3.8[b]
Compressor	0.2280	58.4[b,d]
Sampling connections	0.0150	2.8[c]
Open-ended line	0.0017	11.9[d]
Flange	0.00083	7.2[b,d]

[a]Reference 38.
[b]Reference 38: Table 2-2 through Table 2-6.
[c]Reference 39.
[d]Reference 38: Table 2-25.

TABLE 4-16. OIL-FIRED PARTICULATE SIZING DATA FOR THE CURRENT AP-42 SECTIONS: NUMBER OF A- AND B-RATED DATA SETS[a]

Source category	Emission control device				
	None	Multiple cyclones	Scrubber	ESP	Baghouse
Fuel oil					
- utility boilers, residual	16	0	4	0	0
- industrial boiler, residual	14	0	0	0	0
- industrial boiler, distillate	0	0	0	0	0
- commercial, residual	15	0	0	0	0
- commercial, distillate	3	0	0	0	0
- residential furn., distillate	0	NA	NA	NA	NA

NA = Not applicable.
[a]Data from Reference 40.

TABLE 4-17. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A 5 MILLION BTU/HR SCOTCH DRY-BACK BOILER[a]

Run number[b,c]	Organic CPM			Inorganic CPM		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
1S	9.6	.02	16.1	50.1	.10	83.9
1J	23.0	.04	32.1	48.8	.08	67.9
2S	5.4	.01	26.2	15.0	.03	73.8
2J	6.0	.01	26.2	17.1	.03	73.8
3S	1.9	.003	3.0	62.8	.11	97.0
3J	3.1	.006	15.1	17.4	.03	84.9

[a]Reference 41.
[b]Tests 1 and 3 were run using Wilmington crude oil with a sulfur content of 1.35% sulfur and an ash content of 0.017%. Test 2 was run with No. 6 fuel oil with a sulfur content of 0.28% and an ash content of 0.016%.
[c]The letter S shown immediately after the run number denotes the use of the SASS train; the letter J denotes the use of the EPA Method 5 train.

TABLE 4-18. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A TYPE-H STIRLING BOILER FIRING NO. 2 FUEL OIL[a]

Run number[b]	Organic CPM			Inorganic CPM		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
16J	.2	.005	1.0	13.4	.41	99.0

[a]Reference 41.
[b]Fuel analysis results showed the sulfur content at 0.38% and the ash content at 0.001%.

TABLE 4-19. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A FACE-FIRED SUPERCRITICAL 480 MW STEAM GENERATOR[a]

Run number[b,c]	Organic CPM			Inorganic CPM		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
11S	1.9	5.9	13.4	12.2	38.1	86.6
11J	4.7	14.6	53.1	4.1	12.9	46.9
12S	.7	2.5	8.3	8.3	28.0	91.7
12J	1.6	5.6	28.8	4.1	13.8	71.2
13J	1.2	4.1	7.7	14.4	49.2	92.2
24S	.6	1.2	3.4	18.5	33.3	96.6
24J	6.8	12.3	27.7	17.7	32.0	72.3
32S	2.8	8.5	13.3	18.6	55.6	86.7
32J	1.6	4.7	14.9	8.9	26.5	85.1
33S	2.4	7.7	12.3	17.1	54.7	87.7
33J	8.5	27.3	47.7	9.3	29.9	52.3

[a]Reference 41
[b]All tests were run with No. 6 fuel oil with an average sulfur content of 0.21% and an ash content of 0.011%.
[c]The letter S shown immediately after the run number denotes the use of the SASS train; the letter J denotes the use of the EPA Method 5 train.

TABLE 4-20. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A FACE-FIRED, BALANCED DRAFT UTILITY BOILER[a]

Run number[b,c]	Organic CPM			Inorganic CPM		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
21S	3.0	4.3	19.7	12.4	17.6	80.3
21J	.1	.1	.9	10.3	14.6	99.1
22S	1.1	.9	5.2	19.2	15.5	94.8

[a]Reference 41.
[b]Fuel analysis results showed the sulfur content at 0.20% and the ash content at 0.012%
[c]The letter S shown immediately after the run number denotes the use of the SASS train; the letter J denotes the use of the EPA Method 5 train.

TABLE 4-21. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM AN OIL-FIRED BOILER EQUIPPED WITH A MECHANICAL COLLECTOR[a]

Run number[b]	Organic CPM			Inorganic CPM[c]		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
1	2.3	5.6	7.7	27.6	67.5	92.3
2	0.69	1.6	3.4	19.7	44.3	96.6
3	0.72	1.4	2.1	33.0	62.1	97.9

[a]Reference 42.
[b]Results for runs 1 and 2 are an average of 4 simultaneous trains purged with N_2; run 3 is an average of 3 simultaneous trains.
[c]Corrected for chlorides.

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5. AP-42 SECTION 1.3: FUEL OIL COMBUSTION

The revision to Section 1.3 of AP-42 is presented in the following pages as it would appear in the document. A marked-up copy of the 1986 version of this section is included in Appendix B.

TABLE A-1. CONVERSION FACTORS

To obtain:	From:	Multiply by:	Use:
lb pollutant/10^3 gal	lb pollutant/MMBtu	10^{-3} x Oil HHV in Btu/gal[a]	
kg pollutant/10^3 ℓ	lb pollutant/10^3 gal	0.1195	
Oil HHV in Btu/gal	Oil HHV in Btu/lb	Oil density in lb/gal[b]	
Oil density in lb/gal	°API		141.5/(131.5 + °API) x 8.34

[a]If oil higher heating value (HHV) is not available, use:

Residual oil HHV = 150,000 Btu/gal.

Distillate oil HHV = 140,000 Btu/gal.

[b]If oil density is not available, use:

Residual oil density = 8 lb/gal.

Distillate oil density = 7 lb/gal.

APPENDIX B

MARKED-UP 1986 AP-42 SECTION 1.3

REPORT ON REVISIONS TO

5TH EDITION AP-42

Section 1.3

Fuel Oil Combustion

Prepared for:

Contract No. EPA 68-D2-0160, WA-50
EPA Work Assignment Officer: Roy Huntley
Office of Air Quality Planning and Standards
Office of Air And Radiation
U. S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Prepared by:

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December 1996

Table of Contents

Page

1.0 INTRODUCTION 1-1

2.0 REVISIONS 2-1
- 2.1 General Text Changes 2-1
- 2.2 Sulfur Oxides, SO_x 2-1
- 2.3 Sulfur Trioxide, SO_3 2-1
- 2.4 Nitrogen Oxides, NO_x 2-1
- 2.5 Carbon Monoxide, CO 2-1
- 2.6 Filterable Particulate Matter, PM 2-2
- 2.7 Total Organic Compounds (TOC) and Non-Methane TOC (NMTOC) 2-3
- 2.8 Particle Size Distribution 2-3
- 2.9 Polycyclic Organic Matter (POM) and Formaldehyde (HCOH) 2-4
- 2.10 Trace Elements 2-4
- 2.11 Greenhouse Gases 2-4
  - 2.11.1 Carbon Dioxide, CO_2 2-4
  - 2.11.2 Methane 2-6
  - 2.11.3 Nitrous Oxide 2-6
- 2.12 Speciated Organic Compounds 2-7

3.0 REFERENCES 3-1

4.0 REVISED SECTION 1.3 4-1

5.0 EMISSION FACTOR DOCUMENTATION, APRIL 1993 5-1

APPENDIX A SUPPORTING DOCUMENTATION .....
- A.1 Data Used for Average Emission Factors Development .....
- A.2 Source Test Report Summary Data .....

1.0 INTRODUCTION

This report supplements the Emission Factor (EMF) Documentation for AP-42 Section 1.3, Fuel Oil Combustion, dated April, 1993. The EMF describes the source and rationale for the material in the most recent updates to the 4th Edition, while this report provides documentation for the updates written in both Supplements A and B to the 5th Edition.

Section 1.3 of AP-42 was reviewed by internal peer reviewers to identify technical inadequacies and areas where state-of-the-art technological advances need to be incorporated. Based on this review, text has been updated or modified to address any technical inadequacies or provide clarification. Additionally, emission factors were checked for accuracy with information in the EMF Document and new emission factors generated if recent test data were available.

If discrepancies were found when checking the factors with the information in the EMF Document, the appropriate reference materials were then checked. In some cases, the factors could not be verified with the information in the EMF Document or from the reference materials, in which case the factors were not changed.

Four sections follow this introduction. Section 2 of this report documents the revisions and the basis for the changes. Section 3 presents the references for the changes documented in this report. Section 4 presents the revised AP-42 Section 1.3, and Section 5 contains the EMF documentation dated April, 1993.

2.0 REVISIONS

2.1 General Text Changes

Information in the EMF Document was used to enhance text concerning fuel oil firing practices. Also, at the request of EPA, the metric units were removed.

2.2 Sulfur Oxides, SO_x

The uncontrolled SO_x factors were checked against information in Table 4-3 of the EMF Document and the 10/86 version of Section 1.3 and no changes were required.

2.3 Sulfur Trioxide, SO_3

The SO_3 factors were checked against information in Table 4-4 of the EMF Document and the 10/86 version of Section 1.3 and no changes were required.

2.4 Nitrogen Oxides, NO_x

The uncontrolled NO_x factors were checked against information in Table 4-6 of the EMF Document and the 10/86 version of Section 1.3 and no changes were required.

2.5 Carbon Monoxide, CO

The CO factors were checked against information in Table 4-5 of the EMF Document and the 10/86 version of AP-42 and no changes were required.

2.6 Filterable Particulate Matter, PM

Filterable PM emission factors were checked against information in Table 4-2 of the EMF Documentation and the 10/86 version of AP-42. The only change required was for the PM emission factors for residential furnaces.[1,2] Several new reports were reviewed and two contained PM emission data for new oil-fired residential furnaces. Based on these reports, it was determined that newer furnaces (i.e., pre-1970) emit significantly less PM than older furnaces (i.e., pre-1970). The existing PM emission factor for residential furnaces in the 5th Edition of AP-42 is based solely on pre-1970 data.

Table 1 presents the PM data for newer furnaces. The existing PM factor is 3.0 lb/1000 gal, is rated "A", and is based on 33 pre-1970 data points. The PM emission factor for newer furnaces is 0.4 lb/1000 gal, is based on 9 post-1970 data points, and is rated "C". The PM emission factor for new furnaces (0.4 lb/1000 gal) was added and a footnote included to qualify it as being based on new furnaces designs and pre-1970's burner designs may emit as high as 3.0 lb/1000 gal.

Table 1. Summary of Particulate Emission Data for New Residential Oil-Fired Furnaces

Reference/Page	Data Rating	Furnace/Burner type	Filterable PM Emission Factor (lb/1000 gal)
McCrillis, Page 4	B	Thermo-Pride Model: M-SR	0.42
Krajewski, Page 40-42	B	R.W. Beckett Co. Model: AF	0.38
Krajewski, Page 40-42	B	R.W. Beckett Co. Model: AFG	0.3
Krajewski, Page 40-42	B	R.W. Beckett Co. Model: AFG	0.4
Krajewski, Page 40-42	B	Riello Corp. Model: Mectron 3M	0.65 0.26 0.35
Krajewski, Page 40-42	B	Energy Kinetics Inc. Model: System 2000	0.4 0.24
Krajewski, Page 40-42	B	Bentone Electrol Oil Model: Airtronic	0.38
Krajewski, Page 40-42	B	Combustion Technology No model number	0.35
Krajewski, Page 40-42	B	Foster Miller Carlin Co. No model number	No data
Average	C		0.4

2.7 Total Organic Compounds (TOC) and Non-Methane TOC (NMTOC)

The TOC and NMTOC factors were checked against information on page 4-7 of the EMF Document and the 10/86 version of AP-42 and no changes were necessary.

2.8 Particle Size Distribution

The particle size factors were checked against information in the EMF Document and the 10/86 version of AP-42 and no changes were required.

2.9 Polycyclic Organic Matter (POM) and Formaldehyde (HCOH)

The POM and HCOH factors in Table 1.3-7 were checked with information in Tables 4-12 and 4-14 of the EMF Document and no changes were required.

2.10 Trace Elements

Trace element factors were checked against Table 4-12 in the EMF Document. Based on recent test data, the factors for residual oil firing shown in Table 1.3-8 were revised (with the exception of antimony). New factors for barium, chloride, chromium VI, copper, fluoride, molybdenum, phosphorus, vanadium, and zinc were added. The data used to calculate the new and revised factors are presented in Appendix A.

The spreadsheets found in Appendix A present calculated average emissions factors based on new test data. Trace elements and speciated organic compounds are presented in Section A.1. Section A.2 contains the individual source test report summaries.

Data from sources tested at several EPRI, Southern California Edison, and Pacific Gas and Electric sites were entered into the spreadsheets. The emission factor were evaluated for patterns based on boiler type and controls. No patterns were found; therefore, the data were averaged (arithmetic mean) together by pollutant.

Special consideration was given to non-detected values in calculating the average factors. If a pollutant was not detected in any sampling run, half of the detection limit (DL/2) was used in the calculated average factor. For a given pollutant, any DL/2 factors that were greater than any factors based on detected values were not included in the calculated averages.

Data from each source test were given a quality rating based on EPA procedures. The ratings ranged from B-D in the tests evaluated for this report. A "B" rating was given for tests

performed by a generally sound methodology but lacking enough detail for validation. A "C" rating was given for tests based on untested or new methodology or lacking a significant amount of background data. When a test was based on a generally unacceptable method but provided an order-of-magnitude value for the source, a "D" rating was assigned.

2.11 Greenhouse Gases

2.11.1 Carbon Dioxide, CO_2

Table 1.3-1 computes CO_2 emissions through a footnote that assumes 100 percent conversion of fuel carbon content to CO_2 during combustion. This does not account for unoxidized fuel in the exhaust stream, which is typically 1 percent for liquid fuels in external combustion systems.[3-5] The factor in note f of Table 1.3-1 was modified to reflect 99 percent conversion instead of the current 100 percent. These new factors appear in Table 2, below.

Table 2. Emission Factor Equations for Solid and Liquid Fuel Combustion
Emission Factor Rating: B

Fuel	Multiply	Density (lb/gal)	Conversion Factor[a]	To Obtain
No. 1 (kerosene)	% carbon	6.88	250	lb CO_2/1000 gal
No. 2	% carbon	7.05	256	lb CO_2/1000 gal
No. 6	% carbon	7.88	286	lb CO_2/1000 gal

[a] The following equation was used to develop the emission factor equation for fuel oils in Table 3-1:

$$\frac{44 \text{ lb } CO_2}{12 \text{ lb C}} \times 0.99 \times 7.05 \frac{\text{lb}}{\text{gal}} \times \frac{1}{100\%} \times 1000 = 256 \frac{\text{lb } CO_2}{1000 \text{ gal \%C}}$$

Where: 0.99 = fraction of fuel oxidized during combustion (References 3-5), and
7.05 lb/gal = density of No. 2 fuel oil (AP-42 Appendix A).

The factors for kerosene and No. 6 oil were computed as shown in note a to Table 2 using the density values from AP-42 Appendix A.

Table 3 lists default emission factors for fuel oils when the carbon content is not known. These figures are based on average carbon contents for each type of fuel and the equation shown in note A of Table 2.

Table 3. Default CO_2 Emission Factors for Liquid Fuels
Quality Rating: B

Fuel Type	%C[a]	Density[b] (lb/gal)	Emission Factor (lb/1000 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]An average of the values of fuel samples in References 6-7.
[b]References 6 and 8.

2.11.2 Methane

No new data found.

2.11.3 Nitrous Oxide, N_2O

The current "E" rated N_2O emission factors in Table 1.3-9 were updated with more recent data that take into account an N_2O sampling artifact discovered by Muzio and Kramlich in 1998.[4] These new emission factors in Table 4 are based on a more complete database of source sampling than either of the references listed for the previous N_2O emission factors in AP-42.

Table 4. N_2O Emission Factors for Fuel Oil Combustion[a]
(lb N_2O/1000 gal)

Fuel	Combustion Category	New	New EF	Previous	Previous
No. 6	Industrial/utility boilers	B	0.53	0.11	E
No. 2	Industrial/utility boilers	B	0.26	0.11	E

[a]References 10-11.

The industrial/utility boilers data for No. 6 fuel oil is based on 6 tests at 4 different facilities collected by Nelson.[10] The data for No. 2 fuel oil for industrial/utility boilers is based on 14 source tests conducted at 6 facilities collected by Nelson.[10]

The data sets were converted to lb/MMBtu according to the procedures given in 40 CFR 60, Appendix A. To obtain lbs/MMBtu, the emissions (in ppm) were first multiplied by 1.141 x 10^{-7} (lb/scf)/ppm. These values were then converted to lb/MMBtu using the following formula:

$$E = C_d F_d \left(\frac{20.9}{20.9 - \%O_2} \right)$$

Where: $C_d = N_2O$;
F_d = F-factor for oxygen; and
$\%O_2$ = oxygen concentration in the exhaust gas.

The following F-factors and heating values were used for the calculations:

Fuel	F-Factor (scf/MMBtu)	Heating Value (Btu/gal)
No. 6 (residual)	9,190	150,000
No. 2 (distillate)	9,190	140,000

2.12 Speciated Organic Compounds

Based on new test data, a total of twenty-one new factors were developed for residual oil fired boilers. The average factors and the data used to calculate the factors are presented in Appendix A. The formaldehyde factor calculated with this data is based on recent tests of utility boilers only.

3.0 REFERENCES

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11. Peer, R. L. *et al.*, "Characterization of Nitrous Oxide Emission Sources," Prepared for the US EPA Contract 68-D1-0031, Research Triangle Park, NC: Radian Corporation, 1995.

4.0 REVISED SECTION 1.3

This section contains the revised Section 1.3 of AP-42, 5th Edition. The electronic version can be located on the EPA TTN at http://134.67.104.12/html/chief/fsnpub.htm.

5.0 EMISSION FACTOR DOCUMENTATION, APRIL 1993

This section contains the Emission Factor Documentation for Section 1.3 dated April 1993. The electronic version can be located on the EPA TTN at http://134.67.104.12/html/chief/fbgdocs.htm. The zipped file on the TTN contains this (1996) background report as well as the 1993 Emission Factor Documentation.

APPENDIX A

SUPPORTING DOCUMENTATION

A.1 Data Used for Average Emission Factors Development

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION

Entry No.	Ref No.	Facility	Fuel Type	Boiler Type	SCC	Control Device 1[a]	Control Device 2[a]	Data Quality	No. Of Test Runs
1	1	EPRI SITE 13	Residual (No. 6)	Wall-Fired (Normal)	10100401	Uncontrolled	None	B	3
2	2	EPRI SITE 112	Residual (No. 6)	Tangentially-Fired	10100404	ESP	None	C	3
3	2	EPRI SITE 112	Residual (No. 6)	Tangentially-Fired	10100404	ESP	None	C	4
4	3	EPRI SITE 103	Residual (No. 6)	Wall-Fired (Normal)	10100401	Uncontrolled	None	B	3
5	3	EPRI SITE 104	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
7	3	EPRI SITE 105	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
9	3	EPRI SITE 106	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
11	3	EPRI SITE 107	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
12	3	EPRI SITE 108	Residual (No. 6)	Opposed (Normal)	10100401	Uncontrolled	None	B	3
14	3	EPRI SITE 109	Residual (No. 6)	Opposed (Normal)	10100401	FGR	None	B	3
20	6	Southern California Edison Company, Alamitos Unit 5	Residual	Assumed Normal	10100401	FGR	None	C	3
21	7	Pacific Gas and Electric Company, Morro Bay Unit 3	Residual	Radiant Heat	10100401	None	None	C	3
23	7	Pacific Gas and Electric Company, Morro Bay Unit 3	Residual	Radiant Heat	10100401	None	None	C	3

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Ref No.	Facility	Fuel Type	Boiler Type	SCC	Control Device 1[a]	Control Device 2[a]	Data Quality	No. Of Test Runs
24	8	Southern California Edison Company, El Segundo Station 1	Residual	Assumed Normal	10100401	None	None	C	3
26	8	Southern California Edison Company, El Segundo Station 1	Residual	Assumed Normal	10100401	None	None	C	3
16	4	EPRI SITE 118	Residual (No. 6)	Front-fired (normal)	10100401	OFA/FGR	ESP	D[d]	3
17	5	Southern California Edison Company Long Beach Auxiliary Boiler	Distillate Oil	Assumed Normal	10100501	None	None	C	3

[a] UNC = Uncontrolled; FGR = Flue Gas Recirculation; OFA = Over-fire Air; ESP = Electrostatic Precipitator.
[b,c] At least one test run was "non detect" and the emission factor is based on detection limit values. (b = one "non detect", c = more than one "non detect").
[d] Data quality ratings of "D" were not used for averaging with "B" and "C" quality data.
[f] Pollutant was Not Detected in any of the sampling runs. Half of the detection limit value (DL/2) used to develop factor.
[g] For a given pollutant, any factors based solely on "non detect" values that were greater than any factors based on detected values were not included in the calculated average factor.

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Benzene	1,3-Butadiene	Carbon Tetrachloride	Chloro-benzene	Chloroform	Ethyl-benzene	Ethylene Dichloride
1	2.10e-04						
2							
3	3.51e-04						
4	4.90e-04[f]						
5	1.85e-04[f]						
7	1.87e-04[f]						
9	2.25e-04[f]						
11	3.02e-04[f]						
12	2.02e-04[f]						
14	7.20e-04[f]						
20	1.80e-04[f]						
21	1.85e-04[f]						
23							
24	2.27e-04[f]						
26							
Average[g]	2.14e-04						
16	7.83e-05	1.18e-05[f]	6.95e-05[f]	5.10e-05[f]	8.05e-05[f]	6.36e-05	1.56e-04[f]
17	9.00e-08[f]						

(continued)

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Related Information

Explanation of File Formats

AP-42 Section 1.3 - Fuel Oil Combustion

The data that supports the emission factors are presented in summary in the background report and are reported more completely in an electronic database. The database is in both Microsoft Excel® and Lotus 1-2-3® spreadsheets, and they are "zipped".

Description

Section 1.3: Data file (ZIP 28K)

C:\WINNT\Profiles\powellj\Desktop\AP-42 Sec. 1.3 Zip File.zip

Name	Type	Modified	Size	Ratio	Packed	Path
Oilraw.wk4	WK4 File	11/15/99 9:52 AM	40,168	69%	12,637	
Oilraw.xlw	Microsoft Excel Workspace	9/29/98 9:51 AM	57,128	73%	15,351	
2 file(s)			**97,296**	**71%**	**27,988**	

	A	B	C	D	E	F
1	Oil Fired Summary Table					
2						
3						
4	No. 6 Oil fired, normal Firing					
5						
6	Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)	
7	32	FO6	0.316	0.112	47.4	
8						
9						
10	fired, normal Firing, Low NOx burner					
11						
12	Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)	
13	17	FO6	0.265	0.102	39.8	
14						
15						
16	lo. 6 Oil fired, tangential Firing					
17						
18	Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)	
19	33	FO6	0.211	0.114	31.7	
20						
21						
22	ired, tangential Firing, Low NOx burner					
23						
24	Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)	
25	2	FO6	0.175	0.035	26.3	
26						
27						
28	lo. 2 Oil fired, tangential Firing					
29						
30	Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)	
31	3	FO2	0.169	0.065	23.7	
32						
33						

	A	B	C
1	No. 6 Oil Fired, Normal Firing - third quarter 1996		
2	Entry #	Util Code	Control Type
3	1	5107	UNCONTROLLED
4	2	7140	UNCONTROLLED
5	3	1167	UNCONTROLLED
6	4	14940	UNCONTROLLED
7	5	4176	UNCONTROLLED
8	6	1167	UNCONTROLLED
9	7	6455	UNCONTROLLED
10	8	9617	UNCONTROLLED
11	9	6452	UNCONTROLLED
12	10	7140	UNCONTROLLED
13	11	6452	UNCONTROLLED
14	12	9617	UNCONTROLLED
15	13	17166	UNCONTROLLED
16	14	9617	UNCONTROLLED
17	15	10623	UNCONTROLLED
18	16	6909	UNCONTROLLED
19	17	17166	UNCONTROLLED
20	18	2951	UNCONTROLLED
21	19	17166	UNCONTROLLED
22	20	6452	UNCONTROLLED
23	21	6452	UNCONTROLLED
24	22	10623	UNCONTROLLED
25	23	17166	UNCONTROLLED
26	24	6452	UNCONTROLLED
27	25	6452	UNCONTROLLED
28	26	17166	UNCONTROLLED
29	27	963	UNCONTROLLED
30	28	6452	UNCONTROLLED
31	29	5335	UNCONTROLLED
32	30	6452	UNCONTROLLED
33	31	2951	UNCONTROLLED
34	32	6452	UNCONTROLLED
35			
36			
37			
38			

	D	E	F
1	CEMS data, used in 1998 update of AP-42, section 1.3		
2	Utility	YEAR	Primary/Secondary Fuel
3	Detroit City of	1950	FO6
4	Georgia Power Company	1952	FO6
5	Baltimore Gas and Electric Company	1952	Nat Gas/FO6
6	PECO Energy Company	1953	FO6
7	Northeast Utilities Service Co.	1954	FO6
8	Baltimore Gas and Electric Company	1955	Nat Gas/FO6
9	Florida Power Corporation	1956	FO6/Nat Gas
10	Jacksonville Electric Authority	1958	FO6/Nat Gas
11	Florida Power & Light Company	1958	FO6
12	Georgia Power Company	1959	FO6
13	Florida Power & Light Company	1959	Nat Gas/FO6
14	Jacksonville Electric Authority	1961	FO6/Nat Gas
15	Sierra Pacific Power Company	1963	Nat Gas/FO6
16	Jacksonville Electric Authority	1964	FO6/Nat Gas
17	Lakeland Electric & Water Utilities	1965	Nat Gas/FO6
18	Gainesville Regional Utilities	1965	Nat Gas/FO6
19	Sierra Pacific Power Company	1965	Nat Gas/FO6
20	Canal Electric Co	1968	FO6
21	Sierra Pacific Power Company	1968	Nat Gas
22	Florida Power & Light Company	1969	Nat Gas/FO6
23	Florida Power & Light Company	1969	FO6
24	Lakeland Electric & Water Utilities	1970	Nat Gas/FO6
25	Sierra Pacific Power Company	1971	Nat Gas/FO6
26	Florida Power & Light Company	1972	FO6
27	Florida Power & Light Company	1973	FO6
28	Sierra Pacific Power Company	1974	Nat Gas/FO6
29	Atlantic City Electric Company	1974	FO6
30	Florida Power & Light Company	1975	Nat Gas/FO6
31	D/FD Operating Services LLC	1975	FO6/Nat Gas
32	Florida Power & Light Company	1976	FO6
33	Canal Electric Co	1976	FO6
34	Florida Power & Light Company	1977	FO6
35			
36			
37			
38			

	G	H	I	J	K	L	M
1							
2	orispl	Plant	State	Region	Unit/Stack	Firing Type	SO2 Controls
3	1822	Mistersky	MI	5	5	DB	U
4	715	Mcmanus	GA	4	1	DB	U
5	1553	Gould Street	MD	3	3	DB	U
6	3160	Delaware	PA	3	71	DB	U
7	562	Middletown	CT	1	1	DB	U
8	1554	Herbert A Wagner	MD	3	1	DB	U
9	638	Suwannee River	FL	4	3	DB	U
10	668	Southside	FL	4	4	DB	U
11	612	Fort Myers	FL	4	PFM1	DB	U
12	715	Mcmanus	GA	4	2	DB	U
13	620	Sanford	FL	4	PSN3	DB	U
14	666	J D Kennedy	FL	4	10	DB	U
15	2336	Tracy	NV	9	1	DB	U
16	668	Southside	FL	4	5	DB	U
17	675	Larsen Memorial	FL	4	7	DB	U
18	664	J R Kelly	FL	4	JRK8	DB	U
19	2336	Tracy	NV	9	2	DB	U
20	1599	Canal	MA	1	1	DB	U
21	2330	Fort Churchill	NV	9	1	DB	U
22	609	Cape Canaveral	FL	4	PCC2	DB	U
23	612	Fort Myers	FL	4	PFM2	DB	U
24	676	C D Mcintosh Jr	FL	4	1	DB	U
25	2330	Fort Churchill	NV	9	2	DB	U
26	620	Sanford	FL	4	PSN4	DB	U
27	620	Sanford	FL	4	PSN5	DB	U
28	2336	Tracy	NV	9	3	DB	U
29	2378	B L England	NJ	2	3	DB	U
30	609	Cape Canaveral	FL	4	PCC1	DB	U
31	599	Mckee Run	DE	3	3	DB	U
32	6042	Manatee	FL	4	PMT1	DB	U
33	1599	Canal	MA	1	2	DB	U
34	6042	Manatee	FL	4	PMT2	DB	U
35							
36							
37							
38							

	N	O	P	Q	R
1					
2	NOX Controls	OP Hours	Gross Unit Load	Heat Input	SO2 Tons-3Q
3	U	2208	21754	317905	98
4	U	423	4754	80280	115
5	U	612	18483	254078	13
6	U	591	37065	461902	99
7	U	894	28553	302457	19
8	U	662	25926	377821	7
9	U	2105	111546	1057520	581
10	U	372	9512	120078	31
11	U	1844	165861	1661123	1595
12	U	430	8825	131062	188
13	U	1263	95422	1327603	1101
14	U	620	40544	429696	128
15	U	2104	60508	516790	0
16	U	693	37015	400634	136
17	U	360	7499	119923	52
18	U	1379	34503	437419	0
19	U	1778	76320	483184	0
20	U	1938	665545	6898240	3324
21	U	2208	200656	1994763	1
22	U	2043	550216	6565002	4048
23	U	2126	581530	6270145	6314
24	U	751	33846	475851	79
25	U	2205	164463	1629771	1
26	U	2036	490320	5051072	3353
27	U	2084	530860	5563746	3974
28	U	2058	161455	1618037	5
29	U	406	19832	285878	140
30	U	2155	602679	6134785	3500
31	U	997	51794	652802	132
32	U	2081	743670	9347715	4582
33	U	1320	306659	3734654	1356
34	U	996	357649	4004497	2146
35					Mean
36					Sample Std Dev
37					
38					

	S	T	U
1			
2	Emission NOX Fact	CO2 Tons-3Q	
3	0.217	25731	
4	0.394	6952	
5	0.186	5752842	
6	0.330	37388	
7	0.214	6082	
8	0.140	17886	
9	0.361	185	
10	0.169	8660	
11	0.416	134454	
12	0.370	11366	
13	0.405	102212	
14	0.257	33407	
15	0.288	32877	
16	0.203	32903	
17	0.242	8041	
18	0.166	26045	
19	0.343	30467	
20	0.229	558344	
21	0.418	125695	
22	0.444	477128	
23	0.575	507506	
24	0.295	29690	
25	0.346	102663	
26	0.522	373648	
27	0.505	412738	
28	0.329	102727	
29	0.196	23329	
30	0.453	437245	
31	0.329	39443	
32	0.247	756604	
33	0.246	286812	
34	0.265	324123	
35	0.316		
36	0.112		
37			
38			

	A	B	C
1	No. 6 Oil Fired, Normal Firing, Low NOx Burner -		
2	Entry #	Util Code	Control Type
3	1	3266	With LNBs
4	2	3266	With LNBs
5	3	6452	With LNBs
6	4	6452	With LNBs
7	5	6452	With LNBs
8	6	6452	With LNBs
9	7	6452	With LNBs
10	8	6452	With LNBs
11	9	6452	With LNBs
12	10	6452	With LNBs
13	11	13433	With LNBs
14	12	5027	With LNBs
15	13	13433	With LNBs
16	14	15296	With LNBs and OFA
17	15	9617	With LNBs and OFA
18	16	6452	With LNBs
19	17	6452	With LNBs
20			
21			
22			

	D	E	F
1	third quarter 1996 CEMS data, used in the 1998 update of AP-42, section 1.3		
2	Utility	YEAR	Primary/Secondary Fuel
3	Central Maine Power Company	1957	FO6
4	Central Maine Power Company	1958	FO6
5	Florida Power & Light Company	1960	FO6/Nat Gas
6	Florida Power & Light Company	1961	FO6/Nat Gas
7	Florida Power & Light Company	1962	Nat Gas/FO6
8	Florida Power & Light Company	1963	Nat Gas/FO6
9	Florida Power & Light Company	1964	FO6/Nat Gas
10	Florida Power & Light Company	1965	FO6/Nat Gas
11	Florida Power & Light Company	1967	Nat Gas/FO6
12	Florida Power & Light Company	1968	FO6/Nat Gas
13	New England Power Service Company	1972	FO6
14	Delmarva Power	1973	FO6/Nat Gas
15	New England Power Service Company	1974	FO6
16	New York Power Authority	1976	FO6/Nat Gas
17	Jacksonville Electric Authority	1977	FO6
18	Florida Power & Light Company	1980	FO6/Nat Gas
19	Florida Power & Light Company	1981	Nat Gas/FO6
20			
21			
22			

	G	H	I	J	K	L	M
1							
2	orispl	Plant	State	Region	Unit/Stack	Firing Type	SO2 Controls
3	1507	William F Wyman	ME	1	1	DB	U
4	1507	William F Wyman	ME	1	2	DB	U
5	617	Port Everglades	FL	4	PPE1	DB	U
6	617	Port Everglades	FL	4	PPE2	DB	U
7	619	Riviera	FL	4	PRV3	DB	U
8	619	Riviera	FL	4	PRV4	DB	U
9	617	Port Everglades	FL	4	PPE3	DB	U
10	617	Port Everglades	FL	4	PPE4	DB	U
11	621	Turkey Point	FL	4	PTP1	DB	U
12	621	Turkey Point	FL	4	PTP2	DB	U
13	1626	Salem Harbor	MA	1	4	DB	U
14	593	Edge Moor	DE	3	5	DB	U
15	1619	Brayton Point	MA	1	4	DB	U
16	2491	Charles Poletti	NY	2	1 (# 6)	DB	U
17	667	Northside	FL	4	3	DB	U
18	6043	Martin	FL	4	PMR1	DB	U
19	6043	Martin	FL	4	PMR2	DB	U
20							
21							
22							

	N	O	P	Q	R
1					
2	NOX Controls	OP Hours	Gross Unit Load	Heat Input	SO2 Tons-3Q
3	LNB	422	10289	155438	144
4	LNB	477	11174	163568	155
5	LNB	1893	230346	2696248	847
6	LNB	1921	235782	2782195	942
7	LNB	1337	280590	3618767	3374
8	LNB	2086	440064	5391374	5446
9	LNB	2024	476570	5422178	1414
10	LNB	1962	445743	5250413	1788
11	LNB	2080	580023	7378457	1909
12	LNB	2186	594025	6529479	1632
13	LNB	1419	351871	4233049	4273
14	LNB	1986	424117	4417398	902
15	LNB	1216	238800	2640856	502
16	LNBO	1827	537996	6452122	279
17	LNBO	2122	525719	7604034	3823
18	LNB	2102	801620	8681923	1839
19	LNB	2160	887458	10832941	1981
20					Mean
21					Sample Std Dev
22					

	S	T	U
1			
2	mission NOX Fact	CO2 Tons-3Q	
3	0.385	12496	
4	0.426	13297	
5	0.220	190112	
6	0.197	196765	
7	0.392	278857	
8	0.447	429139	
9	0.314	380775	
10	0.326	386598	
11	0.226	480595	
12	0.296	424348	
13	0.243	342622	
14	0.176	311870	
15	0.151	167187	
16	0.189	403908	
17	0.240	553865	
18	0.131	597569	
19	0.140	746615	
20	0.265		
21	0.102		
22			

	A	B	C	D
1	No. 6 Oil Fired, Tangential Firing - third quarter 1996 CEMS data, used in the 1998 update of AP-42, secti			
2	Entry #	Util Code	Control Type	Utility
3	1	15477	Uncontrolled	Public Service Electric and Gas Co
4	2	15477	Uncontrolled	Public Service Electric and Gas Co
5	3	15477	Uncontrolled	Public Service Electric and Gas Co
6	4	15477	Uncontrolled	Public Service Electric and Gas Co
7	5	13573	Uncontrolled	Niagara Mohawk Power Corporation
8	6	13573	Uncontrolled	Niagara Mohawk Power Corporation
9	7	6455	Uncontrolled	Florida Power Corporation
10	8	15477	Uncontrolled	Public Service Electric & Gas Co.
11	9	13573	Uncontrolled	Niagara Mohawk Power Corporation
12	10	4176	Uncontrolled	Northeast Utilities Service Co.
13	11	13573	Uncontrolled	Niagara Mohawk Power Corporation
14	12	14154	Uncontrolled	Orange and Rockland Utilities, Inc.
15	13	14940	Uncontrolled	PECO Energy Company
16	14	20455	Uncontrolled	Northeast Utilities Service Co.
17	15	14940	Uncontrolled	PECO Energy Company
18	16	6455	Uncontrolled	Florida Power Corporation
19	17	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.
20	18	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.
21	19	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.
22	20	6455	Uncontrolled	Florida Power Corporation
23	21	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.
24	22	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.
25	23	4176	Uncontrolled	Northeast Utilities Service Co.
26	24	5027	Uncontrolled	Delmarva Power
27	25	4176	Uncontrolled	Northeast Utilities Service Co.
28	26	14610	Uncontrolled	Orlando Utilities Comm
29	27	6455	Uncontrolled	Florida Power Corporation
30	28	19497	Uncontrolled	The United Illuminating Company
31	29	15270	Uncontrolled	Potomac Electric Power Company
32	30	14715	Uncontrolled	Pennsylvania Power & Light Company
33	31	14715	Uncontrolled	Pennsylvania Power & Light Company
34	32	19876	Uncontrolled	Virginia Power
35	33	6455	Uncontrolled	Florida Power Corporation
36				
37				
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	E	F	G	H	I
1	on 1.3.				
2	YEAR	Primary/Secondary Fuel	orispl	Plant	State
3	1948	Nat Gas/FO6	2411	Sewaren	NJ
4	1948	Nat Gas/FO6	2411	Sewaren	NJ
5	1949	Nat Gas/FO6	2411	Sewaren	NJ
6	1951	Nat Gas/FO6	2411	Sewaren	NJ
7	1952	Nat Gas/FO6	2539	Albany	NY
8	1952	Nat Gas/FO6	2539	Albany	NY
9	1953	FO6/Nat Gas	638	Suwannee River	FL
10	1953	FO6	2404	Kearny	NJ
11	1953	Nat Gas/FO6	2539	Albany	NY
12	1954	FO6/Nat Gas	546	Montville	CT
13	1954	Nat Gas/FO6	2539	Albany	NY
14	1955	FO6/Nat Gas	2629	Lovett	NY
15	1955	FO6	3159	Cromby	PA
16	1957	FO6/Nat Gas	1642	West Springfield	MA
17	1958	FO6	3169	Schuylkill	PA
18	1961	FO6	634	P L Bartow	FL
19	1961	FO6/Nat Gas	8906	Astoria	NY
20	1962	Nat Gas/FO6	2500	Ravenswood	NY
21	1962	FO6/Nat Gas	8906	Astoria	NY
22	1963	FO6/Nat Gas	634	P L Bartow	FL
23	1963	Nat Gas/FO6	2500	Ravenswood	NY
24	1965	FO6/Nat Gas	2500	Ravenswood	NY
25	1971	FO6	546	Montville	CT
26	1971	FO6	1564	Vienna	MD
27	1973	FO6	562	Middletown	CT
28	1973	Nat Gas/FO6	683	Indian River	FL
29	1974	FO6	8048	Anclote	FL
30	1975	FO6/Nat Gas	6156	New Haven Harbor	CT
31	1975	FO6/Nat Gas	1571	Chalk Point	MD
32	1975	FO6	3148	Martins Creek	PA
33	1976	FO6	3148	Martins Creek	PA
34	1976	FO6/Nat Gas	3809	Yorktown	VA
35	1978	FO6	8048	Anclote	FL
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	J	K	L	M	N	O
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2	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours
3	2	1	T	U	U	234
4	2	2	T	U	U	346
5	2	3	T	U	U	626
6	2	4	T	U	U	830
7	2	2	T	U	U	1296
8	2	1	T	U	U	1305
9	4	1	T	U	U	997
10	2	7	T	U	U	234
11	2	3	T	U	U	717
12	1	5	T	U	U	1628
13	2	4	T	U	U	807
14	2	3	T	U	U	590
15	3	2	T	U	U	876
16	1	3	T	U	U	1395
17	3	1	T	U	U	413
18	4	2	T	U	U	2084
19	2	40	T	U	U	1892
20	2	10	T	U	U	1286
21	2	50	T	U	U	2100
22	4	3	T	U	U	1795
23	2	20	T	U	U	1379
24	2	30	T	U	U	1729
25	1	6	T	U	U	1572
26	3	8	T	U	U	870
27	1	4	T	U	U	1379
28	4	3	T	U	U	1894
29	4	1	T	U	U	2184
30	1	NHB1	T	U	U	2208
31	3	3	T	U	U	803
32	3	3	T	U	U	454
33	3	4	T	U	U	934
34	3	3	T	U	U	522
35	4	2	T	U	U	2171
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	P	Q	R	S	T
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2	Gross Unit Load	Heat Input	SO2 Tons-3Q	Emission NOX Fact	CO2 Tons-3Q
3	9078	99096	0	0.114	5591
4	18080	168855	0	0.103	9499
5	27727	340098	1	0.110	19189
6	38093	487276	1	0.138	26974
7	71081	781377	84	0.135	49868
8	68665	847569	71	0.108	53250
9	22777	287731	212	0.351	12579
10	8704	126089	19	0.171	10626
11	39994	444402	22	0.115	27263
12	75598	921734	203	0.174	65379
13	47626	550767	23	0.094	33595
14	27886	392755	5	0.145	25672
15	119112	1457852	226	0.190	97858
16	78958	968057	86	0.165	57672
17	36071	446974	102	0.320	36178
18	156639	1519804	2063	0.523	142520
19	436363	5464322	165	0.144	344148
20	259481	3581094	1	0.119	212288
21	506435	5443314	154	0.133	359029
22	259022	2645440	2372	0.414	215977
23	330704	4137080	39	0.086	247872
24	840921	9778730	110	0.141	645280
25	233442	3343385	1352	0.162	270615
26	73286	902699	806	0.295	73066
27	218951	3459723	813	0.190	280032
28	320299	3391320	177	0.230	210415
29	662612	7253341	5694	0.379	565115
30	624572	6744371	2688	0.175	545146
31	214716	2456759	742	0.203	176087
32	148181	1899541	883	0.383	165226
33	293065	3663379	886	0.253	281060
34	223411	2386233	1308	0.283	193140
35	667611	7335541	5491	0.414	581115
36			Mean	0.211	
37			Sample Std Dev	0.114	
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	A	B	C	D
1	gential Firing, Low NOx Burners			
2	Entry #	Util Code	Control Type	Utility
3	1	15270	With LNBs	Potomac Electric Power Company
4	2	15472	With LNBs	Northeast Utilities Service Co.
5				
6				
7				

	E	F	G	H	I
1					
2	YEAR	Primary/Secondary Fuel	orispl	Plant	State
3	1981	FO6/Nat Gas	1571	Chalk Point	MD
4	1974	FO6/Crude	8002	Newington	NH
5					
6					
7					

	J	K	L	M	N	O
1					Third quarter 1996	CEMS data, us
2	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours
3	3	4	T	U	LNB	672
4	1	1	T	U	LNB	1554
5						
6						
7						

	P	Q	R	S	T
1	ed in the 1998 update of AP-42, section 1.3.				
2	Gross Unit Load	Heat Input	SO2 Tons-3Q	Emission NOX Factc	CO2 Tons-3Q
3	169341	2256162	327	0.150	155475
4	312536	4051451	3447	0.199	328113
5			Mean	0.174	
6			Sample Std Dev	0.035	
7					

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	A	B	C	D
1	ired, Tangential Firing			
2	Entry #	Util Code	Control Type	Utility
3	1	7140	Uncontrolled	Georgia Power Company
4	2	7140	Uncontrolled	Georgia Power Company
5	3	7140	Uncontrolled	Georgia Power Company
6				
7				
8				

	E	F	G	H	I
1					
2	YEAR	Primary/Secondary Fuel	orispl	Plant	State
3	1941	FO2/Nat Gas	700	Atkinson	GA
4	1945	FO2/Nat Gas	700	Atkinson	GA
5	1948	FO2/Nat Gas	700	Atkinson	GA
6					
7					
8					

	J	K	L	M	N	O
1					Third quarter 1996	CEMS data, us
2	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours
3	4	A2	T	U	U	376
4	4	A3	T	U	U	391
5	4	A4	T	U	U	314
6						
7						
8						

	P	Q	R	S	T
1	ed in the 1998 update of AP-42, section		1.3.		
	Gross Unit Load	Heat Input	SO2 Tons-3Q	mission NOX Fact	CO2 Tons-3Q
3	5897	148031	5	0.098	9356
4	7444	124153	3	0.186	7710
5	6536	96411	2	0.224	5937
6			Mean	0.169	
7			Sample Std Dev	0.065	
8					

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Name	Type	Modified	Size	Ratio	Packed	Path
Oilraw.wk4	WK4 File	11/15/99 9:52 AM	40,168	69%	12,637	
Oilraw.xlw	Microsoft Excel Workspace	9/29/98 9:51 AM	57,128	73%	15,351	
2 file(s)			**97,296**	**71%**	**27,988**	

Oil Fired Summary Table

No. 6 Oil fired, normal Firing

Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)
32	FO6	0.316	0.112	47.4

No. 6 Oil fired, normal Firing, Low NOx burner

Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)
17	FO6	0.265	0.102	39.8

No. 6 Oil fired, tangential Firing

Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)
33	FO6	0.211	0.114	31.7

No. 6 Oil fired, tangential Firing, Low NOx burner

Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)
2	FO6	0.175	0.035	26.3

No. 2 Oil fired, tangential Firing

Entries	Fuel Type	Average EF (lb/MM Btu)	Std Dev	EF(lb/103gal)
3	FO2	0.169	0.065	23.7

No. 6 Oil Fired, Normal Firing - third quarter 1996 CEMS data, used in 1998 update of AP-42, section 1.3

Entry #	Util Code	Control Type	Utility	YEAR	Primary/Secondary Fuel	orispl	Plant	State	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours	Gross Unit Load	Heat Input	SO2 Tons-3Q	Uncontrolled Emission NOX Factor (lb/MMBtu)	CO2 Tons-3Q
1	5107	UNCONTROLLED	Detroit City of	1950	FO6	1822	Mistersky	MI	5	5	DB	U	U	2208	21754	317905	98	0.217	25731
2	7140	UNCONTROLLED	Georgia Power Company	1952	FO6	715	Mcmanus	GA	4	1	DB	U	U	423	4754	80280	115	0.394	6952
3	1167	UNCONTROLLED	Baltimore Gas and Electric Company	1952	Nat Gas/FO6	1553	Gould Street	MD	3	3	DB	U	U	612	18483	254078	13	0.186	5752842
4	14940	UNCONTROLLED	PECO Energy Company	1953	FO6	3160	Delaware	PA	3	71	DB	U	U	591	37065	461902	99	0.330	37388
5	4176	UNCONTROLLED	Northeast Utilities Service Co.	1954	FO6	562	Middletown	CT	1	1	DB	U	U	894	28553	302457	19	0.214	6082
6	1167	UNCONTROLLED	Baltimore Gas and Electric Company	1955	Nat Gas/FO6	1554	Herbert A Wagner	MD	3	1	DB	U	U	662	25926	377821	7	0.140	17886
7	6455	UNCONTROLLED	Florida Power Corporation	1956	FO6/Nat Gas	638	Suwannee River	FL	4	3	DB	U	U	2105	111546	1057520	581	0.361	185
8	9617	UNCONTROLLED	Jacksonville Electric Authority	1958	FO6/Nat Gas	668	Southside	FL	4	4	DB	U	U	372	9512	120078	31	0.169	8660
9	6452	UNCONTROLLED	Florida Power & Light Company	1958	FO6	612	Fort Myers	FL	4	PFM1	DB	U	U	1844	165861	1661123	1595	0.416	134454
10	7140	UNCONTROLLED	Georgia Power Company	1959	FO6	715	Mcmanus	GA	4	2	DB	U	U	430	8825	131062	188	0.370	11366
11	6452	UNCONTROLLED	Florida Power & Light Company	1959	Nat Gas/FO6	620	Sanford	FL	4	PSN3	DB	U	U	1263	95422	1327603	1101	0.405	102212
12	9617	UNCONTROLLED	Jacksonville Electric Authority	1961	FO6/Nat Gas	666	J D Kennedy	FL	4	10	DB	U	U	620	40544	429696	128	0.257	33407
13	17166	UNCONTROLLED	Sierra Pacific Power Company	1963	Nat Gas/FO6	2336	Tracy	NV	9	1	DB	U	U	2104	60508	516790	0	0.288	32877
14	9617	UNCONTROLLED	Jacksonville Electric Authority	1964	FO6/Nat Gas	668	Southside	FL	4	5	DB	U	U	693	37015	400634	136	0.203	32903
15	10623	UNCONTROLLED	Lakeland Electric & Water Utilities	1965	Nat Gas/FO6	675	Larsen Memorial	FL	4	7	DB	U	U	360	7499	119923	52	0.242	8041
16	6909	UNCONTROLLED	Gainesville Regional Utilities	1965	Nat Gas/FO6	664	J R Kelly	FL	4	JRK8	DB	U	U	1379	34503	437419	0	0.166	26045
17	17166	UNCONTROLLED	Sierra Pacific Power Company	1965	Nat Gas/FO6	2336	Tracy	NV	9	2	DB	U	U	1778	76320	483184	0	0.343	30467
18	2951	UNCONTROLLED	Canal Electric Co	1968	FO6	1599	Canal	MA	1	1	DB	U	U	1938	665545	6898240	3324	0.229	558344
19	17166	UNCONTROLLED	Sierra Pacific Power Company	1968	Nat Gas	2330	Fort Churchill	NV	9	1	DB	U	U	2208	200656	1994763	1	0.418	125695
20	6452	UNCONTROLLED	Florida Power & Light Company	1969	Nat Gas/FO6	609	Cape Canaveral	FL	4	PCC2	DB	U	U	2043	550216	6565002	4048	0.444	477128
21	6452	UNCONTROLLED	Florida Power & Light Company	1969	FO6	612	Fort Myers	FL	4	PFM2	DB	U	U	2126	581530	6270145	6314	0.575	507506
22	10623	UNCONTROLLED	Lakeland Electric & Water Utilities	1970	Nat Gas/FO6	676	C D Mcintosh Jr	FL	4	1	DB	U	U	751	33846	475851	79	0.295	29690
23	17166	UNCONTROLLED	Sierra Pacific Power Company	1971	Nat Gas/FO6	2330	Fort Churchill	NV	9	2	DB	U	U	2205	164463	1629771	1	0.346	102663
24	6452	UNCONTROLLED	Florida Power & Light Company	1972	FO6	620	Sanford	FL	4	PSN4	DB	U	U	2036	490320	5051072	3353	0.522	373648
25	6452	UNCONTROLLED	Florida Power & Light Company	1973	FO6	620	Sanford	FL	4	PSN5	DB	U	U	2084	530860	5563746	3974	0.505	412738
26	17166	UNCONTROLLED	Sierra Pacific Power Company	1974	Nat Gas/FO6	2336	Tracy	NV	9	3	DB	U	U	2058	161455	1618037	5	0.329	102727
27	963	UNCONTROLLED	Atlantic City Electric Company	1974	FO6	2378	B L England	NJ	2	3	DB	U	U	406	19832	285878	140	0.196	23329
28	6452	UNCONTROLLED	Florida Power & Light Company	1975	Nat Gas/FO6	609	Cape Canaveral	FL	4	PCC1	DB	U	U	2155	602679	6134785	3500	0.453	437245
29	5335	UNCONTROLLED	D/FD Operating Services LLC	1975	FO6/Nat Gas	599	Mckee Run	DE	3	3	DB	U	U	997	51794	652802	132	0.329	39443
30	6452	UNCONTROLLED	Florida Power & Light Company	1976	FO6	6042	Manatee	FL	4	PMT1	DB	U	U	2081	743670	9347715	4582	0.247	756604
31	2951	UNCONTROLLED	Canal Electric Co	1976	FO6	1599	Canal	MA	1	2	DB	U	U	1320	306659	3734654	1356	0.246	286812
32	6452	UNCONTROLLED	Florida Power & Light Company	1977	FO6	6042	Manatee	FL	4	PMT2	DB	U	U	996	357649	4004497	2146	0.265	324123
																	Mean	**0.316**	
																	Sample Std Dev	**0.112**	

No. 6 Oil Fired, Normal Firing - third quarter 1996 CEMS data, used in 1998 update of AP-42, section 1.3

Entry #	Util Code	Control Type	Utility	YEAR	Primary/Secondary Fuel	orispl	Plant	State	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours	Gross Unit Load	Heat Input	SO2 Tons-3Q	Uncontrolled Emission NOX Factor (lb/MMBtu)	CO2 Tons-3Q
1	5107	UNCONTROLLED	Detroit City of	1950	FO6	1822	Mistersky	MI	5	5	DB	U	U	2208	21754	317905	98	0.217	25731
2	7140	UNCONTROLLED	Georgia Power Company	1952	FO6	715	Mcmanus	GA	4	1	DB	U	U	423	4754	80280	115	0.394	6952
3	1167	UNCONTROLLED	Baltimore Gas and Electric Company	1952	Nat Gas/FO6	1553	Gould Street	MD	3	3	DB	U	U	612	18483	254078	13	0.186	5752842
4	14940	UNCONTROLLED	PECO Energy Company	1953	FO6	3160	Delaware	PA	3	71	DB	U	U	591	37065	461902	99	0.330	37388
5	4176	UNCONTROLLED	Northeast Utilities Service Co.	1954	FO6	562	Middletown	CT	1	1	DB	U	U	894	28553	302457	19	0.214	6082
6	1167	UNCONTROLLED	Baltimore Gas and Electric Company	1955	Nat Gas/FO6	1554	Herbert A Wagner	MD	3	1	DB	U	U	662	25926	377821	7	0.140	17886
7	6455	UNCONTROLLED	Florida Power Corporation	1956	FO6/Nat Gas	638	Suwannee River	FL	4	3	DB	U	U	2105	111546	1057520	581	0.361	185
8	9617	UNCONTROLLED	Jacksonville Electric Authority	1958	FO6/Nat Gas	668	Southside	FL	4	4	DB	U	U	372	9512	120078	31	0.169	8660
9	6452	UNCONTROLLED	Florida Power & Light Company	1958	FO6	612	Fort Myers	FL	4	PFM1	DB	U	U	1844	165861	1661123	1595	0.416	134454
10	7140	UNCONTROLLED	Georgia Power Company	1959	FO6	715	Mcmanus	GA	4	2	DB	U	U	430	8825	131062	188	0.370	11366
11	6452	UNCONTROLLED	Florida Power & Light Company	1959	Nat Gas/FO6	620	Sanford	FL	4	PSN3	DB	U	U	1263	95422	1327603	1101	0.405	102212
12	9617	UNCONTROLLED	Jacksonville Electric Authority	1961	FO6/Nat Gas	666	J D Kennedy	FL	4	10	DB	U	U	620	40544	429696	128	0.257	33407
13	17166	UNCONTROLLED	Sierra Pacific Power Company	1963	Nat Gas/FO6	2336	Tracy	NV	9	1	DB	U	U	2104	60508	516790	0	0.288	32877
14	9617	UNCONTROLLED	Jacksonville Electric Authority	1964	FO6/Nat Gas	668	Southside	FL	4	5	DB	U	U	693	37015	400634	136	0.203	32903
15	10623	UNCONTROLLED	Lakeland Electric & Water Utilities	1965	Nat Gas/FO6	675	Larsen Memorial	FL	4	7	DB	U	U	360	7499	119923	52	0.242	8041
16	6909	UNCONTROLLED	Gainesville Regional Utilities	1965	Nat Gas/FO6	664	J R Kelly	FL	4	JRK8	DB	U	U	1379	34503	437419	0	0.166	26045
17	17166	UNCONTROLLED	Sierra Pacific Power Company	1965	Nat Gas/FO6	2336	Tracy	NV	9	2	DB	U	U	1778	76320	483184	0	0.343	30467
18	2951	UNCONTROLLED	Canal Electric Co	1968	FO6	1599	Canal	MA	1	1	DB	U	U	1938	665545	6898240	3324	0.229	558344
19	17166	UNCONTROLLED	Sierra Pacific Power Company	1968	Nat Gas	2330	Fort Churchill	NV	9	1	DB	U	U	2208	200656	1994763	1	0.418	125695
20	6452	UNCONTROLLED	Florida Power & Light Company	1969	Nat Gas/FO6	609	Cape Canaveral	FL	4	PCC2	DB	U	U	2043	550216	6565002	4048	0.444	477128
21	6452	UNCONTROLLED	Florida Power & Light Company	1969	FO6	612	Fort Myers	FL	4	PFM2	DB	U	U	2126	581530	6270145	6314	0.575	507506
22	10623	UNCONTROLLED	Lakeland Electric & Water Utilities	1970	Nat Gas/FO6	676	C D Mcintosh Jr	FL	4	1	DB	U	U	751	33846	475851	79	0.295	29690
23	17166	UNCONTROLLED	Sierra Pacific Power Company	1971	Nat Gas/FO6	2330	Fort Churchill	NV	9	2	DB	U	U	2205	164463	1629771	1	0.346	102663
24	6452	UNCONTROLLED	Florida Power & Light Company	1972	FO6	620	Sanford	FL	4	PSN4	DB	U	U	2036	490320	5051072	3353	0.522	373648
25	6452	UNCONTROLLED	Florida Power & Light Company	1973	FO6	620	Sanford	FL	4	PSN5	DB	U	U	2084	530860	5563746	3974	0.505	412738
26	17166	UNCONTROLLED	Sierra Pacific Power Company	1974	Nat Gas/FO6	2336	Tracy	NV	9	3	DB	U	U	2058	161455	1618037	5	0.329	102727
27	963	UNCONTROLLED	Atlantic City Electric Company	1974	FO6	2378	B L England	NJ	2	3	DB	U	U	406	19832	285878	140	0.196	23329
28	6452	UNCONTROLLED	Florida Power & Light Company	1975	Nat Gas/FO6	609	Cape Canaveral	FL	4	PCC1	DB	U	U	2155	602679	6134785	3500	0.453	437245
29	5335	UNCONTROLLED	D/FD Operating Services LLC	1975	FO6/Nat Gas	599	Mckee Run	DE	3	3	DB	U	U	997	51794	652802	132	0.329	39443
30	6452	UNCONTROLLED	Florida Power & Light Company	1976	FO6	6042	Manatee	FL	4	PMT1	DB	U	U	2081	743670	9347715	4582	0.247	756604
31	2951	UNCONTROLLED	Canal Electric Co	1976	FO6	1599	Canal	MA	1	2	DB	U	U	1320	306659	3734654	1356	0.246	286812
32	6452	UNCONTROLLED	Florida Power & Light Company	1977	FO6	6042	Manatee	FL	4	PMT2	DB	U	U	996	357649	4004497	2146	0.265	324123
																	Mean	**0.316**	
																	Sample Std Dev	**0.112**	

No. 6 Oil Fired, Normal Firing, Low NOx Burner - third quarter 1996 CEMS data, used in the 1998 update of AP-42, section 1.3																			
Entry #	Util Code	Control Type	Utility	YEAR	Primary/Secondary Fuel	orispl	Plant	State	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours	Gross Unit Load	Heat Input	SO2 Tons-3Q	Uncontrolled Emission NOX Factor (lb/MMBtu)	CO2 Tons-3Q
1	3266	With LNBs	Central Maine Power Company	1957	FO6	1507	William F Wyman	ME	1	1	DB	U	LNB	422	10289	155438	144	0.385	12496
2	3266	With LNBs	Central Maine Power Company	1958	FO6	1507	William F Wyman	ME	1	2	DB	U	LNB	477	11174	163568	155	0.426	13297
3	6452	With LNBs	Florida Power & Light Company	1960	FO6/Nat Gas	617	Port Everglades	FL	4	PPE1	DB	U	LNB	1893	230346	2696248	847	0.220	190112
4	6452	With LNBs	Florida Power & Light Company	1961	FO6/Nat Gas	617	Port Everglades	FL	4	PPE2	DB	U	LNB	1921	235782	2782195	942	0.197	196765
5	6452	With LNBs	Florida Power & Light Company	1962	Nat Gas/FO6	619	Riviera	FL	4	PRV3	DB	U	LNB	1337	280590	3618767	3374	0.392	278857
6	6452	With LNBs	Florida Power & Light Company	1963	Nat Gas/FO6	619	Riviera	FL	4	PRV4	DB	U	LNB	2086	440064	5391374	5446	0.447	429139
7	6452	With LNBs	Florida Power & Light Company	1964	FO6/Nat Gas	617	Port Everglades	FL	4	PPE3	DB	U	LNB	2024	476570	5422178	1414	0.314	380775
8	6452	With LNBs	Florida Power & Light Company	1965	FO6/Nat Gas	617	Port Everglades	FL	4	PPE4	DB	U	LNB	1962	445743	5250413	1788	0.326	386598
9	6452	With LNBs	Florida Power & Light Company	1967	Nat Gas/FO6	621	Turkey Point	FL	4	PTP1	DB	U	LNB	2080	580023	7378457	1909	0.226	480595
10	6452	With LNBs	Florida Power & Light Company	1968	FO6/Nat Gas	621	Turkey Point	FL	4	PTP2	DB	U	LNB	2186	594025	6529479	1632	0.296	424348
11	13433	With LNBs	New England Power Service Company	1972	FO6	1626	Salem Harbor	MA	1	4	DB	U	LNB	1419	351871	4233049	4273	0.243	342622
12	5027	With LNBs	Delmarva Power	1973	FO6/Nat Gas	593	Edge Moor	DE	3	5	DB	U	LNB	1986	424117	4417398	902	0.176	311870
13	13433	With LNBs	New England Power Service Company	1974	FO6	1619	Brayton Point	MA	1	4	DB	U	LNB	1216	238800	2640856	502	0.151	167187
14	15296	With LNBs and OFA	New York Power Authority	1976	FO6/Nat Gas	2491	Charles Poletti	NY	2	1 (# 6)	DB	U	LNBO	1827	537996	6452122	279	0.189	403908
15	9617	With LNBs and OFA	Jacksonville Electric Authority	1977	FO6	667	Northside	FL	4	3	DB	U	LNBO	2122	525719	7604034	3823	0.240	553865
16	6452	With LNBs	Florida Power & Light Company	1980	FO6/Nat Gas	6043	Martin	FL	4	PMR1	DB	U	LNB	2102	801620	8681923	1839	0.131	597569
17	6452	With LNBs	Florida Power & Light Company	1981	Nat Gas/FO6	6043	Martin	FL	4	PMR2	DB	U	LNB	2160	887458	10832941	1981	0.140	746615
																	Mean	0.265	
																	Sample Std Dev	0.102	

No. 6 Oil Fired, Tangential Firing - third quarter 1996 CEMS data, used in the 1998 update of AP-42, section 1.3.

Entry #	Util Code	Control Type	Utility	YEAR	Primary/Secondary Fuel	orispl	Plant	State	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours	Gross Unit Load	Heat Input	SO2 Tons-3Q	Uncontrolled Emission NOX Factor (lb/MMBtu)	CO2 Tons-3Q
1	15477	Uncontrolled	Public Service Electric and Gas Co	1948	Nat Gas/FO6	2411	Sewaren	NJ	2	1	T	U	U	234	9078	99096	0	0.114	5591
2	15477	Uncontrolled	Public Service Electric and Gas Co	1948	Nat Gas/FO6	2411	Sewaren	NJ	2	2	T	U	U	346	18080	168855	0	0.103	9499
3	15477	Uncontrolled	Public Service Electric and Gas Co	1949	Nat Gas/FO6	2411	Sewaren	NJ	2	3	T	U	U	626	27727	340098	1	0.110	19189
4	15477	Uncontrolled	Public Service Electric and Gas Co	1951	Nat Gas/FO6	2411	Sewaren	NJ	2	4	T	U	U	830	38093	487276	1	0.138	26974
5	13573	Uncontrolled	Niagara Mohawk Power Corporation	1952	Nat Gas/FO6	2539	Albany	NY	2	2	T	U	U	1296	71081	781377	84	0.135	49868
6	13573	Uncontrolled	Niagara Mohawk Power Corporation	1952	Nat Gas/FO6	2539	Albany	NY	2	1	T	U	U	1305	68665	847569	71	0.108	53250
7	6455	Uncontrolled	Florida Power Corporation	1953	FO6/Nat Gas	638	Suwannee River	FL	4	1	T	U	U	997	22777	287731	212	0.351	12579
8	15477	Uncontrolled	Public Service Electric & Gas Co.	1953	FO6	2404	Kearny	NJ	2	7	T	U	U	234	8704	126089	19	0.171	10626
9	13573	Uncontrolled	Niagara Mohawk Power Corporation	1953	Nat Gas/FO6	2539	Albany	NY	2	3	T	U	U	717	39994	444402	22	0.115	27263
10	4176	Uncontrolled	Northeast Utilities Service Co.	1954	FO6/Nat Gas	546	Montville	CT	1	5	T	U	U	1628	75598	921734	203	0.174	65379
11	13573	Uncontrolled	Niagara Mohawk Power Corporation	1954	Nat Gas/FO6	2539	Albany	NY	2	4	T	U	U	807	47626	550767	23	0.094	33595
12	14154	Uncontrolled	Orange and Rockland Utilities, Inc.	1955	FO6/Nat Gas	2629	Lovett	NY	2	3	T	U	U	590	27886	392755	5	0.145	25672
13	14940	Uncontrolled	PECO Energy Company	1955	FO6	3159	Cromby	PA	3	2	T	U	U	876	119112	1457852	226	0.190	97858
14	20455	Uncontrolled	Northeast Utilities Service Co.	1957	FO6/Nat Gas	1642	West Springfield	MA	1	3	T	U	U	1395	78958	968057	86	0.165	57672
15	14940	Uncontrolled	PECO Energy Company	1958	FO6	3169	Schuylkill	PA	3	1	T	U	U	413	36071	446974	102	0.320	36178
16	6455	Uncontrolled	Florida Power Corporation	1961	FO6	634	P L Bartow	FL	4	2	T	U	U	2084	156639	1519804	2063	0.523	142520
17	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.	1961	FO6/Nat Gas	8906	Astoria	NY	2	40	T	U	U	1892	436363	5464322	165	0.144	344148
18	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.	1962	Nat Gas/FO6	2500	Ravenswood	NY	2	10	T	U	U	1286	259481	3581094	1	0.119	212288
19	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.	1962	FO6/Nat Gas	8906	Astoria	NY	2	50	T	U	U	2100	506435	5443314	154	0.133	359029
20	6455	Uncontrolled	Florida Power Corporation	1963	FO6/Nat Gas	634	P L Bartow	FL	4	3	T	U	U	1795	259022	2645440	2372	0.414	215977
21	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.	1963	Nat Gas/FO6	2500	Ravenswood	NY	2	20	T	U	U	1379	330704	4137080	39	0.086	247872
22	4226	Uncontrolled	Consolidated Edison Co. of NY, Inc.	1965	FO6/Nat Gas	2500	Ravenswood	NY	2	30	T	U	U	1729	840921	9778730	110	0.141	645280
23	4176	Uncontrolled	Northeast Utilities Service Co.	1971	FO6	546	Montville	CT	1	6	T	U	U	1572	233442	3343385	1352	0.162	270615
24	5027	Uncontrolled	Delmarva Power	1971	FO6	1564	Vienna	MD	3	8	T	U	U	870	73286	902699	806	0.295	73066
25	4176	Uncontrolled	Northeast Utilities Service Co.	1973	FO6	562	Middletown	CT	1	4	T	U	U	1379	218951	3459723	813	0.190	280032
26	14610	Uncontrolled	Orlando Utilities Comm	1973	Nat Gas/FO6	683	Indian River	FL	4	3	T	U	U	1894	320299	3391320	177	0.230	210415
27	6455	Uncontrolled	Florida Power Corporation	1974	FO6	8048	Anclote	FL	4	1	T	U	U	2184	662612	7253341	5694	0.379	565115
28	19497	Uncontrolled	The United Illuminating Company	1975	FO6/Nat Gas	6156	New Haven Harbor	CT	1	NHB1	T	U	U	2208	624572	6744371	2688	0.175	545146
29	15270	Uncontrolled	Potomac Electric Power Company	1975	FO6/Nat Gas	1571	Chalk Point	MD	3	3	T	U	U	803	214716	2456759	742	0.203	176087
30	14715	Uncontrolled	Pennsylvania Power & Light Company	1975	FO6	3148	Martins Creek	PA	3	3	T	U	U	454	148181	1899541	883	0.383	165226
31	14715	Uncontrolled	Pennsylvania Power & Light Company	1976	FO6	3148	Martins Creek	PA	3	4	T	U	U	934	293065	3663379	886	0.253	281060
32	19876	Uncontrolled	Virginia Power	1976	FO6/Nat Gas	3809	Yorktown	VA	3	3	T	U	U	522	223411	2386233	1308	0.283	193140
33	6455	Uncontrolled	Florida Power Corporation	1978	FO6	8048	Anclote	FL	4	2	T	U	U	2171	667611	7335541	5491	0.414	581115
																	Mean	**0.211**	
																	Sample Std Dev	**0.114**	

No. 6 Oil Fired, Tangential Firing, Low NOx Burners													Third quarter 1996 CEMS data, used in the 1998 update of AP-42, section 1.3.						
Entry #	Util Code	Control Type	Utility	YEAR	Primary/Secondary Fuel	orispl	Plant	State	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours	Gross Unit Load	Heat Input	SO2 Tons-3Q	Uncontrolled Emission NOX Factor (lb/MMBtu)	CO2 Tons-3Q
1	15270	With LNBs	Potomac Electric Power Company	1981	FO6/Nat Gas	1571	Chalk Point	MD	3	4	T	U	LNB	672	169341	2256162	327	0.150	155475
2	15472	With LNBs	Northeast Utilities Service Co.	1974	FO6/Crude	8002	Newington	NH	1	1	T	U	LNB	1554	312536	4051451	3447	0.199	328113
																	Mean	0.175	
																	Sample Std Dev	0.035	

No. 2 Oil Fired, Tangential Firing													Third quarter 1996 CEMS data, used in the 1998 update of AP-42, section 1.3.						
Entry #	Util Code	Control Type	Utility	YEAR	Primary/Secondary Fuel	orispl	Plant	State	Region	Unit/Stack	Firing Type	SO2 Controls	NOX Controls	OP Hours	Gross Unit Load	Heat Input	SO2 Tons-3Q	Uncontrolled Emission NOX Factor (lb/MMBtu)	CO2 Tons-3Q
1	7140	Uncontrolled	Georgia Power Company	1941	FO2/Nat Gas	700	Atkinson	GA	4	A2	T	U	U	376	5897	148031	5	0.098	9356
2	7140	Uncontrolled	Georgia Power Company	1945	FO2/Nat Gas	700	Atkinson	GA	4	A3	T	U	U	391	7444	124153	3	0.186	7710
3	7140	Uncontrolled	Georgia Power Company	1948	FO2/Nat Gas	700	Atkinson	GA	4	A4	T	U	U	314	6536	96411	2	0.224	5937
																	Mean	0.169	
																	Sample Std Dev	0.065	

SECTION 1.4

U.S. Environmental Protection Agency

Technology Transfer Network Clearinghouse for Inventories & Emission Factors

Emission Factor & Inventory Information
Conferences
Publications
Emission Inventory Improvement Program
AirDATA
Related Sites
Site Index

AP-42, Fifth Edition, Volume I Chapter 1: External Combustion Sources

Explanation of File Formats

NOTE: Many AP-42 files contain equation fonts that may not be readable on some computers. If you encounter problems with viewing AP-42 documents contact the Info CHIEF Help Desk, (919) 541-1000.

1.0 Introduction to External Combustion Sources

1.1 Bituminous and Subbituminous Coal Combustion

- Final Section - Supplement E, September 1998 (PDF 515K)
- Background Document (PDF 8M)
- Related EIIP Documents (PDF 232K)

1.2 Anthracite Coal Combustion

- Final Section - Supplement B, October 1996 (PDF 59K)
- Background Document (PDF 249K)
- Related EIIP Documents (PDF 232K)

1.3 Fuel Oil Combustion

- Final Section - Supplement E , September 1998 (PDF 293K)
- Errata
- Background Document (PDF 716K)
- Related Info.
- Related EIIP Documents (PDF 232K)

1.4 Natural Gas Combustion

- Final Section - Supplement D , July 1998 (PDF 230K)
- Background Document (PDF 225K)
- Related Info.
- Related EIIP Documents (PDF 232K)

1.5 Liquified Petroleum Gas Combustion

- Final Section - Supplement B , October 1996 (PDF 18K)
- Background Document (PDF 129K)
- Related EIIP Documents (PDF 232K)

1.6 Wood Residue Combustion in Boilers

- Final Section - Update 2001, July 2001 (PDF 480K) Revised March 2002.
- Revision Information
- Background Document (PDF 72K)
- Related Information

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 $lb/10^6$ 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 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. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 scf] = (3.67)(CON)(C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ 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-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

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

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

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

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

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

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

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

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

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

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

References For Section 1.4

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2. *Chemical Engineers' Handbook, Fourth Edition*, J. H. Perry, Editor, McGraw-Hill Book Company, New York, NY, 1963.

3. *Background Information Document For Industrial Boilers*, EPA-450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

4. *Background Information Document For Small Steam Generating Units*, EPA-450/3-87-000, U. S . Environmental Protection Agency, Research Triangle Park, NC, 1987.

5. J. L. Muhlbaier, "Particulate and Gaseous Emissions From Natural Gas Furnaces and Water Heaters", *Journal Of The Air Pollution Control Association*, December 1981.

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8. S. D. Piccot, *et al.*, *Emissions and Cost Estimates For Globally Significant Anthropogenic Combustion Sources Of NO_x, N_2O, CH_4, CO, and CO_2*, EPA Contract No. 68-02-4288, Research Triangle Park, NC: Radian Corporation, 1990.

9. *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.

10. J. P. Kesselring and W. V. Krill, "A Low-NO_x Burner For Gas-Fired Firetube Boilers", *Proceedings: 1985 Symposium On Stationary Combustion NO_x Control, Volume 2*, EPRI CS-4360, Electric Power Research Institute, Palo Alto, CA, January 1986.

11. *Emission Factor Documentation for AP-42 Section 1.4—Natural Gas Combustion*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1997.

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.

AP-42 Section 1.4: Natural Gas Combustion Data Files

The data that supports the emission factors are presented in summary in the background report and are reported more completely in an electronic database. The database is in Microsoft Access 97®. The file is located on the CHIEF web site at http://www.epa.gov/ttn/chief/ap42c1.html.

EMISSION FACTOR DOCUMENTATION FOR AP-42 SECTION 1.4 NATURAL GAS COMBUSTION

Prepared for:

Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
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March 1998

TABLE OF CONTENTS

Section		Page
1.0	Introduction	1.1
1.1	Reasons For Updating	1.1
1.2	References For Section 1	1.2
2.0	Literature Search and Screening	2.1
2.1	Emission Data Quality Rating System	2.1
2.2	Review of Data Sets	2.3
2.3	References For Section 2	2.7
3.0	AP-42 Section Development	3.1
3.1	Revisions to Section Narrative	3.1
3.2	Pollutant Emission Factor Development	3.1
3.2.1	Database Design	3.1
3.2.2	Results of Data Analysis	3.5
3.3	Emission Factor Quality Rating System	3.8
3.4	Emission Factors	3.11
3.5	Peer Review Process	3.11
3.6	References for Section 3	3.11
4.0	AP-42 Section 1.4	4.1

Appendix A - Acid Rain Division Data

Appendix B - Reviewer Comments and EPA Responses

TABLES

		Page
2.2-1	SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 1.4	2.4
3.2-1	SNCR TEST RESULTS FOR WALL-FIRED BOILERS (NO_x)	3.9
3.2-2	SNCR TEST RESULTS FOR TANGENTIAL-FIRED BOILERS (NO_x)	3.10
3.4-1	SUMMARY OF EMISSION FACTORS FOR AP-42 SECTION 1.4	3.13

Emission Factor Documentation for AP-42 Section 1.4
Natural Gas Combustion

1.0 Introduction

The revised AP-42 section described in this report replaces the section published in September 1996 as Supplement B to the Fifth Edition. This background report replaces the Emission Factor (EMF) Documentation for AP-42 Section 1.4, Natural Gas Combustion, issued April 1993. The purpose of this background report is to provide technical documentation supporting the Supplement D revisions to AP-42 Section 1.4.

The EPA publishes emission factors in its Compilation of Air Pollutant Emission Factors, EPA Publication No. AP-42 (AP-42). The document has been published since 1972 as the primary compilation of EPA's emission factor information. Federal, State and local agencies, consultants, and industry use the document to identify major contributors of atmospheric pollutants, develop emission control strategies, determine applicability of permitting programs, and compile emission inventories for ambient air impact analyses and State Implementation Plans (SIPs). Volume 1, Stationary Sources is published by Emission Factor Inventory Group (EFIG) in EPA's Office of Air Quality Planning and Standards (OAQPS).

1.1 Reasons For Updating

The Clean Air Act Amendments of 1990 added greatly to the number of air pollution sources for which emission factor development was required, and also called for the improvement of existing factors. There are several reasons for updating or revising AP-42 sections and emission factors.

- New Standard. After the proposal of a standard, the EPA reviews the available material to determine if sufficient information has been gathered to support the development of emission factors for the industry or process being studied. Oftentimes, the proposal or development of a new standard for a source or source category will trigger a re-evaluation of emission factors for a particular source. In the proposal of a standard, the proposal team gathers tremendous amounts of data to support the standard, much more data than is typically gathered for AP-42. The proposal team may compare their new data with existing information used to develop AP-42 emission factors. If, in the comparison, the team discovers a deficiency in the existing information, they may turn their data over to EFIG, who in turn may use the information to improve emission factors.

- Outside Requests. The EPA receives requests for better source and emission factor information. Requests may come from other Office of Air Quality Planning and Standards (OAQPS) branches, EPA laboratories and regional offices, State agencies, trade associations, special interest groups, or private individuals. The requests may take the form of directives, letters, oral inquiries, or comments on published emission factors.

- Improvement of the National Inventory. The EPA may determine that a particular source category is a significant contributor to the National Inventory and that EPA should develop or improve emission factors.

- New Information. New information will be useful that may have been developed initially for Emission Standards Division (ESD) background documents involving new source performance standards (NSPS), national emission standards for hazardous air pollutants (NESHAP), and Control Techniques Guidelines (CTG), and reports by various EPA laboratories.

- Contractor Expertise. A contractor or consultant may have gained expertise on a source category during previous work, either for EPA or for other clients, and may warrant considering a relatively low-expense update and expansion of available information.

Section 1.4 has been updated to incorporate new available data on this source category. New information has been used to better characterize this source category, develop improved volatile organic compound (VOC) and particulate matter (PM) emission factors, and update criteria pollutant emission factors. In response to the upcoming NESHAP for this source category, an expanded hazardous air pollutant (HAP) emission factor list has also been provided.

This background report consists of four sections. This introduction provides background information on AP-42 and documents such as this one that are issued to update sections of AP-42. Section 2 presents the data search and screening steps, discusses the references used to revise AP-42 Section 1.4, and defines the emissions data quality rating system. Section 3 discusses overall revisions to AP-42 Section 1.4, provides details about the database built for storing the available data, presents the calculations used to calculate emission factors, and defines the emission factor quality rating system. Section 4 presents the proposed revision of the existing AP-42 section as it would appear in Supplement D.

1.2 References For Section 1

1. Procedures For Preparing Emission Factor Documents, Third Revised Draft Version, Office Of Air Quality Planning And Standards, U.S. EPA, Research Triangle Park, NC 27711, November 1996.

2.0 Literature Search and Screening

Data used in this section were obtained from a number of sources within OAQPS and from outside organizations. The AP-42 background files were reviewed for information on these sources, demonstrated pollution control technologies, and emissions data. The Factor Information Retrieval System (FIRE) was searched for emission data on natural gas-fired combustion sources. The Source Test Information Retrieval System (STIRS) data set, compiled by EFIG, was reviewed and provided emissions data from several sources. The STIRS data set is a collection of emission test reports that have been scanned and stored on CD-ROM.

In the review of available references, emissions data were accepted if:

- sufficient information about the combustion source and any pollution control devices was given.
- the test report identified if the emissions tests were conducted before or after a pollution control device.
- emission levels were measured by currently accepted test methods.
- emission test results were reported in units which could be converted into the reporting units selected for this AP-42 section.
- sufficient data existed to characterize operating conditions.

2.1 Emission Data Quality Rating System[1]

After reviewing the test reports, it should be possible to assign a data quality rating to each pollutant emission rate for each test series. The individual data quality ratings are not to be confused with the overall emission factor ratings. The data quality ratings are an appraisal of the reliability of the basic emission data that will be used to later develop the factor.

Test data quality is rated A through D, based on the following criteria:

A - Tests are performed by a sound methodology and are reported in enough detail for adequate validation.

B - Tests are performed by a generally sound methodology, but lacking enough detail for adequate validation.

C - Tests are based on an unproven or new methodology, or are lacking a significant amount of background information.

D - Tests are based on a generally unacceptable method, but the method may provide an order-of-magnitude value for the source.

The quality rating of test data helps identify good data, even when it is not possible to extract a factor representative of a typical source in the category from those data. For example, the data from a given test may be good enough for a data quality rating of "A," but the test may be for a unique feed material, or the production specifications may be either more or less stringent than at the typical facility.

In following the general guidelines discussed above, four specific criteria can be considered to evaluate the emission data to ensure that the data are based on a sound methodology, and documentation provides adequate detail. A test series is initially rated "A through D" in each of the following four areas.

- Source operation. If the manner in which the source was operated is well documented in the report, and the source was operating within typical parameters during the test, an A rating should be assigned. If the report stated parameters were typical, but lacked detailed information, a B rating is assigned. If there is reason to believe operation was not typical, a C or D rating is assigned.

- Test method and sampling procedures. In developing ratings, the accuracy of the test method as well as the adequacy of the documentation are considered. In general, if a current EPA reference test method appropriate for the source was followed, the rating should be higher (A or B). If other methods are used, an assessment is made of their validity. If it is judged that the method was likely to be inaccurate or biased, a lower rating (C or D) is given. A complete report should indicate whether any procedures deviated from standard methods and explain any deviations. If deviations were reported, an evaluation is made of whether these were likely to influence the test results.

- Sampling and process data. During testing, many variations can occur without warning and sometimes without being noticed. Such variations can induce wide deviations in sampling results. If a large spread between test run results cannot be explained by information contained in the site test report or from test reports of other sources, the data are suspect and are given a lower rating. However, it should be recognized that a process may have highly variable emissions and a lower rating may not be appropriate solely on the basis of wide deviations in sampling results.

- Analysis and calculations. Ideally, test reports should contain original raw data sheets and other QA documentation. If there are data sheets, the nomenclature and equations used are compared with those specified by EPA to establish equivalency. The depth of review of the calculations is dictated by the reviewers' confidence in the ability and conscientiousness of the tester, based on such factors as consistency of results and completeness of other areas of the test report. Reports may indicate that raw data sheets were available but were not included. If the test report is of high quality based on the other criteria, the quality rating should not be lowered due to a lack of data sheets.

An overall emission data quality rating is developed considering the scores on the four criteria. There is no precise equation for the relative weighting of the factors, because each report presents different issues, and the rating system needs to provide flexibility to consider the strengths and weaknesses of each test series and reach a judgment on the overall rating. However, the two criteria concerning (1) the test method and sampling procedures and (2) the sampling and process data should be

weighted most heavily. If either of these two criteria are assigned a low rating, this low rating should be assigned as the overall data quality rating, no matter how complete the documentation is.

2.2 Review of Data Sets

A total of 42 documents were reviewed in the process of developing emission factors for this revision to AP-42 Section 1.4, Natural Gas Combustion. A summary review of the references used to develop emission factors and their associated database identification numbers is presented in Table 2-1, following this section. The majority of the references which were used to revise the emission factors for natural gas combustion sources were either compliance test reports or summaries of compliance test results. Seven of the references used in the development of this data were the results of research or specific information gathering efforts. Furthermore, NO_x emission factors for several natural gas combustion sources were developed from an electronic database received from the Acid Rain Division (ARD) of EPA. The data received from the ARD, and the corresponding emission factor averages, are presented in Appendix A.

References 2 Through 6, 8, and 41

References 2 through 6, reference 8, and reference 41 are the results of several research or specific information gathering efforts on natural gas-fired boilers. The data extracted from these reports make up the vast majority of all the HAP information contained in the revision of AP-42 Section 1.4. Pollutants tested in references 2, 3, and 41 also included speciated polycyclic aromatic hydrocarbons (PAH) and speciated metals. The test results reported in these references were all from emission measurements conducted on tangential- and wall-fired utility boilers. Most of the sources detailed in these references were uncontrolled, however, some incorporated flue gas recirculation (FGR) for NO_x control. All of the emission test data contained in these references were assigned a rating of A due to the detailed information provided.

References 7, 9 Through 40, and 43 Through 44

These references were all compliance test results from both utility and industrial boilers firing natural gas. The majority of these compliance tests focused on NO_x and CO emissions, however, several tests included results of total hydrocarbon (THC), non-methane hydrocarbon (NMHC), methane, and particulate matter (PM) measurements. Some of the boilers reported in these references were operated with low-NO_x burners, FGR, or selective non-catalytic reduction (SNCR) for NO_x control. All of the emission test data contained in these references were assigned a rating of A due to the detailed information provided.

Reference 42

Reference 42 is a NO_x emission summary for all national gas-fired utility boilers required to submit CEM data to the ARD as required by Title IV of the Clear Air Act Amendments. These data represent average NO_x emissions from these boilers for the 3rd quarter of 1996. This data set included NO_x emissions from 121 wall-fired boilers, 62 tangential-fired boilers, and five wall-fired boilers with low-NO_x burners. The data received from ARD, and the corresponding emission factor averages, are presented in Appendix A.

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 1.4

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Database I.D.
2	Source Test on a Tangential-Fired Utility Boiler	NO_x, CO, speciated HAP's, metals	A	1
3	Source Test on a Wall-Fired Utility Boiler	NO_x, CO, speciated HAP's, metals	A	2
4	Source Test on a Wall-Fired Utility Boiler	Benzene, Formaldehyde	A	3
5	Source Test on a Wall-Fired Utility Boiler	Benzene, Formaldehyde	A	4
6	Source Test on a Package Boiler	NO_x, CO, Methane, Ethane, PM	A	6
7	Compliance Test on a Package Boiler	NO_x, CO	A	7
8	Source Tests on Seven Wall-Fired Utility Boilers	Benzene, Formaldehyde	A	8, 9, 10, 11, 12, 13, 14
9	Source Test on a Wall-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons, PM	A	15
10	Compliance Test on a Wall-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons, PM	A	23
11	Compliance Test on Two Tangential-Fired Utility Boilers With SNCR Control	NO_x, CO, Hydrocarbons, PM	A	17
12	Compliance Test on Two Wall-Fired Utility Boilers With SNCR Control	NO_x, CO, Hydrocarbons	A	18
13	Compliance Test on a Tangential-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons, PM	A	19
14	Compliance Test on a Tangential-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons	A	20
15	Compliance Test on a Tangential-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons	A	22
16	Compliance Test on a Wall-Fired Utility Boiler	NO_x, CO, Hydrocarbons	A	16
17	Compliance Test on a Tangential-Fired Utility Boiler With SNCR	NO_x, CO, Hydrocarbons	A	21

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 1.4
(Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Database I.D.
18	Compliance Test on a Boiler	NO_x, CO	A	106
19	Compliance Test on a Boiler	NO_x, CO	A	107
20	Compliance Test on a Boiler	NO_x, CO	A	108
21	Compliance Test on Two Boilers	NO_x, CO	A	109
22	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	110
23	Compliance Test on Two Boilers	NO_x	A	111
24	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	112
25	Compliance Test on Two Boilers	NO_x	A	113
26	Compliance Test on a Boiler	NO_x, CO, PM	A	114
27	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	115
28	Compliance Test on a Boiler	NO_x, CO	A	116
29	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	117
30	Compliance Test on a Boiler	NO_x	A	119
31	Source Test on a Boiler	NO_x, CO	A	120
32	Source Test on a Boiler	NO_x, CO, Hydrocarbons, PM	A	121
33	Compliance Test on a Boiler	NO_x	A	122
34	Compliance Test on a Boiler	NO_x	A	123
35	Compliance Test on a Boiler	NO_x, CO	A	125
36	Compliance Test on Two Boilers	NO_x, CO	A	126
37	Compliance Test on a Boiler	PM	A	131
38	Compliance Test on a Boiler	NO_x, PM	A	132

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 1.4
(Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Database I.D.
39	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	133
40	Compliance Test on Four Boilers	NO_x, CO, Hydrocarbons	A	134
41	Source Tests on Two Wall-Fired and Two Tangential-Fired Boilers	NO_x, CO, speciated HAP's, metals	A	200
42	CEM Data Submitted to ARD	NO_x,	A	Not in Database
43	Compliance Test on One Boiler	PM	A	201
44	Compliance Test on One Boiler	PM	A	202

[a]Reference number corresponds to the reference listing at the end of this section.

2.3 References For Section 2

1. Procedures for Preparing Emission Factor Documents, Third Revised Draft Version, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, NC 27711, November 1996.

2. *PICES Field Chemical Emissions Monitoring Project Site 120 Emissions Report.* Carnot, Tustin, CA, December 1995.

3. *PICES Field Chemical Emissions Monitoring Project Site 121 Emissions Report.* Carnot, Tustin, CA, December 1995.

4. *Emission Inventory Testing at El Segundo Generating Station No. 1 for Southern California Edison Company*, Carnot, April 1990.

5. *Air Toxics Emissions Inventory Testing at Alamitos Unit 5*, Carnot, May 1990.

6. *Gas Research Institute/WP Natural Gas @ Boise Cascade Timber and Wood Products Division #2 Package Boiler*, Amtest Air Quality, Inc., May 1995.

7. *Source Test For Measurement Of Nitrogen Oxides And Carbon Monoxide Emissions From Boiler Exhaust At GAF Building Materials*, Pacific Environmental Services, Inc., Baldwin Park, CA, May 1991.

8. *Field Chemical Emissions Monitoring Project: Emissions Report For Sites 103 - 109. Preliminary Draft Report.* Radian Corporation, Austin, TX, March 1993. (EPRI Report)

9. *Urea Permit Compliance Testing at Alamitos Generation Station Unit 2*, Carnot, November 1992.

10. *Emissions Source Test Report For Urea Injection Compliance Testing Huntington Beach Unit 1 Permit Application No. R-249463*, Geraghty & Miller, March 1994.

11. *SCE Etiwanda Units 1 and 2 Urea Compliance Source Test Report, Final Report, Volume 1 of II*, Radian Corporation, March 1994.

12. *Source Test Report For Urea Permit Compliance Testing Redondo Beach Generating Station Units 5 and 6*, Sierra Environmental Engineering, Inc., October 1992.

13. *Urea Permit Compliance Testing at Alamitos Generation Station Unit 4*, Carnot, April 1993.

14. *Urea Permit Compliance Testing at El Segundo Generating Station Unit 3*, Carnot, September 1993.

15. *Emissions Source Test Report For Recirculation Gas By-Pass and Urea Compliance Testing Etiwanda Unit 3 Permit Application No. 261513*, Acurex Environmental, March 1994.

16. *Emissions Source test Report: Permit Application No. R-249462, Huntington Beach Generating Station*, Acurex Environmental, March 1996.

17. *Urea Permit Compliance Testing at El Segundo Generating Station Unit 4*, Carnot, September 1993.

18. *California Fruit Produce, Fresno, Ca. Boiler Emissions Test 12-4-92.* Best Environmental, Inc., San Leandro, CA, December 17, 1992.

19. *California Fruit Produce, Madera, Ca. Boiler Emissions Test 12-2-92.* Best Environmental Inc., San Leandro, CA, December 17, 1992.

20. *Emission Testing at Zacky Farms Kewanee Boiler, Dinuba, California.* Steiner Environmental, Inc., Bakersfield, CA, July 1993.

21. *Compliance Test Report Determination of NO_x emission rates From Boilers 3, 4, and 5. Harrison Radiator, Dayton, Ohio.* Hayden Environmental Group, Inc., Miamisburg, OH, March 20, 1990.

22. *R. F. MacDonald Source Emissions Testing at Tomatek, Inc.* Ecoserve Environmental Services, Inc. Pittsburg, CA, October 1989.

23. *Nitrogen Oxide Emission Tests Boilers Number 4 and 5. Whiteman Air Force Base.* Shell Engineering and Associates, Inc., August 20 and 21, 1990.

24. *Source Emissions Survey of Firestone Synthetic Rubber & Latex company Boiler EB-114 Exhaust Stack, Orange, Texas.* METCO Environmental, Addison, TX, November 1990.

25. *A Compliance Emission Test Report Determination of Nitrogen Oxides. Dual-Fuel Generating Units Nos. 1 and 2.* Greiner, Incorporated, Grand Rapids, MI, September 2, 1993.

26. *Texaco Refining & Marketing, Inc. P. O. Box 1476, Bakersfield, California. Boilers A and B. Annual Compliance Test.* Steiner Environmental, Inc., Bakersfield, CA, June 19, 1992.

27. *Source Emission Test for NO_x, CO, and ROC From Conventional Steam Boiler at Thomas Plant, Building 373, Naval Construction Battalion Center, Port Hueneme, California.* Naval Energy and Environmental Support Activity, October 1990.

28. *Chevron U.S.A., Inc. Section 26C Steam Plant Steam Generator # 50-6 and 50-7. Initial Compliance Test.* Genesis Environmental Services Company, Bakersfield, CA, June 11, 1991.

29. *Source Test for Measurement of Oxides of Nitrogen, Carbon Monoxide and VOC from Boiler Exhaust at Candlewick Yarns, Lemoore, California.* Pacific Environmental Services, Inc., Baldwin Park, CA, April 21, 1993.

30. *Compliance Test for NO_x. Siemens Energy and Automation Natural Gas Fired Boiler #2.* K&B Design, Inc., August 26, 1994.

31. *Source Test Report Gibson 7028-01, Gibson Oil and Refining Company, Bakersfield, California.* Brown and Caldwell, Pleasant Hill, CA, September 11, 1992.

32. *Source Test Report Gibson Oil and Refining Company, Inc.* Bakersfield, California. Brown and Caldwell, Emeryville, CA, May 14-17, 1990.

33. *Compliance Test Report: Determination of Nitrogen Oxide Emissions, Annapolis Hospital Westland Center Boilers #1, 2, and 3, Oakwood Hospital, Westland Michigan.* WW Engineering & Science, Grand Rapids, MI, November 1993.

34. *Report on Compliance Testing for General Motors Corporation, Fort Wayne Assembly Plant, Roanoke, Indiana,* Clean Air Engineering,

35. *Stella Cheese. P. O. Box 1379, Tulare, California. Superior Mohawk Boiler. Initial Compliance Test.* Steiner Environmental, Inc., Bakersfield, CA, July 30, 1993.

36. *Crystal Geyser Water Company. 1233 East California Avenue. Bakersfield, California. Boiler #1 & 2, Initial Compliance Test.* Steiner Environmental, Inc., Bakersfield, CA, February 26, 1993.

37. *Results of the Emissions Testing Services at Minnesota Corn Processors. Marshall Minnesota. December 20-21, 1994.* Nova Environmental Services, Inc., Chaska, MN, January 31, 1995.

38. *Results of the July 27, 1994 Air Emission Compliance Testing of the No. 10 Boiler at the Virginia Public Utilities Plant in Virginia, Minnesota.* Interpoll Laboratories, Inc., Circle Pines, MN, August 17, 1994.

39. *Los Gatos Tomato Products Compliance Emissions Testing.* Best Environmental, Inc., Hayward, CA, April 1991.

40. *Gallo Winery Fresno Plant Boilers # 1, 2, 3, & 4 Emissions Compliance Testing.* Best Environmental, Inc., San Leandro, CA, May 1992.

41. *Gas-Fired Boiler and Turbine Air Toxics Summary Report.* Prepared by Carnot Technical Services, Tustin, CA, For the Gas Research Institute and The Electric Power Research Institute, August 1996.

42. NO_x Emission Reporting for Utility Boilers for 3rd Quarter 1996. Acid Rain Division, U.S. EPA.

43. *Compliance Particulate Matter Source Emissions Measurement Program: Nebraska Package Boiler, Kimberly-Clark Corporation, Neenah, WI.* Geraghty & Miller, Inc., July 1994.

44. *Results of the September 14 and 15, 1994 Air Emission Compliance Tests on the No. 11 Boiler at the Appleton Paper Plant in Combined Locks, WI.* Interpoll Laboratories Inc., October 1994.

3.0 AP-42 Section Development

3.1 Revisions to Section Narrative

The technical discussion in AP-42 Section 1.4 did not need major revisions because no significant technological changes in this source category were identified since the last publication. Some of the discussion on NO_x and PM formation was revised to better describe emissions from this source category.

3.2 Pollutant Emission Factor Development

3.2.1 Database Design

The emission data assembled for the development of natural gas combustion emission factors were stored in a database except for the data received from ARD. A database approach was chosen to easily access and manipulate the large amount of data collected for this section and to facilitate data transfer within other concurrent projects at EPA. The design of this database was accomplished in conjunction with the Industrial Combustion Coordinated Rulemaking (ICCR) effort ongoing within the Emission Standards Division (ESD). Data entered under either of these projects were easily transferred between databases. Furthermore, the common design of the database will allow for future additions to the database and simple recalculation of emission factors.

Within the database, data were stored in two tables to reduce repetitive entry of data. These tables, and the data fields associated with each table are as follows:

Facilities Table

- Facility name
- Location
- Testing Company
- Date of Test
- Boiler Manufacturer
- Boiler Type (wall-fired, tangential-fired, etc.)
- Air Supply (forced draft, induced draft, balanced draft etc.)
- Capacity (MW)
- Load (percent of capacity)
- Fuel Type
- Fuel Higher Heating Value
- Heat Input (MMBtu/hr)
- Post-combustion Emission Controls
- Application (electrical generation, process steam, etc.)

Test Data Table

- Pollutant
- Test Method
- Pollutant Concentration (as reported)
- Detection Limit

- Exhaust Oxygen Percentage
- Data Rating
- Fuel Exhaust Factor (F-Factor)
- Exhaust Flow Rate
- Fuel Flow Rate
- Exhaust Moisture Fraction
- Molecular Weight of Pollutant

The database was programmed to merge the data in the two tables and calculate emission factors for the available pollutants in units of pounds of pollutant per million standard cubic feet of fuel burned. To ensure consistent calculation of emission factors, the database was programmed to use the emission concentration data and process data taken during the testing period to calculate the emission factors. Emission factors provided in test reports were not used. The EPA concluded that this method of calculation would provide the highest quality emission factors. This method of calculating emission factors was chosen because different methods of calculation emission factors were used in some of the references and in some cases, the method of calculating emission factors was not given. Equations used to calculate emission factors for this section were dependent on the pollutant concentration units.

The following equations were used to convert concentration data to the selected emission factors used in this section.

For concentration in parts per million by volume - dry (ppmvd), the following equation was used:

$$EF_{scf} = \frac{(C_{ppmvd} * F * 1{,}020 * MW)}{(10^6 * 385.5)} * \text{temperature correction} * \text{oxygen correction}$$

For concentration in parts per million by volume - wet (ppmvw), the following equation was used:

$$EF_{scf} = \frac{(C_{ppmvw} * F * 1{,}020 * MW)}{(10^6 * 385.5) * (1 - W_c)} * \text{temperature correction} * \text{oxygen correction}$$

For concentration in micrograms per dry standard cubic feet, the following equation was used:

$$EF_{scf} = \frac{(C_{\mu gf} * F * 1{,}020)}{(10^6 * 453.6)} * \text{oxygen correction}$$

For concentration in parts per billion by volume - dry, the following equation was used:

$$EF_{scf} = \frac{(C_{ppbvd} * F * 1{,}020 * MW)}{(10^9 * 385.5)} * \text{temperature correction} * \text{oxygen correction}$$

For concentration in volume percent, the following equation was used:

$$EF_{scf} = \frac{(C_{\%} * F * 1{,}020 * MW)}{(100 * 385.5)} * \text{temperature correction} * \text{oxygen correction}$$

For concentration in nanograms per dry standard cubic feet, the following equation was used:

$$EF_{scf} = \frac{(C_{ngf} * F * 1{,}020)}{(10^9 * 453.6)} * \text{oxygen correction}$$

For concentration in grains/dscf, the following equation was used:

$$EF_{scf} = (C_{grf} * F * 1{,}020 * 1.43 * 10^{-4}) \quad * \text{ oxygen correction}$$

For concentration in micrograms per dry standard cubic meter, the following equation was used:

$$EF_{scf} = \frac{(C_{\mu gm} * F * 1{,}020)}{(10^6 * 453.6 * 35.31)} * \text{oxygen correction}$$

Where:

Ef_{scf}	=	Emission factor (pounds per million standard cubic feet of fuel input)
C_{ppmvd}	=	Concentration (parts per million by volume, dry)
C_{ppmvw}	=	Concentration (parts per million by volume, wet)
$C_{\mu gf}$	=	Concentration (micrograms per dry standard cubic foot)
C_{ppbvd}	=	Concentration (parts per billion by volume, dry)
$C_{\%}$	=	Concentration (percent by volume)
C_{ngf}	=	Concentration (nanograms per dry standard cubic foot)
C_{grf}	=	Concentration (grains per dry standard cubic foot)
$C_{\mu gm}$	=	Concentration (micrograms per dry standard cubic meter)
F	=	F-Factor (dry standard cubic feet per million Btu)
MW	=	Molecular weight (pounds per pound-mole)
T_{std}	=	Reference temperature of F-Factor

$\%O_2$	=	Percent of oxygen in exhaust, by volume
1,020	=	Natural gas heating value (MMBtu per 10^6 scf)
385.5	=	Volume occupied by 1 lb-mole of gas at 68°F (standard cubic feet per lb-mole)
60	=	Conversion factor (minutes per hour)
W_c	=	Water volume fraction in exhaust
453.6	=	Conversion factor (grams per pound)
$1.43*10^{-4}$	=	Conversion factor (pounds per grain)
35.31	=	Conversion factor (dry standard cubic feet per dry standard cubic meter)

$$\text{Temperature correction for F-Factor (to 68°F)} = \left(\frac{528°R}{460°R_t + T_{std}\ °F} \right)$$

$$\text{Oxygen correction (to 0\% } O_2) = \left(\frac{20.9}{20.9 - \%O_2} \right)$$

Detection Limits

Test results from several tests of trace organic and metallic compounds reported concentrations below the method detection limits. If a detection limit was provided in the test report, EPA used that information in the development of AP-42 emission factors. To effectively use this data, two methods were employed. For cases where a portion of the test data for a specific pollutant were below the method detection limit but other test data report detection of that compound, then one-half of the detection limit was averaged with the detected concentrations to calculate of the emission factor for that pollutant. In cases where all of the test data for a specific pollutant reported concentrations below the method detection limit, the lowest detection limit was reported for the emission factor for that pollutant, and that factor noted as a detection limit. If an emission factor for an individual boiler was developed from a detection limit and the resulting emission factor was higher than the emission factors generated from detected concentrations, the emission factor based on a detection limit was removed from the average. The goal of this decision was to prevent an unusually high detection limit from artificially increasing an average emission factor. These methods for addressing detection level issues were provided in the Procedures For Preparing Emission Factor Documents.[1]

Calculation of Average Emission Factors

To provide average emission factors for these sources, the arithmatic average of the emission factors from all tests on a specific source type was calculated in the database. For tests that consisted of multiple runs, the arithmetic average of the runs was used to develop the emission factor of that test. Individual tests were given equal weight in the calculation of average emission factors for each boiler group. In the case of NO_x data received from ARD, the quarterly average from each boiler was treated like an individual test.

Presentation of Data

Due to the size of the database, a printout of all the test data used to generate the boiler emission factors in Section 1.4 is not presented. The NO_x data provided by the Acid Rain Division is provided in Appendix A. For the remaining data that was stored in the database, EPA is providing an electronic copy of the database on the Technology Transfer Network (TTN). This decision has resulted in a substantial decrease in paper needed for this background information document and will provide users with a more detailed background data set for this section. Providing the database to the public will allow anyone to use or augment the database for their individual needs, providing a substantial building block for anyone interested in compiling an extensive database on natural gas-fired combustion sources. An electronic copy of the database in Microsoft Access® format, can be downloaded from the TTN at http://www.epa.gov/tnn/chief/. In this website, go to AP-42 and follow the main menu options to locate and download the database file.

3.2.2 Results of Data Analysis

3.2.2.1 Source Category Selection and Data Review

An important step in emission factor development is to determine which emission sources are similar enough to be grouped together and represented by a single emission factor. This is accomplished by investigating what parameters influence emissions and should be used to establish distinct groups within the natural gas combustion category. The emission factors for each test contained in the database were analyzed to determine appropriate groupings.

NO_x Emission Factors

Based on the analysis of available NO_x data, this category was separated into four general groups: large wall-fired boilers with a heat input greater than 100 MMBtu/hr, small boilers with a heat input less than 100 MMBtu/hr, tangential-fired boilers, and residential furnaces. These groups were further separated into the following subcategories:

- Large Wall-Fired Boilers (>100 MMBtu/hr)
  - Uncontrolled (pre-NSPS)
  - Uncontrolled (post-NSPS)
  - Controlled-Low-NO_x burner
  - Controlled-Flue Gas Recirculation (FGR)
- Small Boilers (<100 MMBtu/hr)
  - Uncontrolled
  - Controlled-Low-NO_x burner
  - Controlled-Low-NO_x burner/FGR
- Tangential-Fired Boilers
  - Uncontrolled
  - Controlled-FGR

- Residential Furnaces

The designation of pre- and post-NSPS refers to boilers that are subject to 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. Analysis of the NO_x data showed that uncontrolled wall-fired boilers subject to the NSPS have considerably lower NO_x emissions that those not subject to the NSPS. Such a distinction was not seen in the data for the tangential boilers and therefore they were not further subcategorized.

The NO_x emission factors for the following categories were developed from data received from ARD: large wall-fired uncontrolled, large wall-fired controlled-low NO_x burners, and tangential-fired uncontrolled. The ARD data were determined to be more representative of these categories than NO_x data taken from compliance and source tests. The ARD data were from all operating utility boilers in the U.S. and averaged continuously over a three-month period. Since most of the data stored in the database were from short-term compliance and source tests, and from a much smaller population of boilers, the ARD data were used for categories where they were available. The NO_x emission factors for the remaining categories, where ARD data were unavailable, were developed from data stored in the database.

The NO_x emission factor for residential furnaces is based on test data from 41 sources.[2-3] Since no new data for NO_x from residential furnaces were obtained during this revision, this factor remains unchanged from the previous version of Section 1.4.

N_2O Emission Factors

The emission factors for N_2O from large wall-fired boilers is based on test data from five source tests conducted at three separate locations.[4-5] The N_2O factor for the large wall-fired boilers with low-NO_x burners is based on two source tests.[4-5] Since no new data for N_2O were obtained during this revision, these factors remain unchanged from the previous version of Section 1.4.

CO Emission Factors

Emission factors for CO were not grouped as extensively as the NO_x emission factors. For the wall-fired boiler groups, no clear correlation was observed between boiler type or size and CO emission levels. CO emission factors for the wall-fired boilers showed wide scatter and average emission factors developed for the distinct grouping were not consistent with expected values. The EPA believes that boiler operation plays a more critical role in determining CO emissions than the boiler type. Therefore, all CO data for wall-fired boilers were averaged to provide a single CO emission factor. For the tangential-fired boilers, CO emission factors showed less scatter and were strongly dependent on boiler type. Therefore, CO emission factors for tangential-fired boilers were grouped under the uncontrolled and controlled-flue gas recirculation categories.

The CO emission factor from residential furnaces is based on test data from 41 sources.[2-3] Since no new data for CO from residential furnaces were obtained during this revision, this factor remains unchanged from the previous version of Section 1.4.

Organic Compound Emission Factors

Similar to CO emission factors from wall-fired boilers, organic compound emission factors (TOC, VOC, methane, formaldehyde, etc.) showed wide scatter and no correlation was observed with boiler type or size. The EPA believes that the randomness of the organic compound emission factors from natural gas combustion sources is driven more by individual source operation than source type. Therefore, the organic compound emission factors for natural gas combustion sources were averaged across the entire source category to provide single factors for all sources covered by AP-42 Section 1.4.

3.2.2.2 Data Not Included in the Database

Several of the emission factors presented in AP-42 Section 1.4 are not calculated via a simple averaging procedure in the database. These emission factors include TOC, VOC, PM, CO_2, SO_2, and controlled emission factors. The next several sections will discuss the development of these emission factors.

VOC and TOC Emission Factors

The VOC emission factor for this source category was calculated to correspond with EPA's definition that VOC comprises total organic compounds excluding methane, ethane, and several chlorinated and fluorinated compounds.[1] Since VOCs cannot be measured directly, VOC emission factors must be calculated from other organic measurements. Data on hydrocarbon emissions collected for the revision of AP-42 Section 1.4 included as total hydrocarbons (THC) and non-methane hydrocarbons (NMHC). Based on an evaluation of the quality and quantity of data available on hydrocarbons, EPA determined that the NMHC data was the most representative for this source category. Given the NMHC as the basis for calculating the VOC emission factor, the ethane emission factor was subtracted and the formaldehyde emission factor added to the NMHC emission factor to provide an estimate of the VOC emission factor. This calculation is shown below. The TOC emission factor was estimated by adding the methane and formaldehyde emission factors to the NMHC emission factor. This calculation is shown below. The data used in these calculations can be found in Table 3.4-1.

$$\text{VOC} = \text{NMHC} + \text{Formaldehyde} - \text{Ethane}$$

$$= 8.5 + 0.07 - 3.1$$

$$= 5.5 \ (\text{lb}/10^6 \ \text{scf})$$

$$\text{TOC} = \text{NMHC} + \text{Formaldehyde} + \text{Methane}$$

$$= 8.5 + 0.07 + 2.3$$

$$= 10.9 \ (\text{lb}/10^6 \ \text{scf})$$

PM Emission Factors

For a limited number of tests, PM measurements were conducted. These PM measurements included both condensable and filterable PM. As with the organic compounds emitted from natural gas combustion sources, no correlation between combustion source type and PM emission levels could be established. Therefore, the PM emission factors presented in AP-42 Section 1.4 are intended to represent all natural gas combustion sources. To provide a total PM emission factor, the average condensible and filterable PM fractions were added together. This calculation is shown below. The EPA has assumed that all condensable and filterable PM resulting from natural gas combustion is less that 1 micrometer (μm) in diameter. Therefore, the total PM emission factor also provided an estimate of PM_{10}, $PM_{2.5}$, and $PM_{1.0}$ emissions from natural gas combustion sources. The EPA believes that these assumptions for PM size are valid since natural gas does not contain ash and the nucleation of PM from combustion products ill not yield particles larger than 1 μm.

$$\text{PM (Total)} = \text{PM (Condensable)} + \text{PM (Filterable)} = PM_{10} = PM_{2.5} = PM_{1.0}$$

$$= 5.7 + 1.9$$

$$= 7.6 \text{ (lb/}10^6 \text{ scf)}$$

CO_2 and SO_2

As outlined in the Procedures for Preparing Emission Factor Documents,[1] emission factors for CO_2 were calculated by mass balance. This approach was also taken for calculating SO_2. Since the carbon and sulfur content in pipeline-quality natural gas is fairly consistent, EPA believes that this is the best method for calculating CO_2 and SO_2 emission factors. For CO_2, it was assumed that approximately 100 percent of the fuel carbon was converted to CO_2. For SO_2, a 100 percent conversion of fuel sulfur was assumed. The CO_2 emission factor was based on a carbon weight percent in natural gas of 76 percent and the SO_2 emission factor was based on a sulfur content in natural gas of 2,000 grains per million standard cubic feet.

Selective Non-catalytic Reduction (SNCR) Controlled Emission Factors

Several of the data sources provided emissions data for sources operating with SNCR control. To evaluate SNCR control efficiency, only tests where NO_x measurements were taken upstream and downstream of the ammonia or urea injection area were considered. This method was chosen to evaluate SNCR performance while avoiding the effects of boiler performance, with respect to NO_x emissions. To estimate SNCR performance, NO_x control efficiency was based on tests conducted upstream and downstream of the control device. Thirty-three sets of upstream and downstream tests on SNCR performance were evaluated. The SNCR performance data for wall-fired boilers are presented in Table 3.2-1 and SNCR performance data for tangential-fired boilers are presented in Table 3.2-2. The average NO_x reduction efficiency achieved by SNCR control on wall-fired and tangential-fired units was 24 percent and 13 percent, respectively. These reduction efficiencies were also put in the footnotes to the tables presented in Section 1.4 so these reduction efficiencies could be applied to the NO_x emission factor if necessary.

3.3 Emission Factor Quality Rating System

The quality of the emission factors developed from analysis of the test data was rated using the following general criteria:

A--Excellent: Developed only from A-rated test data taken from many randomly chosen facilities in the industry population. The source category is specific enough that variability within the source category population may be minimized.

B--Above average: Developed only from A-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industries. The source category is specific enough that variability within the source category population may be minimized.

C--Average: Developed only from A- and B-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. The source category is specific enough that variability within the source category population may be minimized.

D--Below average: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of the emission factor are always noted in the emission factor table.

Table 3.2-1. SNCR TEST RESULTS FOR WALL-FIRED BOILERS (NO_x)

Database I.D.	Uncontrolled Emission Factor ($lb/10^6$ scf)	Controlled Emission Factor ($lb/10^6$ scf)	Percent Reduction (%)
16.1/16.2	1.32E+02	1.17E+02	11
16.3/16.4	8.14E+01	6.31E+01	23
16.5/16.6	5.57E+01	4.53E+01	19
23.1/23.2	1.12E+02	9.64E+01	14
23.3/23.4	8.20E+01	5.96E+01	27
23.5/23.6	5.24E+01	4.10E+01	22
15.1/15.2	1.78E+02	1.29E+02	27
15.3/15.6	1.08E+02	9.25E+01	14
15.8/15.7	1.79E+02	1.51E+02	16
18.2/18.1	1.97E+02	1.30E+02	34
18.4/18.3	1.03E+02	7.76E+01	25
18.6/18.5	5.29E+01	3.08E+01	42
18.7/18.8	1.76E+02	1.25E+02	29
18.9/18.10	1.01E+02	7.79E+01	23
18.12/18.11	7.91E+01	4.81E+01	39
		Average =	24

Table 3.2-2. SNCR TEST RESULTS FOR TANGENTIAL-FIRED BOILERS (NO_x)

Database I.D.	Uncontrolled Emission Factor ($lb/10^6$ scf)	Controlled Emission Factor ($lb/10^6$ scf)	Percent Reduction (%)
20.2/20.1	5.45E+01	4.70E+01	14
20.4/20.3	8.21E+01	6.87E+01	16
20.6/20.5	9.08E+01	8.12E+01	11
21.1/21.2	6.63E+01	5.93E+01	10
21.4/21.3	9.36E+01	7.77E+01	17
21.6/21.5	1.05E+02	9.42E+01	10
22.2/22.3	6.83E+01	5.82E+01	15
22.5/22.6	4.08E+01	3.53E+01	13
17.1/17.2	6.70E+01	6.47E+01	3
17.10/17.9	7.39E+01	5.97E+01	19
17.12/17.11	8.70E+01	7.34E+01	16
17.4/17.3	5.42E+01	4.79E+01	12
17.6/17.5	7.16E+01	4.43E+01	38
17.8/17.7	8.36E+01	7.64E+01	9
19.2/19.3	8.38E+01	7.40E+01	12
19.6/19.8	4.35E+01	4.10E+01	6
19.7/19.8	4.35E+01	4.10E+01	6
19.10/19.9	4.79E+01	4.38E+01	9
		Average =	13

E--Poor: The emission factor was developed from C- and D-rated test data, and there is reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of these factors are always noted, in the emission factor table.

The above criteria for emission factor ratings are defined in and OAQPS document which provided guidance for preparing emission factor documents. The use of these criteria is somewhat subjective and depends to an extent upon the individual reviewer. As these criteria were applied to the emission factors, the term "number of facilities" was interpreted to mean "number of different boilers". This criteria prevented emission factors generated from multiple tests on a single boiler from receiving higher emission factor ratings.

Emission factors for this section were rated in the following manner:

A-Rated — Emission factor average based on results of A-rated data from 20 or more different boilers, or from approved mass balance calculations.

B-Rated — Emission factor average based on results of A-rated data from 10 to 19 different boilers.

C-Rated — Emission factor average based on results of A-rated data from five to

nine different boilers.

D-Rated — Emission factor average based on results of A-rated data from three to four different boilers.

E-Rated — Emission factor based on less than three A- or B-rated source tests.

In several cases for the revision of AP-42 Section 1.4, the data did not show a strong enough correlation to boiler type, boiler size, or combustion control to justify the grouping of data by these parameters. Where data were averaged across these parameters, the resulting emission factors were rated by the above criteria but subsequently lowered one rating. The decision was made to lower the emission factor rating in these cases to reflect the lack of certainty in the resulting emission factor.

3.4 Emission Factors

The emission factors for the sources covered in Section 1.4 of the AP-42 document are presented in Table 3.4-1. This table provides the number of source tests used in calculating the various emission factors as well as the relative standard deviation associated with each emission factor. This additional information is intended to provide greater insight to the reader about the background of each emission factor. For further detail on each emission factor, the database used to generate most of these factors (except for NO_x emission factors generated from ARD data) is provided on the TTN (See Section 3.2.1 of this document for more details on the database). For NO_x emission factors generated from data provided by the Acid Rain Division, the supporting data is provided in Appendix A.

3.5 Peer Review Process

Part of the development processes of an AP-42 section includes review by a peer group. This group include individuals from EPA, industry, and environmental organizations. In the peer review process, EPA gains an extra level of confidence in the final version of a section. Comments received on the draft version of a section are reviewed to determine if they warrant any changes to the draft version of the section before it becomes final. Appendix B presents the substantial comments received on the draft AP-42 Section 1.4 and EPA's responses to those comments.

3.6 References for Section 3

1. Procedures for Preparing Emission Factor Documents, EPA-454/R-95-015, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, September 1997.

2. Muhlbaier, J.L. "Particulate and Gaseous Emissions from Natural Gas Furnaces and Water Heaters," Journal of the Air Pollution Control Association, December 1981.

3. Evaluation of the Pollutant Emissions from Gas-Fired Forced Air Furnaces: Research Report No. 1503, American Gas Association Laboratories, Cleveland, OH. May 1975.

4. Nelson, L.P., L.M. Russell, J. J. Watson. "Global Combustion Sources of Nitrous Oxide Emissions," Research Project 2333-4 Interim Report. Radian Corporation, Sacramento, California. 1991.

5. Peer, R.L., E.P. Epner, R.S. Billings. "Characterization of Nitrous Oxide Emission Sources," Prepared for U.S. EPA Contract 68-D1-0031. Radian Corporation, Research Triangle Park, North Carolina. 1995.

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR AP-42 SECTION 1.4

Pollutant	Number of Tests	Emission Factor ($lb/10^6$ scf)	Relative Standard Deviation (%)
2-Methylnaphthalene	4	2.4E-5	72.77%
3-Methylchloranthrene	1	<1.8E-6	
7,12-Dimethylbenz(a)anthracene	1	<1.6E-5	
Acenaphthene	1	<1.8E-6	
Acenaphthylene	1	<1.8E-6	
Anthracene	1	<2.4E-6	
Arsenic	2	2.0E-4	22.36%
Barium	3	4.4E-3	38.85%
Benz(a)anthracene	1	<1.8E-6	
Benzene	17	2.1E-3	172.00%
Benzo(a)pyrene	1	<1.2E-6	
Benzo(b)fluoranthene	1	<1.8E-6	
Benzo(g,h,i)perylene	1	<1.2E-6	
Benzo(k)fluoranthene	1	<1.8E-6	
Beryllium	1	<1.2E-5	
Butane	1	2.1	
Cadmium	3	1.1E-3	166.72%
Chromium	5	1.4E-3	55.69%
Chrysene	1	<1.8E-6	
CO (Wall-Fired)	49	84	124.00%
CO (Tangential-Uncontrolled)	17	24	179.00%
CO (Tangential-FGR)	7	98	57.00%
Cobalt	2	8.4E-5	63.59%
Copper	4	8.5E-4	49.36%
Dibenzo(a,h)anthracene	1	<1.2E-6	
Dichlorobenzene	1	1.2E-3	
Ethane	4	3.1	43.77%
Fluoranthene	1	3.0E-6	
Fluorene	2	2.8E-6	14.02%
Formaldehyde	22	8.1E-2	194.00%
Hexane	2	1.8	95.61%
Indeno(1,2,3-cd)pyrene	1	<1.8E-6	
Lead	4	4.6E-4	77.61%
Manganese	2	3.8E-4	2.53%
Mercury	2	2.6E-4	43.50%
Methane	42	2.3	118.83%
Molybdenum	2	1.1E-3	64.41%
Naphthalene	2	6.1E-4	85.19%

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR AP-42 SECTION 1.4 (Continued)

Pollutant	Number of Tests	Emission Factor ($lb/10^6$ scf)	Relative Standard Deviation (%)
Nickel	5	2.1E-3	72.26%
NMHC	48	8.5	150.26%
NOx (Small-Unc.)	18	104	51.00%
NOx (Small-Low NOx)	5	50	54.00%
NOx (Small-Low NOx/FGR)	15	32	18%
NOx (Large Wall-Fired-Low NOx)	5	136	37.00%
NOx (Large Wall-Fired-FGR)	4	101	25.00%
NOx (Large Wall-Fired Unc. Pre-NSPS)	108	275	93.00%
NOx (Large Wall-Fired Unc. Post-NSPS)	13	192	36.00%
NOx (Tangential-Unc.)	62	167	37.00%
NOx (Tangential-FGR)	8	76	64.00%
Pentane	1	2.6	
Phenanthrene	4	1.7E-5	63.82%
PM, Condensible	4	5.7	69.79%
PM, Filterable	21	1.9	111.47%
Propane	1	1.6	
Pyrene	1	5.0E-6	
Selenium	1	<2.4E-5	
Toluene	11	3.4E-3	93.00%
Vanadium	3	2.3E-3	71.77%
Zinc	1	2.9E-2	

4.0 AP-42 Section 1.4

APPENDIX A

Acid Rain Division Data

UNCONTROLLED NOx EMISSION DATA FOR LARGE PRE-NSPS WALL-FIRED BOILERS

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
3892	City of Coffeyville Mun. Lght & Pow	Coffeyville	KS	283	0.155	158
814	ENTERGY	Harvey Couch	AR	129	0.282	288
44372	TU Electric	Handley	TX	518	0.403	411
19804	City of Vero Beach	Vero Beach Municipal	FL	337	0.124	126
1167	Baltimore Gas and Electric Company	Riverside	MD	308	0.338	345
22500	Western Resources, Inc.	Murray Gill	KS	251	0.211	215
15474	Central and South West Services	Southwestern	OK	149	0.278	284
14354	Illinois Power	Gadsby	UT	438	0.104	106
814	ENTERGY	Lake Catherine	AR	506	0.24	245
44372	TU Electric	Parkdale	TX	509	0.339	346
44372	TU Electric	Lake Creek	TX	519	0.282	288
17718	Southwestern Public Service Co.	Plant X	TX	348	0.347	354
814	ENTERGY	Harvey Couch	AR	502	0.1	102
16572	Salt River Project Ag. Imp. & Power	Kyrene	AZ	391	0.28	286
14534	City of Pasadena, Water & Power Dep	Broadway	CA	145	0.097	99
22500	Western Resources, Inc.	Murray Gill	KS	381	0.165	168
15474	Central and South West Services	Southwestern	OK	149	0.257	262
44372	TU Electric	Eagle Mountain	TX	736	0.509	519
3278	Central and South West Services	Lon C Hill	TX	447	0.254	259
44372	TU Electric	Morgan Creek	TX	449	0.412	420
14063	Oklahoma Gas & Electric Co.	Mustang	OK	726	0.302	308
44372	TU Electric	Parkdale	TX	620	0.41	418
22500	Western Resources, Inc.	Murray Gill	KS	428	0.224	228
14063	Oklahoma Gas & Electric Co.	Muskogee	OK	826	0.303	309
3278	Central and South West Services	Lon C Hill	TX	433	0.222	226
17698	Central and South West Services	Knox Lee	TX	436	0.324	330
44372	TU Electric	Mountain Creek	TX	704	0.237	242
44372	TU Electric	Eagle Mountain	TX	1051	0.29	296

UNCONTROLLED NOx EMISSION DATA FOR LARGE PRE-NSPS WALL-FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
16572	Salt River Project Ag. Imp. & Power	Agua Fria	AZ	742	0.25	255
16572	Salt River Project Ag. Imp. & Power	Agua Fria	AZ	752	0.25	255
44372	TU Electric	Parkdale	TX	648	0.369	376
6958	City of Garland	Ray Olinger	TX	630	0.187	191
14063	Oklahoma Gas & Electric Co.	Horseshoe Lake	OK	842	0.189	193
44372	TU Electric	Stryker Creek	TX	1050	0.36	367
44372	TU Electric	Mountain Creek	TX	779	0.5	510
44372	TU Electric	Permian Basin	TX	185	0.26	265
22500	Western Resources, Inc.	Murray Gill	KS	315	0.263	268
14063	Oklahoma Gas & Electric Co.	Mustang	OK	396	0.546	557
44372	TU Electric	Lake Creek	TX	1280	0.28	286
44372	TU Electric	Morgan Creek	TX	1233	0.29	296
44372	TU Electric	North Lake	TX	770	0.173	176
20404	Central and South West Services	Paint Creek	TX	169	0.137	140
44372	TU Electric	Graham	TX	1579	0.29	296
17609	Southern California Edison Co.	Cool Water	CA	534	0.098	100
22500	Western Resources, Inc.	Gordon Evans	KS	546	0.225	230
3265	Central Louisiana Electric Co., Inc	Coughlin	LA	488	0.321	327
13407	Nevada Power Company	Clark	NV	361	0.262	267
44372	TU Electric	North Lake	TX	1051	0.24	245
44372	TU Electric	Valley	TX	1114	0.24	245
20404	Central and South West Services	Oak Creek	TX	548	0.209	213
6616	Fort Pierce Utilities Auth	Henry D King	FL	189	0.198	202
20391	WestPlains Energy	Arthur Mullergren	KS	378	0.12	122
20391	WestPlains Energy	Cimarron River	KS	394	0.219	223
14063	Oklahoma Gas & Electric Co.	Horseshoe Lake	OK	1275	0.137	140
16604	City Public Service	W B Tuttle	TX	851	0.131	134
6958	City of Garland	C E Newman	TX	86	0.434	443
2172	Brazos Electric Power Cooperative,	North Texas	TX	245	0.299	305

UNCONTROLLED NOx EMISSION DATA FOR LARGE PRE-NSPS WALL-FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
44372	TU Electric	Handley	TX	2383	0.281	287
7294	City of Glendale, Public Service De	Grayson	CA	161	0.06	61
17609	Southern California Edison Co.	Cool Water	CA	709	0.106	108
13407	Nevada Power Company	Sunrise	NV	379	0.354	361
20447	Western Farmers Electric	Mooreland	OK	252	0.323	329
44372	TU Electric	North Lake	TX	2025	0.28	286
8901	Houston Lighting & Power Company	Webster	TX	1823	0.237	242
11269	Lower Colorado River Authority	Sim Gideon	TX	664	0.202	206
18445	Electric Operations	S O Purdom	FL	272	0.202	206
3265	Central Louisiana Electric Co., Inc	Coughlin	LA	797	0.301	307
1015	City of Austin Electric Utility Dpt	Holly Street	TX	810	0.157	160
5063	City of Denton	Spencer	TX	354	0.334	341
44372	TU Electric	Morgan Creek	TX	3671	0.591	603
10620	City of Lake Worth	Tom G Smith	FL	158	0.234	239
22500	Western Resources, Inc.	Gordon Evans	KS	1514	0.409	417
15474	Central and South West Services	Southwestern	OK	576	0.372	379
44372	TU Electric	Valley	TX	3312	0.25	255
16463	Ruston Utilities System	Ruston	LA	42	0.182	186
20447	Western Farmers Electric	Mooreland	OK	648	0.213	217
2172	Brazos Electric Power Cooperative,	R W Miller	TX	499	0.175	179
11269	Lower Colorado River Authority	Sim Gideon	TX	659	0.189	193
20391	WestPlains Energy	Judson Large	KS	600	0.159	162
7634	City of Greenville	Powerlane Plant	TX	31	0.136	139
44372	TU Electric	Tradinghouse	TX	3111	0.335	342
44372	TU Electric	Graham	TX	2161	0.42	428
2442	Bryan Utilities	Bryan	TX	139	0.211	215
20404	Central and South West Services	Rio Pecos	TX	912	0.384	392
814	ENTERGY	Lake Catherine	AR	2469	0.22	224
20813	City of Winfield	East 12Th St	KS	194	0.261	266

UNCONTROLLED NOx EMISSION DATA FOR LARGE PRE-NSPS WALL-FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
17568	South Missisippi Elec. Power Assoc.	Moselle	MS	454	0.323	329
17568	South Missisippi Elec. Power Assoc.	Moselle	MS	486	0.303	309
17568	South Missisippi Elec. Power Assoc.	Moselle	MS	434	0.28	286
14063	Oklahoma Gas & Electric Co.	Seminole	OK	1806	0.167	170
44372	TU Electric	Lake Hubbard	TX	2198	0.17	173
17698	Central and South West Services	Wilkes	TX	1759	0.299	305
18445	Electric Operations	Arvah B Hopkins	FL	433	0.239	244
2777	Cajun Electric Power Cooperative	Big Cajun 1	LA	925	0.437	446
3265	Central Louisiana Electric Co., Inc	Teche	LA	1758	0.22	224
44372	TU Electric	Eagle Mountain	TX	2021	0.17	173
44372	TU Electric	Valley	TX	2276	0.161	164
17698	Central and South West Services	Wilkes	TX	1653	0.263	268
20404	Central and South West Services	Paint Creek	TX	521	0.309	315
6909	Gainesville Regional Utilities	Deerhaven	FL	638	0.151	154
2777	Cajun Electric Power Cooperative	Big Cajun 1	LA	657	0.347	354
14063	Oklahoma Gas & Electric Co.	Seminole	OK	1870	0.188	192
44372	TU Electric	Tradinghouse	TX	4972	0.441	450
2172	Brazos Electric Power Cooperative,	R W Miller	TX	993	0.36	367
5063	City of Denton	Spencer	TX	418	0.294	300
44372	TU Electric	Permian Basin	TX	3929	0.873	890
44372	TU Electric	Lake Hubbard	TX	2844	0.214	218
20404	Central and South West Services	Fort Phantom	TX	966	0.331	338

Pre-NSPS Average Nox (lb/MMscf) = 275
(lb/MMBtu) = 0.27

UNCONTROLLED NOX EMISSION DATA FOR LARGE POST-NSPS WALL-FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
20447	Western Farmers Electric	Mooreland	OK	721	0.224	228
14063	Oklahoma Gas & Electric Co.	Seminole	OK	1773	0.205	209
3278	Central and South West Services	La Palma	TX	1005	0.272	277
44372	TU Electric	Decordova	TX	5148	0.324	330
6616	Fort Pierce Utilities Auth	Henry D King	FL	291	0.121	123
9096	Lafayette Utilities System	Doc Bonin	LA	822	0.252	257
44372	TU Electric	Handley	TX	2629	0.15	153
6958	City of Garland	Ray Olinger	TX	1009	0.177	181
18445	Electric Operations	Arvah B Hopkins	FL	1510	0.187	191
7634	City of Greenville	Powerlane Plant	TX	162	0.097	99
44372	TU Electric	Handley	TX	2577	0.12	122
20404	Central and South West Services	Fort Phantom	TX	1189	0.122	124
5109	Detroit Edison Company	Greenwood	MI	2483	0.19	194

Post-NSPS Average NOx (lb/MMscf) =192
(lb/MMBtu) = 0.19

NOx EMISSION DATA FOR WALL-FIRED BOILERS WITH LOW NOx BURNERS

util code	utility	plant	state	Average heat input (MMBtu/hr)	NOx rate-3Q (lb/MMBtu)	NOx rate-3Q (lb/MMscf)
2507	City of Burbank - Public Service De	Magnolia	CA	105	0.108	110
14534	City of Pasadena, Water & Power Dep	Broadway	CA	145	0.107	109
2507	City of Burbank - Public Service De	Olive	CA	147	0.082	84
3265	Central Louisiana Electric Co., Inc	Rodemacher	LA	1737	0.203	207
13998	Ohio Edison Company	Edgewater	OH	380	0.167	170

Average NOx (lb/MMscf) = 136
(lb/MMBtu) = 0.13

UNCONTROLLED NOx EMISSION DATA FOR TANGENTIAL FIRED BOILERS

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
9726	GPU Generation Corporation	Gilbert	NJ	505	0.238	243
195	Alabama Power Company	Chickasaw	AL	256	0.168	171
12686	Mississippi Power Company	Sweatt	MS	344	0.335	342
3249	Central Hudson Gas & Electric Corp.	Danskammer	NY	205	0.08	82
14354	Illinois Power	Gadsby	UT	392	0.093	95
12686	Mississippi Power Company	Sweatt	MS	346	0.325	332
17718	Southwestern Public Service Co.	Plant X	TX	605	0.125	128
803	Arizona Public Service Company	Saguaro	AZ	720	0.335	342
6452	Florida Power & Light Company	Cutler	FL	518	0.083	85
3249	Central Hudson Gas & Electric Corp.	Danskammer	NY	381	0.102	104
803	Arizona Public Service Company	Saguaro	AZ	622	0.219	223
6452	Florida Power & Light Company	Cutler	FL	919	0.079	81
44372	TU Electric	Collin	TX	753	0.139	142
17718	Southwestern Public Service Co.	Plant X	TX	529	0.158	161
14354	Illinois Power	Gadsby	UT	624	0.08	82
17609	Southern California Edison Co.	San Bernardino	CA	395	0.1	102
17698	Central and South West Services	Lieberman	LA	471	0.15	153
12686	Mississippi Power Company	Jack Watson	MS	309	0.197	201
17718	Southwestern Public Service Co.	Cunningham	NM	502	0.225	230
24211	Tucson Electric Power Company	Irvington	AZ	363	0.147	150
17609	Southern California Edison Co.	San Bernardino	CA	393	0.103	105
803	Arizona Public Service Company	Yuma Axis	AZ	343	0.071	72
17698	Central and South West Services	Lieberman	LA	424	0.14	143
803	Arizona Public Service Company	Ocotillo	AZ	598	0.147	150
803	Arizona Public Service Company	Ocotillo	AZ	561	0.138	141
24211	Tucson Electric Power Company	Irvington	AZ	367	0.185	189
7806	Entergy Corporation	R S Nelson	LA	810	0.161	164
17698	Central and South West Services	Arsenal Hill	LA	505	0.134	137

UNCONTROLLED NOx EMISSION DATA FOR TANGENTIAL FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
12686	Mississippi Power Company	Jack Watson	MS	307	0.149	152
1015	City of Austin Electric Utility Dpt	Holly Street	TX	512	0.102	104
8901	Houston Lighting & Power Company	T H Wharton	TX	954	0.157	160
24211	Tucson Electric Power Company	Irvington	AZ	443	0.202	206
12686	Mississippi Power Company	Jack Watson	MS	490	0.194	198
17718	Southwestern Public Service Co.	Nichols Station	TX	652	0.15	153
17698	Central and South West Services	Wilkes	TX	841	0.151	154
17718	Southwestern Public Service Co.	Plant X	TX	859	0.181	185
22500	Western Resources, Inc.	Hutchinson	KS	579	0.272	277
17718	Southwestern Public Service Co.	Cunningham	NM	1200	0.208	212
44372	TU Electric	Stryker Creek	TX	3615	0.16	163
16604	City Public Service	V H Braunig	TX	1216	0.162	165
17718	Southwestern Public Service Co.	Maddox	NM	883	0.154	157
6958	City of Garland	Ray Olinger	TX	332	0.12	122
44372	TU Electric	Mountain Creek	TX	3481	0.162	165
16604	City Public Service	V H Braunig	TX	1069	0.179	183
17718	Southwestern Public Service Co.	Nichols Station	TX	945	0.218	222
9096	Lafayette Utilities System	Doc Bonin	LA	427	0.141	144
14063	Oklahoma Gas & Electric Co.	Horseshoe Lake	OK	590	0.081	83
1015	City of Austin Electric Utility Dpt	Decker Creek	TX	1574	0.155	158
16604	City Public Service	V H Braunig	TX	1945	0.218	222
17718	Southwestern Public Service Co.	Jones Station	TX	1422	0.249	254
16604	City Public Service	O W Sommers	TX	2138	0.205	209
11269	Lower Colorado River Authority	Sim Gideon	TX	1603	0.174	177
8901	Houston Lighting & Power Company	Greens Bayou	TX	2094	0.113	115
16604	City Public Service	O W Sommers	TX	2525	0.153	156
16463	Ruston Utilities System	Ruston	LA	17	0.14	143
1015	City of Austin Electric Utility Dpt	Holly Street	TX	1151	0.178	182
17718	Southwestern Public Service Co.	Jones Station	TX	1368	0.245	250
11269	Lower Colorado River Authority	T C Ferguson	TX	2120	0.175	179

UNCONTROLLED NOx EMISSION DATA FOR TANGENTIAL FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
1015	City of Austin Electric Utility Dpt	Decker Creek	TX	2504	0.113	115
16687	Savannah Electric and Power Co.	Riverside	GA	175	0.114	116
17718	Southwestern Public Service Co.	Moore County Station	TX	345	0.138	141
44372	TU Electric	Trinidad	TX	1550	0.204	208

Average (lb/MMscf) = 167
(lb/MMBtu) = 0.16

APPENDIX B

Reviewer Comments and EPA Responses

List of Addresseses for Draft Section 1.4

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Summary of Comments
Section 1.4 - Natural Gas Combustion

Emission Factors

GRI: In Table 1.4-1, small wall-fired and residential furnaces (<100 MMBtu/hr) are grouped in one category. Previous versions had size ranges at <0.3, 0.3 to <10, 10 to <100, and >100 MMBtu/hr. With the present single grouping of <100 MMBtu/hr, the implication is that NO_x, CO, and N_2O emissions are independent of size. Is there data to support this grouping under one size range?

Response: Based on the available data, EPA determined that boiler size had no clear effect on NO_x and CO emissions for boilers less than 100 MMBtu/hr of heat input. The majority of boilers that are smaller than 100 MMBtu/hr are package units and emissions appear to be more dependent on individual boiler operation than boiler size.

Atlanta Gas: The EPA should consider adding a third category to Table 1.4-1 to address either "other" boilers by heat input or address the "ring retention" type boilers. Atlanta Gas has only ring retention type, fire tube, water/glycol boilers. In order for Atlanta Gas to use emission factors versus stack testing on boilers, it would need the previously published emission factors that used heat input or a new category for ring retention.

Response: The EPA changed the small boiler category to include "other" boiler types. In addition, a footnote to Table 1.4-1 provides a conversion factor for heat input: to convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020.

GRI: In Table 1.4-1, the value of 84 $lb/10^6$ scf for CO converts to about 115 ppm, which seems high. In addition, this value implies there is no variation as a function of size. Previous versions had additional size categories. Is there a reason for the change?

Response: The data supports a CO emission factor for wall-fired boilers that is not dependent on size. There were 49 tests conducted on 23 boilers, with an average emission factor of 84.15 and a relative standard deviation of 124 percent. The EPA analyzed CO emissions versus boiler size and determined that there is no clear relation between size and CO emissions. It is true that if CO emissions were averaged across the previous size ranges, the various boiler size categories would have slightly different CO emission factors, but the overall data set showed no clear relation to size. Therefore, CO emission factors were not categorized by size for the wall-fired and small boiler categories. During the next revision of this section, if additional CO

emission data indicates a stronger correlation between size and CO emission levels, then CO emission factors would be distinguished by size.

Burns & McDonnell: Footnote "d" is not properly referenced in Table 1.4-2. It should appear with SO_2 in the pollutant column. Also, EPA should stress that since the emission factors are based on a natural gas heat content of 1,020 Btu/scf, users may need to adjust the emission factors. If the heat content of their natural gas differs from the 1,020 Btu value, users should adjust the emission factor by a ratio of the heat rates (actual Btu heat content /1,020 Btu value). In addition, this same approach applies to the assumed 2,000 grains of sulfur/MMscf for the SO_2 emission rates within the Table 1.4-2.

Response: Footnote "d" has been corrected to properly reference the SO_2 emission factor. Footnote "d" of Table 1.4-2 was also amended to provide guidance on adjusting emission factors for sources firing natural gas with Btu ratings different from 1,020 Btu/scf. A similar approach was taken with the SO_2 emission factor; in this case, EPA provided guidance to adjust the SO_2 emission factor at sources where the sulfur content of the natural gas was different from 2,000 grains/MMscf.

U.S. EPA, EFIG: The CO_2 emission factor in Table 1.4-2 should be 120,000, not 12,000. Also, correct footnote "b" calculation.

Response: The emission factor has been corrected to 120,000 lb/MMscf. The EPA also corrected an error in footnote "b" regarding the calculation of the CO_2 emission factor.

GRI: Table 1.4-2 indicates a conversion of fuel carbon to CO_2 of 99.5%. This converts to about 5,000 ppm of CO and other hydrocarbons. This seems high for commercial boilers. Typical values of CO are less than 50 ppm and other hydrocarbons are typically below 100 ppm. These would result in a conversion efficiency of 99.995% rounded down to 99.9%. Is this value correct?

Response: The assumed fuel carbon conversion as been changed to 99.9%. This adjustment will not change the CO_2 emission factor since it was rounded to two significant figures.

Unidentified commenter via U.S. EPA, EFIG: Put Chemical Abstract Services (CAS) numbers with the Hazardous Air Pollutant (HAP) in the tables. The HAP list in the section is confusing because many of those compounds listed are not listed in section 112(b) of the 1990 Amendments to the Clean Air Act, and they only qualify as HAPs because they are Polycylic Organic Matter (POMs). It would be more clear to label which compounds are HAPs and which are HAPs because they are POMs.

Response: CAS numbers were assigned to all pollutants for easy identification. The EPA also distinguished between HAPs and compounds that are classified as HAPs because they are POMs.

GRI: GRI suggests adding a footnote to the tables to explain to the casual reader the meaning of "emission factor rating."

Response: Rather than footnote each table with an explanation of emission factor ratings, the ratings are discussed at the end of the section. In addition, the EPA fully discusses emission factor ratings in the introduction to AP-42 and in the Emission Factor Documentation for Section 1.4 (background report).

Phillips: The emissions data suggest that grouping the toxics data into specific categories of heaters/boilers could provide more accurate emission factors for air toxics. In the database enclosed with the report, arithmetic averages are used to calculate the criteria pollutant and toxics emission factors. By using arithmetic averages, the assumption is made that the distribution is normal. However, Phillips' review of the normality and probability of the toxics data shows non-random behavior (non-normal distribution). The commenter suggests that, if it has not already been considered, the toxics data may be grouped by heater/boiler heat input to increase the accuracy of the resulting emission factors. (The commenter recognizes that small sample sizes reduce the effectiveness of normality tests.) If this suggested grouping has already been considered and would not work, EPA should discuss this in the background report. Otherwise, EPA should consider a new grouping.

Response: The toxic data were analyzed for these source categories to determine if grouping these data by source type would provide more accurate emission factors. Based on this analysis and given the limited data available, no clear relation is apparent between these source categories

and toxic emission levels. Therefore, EPA maintains that the current grouping is the most appropriate. The background report provides a discussion of this decision.

Phillips: The emission factors for natural gas-fired heaters should be delayed pending the results of the GRI/API/Radian study of engine emissions. A program for characterizing and quantifying emissions from reciprocating engines used in oil and gas production is underway and the data will be available in October 1997. The program will also investigate the emissions from a 62.5 MMBtu/hr boiler and a heater treater which is representative of small heaters used in the oil and gas production industry. The list of analytes chosen for this effort includes those reported in Tables 1.4-2 and 1.4-4. The resulting data meet EPA's criteria for an emission factor rating of "A." The value of the data justifies a short delay in publishing the revised emission factors.

Response: The EPA is aware of the data that will be available in the GRI/API/Radian study but that the final report will not be ready for distribution until early 1998. Given the time frame of the publication of this report, EPA does not want to delay the revision of Section 1.4 of AP-42 to include this data. The EPA understands that the report has data from 1 boiler and that the inclusion of 1 extra boiler in the database should have little effect on the emission factors in this revision. However, the emission test data from the boilers tested in the GRI study will be incorporated in the next revision to Section 1.4.

Phillips: Only emission factors with an emission factor rating of A, B, or C should be published in the public domain. The use of emission factors based on poor quality data may have far-reaching, undesirable consequences.

Response: The primary purpose of AP-42 is to provide emission factors for emission inventories. The EPA provides emission factors for as many sources and as many pollutants as available resources allow. The factors are rated "A" through "E" to provide the user with an indication of how good an emission factor is, with an "A" being excellent and "E" being poor. The criteria that are used to determine a rating for a factor can be found in the document entitled "Procedures for Preparing Emission Factor Documents, EPA-454/R-95-0150." While the EPA shares your concern about poor quality emission factors for various reasons, the factor rating is used to judge whether the factor is appropriate.

Controls

GRI: Section 1.4 states that low-NO_x burners and flue gas recirculation (FGR) are the most prevalent combustion NO_x control techniques being applied to natural gas-fired boilers. GRI agrees that low-NO_x burners are prevalent in all classes and size ranges of boilers. However, GRI does not agree that FGR is prevalent for boilers with capacities less than 100 MMBtu/hr. Also, one NO_x control system not mentioned is gas reburning. Gas reburning is an attractive technical and economic alternative to SNCR or SCR. The commenter cited demonstrations of gas reburn on a tangentially-fired utility boiler, a front-wall boiler, and an opposed-wall boiler. The tangentially-fired boiler achieved a 55-65% reduction of NO_x and the opposed-wall and front-wall burners achieved 80% and 73% reductions, respectively.

Response: The EPA is aware that FGR technology is most prevalent in boilers with heat inputs greater than 100 MMBtu/hr, however, EPA has data from boilers with heat inputs less than 100 MMBtu/hr that employ FGR and low-NO_x burners for NO_x control. The EPA has received tests from several boilers with heat inputs less than 100 MMBtu/hr that have FGR and low-NO_x burners. Furthermore, there is a separate category for the boilers for NO_x emission factors. With respect to gas reburning, EPA does not have any data to evaluate the performance of gas reburning. In the final version of this revision to Section 1.4, gas reburning will be mentioned as a NO_x control technology. However, NO_x reduction efficiencies will not be presented in this revision to Section 1.4 due to the lack of supporting data.

GRI: Section 1.4 states that the addition of low-NO_x burners and FGR may reduce combustion efficiency. This implies that low-NO_x burners and FGR are the direct cause of reduced combustion efficiency. This is not necessarily correct. Incomplete combustion can be unburned fuel, unburned carbon, and newly formed solid, liquid, or gaseous hydrocarbons. One of the later species could be CO. GRI suggests the following revision to the paragraph: "Improperly tuned boilers and boilers operating at off-design levels can result in increased partially oxidized combustibles (e.g., CO) and thus, decreased combustion efficiency. The addition of NO_x control systems such as low-NO_x burners and FGR may also result in increased CO or other partially oxidized combustibles, and likewise, decreased combustion efficiency."

Response: The effects of improperly tuned boilers on CO and hydrocarbon emissions were addressed in the discussions on CO and hydrocarbon emissions. Therefore, GRI's suggestion will not be added.

GRI: It is also worth mentioning that current NO_x control systems can lower NO_x emissions without increases in other emissions such as CO, VOCs, and PM. An example of this is shown in Section 2, Reference 6.

Response: The EPA will add this to its discussion of NO_x control technologies.

GRI: There has been significant testing of minor products of combustion and also significant development of low-NO_x burners and NO_x control technology in recent years. If it is not within EPA's current resources to obtain later information, it would be well to indicate the data in the tables are from sources with publication dates ranging from 1990-1996.

Response: The background report provides a list of all the references used in this revision including testing dates. If users wish to evaluate the age of the data, they can download this document from the TTN.

Emission Data

ABMA and EPRI both provided emission data for natural gas fired boilers. The data provided by ABMA was used for comparative purposes and was not included for emission factor development because it did not contain complete testing information. The data provided by EPRI did contain complete testing information and was used in the development of emission factors.

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Related Information

Explanation of File Formats

AP-42 Section 1.4 - Natural Gas Combustion

The data that supports the emission factors are presented in summary in the background report and are reported more completely in an electronic database. The database is in Microsoft Access 97®, and it is "zipped".

Description

Section 1.4: Data file (ZIP 239K)

AP-42 CHAPTER 1.4 - BOILERS MAIN MENU

CO Reports:

- Wall-Fired Boilers
- Tangential Boilers (uncontrolled)
- Tangential Boilers (FGR)

NOx Reports:

- Large Wall-Fired Boilers (FGR)
- Tangential Boilers (FGR)
- Small Boilers/Res Furnaces (uncontrolled)
- Small Boilers (low NOx burner)
- Small Boilers (Low NOx Burners /FGR)

Facility Data:

- View Facilities

All Other Pollutant Reports:

- Overall Average by Pollutant
- Overall Average All Pollutants

Test Data:

- View Test Data

- Close Screen
- Exit Program

Small Boilers Emission Factor Report for NOx

16-Jan-03

NOx Control	ID	Manufacturer	Type	Rating (MMBtu/hr)	Load (%)	Ef (lb/MMscf)
None						
	106.1	Keeler	NR	3.300E+01	90	7.998E+01
	107.1	Bisceglia Bros	NR	6.700E+01	90	1.064E+02
	108.1	Kewanee	NR	1.248E+01	96	3.724E+01
	110.1	Cleaver Brooks	NR	8.424E+01	100	3.854E+01
	110.2	Cleaver Brooks	NR	8.512E+01	100	4.047E+01
	111.1	Nebraska	Watertube	5.200E+01	100	8.323E+01
	111.2	Nebraska	Watertube	7.500E+01	100	9.598E+01
	113.1	Cleaver Brooks	NR	1.240E+01	100	1.564E+02
	113.2	Cleaver Brooks	NR	1.080E+01	100	1.337E+02
	114.1	NR	NR	4.100E+01	100	1.247E+02
	116.1	Struthers	NR	6.266E+01	79	4.161E+01
	116.2	Struthers	NR	6.266E+01	79	4.355E+01
	120.1	NR	NR	2.200E+00	100	1.802E+02

NOx Control	ID	Manufacturer	Type	Rating (MMBtu/hr)	Load (%)	Ef (lb/MMscf)
	121.1	NR	NR	2.200E+00	100	1.163E+02
	122.1	NR	NR	2.870E+01	100	1.316E+02
	122.2	NR	NR	2.870E+01	100	1.906E+02
	122.3	NR	NR	1.180E+01	100	1.945E+02
	126.1	NR	NR	1.050E+01	100	8.254E+01
					Avg EF =	1.043E+02
					Std Dev =	5.331E+01
					Count =	18
					RSD(%) =	51.11%

NOx Control	ID	Manufacturer	Type	Rating (MMBtu/hr)	Load (%)	Ef (lb/MMscf)

Facilities

ID:	1.1
Facility Name:	EPRI Site 120
Location:	NR
Testing Company:	Carnot
Date:	04-Apr-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	700
Load (%):	20
Fuel Type:	NG
HHV:	1002
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	FGR
Application Type:	Utility Boiler
Comments:	Tests 1,2,3 (FGR/OFA/BOOS)
Data Entered By:	CL

ID:	1.2
Facility Name:	EPRI Site 120
Location:	NR
Testing Company:	Carnot
Date:	04-Apr-93
Manufacturer:	CE
Type:	Tangential

Air Supply:	FD
Capacity (MW):	700
Load (%):	100
Fuel Type:	NG
HHV:	1002
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	FGR
Application Type:	Utility Boiler
Comments:	Tests 4,5,6 (FGR/OFA/BOOS)
Data Entered By:	CL
ID:	1.3
Facility Name:	EPRI Site 120
Location:	NR
Testing Company:	Carnot
Date:	04-Apr-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	700
Load (%):	97
Fuel Type:	NG
HHV:	1002
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	FGR
Application Type:	Utility Boiler

Comments:	Tests 7,8,9 (FGR/OFA/BOOS)
Data Entered By:	CL
ID:	10.1
Facility Name:	EPRI Site 105
Location:	NR
Testing Company:	Carnot
Date:	18-Feb-90
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	
Capacity (MW):	750
Load (%):	96
Fuel Type:	NG
HHV:	1042.5
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1
Data Entered By:	MKO
ID:	106.1
Facility Name:	California Fruit Produce
Location:	Fresno, CA
Testing Company:	Best Environmental Inc.
Date:	04-Dec-92
Manufacturer:	Keeler
Type:	NR

Air Supply:	NR
Capacity (MW):	33
Load (%):	90
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	29.7
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Btu/scf is default value
Data Entered By:	CL
ID:	107.1
Facility Name:	California Fruit Produce
Location:	Madera, CA
Testing Company:	Best Environmental Inc.
Date:	02-Dec-92
Manufacturer:	Bisceglia Bros
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	90
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	60.3
NOx Control:	None
Application Type:	Industrial Boiler

Comments:	
Data Entered By:	MKO
ID:	108.1
Facility Name:	Zacky Farms
Location:	Dinuba,CA
Testing Company:	Steiner Enviromental Inc.
Date:	16-Jul-93
Manufacturer:	Kewanee
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	96
Fuel Type:	NG
HHV:	1088
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	11.98
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	
Data Entered By:	MKO
ID:	109.1
Facility Name:	Harrison Radiator
Location:	Dayton Ohio
Testing Company:	Hayden Enviromental Group Inc. Boiler #3
Date:	08-Feb-90
Manufacturer:	NR
Type:	NR

Air Supply:	FD
Capacity (MW):	0
Load (%):	90
Fuel Type:	NG
HHV:	1022
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	235
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Boiler #3
Data Entered By:	MKO
ID:	109.2
Facility Name:	Harrison Radiator
Location:	Dayton Ohio
Testing Company:	Hayden Enviromental Group Inc. Boiler #3
Date:	06-Feb-90
Manufacturer:	NR
Type:	NR
Air Supply:	FD
Capacity (MW):	0
Load (%):	90
Fuel Type:	NG
HHV:	1022
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	127
NOx Control:	None
Application Type:	Industrial Boiler

Comments:	Boiler #4
Data Entered By:	MKO
ID:	11.1
Facility Name:	EPRI Site 106
Location:	NR
Testing Company:	Carnot
Date:	16-Mar-90
Manufacturer:	
Type:	Wall-fired
Air Supply:	
Capacity (MW):	480
Load (%):	97
Fuel Type:	NG
HHV:	947
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1
Data Entered By:	MKO
ID:	110.1
Facility Name:	Tometax
Location:	Firebaugh, Ca
Testing Company:	Ecoserve Enviromental Services Boiler #1
Date:	19-Oct-89
Manufacturer:	Cleaver Brooks
Type:	NR

Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1044
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	84.24
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	110.2
Facility Name:	Tometax
Location:	Firebaugh,Ca
Testing Company:	Ecoserve Enviromental Services Boiler #2
Date:	19-Oct-89
Manufacturer:	Cleaver Brooks
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1044
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	85.12
NOx Control:	None
Application Type:	Industrial Boiler

Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	111.1
Facility Name:	Whiteman Air Force Base Boiler #4
Location:	Knob Noster,MO
Testing Company:	Shell Enginering & Associates
Date:	20-Oct-90
Manufacturer:	Nebraska
Type:	Watertube
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	52
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	111.2
Facility Name:	Whiteman Air Force Base Boiler #5
Location:	Knob Noster,MO
Testing Company:	Shell Enginering & Associates
Date:	21-Oct-90
Manufacturer:	Nebraska
Type:	Watertube

Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	75
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	112.1
Facility Name:	Firestone Synthetic Rubber & Latex Boiler EB-114
Location:	Orange,Texas
Testing Company:	Metco Enviromental
Date:	06-Nov-90
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	33
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	36
NOx Control:	None

Application Type:	Industrial Boiler
Comments:	Condition 1,run 1,2,3
Data Entered By:	MKO
ID:	112.2
Facility Name:	Firestone Synthetic Rubber & Latex Boiler EB-114
Location:	Orange, Texas
Testing Company:	Metco Enviromental
Date:	06-Nov-90
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	108
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Condition 1,run 4,5,6
Data Entered By:	MKO
ID:	113.1
Facility Name:	Greiner Incorporated Boiler#1
Location:	Grand Rapids, Mich
Testing Company:	WW Enginering & Science
Date:	11-May-93
Manufacturer:	Cleaver Brooks

Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	12.4
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2,3. F-factor is an average.
Data Entered By:	MKO
ID:	113.2
Facility Name:	Greiner Incorporated Boiler#2
Location:	Grand Rapids, Mich
Testing Company:	WW Enginering & Science
Date:	10-Jun-93
Manufacturer:	Cleaver Brooks
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	10.8
NOx Control:	None

Application Type:	Industrial Boiler
Comments:	Test 1,2,3. F-factor is an average.
Data Entered By:	MKO
ID:	114.1
Facility Name:	Texaco Refining & Marketing
Location:	Bakersfield,Ca
Testing Company:	Steiner Enviromental
Date:	19-Jun-92
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1149
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	41
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	115.1
Facility Name:	Naval Construction Batallion Center
Location:	Port Hueneme,Ca
Testing Company:	NEESA
Date:	20-Sep-90
Manufacturer:	Cleaver Brooks

Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	25
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	6.3
NOx Control:	Low NOx burner - FGR
Application Type:	Industrial Boiler
Comments:	Test 1,2 (Low NOx burner, FGR)
Data Entered By:	MKO

ID:	115.2
Facility Name:	Naval Construction Batallion Center
Location:	Port Hueneme,Ca
Testing Company:	NEESA
Date:	20-Sep-90
Manufacturer:	Cleaver Brooks
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	50
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	9.77025
NOx Control:	Low NOx burner - FGR

Application Type:	Industrial Boiler
Comments:	Test 1,2 (Low NOx burner, FGR)
Data Entered By:	MKO
ID:	115.3
Facility Name:	Naval Construction Batallion Center
Location:	Port Hueneme, Ca
Testing Company:	NEESA
Date:	20-Sep-90
Manufacturer:	Cleaver Brooks
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	75
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	16.611
NOx Control:	Low NOx burner - FGR
Application Type:	Industrial Boiler
Comments:	Test 1,2 (Low NOx burner, FGR)
Data Entered By:	MKO
ID:	115.4
Facility Name:	Naval Construction Batallion Center
Location:	Port Hueneme, Ca
Testing Company:	NEESA
Date:	20-Sep-90
Manufacturer:	Cleaver Brooks

Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	28.0455
NOx Control:	Low NOx burner - FGR
Application Type:	Industrial Boiler
Comments:	Test 1,2 (Low NOx burner, FGR)
Data Entered By:	MKO
ID:	115.7
Facility Name:	Naval Construction Batallion Center
Location:	Port Hueneme,Ca
Testing Company:	NEESA
Date:	24-Sep-90
Manufacturer:	Cleaver Brooks
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	27.9615
NOx Control:	Low NOx burner - FGR

Application Type:	Industrial Boiler
Comments:	Test 2 (Low NOx burner, FGR)
Data Entered By:	MKO
ID:	116.1
Facility Name:	Chevron 50-7
Location:	Bakersfield,Ca
Testing Company:	Genesis
Date:	11-Jun-91
Manufacturer:	Struthers
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	79
Fuel Type:	NG
HHV:	985
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	49.5
NOx Control:	None
Application Type:	Steam Generator
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	116.2
Facility Name:	Chevron 50-6
Location:	Bakersfield,Ca
Testing Company:	Genesis
Date:	11-Jun-91
Manufacturer:	Struthers

Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	79
Fuel Type:	NG
HHV:	985
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	49.5
NOx Control:	None
Application Type:	Stean Generator
Comments:	Test 1,2,3
Data Entered By:	MKO

ID:	117.1
Facility Name:	Candlewick Yarns
Location:	Lemoore,Ca
Testing Company:	Pacific Enviromental Services
Date:	21-Apr-93
Manufacturer:	Johnston
Type:	Fire-tube
Air Supply:	NR
Capacity (MW):	0
Load (%):	95
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	20
NOx Control:	Low NOx burner - FGR

Application Type:	Industrial Boiler
Comments:	Test 1,2,3 (Low NOx burner, FGR)
Data Entered By:	MKO
ID:	119.1
Facility Name:	Siemans Enegry and Automation, Inc Boiler 2
Location:	Norwood Ohio
Testing Company:	K & B Design, Inc
Date:	08-Aug-94
Manufacturer:	Clayton Industries
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	83.7
Fuel Type:	NG
HHV:	1025
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	20.5
NOx Control:	Low NOx burner
Application Type:	Industrial Boiler
Comments:	Test 1,2 3
Data Entered By:	MKO
ID:	12.1
Facility Name:	EPRI Site 107
Location:	NR
Testing Company:	Carnot
Date:	25-Feb-90

Manufacturer:	B&W
Type:	Radiant heat
Air Supply:	
Capacity (MW):	175
Load (%):	86
Fuel Type:	NG
HHV:	957
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1
Data Entered By:	MKO
ID:	120.1
Facility Name:	Gibson Oil and Refining Company
Location:	Bakersfield, Ca
Testing Company:	Brown and Caldwell
Date:	30-Jul-92
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	2.2

NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1
Data Entered By:	MKO
ID:	121.1
Facility Name:	Gibson Oil and Refining Company
Location:	Bakersfield, Ca
Testing Company:	Brown and Caldwell
Date:	14-May-90
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	2.2
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	121.2
Facility Name:	Gibson Oil and Refining Company
Location:	Bakersfield,Ca
Testing Company:	Brown and Caldwell
Date:	14-May-90

Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	2.2
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 2,3,4
Data Entered By:	MKO

ID:	121.3
Facility Name:	Gibson Oil and Refining Company
Location:	Bakersfield, Ca
Testing Company:	Brown and Caldwell
Date:	14-May-90
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	2.2

NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 5,6,7
Data Entered By:	MKO
ID:	121.4
Facility Name:	Gibson Oil and Refining Company
Location:	Bakersfield, Ca
Testing Company:	Brown and Caldwell
Date:	17-May-90
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	2.2
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 9,10,11
Data Entered By:	MKO
ID:	121.5
Facility Name:	Gibson Oil and Refining Company
Location:	Bakersfield,Ca
Testing Company:	Brown and Caldwell
Date:	17-May-90

Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	2.2
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 13,14,15
Data Entered By:	MKO

ID:	121.6
Facility Name:	Gibson Oil and Refining Company
Location:	Bakersfield ,Ca
Testing Company:	Brown and Caldwell
Date:	17-May-90
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0

NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2 3
Data Entered By:	MKO
ID:	122.1
Facility Name:	Oakwood Hospital
Location:	Westland,Mich.
Testing Company:	WWES
Date:	02-Nov-93
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	28.7
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Boiler 1
Data Entered By:	MKO
ID:	122.2
Facility Name:	Oakwood Hospital
Location:	Westland,Mich
Testing Company:	WWES
Date:	03-Nov-93

Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	28.7
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Boiler 2
Data Entered By:	MKO

ID:	122.3
Facility Name:	Oakwood Hospital
Location:	Westland, Mich
Testing Company:	WWES
Date:	04-Nov-93
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	11.8

NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Boiler 3
Data Entered By:	MKO
ID:	123.1
Facility Name:	General Motors
Location:	Roanoke, Indiana
Testing Company:	CAE
Date:	02-Feb-93
Manufacturer:	Riley Stoker
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	98
Fuel Type:	NG
HHV:	1040
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	234
NOx Control:	FGR
Application Type:	Industrial Boiler
Comments:	Boiler 4
Data Entered By:	MKO
ID:	125.1
Facility Name:	Stella Cheese
Location:	Tulare, Ca
Testing Company:	Steiner Enviromental
Date:	30-Jul-93

Manufacturer:	Mohawk
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	82.5
Fuel Type:	NG
HHV:	1069
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	26
NOx Control:	Low NOx burner - FGR
Application Type:	Industrial Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	126.1
Facility Name:	Crystal Geyser Water Company
Location:	Bakersfield,Ca
Testing Company:	Steiner Enviromental Boiler 1
Date:	26-Feb-93
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	998
HHVUnit:	Btu/scf

Heat Input (MMBtu/hr):	10.5
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	126.2
Facility Name:	Crystal Geyser Water Company
Location:	Bakersfield, Ca
Testing Company:	Steiner Enviromental Boiler 1
Date:	26-Feb-93
Manufacturer:	NR
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1000
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	10.5
NOx Control:	Low NOx burner
Application Type:	Industrial Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	13.1
Facility Name:	EPRI Site 108
Location:	NR
Testing Company:	Carnot

Date:	19-Mar-90
Manufacturer:	Riley Stoker
Type:	NR
Air Supply:	NR
Capacity (MW):	50
Load (%):	96
Fuel Type:	NG
HHV:	1070
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1
Data Entered By:	MKO
ID:	131.1
Facility Name:	Minnesota Corn Processors
Location:	Marshall, Minn
Testing Company:	Nova Enviromental Services
Date:	21-Dec-94
Manufacturer:	Zurn Model No.Go1767
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1000
HHVUnit:	Btu/scf

Heat Input (MMBtu/hr):	180
NOx Control:	Low NOx burner
Application Type:	Commerical Boiler
Comments:	Test 1,2 3
Data Entered By:	MKO
ID:	132.1
Facility Name:	Virginia Public Utilities Boiler# 10
Location:	Virginia, Minn
Testing Company:	Interpoll Laboratories
Date:	27-Jul-94
Manufacturer:	Zurn
Type:	Water-tube, package
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1000
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	205
NOx Control:	None
Application Type:	Industrial Boiler
Comments:	Test 1,2 3
Data Entered By:	MKO
ID:	132.2
Facility Name:	Minnesota Corn Processors Boiler#3
Location:	Marshal, Minn
Testing Company:	Interpoll Laboratories

Date:	22-Jul-92
Manufacturer:	Zurn
Type:	Water-tube, package
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1050
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	180
NOx Control:	None
Application Type:	Commerical Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	133.1
Facility Name:	Los Gatos Tomato Products
Location:	Huron, Ca.
Testing Company:	Best Environmental, inc.
Date:	01-Feb-91
Manufacturer:	Cleaver Brooks
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1040
HHVUnit:	Btu/scf

Heat Input (MMBtu/hr):	87.8
NOx Control:	Low NOx Burner - FGR
Application Type:	Steam Production
Comments:	Boiler #1. Boiler was retested due to high TNMTHC level
Data Entered By:	JJ
ID:	133.2
Facility Name:	Los Gatos Tomato Products
Location:	Huron, Ca.
Testing Company:	Best Environmental, inc.
Date:	01-Feb-91
Manufacturer:	Cleaver Brooks
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1040
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	82.8
NOx Control:	Low NOx Burner - FGR
Application Type:	Steam Production
Comments:	Boiler #2.
Data Entered By:	JJ
ID:	133.3
Facility Name:	Los Gatos Tomato Products
Location:	Huron, Ca.
Testing Company:	Best Environmental, inc.

Date:	01-Feb-91
Manufacturer:	Cleaver Brooks
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1040
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	81.3
NOx Control:	Low NOx Burner - FGR
Application Type:	Steam Production
Comments:	Boiler #1.
Data Entered By:	JJ
ID:	134.1
Facility Name:	Gallo Winery
Location:	Fresno, Ca.
Testing Company:	Best Environmental, inc.
Date:	19-May-92
Manufacturer:	B&W
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1040
HHVUnit:	Btu/scf

Heat Input (MMBtu/hr):	59.1
NOx Control:	Low NOx Burner - FGR
Application Type:	NR
Comments:	Boiler #1
Data Entered By:	JJ
ID:	134.2
Facility Name:	Gallo Winery
Location:	Fresno, Ca.
Testing Company:	Best Environmental, inc.
Date:	30-Apr-92
Manufacturer:	Nebraska
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1040
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	110.9
NOx Control:	Low NOx Burner - FGR
Application Type:	NR
Comments:	Boiler #2
Data Entered By:	JJ
ID:	134.3
Facility Name:	Gallo Winery
Location:	Fresno, Ca.
Testing Company:	Best Environmental, inc.

Date:	18-May-92
Manufacturer:	Bigelow
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1040
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	69.9
NOx Control:	Low NOx Burner - FGR
Application Type:	NR
Comments:	Boiler #3
Data Entered By:	JJ

ID:	134.4
Facility Name:	Gallo Winery
Location:	Fresno, Ca.
Testing Company:	Best Environmental, inc.
Date:	18-May-92
Manufacturer:	Bigelow
Type:	NR
Air Supply:	NR
Capacity (MW):	0
Load (%):	100
Fuel Type:	NG
HHV:	1040
HHVUnit:	Btu/scf

Heat Input (MMBtu/hr):	67.5
NOx Control:	Low NOx Burner - FGR
Application Type:	NR
Comments:	Boiler #4
Data Entered By:	JJ
ID:	14.1
Facility Name:	EPRI Site 109
Location:	NR
Testing Company:	KVB-Analect
Date:	28-Nov-90
Manufacturer:	
Type:	Opposed wall-fired
Air Supply:	FGR
Capacity (MW):	230
Load (%):	100
Fuel Type:	NG
HHV:	1000
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	FGR
Application Type:	Utility Boiler
Comments:	Test 1,2,3
Data Entered By:	MKO
ID:	14.2
Facility Name:	EPRI Site 109
Location:	NR

Testing Company:	KVB-Analect
Date:	28-Nov-90
Manufacturer:	
Type:	Opposed wall-fired
Air Supply:	FGR
Capacity (MW):	230
Load (%):	100
Fuel Type:	NG
HHV:	1000
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	FGR
Application Type:	Utility Boiler
Comments:	Test 4,5,6
Data Entered By:	MKO
ID:	14.3
Facility Name:	EPRI Site 109
Location:	NR
Testing Company:	KVB-Analect
Date:	29-Nov-90
Manufacturer:	
Type:	Opposed wall-fired
Air Supply:	FGR
Capacity (MW):	230
Load (%):	75
Fuel Type:	NG
HHV:	1000

HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	FGR
Application Type:	Utility Boiler
Comments:	Test 7,8,9
Data Entered By:	MKO
ID:	14.4
Facility Name:	EPRI Site 109
Location:	NR
Testing Company:	KVB-Analect
Date:	29-Nov-90
Manufacturer:	
Type:	Opposed wall-fired
Air Supply:	FGR
Capacity (MW):	230
Load (%):	50
Fuel Type:	NG
HHV:	1000
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	FGR
Application Type:	Utility Boiler
Comments:	Test 10,11 12
Data Entered By:	MKO
ID:	15.1
Facility Name:	Alamitos Generating Station
Location:	Unit 2

Testing Company:	Carnot
Date:	06-Oct-92
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	94
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1,3
Data Entered By:	MKO
ID:	15.2
Facility Name:	Alamitos Generating Station
Location:	Unit 2
Testing Company:	Carnot
Date:	06-Oct-92
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	94
Fuel Type:	NG
HHV:	1020

HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 4,5
Data Entered By:	MKO
ID:	15.3
Facility Name:	Alamitos Generating Station
Location:	Unit 2
Testing Company:	Carnot
Date:	07-Oct-92
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	78
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 6,7
Data Entered By:	MKO
ID:	15.4
Facility Name:	Alamitos Generating Station
Location:	Unit 2

Testing Company:	Carnot
Date:	07-Oct-92
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	78
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 8,9
Data Entered By:	MKO
ID:	15.6
Facility Name:	Alamitos Generating Station
Location:	Unit 2
Testing Company:	Carnot
Date:	07-Oct-92
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	78
Fuel Type:	NG
HHV:	1020

HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 9
Data Entered By:	MKO
ID:	15.7
Facility Name:	Alamitos Generating Station
Location:	Unit 2
Testing Company:	Carnot
Date:	08-Oct-92
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	23
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 10,11
Data Entered By:	MKO
ID:	15.8
Facility Name:	Alamitos Generating Station
Location:	Unit 2

Testing Company:	Carnot
Date:	08-Oct-92
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	23
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 12,13
Data Entered By:	MKO
ID:	16.1
Facility Name:	SCE-Huntington Beach Generating Station
Location:	Unit 2
Testing Company:	Geraghty & Miller
Date:	09-Mar-96
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD
Capacity (MW):	215
Load (%):	100
Fuel Type:	NG
HHV:	1020

HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1
Data Entered By:	MKO
ID:	16.2
Facility Name:	SCE-Huntington Beach Genersting Station
Location:	Unit 2
Testing Company:	Geraghty & Miller
Date:	09-Mar-96
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD
Capacity (MW):	215
Load (%):	100
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 2
Data Entered By:	MKO
ID:	16.3
Facility Name:	SCE-Huntington Beach Generating Station
Location:	Unit2

Testing Company:	Geraghty & Miller
Date:	10-Mar-96
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD
Capacity (MW):	215
Load (%):	51
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 3
Data Entered By:	MKO
ID:	16.4
Facility Name:	SCE-Huntington Beach Generating Station
Location:	Unit 2
Testing Company:	Geraghty & Miller
Date:	10-Mar-96
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD
Capacity (MW):	215
Load (%):	51
Fuel Type:	NG

HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 4
Data Entered By:	MKO
ID:	16.5
Facility Name:	SCE-Huntington Beach Generating Station
Location:	Unit 2
Testing Company:	Geraghty & Miller
Date:	11-Mar-96
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD
Capacity (MW):	215
Load (%):	33
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 5
Data Entered By:	MKO
ID:	16.6
Facility Name:	SCE-Huntington Beach Generating Station

Location:	Unit 2
Testing Company:	Geraghty & Miller
Date:	11-Mar-96
Manufacturer:	B&W
Type:	Wall-fired
Air Supply:	FD
Capacity (MW):	215
Load (%):	33
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 6
Data Entered By:	MKO
ID:	17.1
Facility Name:	Etiwanda Generating Station
Location:	Unit 1
Testing Company:	Radian
Date:	07-Oct-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	98
Fuel Type:	NG

HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 5,8
Data Entered By:	MKO
ID:	17.10
Facility Name:	Etiwanda Generating Station
Location:	Unit 2
Testing Company:	Radian
Date:	04-Nov-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	49
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 6
Data Entered By:	MKO
ID:	17.11
Facility Name:	Etiwanda Generating Station

Location:	Unit 2
Testing Company:	Radian
Date:	05-Nov-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	30
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 7
Data Entered By:	MKO
ID:	17.12
Facility Name:	Etiwanda Generating Station
Location:	Unit 2
Testing Company:	Radian
Date:	05-Nov-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	30
Fuel Type:	NG

HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 8
Data Entered By:	MKO
ID:	17.2
Facility Name:	Etiwanda Generating Station
Location:	Unit 1
Testing Company:	Radian
Date:	07-Oct-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	98
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 6,7
Data Entered By:	MKO
ID:	17.3
Facility Name:	Etiwanda Generating Station

Location:	Unit 1
Testing Company:	Radian
Date:	08-Oct-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	49
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 9
Data Entered By:	MKO
ID:	17.4
Facility Name:	Etiwanda Generating Station
Location:	Unit 1
Testing Company:	Radian
Date:	08-Oct-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	49
Fuel Type:	NG

HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 10
Data Entered By:	MKO
ID:	17.5
Facility Name:	Etiwanda Generating Station
Location:	Unit 1
Testing Company:	Radian
Date:	09-Oct-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	30
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 11,13
Data Entered By:	MKO
ID:	17.6
Facility Name:	Etiwanda Generating Station

Location:	Unit 1
Testing Company:	Radian
Date:	09-Oct-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	30
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 12
Data Entered By:	MKO
ID:	17.7
Facility Name:	Etiwanda Generating Station
Location:	Unit2
Testing Company:	Radian
Date:	03-Nov-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	98
Fuel Type:	NG

HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 3
Data Entered By:	MKO
ID:	17.8
Facility Name:	Etiwanda Generating Station
Location:	Unit 2
Testing Company:	Radian
Date:	03-Nov-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	98
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 4
Data Entered By:	MKO
ID:	17.9

Facility Name:	Etiwanda Generating Station
Location:	Unit 2
Testing Company:	Radian
Date:	04-Nov-93
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	132
Load (%):	49
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 5
Data Entered By:	MKO

ID:	18.1
Facility Name:	Redondo Beach Generating Station
Location:	Unit 5
Testing Company:	Sierra Enviromental Enginering
Date:	01-Oct-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	95

Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 1,2
Data Entered By:	MKO
ID:	18.10
Facility Name:	Redondo Beach Generating Station
Location:	Unit 6
Testing Company:	Sierra Enviromental Enginering
Date:	22-Sep-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	80
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 3,4
Data Entered By:	MKO
ID:	18.11

Facility Name:	Redondo Beach Generating Station
Location:	Unit 6
Testing Company:	Sierra Enviromental Enginering
Date:	24-Sep-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	23
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 1,2
Data Entered By:	MKO
ID:	18,12
Facility Name:	Redondo Beach Generating Station
Location:	Unit 6
Testing Company:	Sierra Enviromental Enginering
Date:	24-Sep-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	23

Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 3,4
Data Entered By:	MKO
ID:	18.2
Facility Name:	Redondo Beach Generating Station
Location:	Unit 5
Testing Company:	Sierra Enviromental Enginering
Date:	01-Oct-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	95
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 3,4
Data Entered By:	MKO
ID:	18.3

Facility Name:	Redondo Beach Generating Station
Location:	Unit 5
Testing Company:	Sierra Environmental Enginering
Date:	02-Oct-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	80
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 1,2
Data Entered By:	MKO
ID:	18.4
Facility Name:	Redondo Beach Generating Station
Location:	Unit 5
Testing Company:	Sierra Enviromental Enginering
Date:	02-Oct-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	80

Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 3,4
Data Entered By:	MKO
ID:	18.5
Facility Name:	Redondo Beach Generating Station
Location:	Unit 5
Testing Company:	Sierra Enviromental Enginering
Date:	29-Sep-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	23
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 1,2
Data Entered By:	MKO
ID:	18.6

Facility Name:	Redondo Beach Generating Station
Location:	Unit 5
Testing Company:	Sierra Enviromental Enginering
Date:	29-Sep-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	23
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 3,4
Data Entered By:	MKO
ID:	18.7
Facility Name:	Redondo Beach Generating Station
Location:	Unit 6
Testing Company:	Sierra Enviromental Enginering
Date:	21-Sep-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	98

Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1,2
Data Entered By:	MKO
ID:	18.8
Facility Name:	Redondo Beach Generating Station
Location:	Unit 6
Testing Company:	Sierra Enviromental Enginering
Date:	21-Sep-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	98
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	SNCR
Application Type:	Utility Boiler
Comments:	Test 3,4
Data Entered By:	MKO
ID:	18.9

Facility Name:	Redondo Beach Generating Station
Location:	Unit 6
Testing Company:	Sierra Enviromental Enginering
Date:	22-Sep-92
Manufacturer:	B&W
Type:	Not listed
Air Supply:	FD,ID
Capacity (MW):	175
Load (%):	80
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1,2
Data Entered By:	MKO
ID:	19.1
Facility Name:	Alamitos Generating Station
Location:	Unit 4
Testing Company:	Carnot
Date:	14-Sep-92
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	320

Load (%):	79
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 1
Data Entered By:	MKO

ID:	19.10
Facility Name:	Alamitos Generating Station
Location:	Unit 4
Testing Company:	Carnot
Date:	28-Sep-92
Manufacturer:	CE
Type:	Tangential
Air Supply:	FD
Capacity (MW):	320
Load (%):	22
Fuel Type:	NG
HHV:	1020
HHVUnit:	Btu/scf
Heat Input (MMBtu/hr):	0
NOx Control:	None
Application Type:	Utility Boiler
Comments:	Test 15,16
Data Entered By:	MKO

SECTION 3.1

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AP-42, Fifth Edition, Volume I Chapter 3: Stationary Internal Combustion Sources

Explanation of File Formats

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3.1 Stationary Gas Turbines
- Final Section - Supplement F, April 2000 (PDF 84K)
- Background Document (PDF 246K)
- Related Info.

3.2 Natural Gas-fired Reciprocating Engines
- Final Section - Supplement F, August 2000 (PDF 52K)
- Background Document (PDF 160K)
- Related Info.

3.3 Gasoline and Diesel Industrial Engines
- Final Section - Supplement B, October 1996 (PDF 35K)
- Background Document (PDF 184K)

3.4 Large Stationary Diesel and All Stationary Dual-fuel Engines
- Final Section - Supplement B, October 1996 (PDF 41K)
- Background Document (PDF 254K)

AP-42 Emission Factors by Chapter

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3.1 Stationary Gas Turbines

3.1.1 General[1]

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

3.1.2 Process Description[1,2]

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

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

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

The simple cycle is the most basic operating cycle of gas turbines with a thermal efficiency ranging from 15 to 42 percent. The cycle thermal efficiency is defined as the ratio of useful shaft energy to fuel energy input. Simple cycle gas turbines are typically used for shaft horsepower applications without recovery of exhaust heat. For example, simple cycle gas turbines are used by electric utilities for generation of electricity during emergencies or during peak demand periods.

A regenerative cycle is a simple cycle gas turbine with an added heat exchanger. The heat exchanger uses the turbine exhaust gases to heat the combustion air which reduces the amount of fuel required to reach combustor temperatures. The thermal efficiency of a regenerative cycle is approximately 35 percent. However, the amount of fuel efficiency and saving may not be sufficient to justify the capital cost of the heat exchanger, rendering the process unattractive.

A cogeneration cycle consists of a simple cycle gas turbine with a heat recovery steam generator (HRSG). The cycle thermal efficiency can be as high as 84 percent. In a cogeneration cycle, the steam generated by the HRSG can be delivered at a variety of pressures and temperatures to other thermal processes at the site. For situations where additional steam is required, a supplementary burner, or duct burner, can be placed in the exhaust duct stream of the HRSG to meet the site's steam requirements.

A combined cycle gas turbine is a gas turbine with a HRSG applied at electric utility sites. The gas turbine drives an electric generator, and the steam from the HRSG drives a steam turbine which also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle gas turbine is between 38 percent and 60 percent.

Gas turbine applications include gas and oil industry, emergency power generation facilities, independent electric power producers (IPP), electric utilities, and other industrial applications. The petroleum industry typically uses simple cycle gas turbines with a size range from 300 hp to 20,000 hp. The gas turbine is used to provide shaft horsepower for oil and gas production and transmission. Emergency power generation sites also utilize simple cycle gas turbines. Here the gas turbine is used to provide backup or emergency power to critical networks or equipment. Usually, gas turbines under 5,000 hp are used at emergency power generation sites.

Independent electrical power producers generate electricity for resale to larger electric utilities. Simple, regenerative, or combined cycle gas turbines are used at IPP; however, most installations use combined cycle gas turbines. The gas turbines used at IPP can range from 1,000 hp to over 100,000 hp. The larger electric utilities use gas turbines mostly as peaking units for meeting power demand peaks imposed by large commercial and industrial users on a daily or seasonal basis. Simple cycle gas turbines ranging from 20,000 hp to over 200,000 hp are used at these installations. Other industrial applications for gas turbines include pulp and paper, chemical, and food processing. Here, combined cycle gas turbines are used for cogeneration.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NO_X), carbon monoxide (CO), and to a lesser extent, volatile organic compounds (VOC). Particulate matter (PM) is also a primary pollutant for gas turbines using liquid fuels. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion. Trace to low amounts of HAP and sulfur dioxide (SO_2) are emitted from gas turbines. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Oxides of sulfur (SO_X) will only appear in a significant quantity if heavy oils are fired

in the turbine. Emissions of sulfur compounds, mainly SO_2, are directly related to the sulfur content of the fuel.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors for this sections are presented for gas turbines operating under high load conditions. Section 3.1 background information document and emissions database contain additional emissions data for gas turbines operating under various load conditions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

If the HRSG is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal units [lb/MMBtu]) will also apply to cogeneration/combined cycle systems. If the HRSG is supplementary fired, the emissions attributable to the supplementary firing must also be considered to estimate total stack emissions.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel 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 high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface.

The second mechanism, called prompt NO_X, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X forms within the flame and is usually negligible when compared to the amount of thermal NO_X formed. The third mechanism, fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NO_X formed from natural gas combustion is thermal NO_X. Distillate oils have low levels of fuel-bound nitrogen. Fuel NO_X from distillate oil-fired turbines may become significant in turbines equipped with a high degree of thermal NO_X controls. Otherwise, thermal NO_X is the predominant NO_X formation mechanism in distillate oil-fired turbines.

The maximum thermal NO_X formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_X. Thermal NO_X formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_X can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place downstream of the primary flame, which does not minimize peak temperature in the flame and suppress thermal NO_X formation.

Diffusion flames are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and significant thermal NO_X is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame, and therefore to thermal NO_X emissions. Thermal NO_X can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature, and therefore thermal NO_X. Newer model gas turbines use lean, premixed combustion where the fuel is typically premixed with more than 50 percent theoretical air which results in lower flame temperatures, thus suppressing thermal NO_X formation.

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure.[4] Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature is the flame zone will decrease resulting in a decrease of thermal NO_X formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_X significantly. Similarly, the gas turbine operating loads affect NO_X emissions. Higher NO_X emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_X.

3.1.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized volatile organic emissions.

Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

3.1.3.3 Particulate Matter[13] -

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state and

can be measured on a EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers is described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

3.1.3.4 Greenhouse Gases[5-11] -

Carbon dioxide (CO_2) and nitrous oxide (N_2O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Methane (CH_4) is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas or a product of combustion in the case of distillate fuel oil.

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.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent).

3.1.3.5 HAP Emissions -

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, formaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired turbines, small amount of metallic HAP are present in the turbine's exhaust in addition to the gaseous HAP identified under gas fired turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, combustion turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

3.1.4 Control Technologies[12]

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NO_X and/or oxidize CO emission from the turbine. Other recently developed technologies promise significantly lower levels of NO_X and CO emissions from diffusion combustion type gas turbines. These technologies are currently being demonstrated in several installations.

Emission factors in this section have been determined from gas turbines with no add-on control devices (uncontrolled emissions). For NO_X and CO emission factors for combustion controls, such as water-steam injection, and lean pre-mix units are presented. Additional information for controlled

emissions with various add-on controls can be obtained using the section 3.1 database. Uncontrolled, lean-premix, and water injection emission factors were presented for NO_X and CO to show the effect of combustion modification on emissions.

3.1.4.1 Water Injection -

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NO_X levels, such rates of injection may reduce NO_X by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.

3.1.4.2 Dry Controls -

Since thermal NO_X is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_X emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_X formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_X emissions associated with the high temperature pilot flame are insignificant. Low NO_X emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H_2, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_X generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_X formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx.

3.1.4.3 Catalytic Reduction Systems -

Selective catalytic reduction (SCR) systems selectively reduce NO_X emissions by injecting ammonium (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 450°F to 850°F) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850°F) cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia emissions, called NH_3 slip, may be a consideration when specifying an SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NO_X emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems). The SCR system for landfill or digester gas-fired turbines requires a substantial fuel gas pretreatment to remove trace contaminants that can poison the catalyst. Therefore, SCR and other catalytic treatments may be inappropriate control technologies for landfill or digester gas-fired turbines.

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_X, O_2, and NH_3, to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations incorporate CO catalytic oxidation modules along with the NO_X reduction catalyst for simultaneous CO/NO_X control.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants.

3.1.4.4 Other Catalytic Systems[14,15] -

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NO_X and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO_2 and NO_2. The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of 1 ppm and NO_X emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims.

The XONON system is applicable to diffusion and lean-premix combustors and is currently being demonstrated with the assistance of leading gas turbine manufacturers. The system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NO_X, and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NO_X. The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NO_X levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm. Emissions data from gas turbines equipped with a XONON Catalyst were not available as of the drafting of this section.

3.1.5 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. These and other documents can be found on the new EFIG home page (http://www.epa.gov/ttn/chief).

Supplement A, February 1996

- For the PM factors, a footnote was added to clarify that condensables and all PM from oil- and gas-fired turbines are considered PM-10.
- In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, 0.6 lb/10^6 ft^3 (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

- Text was revised and updated for the general section.
- Text was added regarding firing practices and process description.
- Text was revised and updated for emissions and controls.
- All factors for turbines with SCR-water injection control were corrected.
- The CO_2 factor was revised and a new set of N_2O factors were added.

Supplement F, April 2000

- Text was revised and updated for the general section.
- All emission factors were updated except for the SO_2 factor for natural gas and distillate oil turbines.

- Turbines using staged (lean-premix) combustors added to this section.
- Turbines used for natural gas transmission added to this section.
- Details for turbine operating configurations (operating cycles) added to this section.
- Information on new emissions control technologies added to this section (SCONOX and XONON).
- HAP emission factors added to this section based on over 400 data points taken from over 60 source tests.
- PM condensable and filterable emission factors for natural gas and distillate oil fired turbines were developed.
- NOx and CO emission factors for lean-premix turbines were added.
- Emission factors for landfill gas and digester gas were added.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Emission Factors[a] - Uncontrolled				
Pollutants	Landfill Gas-Fired Turbines[b]		Digester Gas-Fired Turbines[d]	
	(lb/MMBtu)[c]	Emission Factor Rating	(lb/MMBtu)[e]	Emission Factor Rating
CO_2[f]	50	D	27	C
Lead	ND	NA	< 3.4 E-06[g]	D
PM-10	2.3 E-02	B	1.2 E-02	C
SO_2	4.5 E-02	C	6.5 E-03	D
VOC[h]	1.3 E-02	B	5.8 E-03	D

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

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

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

[d] SCC for digester gas-fired turbine include 2-03-007-01.

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

[f] For landfill gas and digester gas, CO_2 is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).

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

[h] Based on adding the formaldehyde emissions to the NMHC.

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

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

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

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

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

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

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

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

Table 3.1-4. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 1.6 E-05	D
Benzene	5.5 E-05	C
Formaldehyde	2.8 E-04	B
Naphthalene	3.5 E-05	C
PAH	4.0 E-05	C

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

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

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

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

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 1.1 E-05	D
Beryllium[d]	< 3.1 E-07	D
Cadmium	4.8 E-06	D
Chromium	1.1 E-05	D
Lead	1.4 E-05	D
Manganese	7.9 E-04	D
Mercury	1.2 E-06	D
Nickel[d]	< 4.6 E-06	D
Selenium[d]	< 2.5 E-05	D

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act.*

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

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

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

Table 3.1-6. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM LANDFILL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Acetonitrile[d]	< 1.2E-05	D
Benzene	2.1E-05	B
Benzyl Chloride[d]	< 1.2 E-05	D
Carbon Tetrachloride[d]	< 1.8 E-06	D
Chlorobenzene[d]	< 2.9 E-06	D
Chloroform[d]	< 1.4 E-06	D
Methylene Chloride	2.3 E-06	D
Tetrachloroethylene[d]	< 2.5 E-06	D
Toluene	1.1 E-04	B
Trichloroethylene[d]	< 1.9 E-06	D
Vinyl Chloride[d]	< 1.6 E-06	D
Xylenes	3.1 E-05	B

[a] SCC for landfill gas-fired turbines is 2-03-008-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

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

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

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

Table 3.1-7. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Ratings
1,3-Butadiene[d]	< 9.8 E-06	D
1,4-Dichlorobenzene[d]	< 2.0 E-05	D
Acetaldehyde	5.3 E-05	D
Carbon Tetrachloride[d]	< 2.0 E-05	D
Chlorobenzene[d]	< 1.6 E-05	D
Chloroform[d]	< 1.7 E-05	D
Ethylene Dichloride[d]	< 1.5 E-05	D
Formaldehyde	1.9 E-04	D
Methylene Chloride[d]	< 1.3 E-05	D
Tetrachloroethylene[d]	< 2.1 E-05	D
Trichloroethylene[d]	< 1.8 E-05	D
Vinyl Chloride[d]	< 3.6 E-05	D
Vinylidene Chloride[d]	< 1.5 E-05	D

[a] SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

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

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

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

Table 3.1-8. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 2.3 E-06	D
Cadmium[d]	< 5.8 E-07	D
Chromium[d]	< 1.2 E-06	D
Lead[d]	< 3.4 E-06	D
Nickel	2.0 E-06	D
Selenium	1.1 E-05	D

[a] SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

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

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

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

References For Section 3.1

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3. *Final Report - Gas Turbine Emission Measurement Program*, GASLTR787, General Applied Science Laboratories, Westbury, NY, August 1974.

4. *Standards Support And Environmental Impact Statement, Volume 1: Proposed Standards Of Performance For Stationary Gas Turbines*, EPA-450/2-77-017a, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1977.

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8. G. Marland and R. M. Rotty, *Carbon Dioxide Emissions From Fossil Fuels: A Procedure For Estimation And Results For 1951-1981*, DOE/NBB-0036 TR-003, Carbon Dioxide Research Division, Office of Energy Research, U. S. Department of Energy, Oak Ridge, TN, 1983.

9. 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.

10. *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.

11. *IPCC Guidelines For National Greenhouse Gas Inventories Workbook*, Intergovernmental Panel on Climate Change/Organization for Economic Cooperation and Development, Paris, France, 1995.

12. L. M. Campbell and G. S. Shareef, *Sourcebook: NO_x Control Technology Data*, Radian Corp., EPA-600/2-91-029, Air and Energy Engineering Research Laboratory, U. S. Environmental Protection Agency, Research Triangle Park, July 1991.

13. *In-stack Condensible Particulate Matter Measurement and Permitting Issues for Maryland Power Plants*, Maryland Department of Natural Resource, Prepared by Versar, INC, January 1998.

14. *Catalysts for Power Generation, The $_{SCONOX}$ System.* Goal Line Environmental Technologies, www.glet.com/gl_prod_SCONOX.htm, March 1998.

15. Information form Chuck Solt of Catalytica Combustion Systems, Inc., to EPA, XONON Flameless Combustion, January 1996.

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EMISSION FACTOR DOCUMENTATION FOR AP-42 SECTION 3.1 STATIONARY GAS TURBINES

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Office of Air Quality Planning and Standards
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April 2000

TABLE OF CONTENTS

Section		Page
1.0	Introduction	1.1
1.1	Reasons For Updating	1.1
1.2	References For Section 1	1.2
2.0	Literature Search and Screening	2.1
2.1	Review of Data Sets	2.1
2.2	Emission Data Quality Rating System	2.2
2.3	References For Section 2	2.14
3.0	AP-42 Section Development	3.1
3.1	Revisions to Section Narrative	3.1
3.2	Pollutant Emission Factor Development	3.1
3.2.1	Data Base Design	3.1
3.2.2	Results of Data Analysis	3.6
3.3	Emission Factor Quality Rating System	3.8
3.4	Emission Factors	3.9
3.5	References for Section 3	3.20
4.0	Revised Section 3.1 of AP-42	4.1

TABLES

2.2-1 SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 3.1 ..... 2.4
2.2-2 SUMMARY OF REFERENCES NOT USED IN THE REVISION OF SECTION 3.1 .... 2.11
3.4-1 SUMMARY OF EMISSION FACTORS FOR NATURAL GAS-FIRED TURBINES 3.10
3.4-2 SUMMARY OF EMISSION FACTORS FOR DISTILLATE OIL-FIRED TURBINES ... 3.13
3.4-3 SUMMARY OF EMISSION FACTORS FOR LANDFILL GAS-FIRED TURBINES 3.16
3.4-4 SUMMARY OF EMISSION FACTORS FOR DIGESTER GAS-FIRED TURBINES 3.18

Emission Factor Documentation for AP-42 Section 3.1
Stationary Gas Turbines

1.0 Introduction[1]

The revised AP-42 section described in this report replaces the section published in September 1996 as Supplement B to the Fifth Edition. This background report replaces the Emission Factor (EMF) Documentation for AP-42 section 3.1, Stationary Gas Turbines For Electricity Generation, issued February 1993 and amended in 1996 to support Supplement B of the Fifth Edition. The purpose of this background report is to provide technical documentation supporting the Supplement E revisions to AP-42 section 3.1.

The EPA publishes emission factors in its Compilation of Air Pollutant Emission Factors, Volume I Stationary Point and Area Sources, EPA Publication No. AP-42 (AP-42). The document has been published since 1968 as the primary compilation of EPA's emission factor information. Federal, state, and local agencies, consultants, and industry use the document to identify major contributors of atmospheric pollutants, develop emission control strategies, determine applicability of permitting programs, and compile emission inventories for ambient air impact analyses and State Implementation Plans (SIPs). Volume I is published by Emission Factor Inventory Group (EFIG) in EPA's Office of Air Quality Planning and Standards (OAQPS). The OAQPS is located in Research Triangle Park, NC.

1.1 Reasons For Updating

The Clean Air Act Amendments of 1990 added greatly to the number of air pollution sources for which emission factor development was required, and also called for the improvement of existing factors. There are several reasons for updating or revising AP-42 sections and emission factors.

- Contractor Expertise. A contractor or consultant may have gained expertise on a source category during previous work, either for EPA or for other clients, and may warrant consideration by EPA for a relatively low-expense update and expansion of available information.

- New Standard. After the proposal of a standard, the contractor reviews the available material to determine if sufficient information has been gathered to support the development of emission factors for the industry or process being studied. Oftentimes, the proposal or development of a new standard for a source or source category will trigger a re-evaluation of emission factors for a particular source. In the proposal of a standard, the proposal team gathers tremendous amounts of data to support the standard, much more data than is typically gathered for AP-42. The proposal team may compare their new data with existing information used to develop AP-42 emission factors. If, in the comparison, the team discovers a deficiency in the existing information, they may turn their data over to EFIG, who in turn may use the information to improve emission factors.

- Outside Requests. EPA receives requests for better source and emission factor information. Requests may come from other Office of Air Quality Planning and Standards (OAQPS) branches, EPA laboratories and regional offices, state agencies, trade

associations, special interest groups, or private individuals. The requests may take the form of directives, letters, oral inquiries, or comments on published emission factors.

- Improvement of the National Inventory. The EPA may determine that a particular source category is a significant contributor to the National Inventory and that EPA should develop or improve emission factors.

- New Information. New information will be useful that may have been developed initially for Emission Standards Division (ESD) background documents involving New Source Performance Standards, Maximum Achievable Control Technologies (MACT), National Emission Standards For Hazardous Air Pollutants (NESHAP), and Control Techniques Guidelines (CTG), and reports by various EPA laboratories.

Section 3.1 has been updated to incorporate new available data on this source category. New information has been used to better characterize this source category and to develop improved criteria pollutant emission factors. In response to upcoming MACT standards for this source category, an expanded hazardous air pollutant (HAP) emission factor list has also been provided.

This background report consists of four sections. Section 1 provides information on AP-42 documents such as this one that are issued to update sections of AP-42. Section 2 presents the data search and screening steps, discusses the references used to revise AP-42 Section 3.1, and defines the emissions data quality rating system. Section 3 discusses overall revisions to AP-42 Section 3.1, provides details about the data base built for storing the available data, presents the calculations used to calculate emission factors, and defines the emission factor quality rating system. Section 4 presents the revised AP-42 Section 3.1.

1.2 REFERENCES FOR SECTION 1

1. *Procedures For Preparing Emission Factor Documents*, EPA-454/R-95-015, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, NC 27711, May 1997.

2.0 Literature Search and Screening

Data used in this section were obtained from a number of sources within the OAQPS and from outside organizations. The AP-42 background files were reviewed for information on stationary gas turbines, applicable pollution control technologies, and emissions data. The Factor Information Retrieval System (FIRE) was searched for emissions data on natural gas-fired gas turbines. The Source Test Information Retrieval System (STIRS) data set, compiled by EFIG, was also reviewed. The STIRS data set is a collection of emission test reports which were scanned and stored on CD-ROM. The Combustion Turbine Workgroup of the former EPA Industrial Combustion Coordinated Rulemaking (ICCR) submitted test reports for natural gas, No. 2 fuel oil, digester gas, and landfill gas-fired gas turbines. Test reports were also gathered from the state of Wisconsin and the state of California.

In the review of available references, emissions data were accepted if:

- sufficient information about the turbine and any pollution control devices was given,
- the test report identified if the emission tests were conducted before or after a pollution control device,
- emissions levels were measured by a current test method,
- emission test results were reported in units which could be converted into the reporting units selected for this section, and
- sufficient data existed to characterize operating conditions during testing.

Several test reports were not used in the emission factor development due to missing information regarding the turbine operating parameters. However, these reports are included in the data base provided for this section and are identified by an "x" in their ID numbers. Also appropriate comments are given in the corresponding "Comment" field.

2.1 Review of Data Sets

Since Supplement B was published, EPA has initiated several efforts towards gathering emissions data for combustion sources, including gas turbines. These efforts include the STIRS and the former EPA ICCR efforts.

A total of 119 source test reports containing 369 tests were obtained for gas turbines. In most cases, the test reports included pooled testing efforts for different gas turbines. For NO_X and CO emissions, the data included test reports and test summary data submitted by the San Diego Air Pollution Control District. Out of the gathered 119 test reports, 88 reports containing 267 tests provided sufficient information for emission classification and categorization.

A summary of the references used to develop emission factors and their associated data base identification numbers is presented in Table 2.2-1. A summary review of the references which were not used to develop emission factors is presented in Table 2.2-2.

Detailed information for each test report used for developing the presented emission factors in Section 3.1 of the AP-42 Document is provided in the emissions data base for the section. Refer to Section 3.2.1 of this background report for instructions on how to obtain, use, and review the gathered emissions data for stationary gas turbines.

Table 2.2-1, References Used to Develop Emission Factors

Nearly all of the emission test data contained in these references were assigned a rating of "A" due to the detailed information provided, with the exception of the summary reports provided by the San Diego Air Pollution Control District which were assigned a rating of "B". These references are source test reports for natural gas, landfill gas, digester gas, and oil-fired gas turbines used for electric generation, gas transmission, and industrial uses. A total of 200 tests are for natural gas-fired gas turbines, 43 tests are for distillate oil-fired gas turbines, 20 tests are for landfill gas-fired gas turbines, 3 tests are for digester gas-fired gas turbines, and 1 test is for a field gas-fired combustion turbine. The data extracted from these reports include both criteria and HAP emission data and are available in Microsoft Access on the web at "www.epa.gov/ttn/chief". Several of these test reports contained HAP emission data resulting from the AB 2588 reporting requirements in California.

Table 2.2-2, References Not Used to Develop Emission Factors

Test reports identified with an "x" in the ID number were not used to determine emission factors for Section 3.1 due to the absence of essential turbine operating parameters for the calculation or categorization of emission factors. Other reasons for the exclusion of test reports include indications of poor operating conditions or sample contamination.

2.2 Emission Data Quality Rating System[1]

As part of the emissions data analysis, the quality of the information contained in the set of referenced documents were evaluated. Source test reports were considered to have sound methodology and adequate detail if they met the following criteria:

1. Source operation. The manner in which the source was operated is well documented in the report. The source was operating within typical parameters during the test.

2. Sampling procedures. The sampling procedures conformed to a generally acceptable methodology. The emission tests were conducted using an up to date measurement method. If actual procedures deviated from accepted methods, the deviations are well documented. When this occurred, an evaluation was made of the extent to which such alternative procedures could influence the test results.

3. Sampling and process data. Adequate sampling and process data are documented in the report, and any variations in the sampling and process operation are noted. If a difference between test results cannot be explained by information contained in the test report, the data are suspect and are given a lower rating.

4. Analysis and calculations. The test reports contain original raw data sheets. The nomenclature and equations used were compared to those (if any) specified by EPA to establish equivalency. The depth of review of the calculations was dictated by the reviewer's confidence in the ability and conscientiousness of the tester, which in turn was

based on factors such as consistency of results and completeness of other areas of the test report.

After the source test reports were deemed acceptable based on the aforementioned criteria, data contained in these reports that were used to calculate emission factors were assigned a quality rating. The rating system used was that specified by OAQPS for preparing AP-42 sections.[12] The data were rated as follows:

A - Multiple tests that were performed on the same source using sound methodology and reported in enough detail for adequate validation. These tests do not necessarily conform exactly to the methodology specified in EPA referenced test methods, but at least follow EPA methods in form and function.

B - Tests that were performed by a generally sound methodology, but lack enough detail for adequate validation.

C - Tests that were based on an untested or new methodology or that lacked a significant amount of background data.

D - Tests that were based on a generally unacceptable method but may provide an order-of-magnitude value for the source.

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 3.1

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
3	Source test on a natural turbine firing both natural gas and oil	Formaldehyde, acetaldehyde	A	2
4	AB 2588 test on a turbine firing both natural gas and oil	Benzene, formaldehyde	A	3
5	AB 2588 test on a turbine firing both natural gas and oil	Speciated HAPs	A	4
6	AB 2588 test on a turbine firing both natural gas and oil	Speciated HAPs, metals	A	6
7	AB 2588 test on a natural gas-fired turbine	Speciated HAPs	A	7
9	Source test on a natural gas-fired turbine	Speciated HAPs	A	9
12	Source test on a turbine firing both natural gas and oil	Speciated HAPs	A	12
13	AB 2588 test on a turbine firing both natural gas and oil	Speciated HAPs	A	13
15	Source test on a turbine firing both natural gas and oil	Speciated HAPs, NO_X, CO	A	15
16	AB 2588 test on a natural gas-fired turbine	Formaldehyde	A	16
17	Source test on a natural gas-fired turbine	Benzene	A	17
18	Source test on a natural gas-fired turbine	Speciated HAPs	A	18
19	Source test on an oil-fired turbine	Speciated HAPs	A	19
20	AB 2588 test on a natural gas-fired turbine	Benzene, formaldehyde	A	20
21	AB 2588 test on a natural gas-fired turbine	Speciated HAPs	A	21
22	AB 2588 test on a natural gas-fired turbine	Speciated HAPs	A	22

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 3.1 (Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
24	AB 2588 test on a natural gas-fired turbine	Speciated HAPs	A	27
26	Source test on a natural gas-fired turbine.	Formaldehyde	A	26
27	Compliance test on a natural gas-fired turbine	Speciated HAPs	A	28
28	Source test on a natural gas-fired turbine	NO_X, CO	A	243
29	Source tests on nine natural gas-fired gas turbines	NO_X, CO, THC	A	244
30	Source test on two oil-fired gas turbines with water injection	NO_X, CO, THC, VOC	C	225
31	Source test on a natural gas-fired turbine	NO_X, CO	A	245
33	Source tests on eight natural gas and oil fired gas turbines with water injection	NO_X	A	246
34	Compliance test on two natural gas-fired gas turbines	NO_X, CO, THC	A	202
36	Source test report on one natural gas lean-premix turbine and one natural gas diffusion turbine.	NO_X, CO	A	203
37	Source test report for a natural gas lean-premix turbine.	NO_X, CO, VOC	A	204
38	Compliance test for a natural gas-fired turbine	CO, SO_2	A	205
39	Source test report for a natural gas-fired lean-premix turbine	NO_X, CO	A	206
40	Source test report for four natural gas-fired gas turbines	NO_X, CO, SO_2	A	207
41	Compliance test for a natural gas-fired turbine	NO_X	A	208

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 3.1
(Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
42	Source test report for two natural gas-fired turbine	NO_X, CO, SO_2	A	209
43	Source test report for four natural gas-fired gas turbines with water injection	NO_X, CO	A	210
44	Source test report for a natural gas-fired turbine	NO_X	A	211
45	Source test report for four natural gas-fired gas turbines with water injection	NO_X, CO	A	214
46	Compliance test for a natural gas-fired turbine	NO_X, CO	A	219
47	Source test report for a natural gas-fired turbine with water injection	NO_X, CO	A	221
48	Source test report for an oil-fired turbine with water injection	NO_X, CO	A	223
49	Source test report for a natural gas-fired turbine	NMHC	A	224
50	Source test report for five natural gas-fired lean-premix gas turbines	NO_X, CO	A	226
51	Source test report for three oil-fired gas turbines	NO_X, CO	A	227
52	Source test report for two natural gas-fired gas turbines with water injection	NO_X	A	228
54	Source test report for a natural gas-fired turbine	NO_X, CO	A	231
55	Source test report for two natural gas-fired gas turbines	CO, SO_2	A	232
56	Source test report for a natural gas-fired turbine	NO_X, CO	A	234

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 3.1 (Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
57	Source test report for a natural gas-fired turbine	NO_X, CO	A	237
59	Source test report for a natural gas-fired turbine with ammonia injection and SCR	NO_X, CO, and NMHC	A	216
60	Source test report for two oil-fired and two digester gas-fired gas turbines	Speciated HAPs, metals, NO_X, CO, NMHC, SO_2, CO_2	A	300
61	Source test report for one oil-fired and one digester gas-fired turbine	Speciated HAPs, metals	A	301
62	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC, CO_2	A	302
63	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC	A	303
64	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC, CO_2	A	304
65	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC, SO_2, CO_2	A	305
66	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC	A	306
67	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC, SO_2	A	307
68	Source test report for a landfill-gas fired turbine	Speciated HAPs, NO_X, CO, NMHC, SO_2	A	308
69	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC, SO_2	A	309
70	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC	A	310
71	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC	A	311
72	Source test report for a landfill gas-fired turbine	Speciated HAPs, NO_X, CO, NMHC, SO_2	A	312

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 3.1 (Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
73	Source test report for two natural gas-fired gas turbines	Benzene, formaldehyde, NO_X, CO	A	313
74	Source test report for a natural gas-fired turbine	Benzene, formaldehyde, NO_X, CO	A	315
75	Source test report for a natural gas-fired and an oil-fired gas turbines with water injection	PM-condensables, PM-filterable	C	WDNR-0098
76	Source test report for a natural gas-fired and an oil-fired gas turbines with water injection	PM-condensables, PM-filterable	C	WDNR-0099
77	Source test report for a natural gas-fired and a oil-fired gas turbines with water injection	PM-condensables, PM-filterable	C	WDNR-0102
81	Source test report for a natural gas-fired turbine	NO_X, CO, NMHC	D	212
87	Source test report for a natural gas-fired turbine with steam injection and SCR	NO_X, CO, THC	A	241
96	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	406
97	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	407
98	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	408
99	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	409
100	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	410

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 3.1 (Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
102	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	412
104	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	425
105	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	428
106	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	430
107	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	432
108	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	435
109	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	441
110	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	444
111	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	446
112	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	447
113	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	B	448
114	Source test report for natural gas-fired gas turbines with steam injection and SCONOX.	Benzene, formaldehyde, and acetaldehyde	A	318

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 3.1
(Concluded)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
117	Compliance test report for a natural gas-fired turbine with lean pre-mix.	Speciated HAPs, NO_X, and CO	A	314
118	Compliance test report for a natural gas-fired turbine.	Speciated HAPs, NO_X, and CO	A	316
119	Compliance test report for a natural gas-fired turbine.	Speciated HAPs, NO_X, and CO	A	317

Table 2.2-2. SUMMARY OF REFERENCES NOT USED IN THE REVISION OF SECTION 3.1

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
2	AB 2588 test on a refinery gas-fired turbine	Speciated HAPs, metals	C	1
8	Source test on a natural gas-fired turbine	Speciated HAPs	C	8
10	Source test on a natural gas-fired turbine	Metals	C	10
11	Source test on a natural gas-fired turbine	Speciated HAPs	B	11
14	AB 2588 test on an oil-fired turbine	Speciated HAPs, metals	C	14
23	AB 2588 test on a natural gas-fired turbine	Speciated HAPs	C	23
25	Source test on a natural gas-fired turbine.	Formaldehyde	C	25
32	Source test on a natural gas-fired turbine with steam injection	NO_X, CO	C	200
35	Compliance test on a turbine firing both natural gas and oil	NO_X	C	201
53	Source test report for two natural gas-fired lean-premix gas turbines with water injection	SO_2, PM-condensables, PM-filterable	C	229
58	Source test report for two natural gas-fired lean-premix gas turbines with water injection	SO_2, PM-condensables, PM-filterable	C	240
78	Source test report for gas turbines used for gas transmission	Speciated HAPs	B	29
79	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	C	PEDP-0004
80	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	C	TNRC-0077
82	Compliance test report for a natural gas-fired turbine	NO_X, CO	C	215

Table 2.2-2. SUMMARY OF REFERENCES NOT USED IN THE REVISION OF SECTION 3.1
(Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
83	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	C	217
84	Source test report for a landfill gas-fired turbine	NO_X, CO	C	218
85	Source test report for two natural gas-fired gas turbines with steam injection, SCR and CO catalyst	NO_X, CO	C	220
86	Compliance test report for four natural gas-fired gas turbines with water injection	NO_X, CO	C	222
88	Source test report for a natural gas-fired turbine with steam injection and SCR	NO_X, CO	C	236
89	Source test report for two natural gas-fired gas turbines with steam injection and SCR	NO_X, CO	C	238
90	Source test report for two natural gas-fired gas turbines with steam injection, SCR and CO catalyst	NO_X, CO	C	239
91	Source test report for three natural gas-fired gas turbines with water injection, SCR and CO catalyst	NO_X, CO	C	242
92	Compliance test report for two natural gas-fired gas turbines with steam injection, SCR and CO catalyst	NO_X, CO	C	230
93	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	C	402
94	Source test report for natural gas-fired gas turbines.	NO_X, CO, and SO_2	C	403

Table 2.2-2. SUMMARY OF REFERENCES NOT USED IN THE REVISION OF SECTION 3.1
(Concluded)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Data Base I.D.
95	Source test report for natural gas-fired gas turbines with water injection.	NO_X	C	404
101	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	C	411
103	Compliance test report for a natural gas-fired turbine with water injection	NO_X, CO	C	417
115	Source test report for natural gas-fired gas turbines.	NO_X, CO, and SO_2	C	235
116	Source test report for natural gas-fired gas turbines with NH_3 injection	Naphthalene, toluene, xylene, benzene, and formaldehyde	C	213
120	Source test report for a natural gas-fired turbine	NO_X, CO, and NMHC	C	233

[a]Reference number corresponds to the reference listing at the end of this section.

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6. Source Test Report AB 2588 for Turbine No. 1 at Choachella Power Plant. Prepared by South Coast Environmental Company, La Verne, California for Imperial Irrigation District, Imperial, California. February 25, 1991.

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69. Emission Test Results on the Solar Turbine at Puente Hills Landfill, November 21, 1995. Prepared by Carnot, Tustin, California for Los Angeles County Sanitation District, Whitter, California. January, 1996.

70. Emission Tests on the Natco Turbine at Puente Hills Landfill, July 1990. Prepared by Carnot, Tustin, California for Los Angeles County Sanitation District, Whitter, California. September, 1990.

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73. Source Test Report on a Natural Gas Turbine at a Gas Compressor Station. Prepared by Carnot. March, 1994.

74. Source Test Report Two Natural Gas Turbines at a Gas Compressor Station. Prepared by Carnot.

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75. Wisconsin Power and Light Company 86 MW ABB Gt11N1 Natural Gas and Diesel Stationary Gas Turbines at Fon du Lac, Wisconsin, April 1994.

76. Wisconsin Power and Light Company 86 MW ABB GT11N1 Natural Gas and Diesel Stationary Gas Turbines at Fon du Lac, Wisconsin, June 1994.

77. Wisconsin Public Service Corporation 86 MW ABB GT11N1 Natural Gas and Diesel Stationary Gas Turbines at Fon du Lac, Wisconsin, April 1996.

78. Shareef, G. S., K. R. Ferry, M. Gundappa, C. A. Leatherwood, L. D. Ogle, L. M. Campbell. Measurement of Air Toxic Emissions from Natural Gas-Fired Internal Combustion Engines at Natural Gas Transmission and Storage Facilities, prepared by Radian Corporation for the Gas Research Institute, GRI-96/0009, February 1996.

79. Continental Energy Associates 785 MMBtu/hr Stationary Natural Gas Turbine at Hazleton, Pennsylvania, September 1993.

80. Union Carbide Corporation Natural Gas Stationary Turbine at Texas City, Texas, January 1996.

81. Agrico Cogeneration Corporation, San Joaquin, California, Emission Tests. Report #7777-0263. Prepared by Genesis Environmental Services Company. June 12, 1991.

82. Air Pollution Compliance Test, Live Oak Cogeneration Facility. Prepared by Petro Chem Environmental Services, Inc. May 1993.

83. Compliance Source Test Report for U.S. Borax & Chemical Corporation Boron (48MW Cogen) Facility. Prepared by Titan Environmental. Tested December 8, 1993.

84. Report On Source Emission Testing of a Gas Turbine Conducted For Oakland Scavenger. Reference: TMA/Norcal C.N. 5-410. May 22, 1990.

85. Source Test Report Double C Limited, Bakersfield, California. Prepared by Petro Chem Environmental Services. March 1993.

86. Annual Compliance Test Chevron U.S.A. 26C Cogeneration Plant Unit #'s 1,2,3,&4. Report #7777-0361. Prepared by Genesis Environmental Services Company. August 1992.

87. Air Pollution Compliance Test for Two Gas Turbines at Kern Front Limited Cogeneration Facility, Bakersfield, California. Prepared by Engineering-Science for Kern County Air Pollution Control District. March 1993.

88. Source Test Report Gas Turbine at Chalk Cliff. Prepared by Petro Chem Environmental Services, Inc. January 1993.

89. Test Report for Air Emissions Testing and Relative Accuracy Audit at the SERK Cogeneration Facility Bakersville, California. Prepared by Engineering-Science, Inc. for San Joaquin Valley Unified Air Pollution Control District. February 11, 1993.

90. Source Test Report High Sierra Limited Cogeneration Facility. Prepared by Petro Chem Environmental Services, Inc. March 1992.

91. Source Test of Three Natural Gas Fired Gas Turbines at the SEKR Cogeneration Facility, Bakersfield, California. Prepared by Engineering-Science, Inc. for San Joaquin Valley Unified Air Pollution Control District. April 27, 1992.

92. Emission Tests at Destec Operating Company, Kern Front Cogeneration Facility, Kern County, California. Prepared by Petro-Chemical Environmental. February 1993

93. Emission Tests at San Marcos Landfill. Prepared by San Diego Air Pollution Control District, San Marcos, California, March 1996.

94. Emission Tests at SDGE South Bay. Prepared by San Diego Air Pollution Control District, San Diego, California, February 1994.

95. Emission Tests at SDGE North Island. Prepared by San Diego Air Pollution Control District, San Diego, California, November 1994.

96. Emission Tests at Sycamore Landfill #1 Eng. #1. Prepared by San Diego Air Pollution Control District, San Diego, California, October 1995.

97. Emission Tests at SDGE NTC GT. Prepared by San Diego Air Pollution Control District, San Diego, California, March 1998.

98. Emission Tests at SDGE (MCRD/NTC). Prepared by San Diego Air Pollution Control District, San Diego, California, January 1996.

99. Emission Tests at SDGE Division Street. Prepared by San Diego Air Pollution Control District, San Diego, California, March 1998.

100. Emission Tests at SDGE Harbor and Vesta. Prepared by San Diego Air Pollution Control District, San Diego, California, December 1995.

101. Emission Tests at Hotel Del Coronado. Prepared by San Diego Air Pollution Control District, Coranado, California, January 1986.

102. Emission Tests at SDGE/32nd Street Harbor. Prepared by San Diego Air Pollution Control District, San Diego, California, October 1994.

103. Emission Tests at Computer Science Corporation. Prepared by San Diego Air Pollution Control District, San Diego, California, May 1995.

104. Emission Tests at SDGE Naval Station. Prepared by San Diego Air Pollution Control District, San Diego, California, April 1997.

105. Emission Tests at SDGE Miramar. Prepared by San Diego Air Pollution Control District, San Diego, California, March 1995.

106. Emission Tests at SDGE KMA. Prepared by San Diego Air Pollution Control District, San Diego, California, May 1995.

107. Emission Tests at SDGE El Cajon. Prepared by San Diego Air Pollution Control District, El Cajon, California, October 1994.

108. Emission Tests at University Cogeneration GT1. Prepared by San Diego Air Pollution Control District, Chula Vista, California, July 1996.

109. Emission Tests at SDG&E Company South Bay GT. Prepared by San Diego Air Pollution Control District, Chula Vista, California, March 1998.

110. Emission Tests at SDGE Encina. Prepared by San Diego Air Pollution Control District, Carlsbad, California, March 1995.

111. Emission Tests at US Naval Station at 42nd Street. Prepared by San Diego Air Pollution Control District, San Diego, California, April 1995.

112. Emission Tests at Laidlaw Gas Recovery Engine #2. Prepared by San Diego Air Pollution Control District, San Marcos, California, April 1996.

113. Emission Tests at San Marcos Landfill. Prepared by San Diego Air Pollution Control District, San Marcos, California, March 1997.

114. Emission Tests on natural gas-fired cogeneration gas turbines. Prepared by Delta Air Quality Services, Los Angeles, California, March 1997.

115. Emission Tests at Fina Oil and Chemical Company. Prepared by ARI Environmental, Inc., Port Arthur, Texas, February 1989.

116. Emission Tests at Gaviota Oil and Gas Company. Prepared by Engineering-Science, Goleta, California, May 1993.

117. Emission Tests for natural gas-fired gas turbines. Prepared by Carnot, December 1993.

118. Emission Tests for natural gas-fired gas turbines. Prepared by Carnot, November 1993.

119. Emission Tests for natural gas-fired gas turbines. Prepared by Carnot, December 1993.

120. Emission Tests for Riverside Hospital Cogeneration Unit. Prepared by Monarch Analytical Laboratories, Toledo, Ohio. May 1989.

3.0 AP-42 Section Development

3.1 Revisions To Section Narrative

The main change to Section 3.1 of AP-42 was to incorporate gas turbines used for natural gas distribution, which were previously addressed in Section 3.2 of AP-42. The EPA decided that it was more effective to present emission factors for gas turbines in a single section, independent of industrial application, since emission levels from these gas turbines were determined to be similar.

Gas turbines using staged (lean-premix) combustors were also added to the section. A brief discussion of the combustion differences between diffusion flame and lean-premix combustors was added. Other technical discussion updated in this section includes a detailed discussion of the gas turbine operating configurations (operating cycles), identification of the existing industries utilizing gas turbines, and information regarding new control technologies for NO_X and CO emissions reduction. These control technologies include the SCONOX and the XONON technologies for gas turbines.

As for emissions information, the most significant change to the previous section is the inclusion of emission factors for landfill gas and digester gas turbines. In addition, emission factors for natural gas turbines and distillate oil gas turbines were updated. EPA has gathered 119 source test reports for HAPs and criteria pollutants for gas turbines, of which 88 test reports were used in the development of the emission factors presented in Section 3.1. The remaining test reports were not used due to lack of essential information regarding the gas turbine operating parameters during testing. A further discussion of the emissions data is presented in Section 3.2.2.

3.2 Pollutant Emission Factor Development

3.2.1 Data Base Design

The emission data assembled for the development of stationary combustion turbine emission factors was stored in an electronic relational data base formatted in Microsoft® Access 97 data base. A data base approach was chosen in order to easily access and manipulate the large amount of data collected for this section and to facilitate data transfer to and from other concurrent projects at EPA. The design of this data base was accomplished in conjunction with the former Industrial Combustion Coordinated Rulemaking (ICCR) effort of the Emission Standards Division (ESD). Data entered under either of these projects are easily transferred between data bases. Furthermore, the common design of the data base will allow for simple future additions to the data base and simple recalculation of turbine emission factors.

Test reports containing HAP emissions were assigned ID numbers of less than 200. Test containing criteria emissions were assigned ID numbers between 200 and 300. Tests containing both HAP and criteria emissions were assigned ID numbers between 300 and 400, and the summary tests submitted by San Diego Air Pollution Control District were assigned ID numbers greater than 400. Within the data base, data was stored in two tables to reduce repetitive entry of data. These tables, and the data fields associated with each table are described below:

The Facilities Table includes the following data fields:

- Facility Name,
- Location,
- Testing Company,

- Date of Test,
- Turbine Manufacturer,
- Turbine Model Number,
- Operating Load (percent of Capacity),
- Rating (MW),
- Rating (HP),
- Test HP,
- Fuel Type,
- Application Type, and
- Emission Controls.

The Test Data Table includes the following data fields:

- Pollutant,
- Test Method,
- Pollutant Concentration (as reported),
- Detection Limit,
- Exhaust Oxygen Percentage,
- Data Rating,
- Fuel Exhaust Factor (F-Factor),
- Exhaust Flow Rate,
- Fuel Heating Value,
- Standard Temperature of F-Factor,
- Fuel Flow Rate,
- Exhaust Moisture Content (percent by Volume), and
- Molecular Weight of Pollutant.

The data base was programmed to relate the data in the two tables and calculate emission factors for the available pollutants in units of pounds per million standard cubic feet (lb/MMscf) and pounds per million British thermal units (lb/MMBtu) for gaseous fuels and pounds per one thousand gallons (lb/1000 gal) and pounds per million British thermal units (lb/MMBtu) for liquid fuels. The data base also provides emissions concentrations in parts per billion (ppb) corrected to 15 percent oxygen, and emission rates in pounds per hour (lb/hr) and pounds per megawatt-hour (lb/MW-hr) for all fuel types. To ensure consistent calculation of emission factors, the data base was programmed to use the emission concentration data and process data taken during the testing period to calculate the emission factors. Emission factors provided in test reports were not used. The EPA concluded that this method of calculation would provide the highest quality emission factors, since different methods of calculating emission factors were used in some of the references, and in some cases, the method of calculating emission factors was not given. Equations used to calculate emission factors were dependent on the pollutant concentration units and on the desired emission factor.

For concentration in micrograins per dry standard cubic meter, the following equation was used:

$$EF_{MMBtu} = \frac{(C_{ugrm} * F * 1.43 * 10^{-4})}{(35.31)} * \text{oxygen correction}$$

For concentration in parts per billion by volume - dry, the following equation was used:

$$EF_{MMBtu} = \frac{(Cppbvd * F * MW)}{(10^9 * 385.5)} * \text{temperature correction} * \text{oxygen correction}$$

For concentration in grains/dscf, the following equation was used:

$$EF_{MMBtu} = (C_{grf} * F * 1.43 * 10^{-4}) * \text{oxygen correction}$$

For concentration in micrograms per dry standard cubic meter, the following equation was used:

$$EF_{MMBtu} = \frac{(C_{ugm} * F)}{(10^6 * 453.6 * 35.31)} * \text{oxygen correction}$$

Where:

EF_{MMBtu}	=	Emission factor (pounds per million British thermal units of heat input)
C_{ugrm}	=	Concentration (micrograins per dry standard cubic meter)
C_{ppbvd}	=	Concentration (parts per billion by volume, dry)
C_{grf}	=	Concentration (grains per dry standard cubic foot)
C_{ugm}	=	Concentration (micrograms per dry standard cubic meter)
F	=	F-Factor (dry standard cubic feet per million Btu, default values used from 40 CFR Part 60, App. A, Table 19-1)
MW	=	Molecular weight (pounds per pound-mole)
T_{std}	=	Standard temperature (°F)
% O_2	=	Percent of oxygen is exhaust, by volume
1020	=	Natural gas heating value (MMBtu per MMscf)
139	=	Distillate oil heating value (MMBtu per Mgal)
400	=	Landfill gas heating value (MMBtu per MMscf)
600	=	Digester gas heating value (MMBtu per MMscf)
385.5	=	Volume occupied by 1 lb-mole at 68°F and 1 atm (standard cubic feet per lb-mole)
60	=	Conversion factor (minutes per hour)
453.6	=	Conversion factor (grams per pound)
$1.43*10^{-4}$	=	Conversion factor (pounds per grain)
35.31	=	Conversion factor (dry standard cubic feet per dry standard cubic meter)

$$\text{Temperature correction (to 68°F)} = \left(\frac{528°R}{460°R_t + T_{std}\,°F} \right)$$

$$\text{Oxygen correction (to 0\% } O_2) = \left(\frac{20.9}{20.9 - \%O_2} \right)$$

The emission factors are based on gas turbines operating on both gaseous and liquid fuels. For consistency in comparing control options, the emission factors are presented in units of lb/MMBtu. A method to convert units from lb/MMBtu to lb/MMscf for natural gas-fired, landfill gas-fired, and digester gas-fired gas turbines is provided below. Also, a method of conversion is provided to obtain lb/1,000 gallons for distillate fired gas turbines.

For gas turbines that burn natural gas, the conversion of lb/MMBtu to lb/10^6 scf can be made using an assumed natural gas heating value of 1020 MMBtu/10^6 scf. This conversion can be done through the following equation:

lb/10^6 scf = lb/MMBtu * 1020 (MMBtu/10^6 scf)

For gas turbines that burn landfill gas, the conversion of lb/MMBtu to lb/10^6 scf can be made using an assumed natural gas heating value of 400 MMBtu/10^6 scf. This conversion can be done through the following equation:

lb/10^6 scf = lb/MMBtu * 400 (MMBtu/10^6 scf)

For gas turbines that burn digester gas, the conversion of lb/MMBtu to lb/10^6 scf can be made using an assumed natural gas heating value of 600 MMBtu/10^6 scf. This conversion can be done through the following equation:

lb/10^6 scf = lb/MMBtu * 600 (MMBtu/10^6 scf)

For gas turbines that burn distillate oil, the conversion of lb/MMBtu to lb/10^3 gallons can be made using an assumed distillate oil heating value of 139 MMBtu/10^3 gallon. This conversion can be done through the following equation:

lb/10^3 gallon = lb/MMBtu * 139 (MMBtu/10^3 gallon)

Detection Limits

For cases where the concentration of a specific pollutant was below the test method detection limit and a detection limit was provided, then half of the detection limit was used to calculate an emission factor. If no detection limit was provided, then the results from that test were not used. Furthermore, if an emission factor for an individual engine was developed from a detection limit and the resulting emission factor was higher than the emission factors generated from detected concentrations, then the emission factor based on a detection limit was removed from the average. The goal of this decision was to prevent

unusually high detection limits from artificially increasing an average emission factor. If an average emission factor was generated entirely from detection limits and not on measured values, it is noted as an emission factor based on detection limits and that expected emissions are lower than the emission factor. These methods for addressing detection level issues were provided in the Procedures For Preparing Emission Factor Documents.[1]

Calculation of Average Emission Factors

To provide average emission factors for these sources, the emission factors from all tests in a specific group were averaged to generate an emission factor. The averaging method used in the data base was an arithmetic average. For tests that consisted of multiple runs, the arithmetic average of the runs was used to develop the emission factor of that test. Individual tests were given equal weight in the calculation of average emission factors for each turbine group. If the majority of data used to generate an emission factor were from non-detect results where the detection limit was used, then the average emission factor was noted to be made up of mostly detection limit estimates. The EPA intends for average emission factors generated from mostly detection levels to provide order of magnitude estimates of emissions levels, and these data are given a low quality rating.

Presentation of Data

Due to the size of the data base, a printout of all the test data used to generate the engine emission factors in Section 3.1 is not presented. Instead, EPA is providing an electronic copy of the data base in Microsoft Access format on the Technology Transfer Network (TTN). This decision has resulted in a substantial decrease in paper needed for this background information document and will provide users with a more detailed background data set for this section. Furthermore, by providing the data base to the public, anyone may use or augment the data base for their individual needs, providing a substantial building block for anyone interested in compiling an extensive data base on natural gas-fired combustion sources. An electronic copy of the data base can be downloaded from the TTN at http://www.epa.gov/ttn/chief. In this website, follow the main menu options to locate the file and then download it.

To view the tests used to calculate the emission factors calculated for theses sources, open the data base file which will automatically open the MAIN FORM view (in cases where the MAIN FORM does not open, open the file and choose the FORMS selection on the main data base screen, then under the FORMS selection, choose MAIN FORM). This will activate a macro which will provide a pollutant list, fuel type, and control device type available for these sources. This provides the option to view the input data, source information, or the emission tests used to calculate the emission factor for a specific pollutant (based on fuel type and control information) by simply clicking on the desired button: To view the data used to calculate the average emission factor for each test, click the EF INPUTS button; to view the individual source information, click the VIEW FACILITIES button; to view the data used for calculating the emission factor, click the EF REPORT button.

To view the tests that were not used to determine the emission factors, close the MAIN FORM and select the Report Menu. Under the Report Menu, select the "Report for not used tests". This report provides a brief summary of the test information, fuel type, and the corresponding emissions.

3.2.2 Results of Data Analysis

Source Category Selection

An important step in emission factor development is the determination of emission sources which are similar enough to be grouped together and represented by a single emission factor. This is accomplished by investigating which parameters influence emissions, and which should be used to establish distinct groups within the stationary combustion turbine source category. The emission factors for each test contained in the data base were analyzed to determine appropriate groupings.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads, or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors presented in the background information document are categorized for gas turbines operating under high load conditions and for gas turbines operating under all load condition. Emission factors presented in Section 3.1 are for gas turbines operating at high load conditions only.

NO_X and CO Emission Factors

Based on the analysis of available NO_X and CO data, this category was separated into four main groups: natural gas-fired gas turbines, distillate oil-fired gas turbines, landfill gas-fired gas turbines, and digester gas-fired gas turbines. For natural gas-fired gas turbines, NO_X and CO data were further separated into uncontrolled, water-steam injection, lean-premix combustion, and selected catalytic reduction (SCR). It should be noted that either water-steam injection or lean-premix combustors can reduce NO_X emissions by over 50 percent, when compared to uncontrolled emissions. Based on the presented data, CO emissions also decrease with water-steam injection which is contrary to that which is expected. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different. It is important to note that the presented emission factors are based on a wide range of calculated emission levels (1 to 500 lb/10^6 scf with O_2 levels ranging from 15 percent to 17.5 percent).

For distillate oil-fired gas turbines, NO_X and CO data were separated into uncontrolled and water-steam injection categories. Water-steam injection for distillate oil-fired gas turbines reduces NO_X by 50 percent or more and increases CO emissions. No subcategorization was possible for landfill gas and digester gas-fired gas turbines due to the limited available data.

It is noticed that the turbine load conditions have a considerable effect on the measured NO_X and CO emissions. Typically, NO_X and CO emissions are reduced with increasing turbine load conditions.

Organic and Metallic Compound Emission Factors

Emission factors for organic compounds (methane, formaldehyde, benzene, etc.) were not grouped as extensively as the NO_X and CO emission factors. Analysis of this data showed that fuel type had an effect on organic emission levels, but NO_X controls such as water-steam injection did not show an observable effect within the data scatter. Therefore, organic compound emission factors were grouped by fuel type for the stationary combustion turbine category.

Within the organic compound category, one test (test ID # 316.1.1) for methane emissions from a natural gas-fired turbine was eliminated to make the data more applicable. Prior to eliminating this test report, the methane emission factors were higher than the total hydrocarbon (THC) emission factors. This is an unrealistic scenario, as the methane emission factors is a component of the THC emission factor. The elimination of this test report corrects this unrealistic condition.

For HAP emissions, the emissions data also indicate that formaldehyde is the most significant HAP emitted from gas turbines. For natural gas fired gas turbines, formaldehyde accounts for about two-thirds of the total HAP emission. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired gas turbines, small amount of metallic HAP are present in the turbine's exhaust in addition to the gaseous HAP identified under gas fired gas turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, gas turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

Similar to organic compound emission factors, metallic compound emission factors were determined to be affected by fuel type, and no effect of NO_X control was observed. Therefore, metallic compound emission factors were also grouped by fuel type for the stationary combustion turbine category.

PM Emission Factors

PM emissions data for uncontrolled gas turbines were not available. Therefore, emission factors for condensable and filterable PM were developed for natural gas-fired gas turbines using water-steam injection control and distillate oil-fired gas turbines using water-steam injection control. Water-steam injection is not expected to have a large effect on PM emissions for gas turbines. For both natural gas and distillate oil-fired gas turbines, the emission factors were determined based on source test reports from Wisconsin. There were 5 tests done on one gas turbine for the condensible and filterable for both the natural gas and the oil (for details, see database). Each test was for 3 runs and each test is rated "C". All of these tests indicated sampling times of 2 hours or more per run. No indication of N_2 purging was provided for the tests gathered from the State of Wisconsin. However, the resulting emission levels compared well with the tests that indicated N_2 purging.

Condensable 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). Total PM is the sum of the condensable PM and filterable PM. PM emissions from combustion turbines are considered PM-10 emissions.

For landfill gas and digester gas-fired gas turbines, only PM-10 emission factors based on EPA Method 5 were determined from source test reports gathered from the EPA ICCR effort.

CO_2 Emission Factors

As outlined in the Procedures for Preparing Emission Factor Document,[1] emission factors for CO_2 were calculated by mass balance for natural gas and distillate oil-fired gas turbines. This approach was taken because the carbon content in pipeline-quality natural gas in fairly consistent. It was assumed that 99.5 percent and 99 percent of the fuel carbon is converted to CO_2, for natural gas and distillate oil-fired gas turbines, respectively. The carbon weight percent for natural gas was assumed at 75 percent, and for

distillate oil, it was assumed at 70 percent.

For landfill gas and digester gas-fired gas turbines, CO_2 content in the exhaust stream (volume percent) was provided for several tests. For landfill gas-fired gas turbines, CO_2 emission factors were determined from three test reports; report ID 302, 304, and 305. The average CO_2 emission factor from these reports was 50 lb/MMBtu. The corresponding CO_2 percent in the exhaust stream ranged from 4 percent to 4.5 percent. For digester gas, the CO_2 emission factor was determined from two tests included in report ID 300. The average CO_2 emission factor from these tests was 27 lb/MMBtu. The CO_2 percent in the exhaust stream was measured at 4 percent for both tests.

3.3 Emission Factor Quality Rating System

The quality of the emission factors developed from analysis of the test data was rated using the following general criteria:

A - Excellent: Developed only from A-rated test data taken from many randomly chosen facilities in the industry population. The source category is specific enough that variability within the source category population may be minimized.

B - Above Average: Developed only from A-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry population. The source category is specific enough that variability within the source category population may be minimized.

C - Average: Developed only from A- and B-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry population. The source category is specific enough that variability within the source category population may be minimized.

D - Below Average: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There may also be evidence of variability within the source category population. Limitations on the use of the emission factor are always noted in the emission factor table.

E - Poor: The emission factor was developed from C- and D-rated test data, and there is reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population.

The above criteria for emission factor ratings are defined in the OAQPS document which provided guidance for preparing emission factor documents. The use of these criteria is somewhat subjective and depends to an extent upon the individual reviewer. As these criteria were applied to the emission factors, the term "number of facilities" was interpreted to mean "number of different turbine models". This criteria prevented emission factors generated from multiple tests on a single turbine model type from receiving higher emission factor ratings. Emission factors for this section were rated in the following manner:

A-Rated	Emission factor average based on results of A or B-rated data from fifteen or more emissions tests.
B-Rated	Emission factor average based on results of A or B-rated data from ten to fourteen

different emissions tests.

C-Rated — Emission factor average based on results of A or B-rated data from three to nine different emissions tests.

D-Rated — Emission factor average based on results of A or B-rated data from two or less emissions tests.

E-Rated — Emission factor average based on engineering judgement or tests rated at C or below.

3.4 Emission Factors

The emission factors for the sources covered in Section 3.1 of the AP-42 document are presented in Tables 3.4-1, 3.4-2, 3.4-3, and 3.4-4. These tables provide the number of tests used in calculating the various emission factors as well as the relative standard deviation (in percent) associated with each emission factor. This additional information is intended to provide greater insight to the reader about the background of each emission factor. For further detail on each emission factor, the complete data base used to generate these factors is provided on the web at "www.epa.gov/ttn/chief" (See Section 3.2.1 of this document for more details on the data base).

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR NATURAL GAS-FIRED GAS TURBINES

Natural Gas-Fired Gas Turbine HAP Emissions

			All Loads				**High Loads: Greater Than or Equal to 80 Percent**			
Pollutant	CAS No.	Control Method	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count
1,3-Butadiene	106-99-0	Uncontrolled	< 4.29 E-07	< 4.38 E-04	121.5	2	< 4.29 E-07	< 4.38 E-04	121.5	2
Acetaldehyde	75-07-0	Uncontrolled	4.45 E-05	4.54 E-02	64.3	9	4.02 E-05	4.10 E-02	68.0	8
Acetaldehyde	75-07-0	CO Catalyst	1.76 E-04	1.80 E-01	139.5	2	1.76 E-04	1.80 E-01	139.5	2
Acrolein	107-02-8	Uncontrolled	8.31 E-06	8.48 E-03	71.5	7	6.36 E-06	6.49 E-03	50.9	6
Acrolein	107-02-8	CO Catalyst	3.62 E-06	3.69 E-03	NA	1	3.62 E-06	3.69 E-03	NA	1
Benzene	71-43-2	Uncontrolled	1.03 E-04	1.05 E-01	440.0	27	1.18 E-05	1.20 E-02	136.1	17
Benzene	71-43-2	CO Catalyst	3.26 E-06	3.33 E-03	101.9	2	3.26 E-06	3.33 E-03	101.9	2
Ethylbenzene	100-41-4	Uncontrolled	2.58 E-05	2.63 E-02	130.4	5	3.20 E-05	3.27 E-02	110.2	4
Formaldehyde	50-00-0	Uncontrolled	3.12 E-03	3.18 E+00	204.0	33	7.09 E-04	7.23 E-01	206.1	22
Formaldehyde	50-00-0	CO Catalyst	3.60 E-04	3.67 E-01	133.5	2	3.60 E-04	3.67 E-01	133.5	2
Naphthalene	91-20-3	Uncontrolled	1.37 E-06	1.40 E-03	87.6	5	1.27 E-06	1.30 E-03	107.3	4
PAH	NA	Uncontrolled	2.25 E-06	2.30 E-03	131.1	5	2.23 E-06	2.27 E-03	152.9	4
Propylene Oxide	75-56-9	Uncontrolled	< 2.86 E-05	< 2.92 E-03	NA	1	< 2.86 E-05	< 2.92 E-03	NA	1
Toluene	108-88-3	Uncontrolled	9.37 E-05	9.56 E-02	220.6	11	1.34 E-04	1.37 E-01	191.0	7
Xylenes	1330-20-7	Uncontrolled	5.48 E-05	5.59 E-02	108.1	7	6.38 E-05	6.50 E-02	93.2	6

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR NATURAL GAS-FIRED GAS TURBINES
(Continued)

Natural Gas-Fired Gas Turbine Criteria Emissions

		All Loads				**High Loads: Greater Than or Equal to 80 Percent**			
Pollutant	Control Method	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count
CO	Uncontrolled	1.77 E-01	1.80 E+02	267.5	76	8.23 E-02	8.39 E+01	171.4	53
CO	Water-Steam Injection	3.34 E-02	3.41 E+01	106.3	18	2.95 E-02	3.01 E+01	117.0	16
CO	Lean Pre-Mix	1.27 E+00	1.30 E+03	189.5	4	1.51 E-02	1.54 E+01	NA	1
Methane	Uncontrolled	8.64 E-03	8.81 E+00	142.2	5	8.64 E-03	8.81 E+00	142.2	5
NO_x	Uncontrolled	2.95 E-01	3.01 E+02	75.0	80	3.23 E-01	3.29 E+02	69.8	56
NO_x	Water-Steam Injection	1.26 E-01	1.28 E+02	29.8	75	1.28 E-01	1.30 E+02	29.8	46
NO_x	Lean Pre-Mix	1.11 E-01	1.13 E+02	23.6	4	9.91 E-02	1.01 E+02	NA	1
NO_x	SCR	1.28 E-02	1.31 E+01	13.1	4	1.28 E-02	1.31 E+01	13.1	4
PM Condensable	Water-Steam Injection	4.73 E-03	4.82 E+00	90.9	1	4.73 E-03	4.82 E+00	90.9	1
PM Filterable	Water-Steam Injection	1.90 E-03	1.93 E+00	49.5	1	1.90 E-03	1.93 E+00	49.5	1

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR NATURAL GAS-FIRED GAS TURBINES
(Concluded)

Natural Gas-Fired Turbine Criteria Emissions

		All Loads				**High Loads: Greater Than or Equal to 80 Percent**			
Pollutant	Control Method	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count
PM total[a]	Water-Steam Injection	6.63 E-03	6.76 E+00	NA	1	6.63 E-03	6.76 E+00	NA	1
SO_2	Uncontrolled	3.38 E-03	3.45 E+00	45.5	6	3.38 E-03	3.45 E+00	45.5	6
TOC[b]	Uncontrolled	1.07 E-02	1.09 E+01	141.1	10	1.07 E-02	1.09 E+01	141.1	10
VOC[c]	Uncontrolled	2.06 E-03	2.09 E+00	NA	5	2.06 E-03	2.09 E+00	NA	5

[a] Calculated value: PM total = PM (condensable) + PM (filterable).
[b] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.
[c] Calculated value: VOC = THC - Methane.

Table 3.4-2. SUMMARY OF EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES

Distillate Oil-Fired Gas Turbines HAP Emissions

Pollutant	CAS No.	Control Method	All Loads				High Loads: Greater Than or Equal to 80 Percent			
			Emission Factor (Lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count	Emission Factor (Lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count
1,3-Butadiene	106-99-0	Uncontrolled	< 1.65 E-05	< 2.30 E-03	47.5	4	< 1.58 E-05	< 2.20 E-03	NA	1
1,4-Dichlorobenzene	106-46-7	Uncontrolled	< 2.97 E-05	< 4.12 E-03	5.8	3	NA	NA	NA	NA
Acetaldehyde	75-07-0	Uncontrolled	3.03 E-05	4.21 E-03	36.9	2	NA	NA	NA	NA
Arsenic	NA	Uncontrolled	< 1.10 E-05	< 1.53 E-03	72	4	< 1.06 E-05	< 1.47 E-03	NA	1
Benzene	71-43-2	Uncontrolled	5.48 E-05	7.62 E-03	104.9	5	5.48 E-05	7.62 E-03	104.9	5
Beryllium	NA	Uncontrolled	< 3.07 E-07	< 4.27 E-05	NA	1	< 3.07 E-07	< 4.27 E-05	NA	1
Cadmium	NA	Uncontrolled	3.75 E-06	5.21 E-04	78.3	4	4.80 E-06	6.67 E-04	NA	1
Carbon Tetrachloride	56-23-5	Uncontrolled	< 3.06 E-05	< 4.25 E-03	8.2	3	NA	NA	NA	NA
Chlorobenzene	108-90-7	Uncontrolled	< 2.49 E-05	< 3.46 E-03	10.2	3	NA	NA	NA	NA
Chloroform	67-66-3	Uncontrolled	< 2.55 E-05	< 3.55 E-03	4.4	3	NA	NA	NA	NA
Chromium	NA	Uncontrolled	8.43 E-06	1.17 E-03	64.6	5	1.08 E-05	1.51 E-03	8.5	2
Ethylene Dichloride	107-06-2	Uncontrolled	2.02 E-05	2.81 E-03	1.4	2	NA	NA	NA	NA
Formaldehyde	50-00-0	Uncontrolled	2.45 E-04	3.41 E-02	120.6	10	2.82 E-04	3.92 E-02	115.0	8
Lead	NA	Uncontrolled	1.34 E-05	1.87 E-03	50.6	5	1.42 E-05	1.97 E-03	51.2	2
Manganese	NA	Uncontrolled	7.89 E-04	1.10 E-01	NA	1	7.89 E-04	1.10 E-01	NA	1
Methylene Chloride	74-87-3	Uncontrolled	< 2.13 E-05	< 2.97 E-03	29.5	3	NA	NA	NA	NA
Mercury	NA	Uncontrolled	1.20 E-06	1.67 E-04	NA	1	1.20E-06	1.67E-04	NA	1
Naphthalene	91-20-3	Uncontrolled	3.52 E-05	4.89 E-03	187.9	5	3.52 E-05	4.89 E-03	187.9	5

Table 3.4-2. SUMMARY OF EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES
(Continued)

Distillate Oil-Fired Gas Turbines HAP Emissions

Pollutant	CAS No.	Control Method	All Loads				High Loads: Greater Than or Equal to 80 Percent			
			Emission Factor (lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count
Nickel	NA	Uncontrolled	1.62 E-05	2.26 E-03	146.9	4	< 4.61 E-06	< 6.41 E-04	NA	1
PAH	NA	Uncontrolled	4.03 E-05	5.61 E-03	182.0	6	4.03 E-05	5.61 E-03	163.9	5
Selenium	NA	Uncontrolled	< 2.88 E-05	< 4.00 E-03	110.5	4	< 2.52 E-05	< 3.50 E-03	NA	1
Tetrachloroethylene	127-18-4	Uncontrolled	< 3.24 E-05	< 4.50 E-03	12.0	3	NA	NA	NA	NA
Trichloroethylene	79-01-6	Uncontrolled	< 2.75 E-05	< 3.82 E-03	1.0	3	NA	NA	NA	NA
Vinyl Chloride	75-01-4	Uncontrolled	< 5.27 E-05	< 7.33 E-03	40.5	3	NA	NA	NA	NA
Vinylidene Chloride	75-35-4	Uncontrolled	< 2.02 E-05	< 2.81 E-03	1.4	2	NA	NA	NA	NA

Table 3.4-2. SUMMARY OF EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES
(Concluded)

Distillate Oil-Fired Gas Turbines Criteria Emissions

		All Loads				High Loads: Greater Than or Equal to 80 Percent			
Pollutant	Fuel Source	Emission Factor (lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count
CO	Uncontrolled	1.24 E-02	1.72 E+00	125.7	5	3.29 E-03	4.57 E-01	23.3	3
CO	Water-Steam Injection	1.03 E-01	1.43 E+01	44.1	8	7.61 E-02	1.05 E+01	43.2	5
NMHC	Uncontrolled	8.03 E-03	1.22 E+00	34.8	2	NA	NA	NA	NA
NO_x	Uncontrolled	6.37 E-01	8.85 E+01	55.1	6	8.82 E-01	1.23 E+02	36.0	3
NO_x	Water-Steam Injection	2.34 E-01	3.25 E+01	22.0	23	2.44 E-01	3.39 E+01	21.9	13
PM Condensable	Water-Steam Injection	7.18 E-03	9.98 E-01	NA	1	7.18 E-03	9.98 E-01	65.3	1
PM Filterable	Water-Steam Injection	4.32 E-03	6.00 E-01	NA	1	4.32 E-03	6.00 E-01	55.3	1
PM total[a]	Water-Steam Injection	1.15 E-02	1.60 E+00	NA	1	1.15 E-02	1.60 E+00	NA	1
PM-10	Uncontrolled	2.03 E-02	2.82 E+00	76.4	2	NA	NA	NA	NA
PM-10	Water-Steam Injection	4.40 E-02	6.12 E+00	141.4	2	4.40 E-02	6.12 E+00	141.4	2
SO_2	Uncontrolled	3.30 E-02	4.58 E+00	69.1	2	NA	NA	NA	NA
TOC[b]	Water-Steam injection	4.64 E-03	6.46 E-01	28.6	6	4.01 E-03	5.58 E-01	21.9	3

[a] Calculated value: PM (total) = PM (condensable) + PM (filterable)

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

Table 3.4-3. SUMMARY OF EMISSION FACTORS FOR LANDFILL GAS- FIRED GAS TURBINES

Landfill Gas-Fired Gas Turbine HAP Emissions

Pollutant	CAS No.	Control Method	All Loads				High Loads Greater Than or Equal to 80 Percent			
			Emission Factor (lb/MMBtu)	Emission Factor (lb/SCF)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/SCF)	RSD Percent	Count
Acetonitrile	107-13-1	Uncontrolled	< 1.18 E-05	< 4.72 E-03	85.8	11	< 1.18 E-05	< 4.72 E-03	85.8	11
Benzene	71-43-2	Uncontrolled	2.07 E-05	8.28 E-03	95.8	11	2.07 E-05	8.28 E-03	95.8	11
Benzyl Chloride	100-44-7	Uncontrolled	< 1.18 E-05	< 4.71 E-03	82.5	11	< 1.18 E-05	< 4.71 E-03	82.5	11
Carbon Tetrachloride	56-23-5	Uncontrolled	< 1.75 E-06	< 7.01 E-04	60.6	11	< 1.75 E-06	< 7.01 E-04	60.6	11
Chlorobenzene	108-90-7	Uncontrolled	< 2.91 E-06	< 1.16 E-04	79.4	11	< 2.91 E-06	< 1.16 E-04	79.4	11
Chloroform	67-66-3	Uncontrolled	< 1.36 E-06	< 5.45 E-04	60.5	11	< 1.36 E-06	< 5.45 E-04	60.5	11
Methylene Chloride	74-87-3	Uncontrolled	2.29 E-06	9.14 E-04	133.1	11	2.29 E-06	9.14 E-04	133.1	11
Tetrachloroethylene	127-18-4	Uncontrolled	< 2.44 E-06	< 9.78 E-04	61.1	11	< 2.44 E-06	< 9.78 E-04	61.1	11
Toluene	108-88-3	Uncontrolled	1.10 E-04	4.39 E-02	254.8	11	1.10 E-04	4.39 E-02	254.8	11
Trichloroethylene	79-01-6	Uncontrolled	< 1.91 E-06	< 7.62 E-04	113.4	11	< 1.91 E-06	< 7.62 E-04	113.4	11
Vinyl Chloride	75-01-4	Uncontrolled	< 1.55 E-06	< 6.20 E-04	63.5	11	< 1.55 E-06	< 6.20 E-04	63.5	11
Xylenes	1330-20-7	Uncontrolled	3.12 E-05	1.25 E-02	236.8	10	3.12 E-05	1.25 E-02	236.8	10

Table 3.4-3. SUMMARY OF EMISSION FACTORS FOR LANDFILL GAS- FIRED GAS TURBINES
(Concluded)

Landfill Gas-Fired Combustion Turbine Criteria Emission

		All Loads				High Loads: Greater Than or Equal to 80 Percent			
Pollutant	Fuel Source	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count
CO	Uncontrolled	3.34 E-01	1.34 E+01	172.0	20	4.37 E-01	1.75 E+02	145.1	15
VOC[a]	Uncontrolled	1.34 E-02	5.36 E+00	93.9	11	1.34 E-02	5.36 E+00	93.9	11
NO_X	Uncontrolled	1.87 E-01	7.48 E+01	66.9	20	1.41 E-01	5.63 E+01	67.5	15
PM-10	Uncontrolled	2.32 E-02	9.28 E+00	52.4	11	2.32 E-02	9.28 E+00	52.4	11
SO_2	Uncontrolled	4.49 E-02	1.79 E+01	38.4	5	4.49 E-02	1.79 E+01	38.4	5

[a] Based on adding the formaldehyde emissions to the NMHC.

Table 3.4-4. SUMMARY OF EMISSION FACTORS FOR DIGESTER GAS FIRED GAS TURBINES

Digester Gas-Fired Gas Turbine HAP Emissions			All Loads				High Loads: Greater Than or Equal to 80 Percent			
Pollutant	CAS No.	Fuel Source	Emission Factor		RSD %	Count	Emission Factor		RSD %	Count
			(lb/MMBtu)	(lb/MMscf)			(lb/MMBtu)	(lb/MMscf)		
1,3-Butadiene	106-99-0	Uncontrolled	< 9.80 E-06	< 5.88 E-03	26.9	3	< 9.80 E-06	< 5.88 E-03	26.9	3
1,4-Dichlorobenzene	106-46-7	Uncontrolled	< 1.95 E-05	< 1.17 E-02	28.7	3	< 1.95 E-05	< 1.17 E-02	28.7	3
Acetaldehyde	75-07-0	Uncontrolled	5.27 E-05	3.16 E-02	25.0	2	5.27 E-05	3.16 E-02	25.0	2
Arsenic	NA	Uncontrolled	< 2.28 E-06	< 1.37 E-03	NA	3	< 2.28 E-06	< 1.37 E-03	NA	3
Cadmium	NA	Uncontrolled	< 5.79 E-07	< 3.47 E-04	68	3	< 5.79 E-07	< 3.47 E-04	68	3
Carbon Tetrachloride	56-23-5	Uncontrolled	< 1.99 E-05	< 1.20 E-02	33.0	3	< 1.99 E-05	< 1.20 E-02	33.0	3
Chlorobenzene	108-90-7	Uncontrolled	<1.58 E-05	< 9.48 E-03	17.6	3	< 1.58 E-05	< 9.48 E-03	17.6	3
Chloroform	67-66-3	Uncontrolled	< 1.65 E-05	< 9.88 E-03	20.8	3	< 1.65 E-05	< 9.88 E-03	20.8	3
Chromium	NA	Uncontrolled	< 1.16 E-06	< 6.95 E-04	67.8	3	< 1.16 E-06	< 6.95 E-04	67.8	3
Ethylene Dichloride	107-06-2	Uncontrolled	< 1.50 E-05	< 8.97 E-03	8	2	< 1.50 E-05	< 8.97 E-03	8	2
Formaldehyde	50-00-0	Uncontrolled	1.89 E-04	1.13 E-01	19.9	2	1.89 E-04	1.13 E-01	19.9	2
Lead	NA	Uncontrolled	< 3.35 E-06	< 2.01 E-03	.77	3	< 3.35 E-06	< 2.01 E-03	77	3
Methylene Chloride	74-87-3	Uncontrolled	< 1.29 E-05	< 7.72 E-03	6.3	3	< 1.29 E-05	< 7.72 E-03	6.3	3
Nickel	NA	Uncontrolled	1.97 E-06	1.18 E-03	40.3	3	1.97 E-06	1.18 E-03	40.3	3
Selenium	NA	Uncontrolled	1.13 E-05	6.79 E-03	99.2	3	1.13 E-05	6.79 E-03	99.2	3
Tetrachloroethylene	127-18-4	Uncontrolled	< 2.13 E-05	< 1.28 E-02	35.5	3	< 2.13 E-05	< 1.28 E-02	35.5	3
Trichloroethylene	79-01-6	Uncontrolled	< 1.78 E-05	< 1.07 E-02	24.7	3	< 1.78 E-05	<1.07 E-02	24.7	3
Vinyl Chloride	75-01-4	Uncontrolled	< 3.63 E-05	< 2.80 E-02	56.8	3	< 3.63 E-05	< 2.80 E-02	56.8	3
Vinylidene Chloride	75-35-4	Uncontrolled	< 1.50 E-05	< 8.97 E-03	8.0	2	< 1 .50 E-05	< 8.97 E-03	8.0	2

Table 3.4-4. SUMMARY OF EMISSION FACTORS FOR DIGESTER GAS FIRED GAS TURBINES
(Concluded)

Digester Gas-Fired Gas Turbine Criteria Emissions

		All Loads				High Loads: Greater Than or Equal to 80 Percent			
Pollutant	Fuel Source	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count
CO	Uncontrolled	1.70 E-02	1.02 E+01	7.1	2	1.70 E-02	1.02 E+01	7.1	2
VOC[a]	Uncontrolled	5.82 E-03	3.48 E+00	16.9	2	5.82 E-03	3.48 E+00	16.9	2
NO_X	Uncontrolled	1.63 E-01	9.78 E+01	5.2	2	1.63 E-01	9.78 E+01	5.2	2
PM-10	Uncontrolled	1.20 E-02	7.21 E+00	63.1	3	1.20 E-02	7.21 E+00	63.1	3
SO_2	Uncontrolled	6.53 E-03	3.92 E+00	7.4	2	6.53 E-03	3.92 E+00	7.4	2

[a] Based on adding the formaldehyde emissions to the NMHC.

3.5 REFERENCES FOR SECTION 3

1. Procedures for Preparing Emission Factor Documents, Third Revised Draft Version, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, NC 27711, November 1996.

BEST AVAILABLE COPY

Related Information

Explanation of File Formats

AP-42 Section 3.1 - Stationary Gas Turbines for Electricity Generation

The data that supports the emission factors are presented in summary in the background report and are reported more completely in an electronic database. The database is a Microsoft Access® file and it has been "zipped".

Description

Section 3.1: Data file (ZIP 235K)

AP-42 Chapter 3, Section 3.1 Emission Factor Query

Chemical Name:

- NOx
- PAHs
- PM-10
- PM-10 (Filterable)
- PM-condensibles
- PM-filterable
- Propylene oxide
- Selenium
- SO2
- Tetrachloroethylene
- TGNMO
- THC
- TMA

Fuel Type:

- Natural Gas
- #2 Fuel Oil
- Landfill Gas
- Digester Gas

Control Device:

- Steam/Water Injection & SCONOX
- Steam/Water Injection & CO Catalyst
- No HAP Controls
- All HAP Controls

Load:

- [x] All Loads
- [ ] 80 to 110
- [ ] < 80

Emission Units:

- [x] lb/MMBtu
- [ ] lb/hr
- [ ] lb/MW-hr
- [ ] ppb@15% O2
- [ ] lb/MMscf (gas turbines only)
- [ ] lb/1000gal (diesel turbines only)

View Facilities | View EF Inputs | EF Report | Done

#2 Fuel Oil

Emission Factor Report for NOx with No Control

16-Jan-03

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF	(lb/MMBtu)	Count of Runs	ND Count	Control Device
412		PG-5191	317	76		2.04E-01	3	0	None
15.2	General Electric	Frame 7B	50	100		1.01E-01	3	0	Water Injection
223	General Electric	MS 7001	55	100		1.66E-01	3	0	Water injection for NOx
246.17	General Electric	NR	29	93		2.69E-01	3	0	Water Injection for NOx control.
246.1	General Electric	NR	25	100		2.41E-01	3	0	Water Injection for NOx control.
246.10	General Electric	NR	29	100		2.90E-01	3	0	Water Injection for NOx control.
246.16	General Electric	NR	29	69		2.14E-01	3	0	Water Injection for NOx control.
246.2	General Electric	NR	25	100		2.55E-01	3	0	Water Injection for NOx control.

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
246.3	General Electric	NR	25	100	2.63E-01	3	0	Water Injection for NOx control.
246.4	General Electric	NR	25	100	2.62E-01	3	0	Water Injection for NOx control.
246.6	General Electric	NR	25	100	2.38E-01	3	0	Water Injection for NOx control.
246.7	General Electric	NR	29	10	1.28E-01	3	0	Water Injection for NOx control.
246.8	General Electric	NR	29	38	2.06E-01	3	0	Water Injection for NOx control.
246.9	General Electric	NR	29	69	2.22E-01	3	0	Water Injection for NOx control.
246.15	General Electric	NR	29	38	1.75E-01	3	0	Water Injection for NOx control.
246.5	General Electric	NR	25	100	2.48E-01	3	0	Water Injection for NOx control.
410	General Electric	PG-5191	317	70.3	2.04E-01	3	0	Water Injection

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
409	General Electric	PG-5191	317	76.2	2.22E-01	3	0	Water Injection
227.3	NR	NR	NR	100	5.16E-01	3	0	None
227.2	NR	NR	NR	100	1.05E+00	3	0	None
227.1	NR	NR	NR	100	1.08E+00	3	0	None
300.3	Solar Mars	NR	7.2	20.83	4.50E-01	1	0	None
300.1	Solar Mars	NR	7.2	20.83	5.24E-01	1	0	None
225.6	Westinghouse	W301-G	29	97	2.90E-01	1	0	Water Injection for NOx
225.5	Westinghouse	W301-G	29	71.3	2.89E-01	3	0	Water Injection for NOx
225.4	Westinghouse	W301-G	29	91.7	2.76E-01	3	0	Water Injection for NOx

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF	(lb/MMBtu)	Count of Runs	ND Count	Control Device
225.3	Westinghouse	W301-G	29	86		2.79E-01	3	0	Water Injection for NOx
225.2	Westinghouse	W301-G	29	75		2.73E-01	3	0	Water Injection for NOx
225.1	Westinghouse	W301-G	29	62		2.61E-01	3	0	Water Injection for NOx
				Avg EF =		**3.17E-01**			
				Count =		**29**			
				Std Dev =		**2.28E-01**			
				RSD(%) =		**71.8%**			

ID	Pollutant	Run 1 Cc	Run 2 Cc	Run 3 Conc C	lbh1	lbh2	lbh3	lbhAvg
15.2	NOx	33300	40500	38400	86.6	105	99.9	97.2
223	NOx	37800	40200	42500	121	103	116	113
225.	NOx	32500	32500	32800	80.3	91.8	80.7	84.3
225.	NOx	38100	38700	39500	94.3	94.6	95.8	94.9
225.	NOx	43800	44500	45200	104	106	108	106
225.	NOx	47000	47000	47500	111	111	111	111
225.	NOx	36200	43000	48500	87.1	101	114	101
225.	NOx	50000	NR	NR	119	NR	NR	119
227.	NOx	214700	223300	194200	497	535	467	500
227.	NOx	214300	203900	189500	573	536	527	545
227.	NOx	125800	129100	130700	344	340	343	342
246.	NOx	60000	61000	61000	NR	NR	NR	NR
246.	NOx	76000	75000	77000	NR	NR	NR	NR
246.	NOx	27000	28000	27000	NR	NR	NR	NR
246.	NOx	47000	46000	44000	NR	NR	NR	NR
246.	NOx	72000	73000	72000	NR	NR	NR	NR
246.	NOx	66000	66000	66000	NR	NR	NR	NR
246.	NOx	70000	67000	68000	NR	NR	NR	NR
246.	NOx	70000	66000	66000	NR	NR	NR	NR
246.	NOx	63000	66000	67000	NR	NR	NR	NR
246.	NOx	63000	64000	63000	NR	NR	NR	NR
246.	NOx	14000	13000	13000	NR	NR	NR	NR
246.	NOx	28000	28000	27000	NR	NR	NR	NR
246.	NOx	44000	45000	45000	NR	NR	NR	NR
300.	NOx	82800	NR	NR	26.3	NR	NR	26.3
300.	NOx	69900	NR	NR	22.7	NR	NR	22.7
409	NOx	46300	46400	45600	NR	NR	NR	NR
410	NOx	45300	45300	45300	NR	NR	NR	NR
412	NOx	45630	45630	45630	NR	NR	NR	NR

ID	Pollutant	lbMMBtu1	lbMMBtu2	lbMMBtu3	lbMMBtuAvg	lbMW1
15.2	NOx	.0898	.109	.104	.101	1.73
223	NOx	.159	.166	.172	.166	2.2
225.	NOx	.257	.261	.264	.261	4.47
225.	NOx	.273	.27	.276	.273	4.34
225.	NOx	.275	.278	.284	.279	4.17
225.	NOx	.276	.276	.276	.276	4.17
225.	NOx	.286	.286	.295	.289	4.21
225.	NOx	.29	NR	NR	.29	4.23
227.	NOx	1.06	1.14	1.04	1.08	NR
227.	NOx	1.08	1.04	1.04	1.05	NR
227.	NOx	.509	.51	.53	.516	NR
246.	NOx	.238	.236	.249	.241	NR
246.	NOx	.293	.286	.292	.29	NR
246.	NOx	.175	.176	.173	.175	NR
246.	NOx	.215	.217	.209	.214	NR
246.	NOx	.269	.271	.267	.269	NR
246.	NOx	.274	.25	.242	.255	NR
246.	NOx	.261	.265	.262	.263	NR
246.	NOx	.271	.251	.264	.262	NR
246.	NOx	.227	.244	.273	.248	NR
246.	NOx	.226	.247	.241	.238	NR
246.	NOx	.131	.134	.12	.128	NR
246.	NOx	.188	.176	.255	.206	NR
246.	NOx	.233	.221	.211	.222	NR
300.	NOx	.524	NR	NR	.524	17.5
300.	NOx	.45	NR	NR	.45	15.1
409	NOx	.223	.224	.219	.222	NR
410	NOx	.204	.204	.204	.204	NR
412	NOx	.204	.204	.204	.204	NR

ID	Pollutant	lbMW2	lbMW3	lbMWAvg	Facility Name
15.2	NOx	2.1	2	1.94	Modesto Irrigation District/Mclure
223	NOx	1.87	2.11	2.06	McClure Generation Station
225.	NOx	5.11	4.49	4.69	Sun Oil Refinery
225.	NOx	4.35	4.4	4.36	Sun Oil Refinery
225.	NOx	4.25	4.33	4.25	Sun Oil Refinery
225.	NOx	4.17	4.17	4.17	Sun Oil Refinery
225.	NOx	4.88	5.51	4.87	Sun Oil Refinery
225.	NOx	NR	NR	4.23	Sun Oil Refinery
227.	NOx	NR	NR	NR	Philadelphia Electric Company
227.	NOx	NR	NR	NR	Philadelphia Electric Company
227.	NOx	NR	NR	NR	Philadelphia Electric Company
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
300.	NOx	NR	NR	17.5	County Sanitation Districts of Los
300.	NOx	NR	NR	15.1	County Sanitation Districts of Los
409	NOx	NR	NR	NR	SDGE Division St. GT
410	NOx	NR	NR	NR	SDGE Harbor and Vesta
412	NOx	NR	NR	NR	SDGE/32nd Street Harbor & Vesta

ID	Pollutant	Method	Location	Facility	Testing Compa	Date
15.2	NOx	CARB 1-100	Modesto, CA	Modesto Irrigati	ECOSERVE, In	9/24/90
223	NOx	EPA 20	Modesto Irrigati	McClure Gener	Acurex Corpor	1/17/89
225.	NOx	EPA 20	Philadelphia, P	Sun Oil Refiner	CUBIX Corpora	5/30/91
225.	NOx	EPA 20	Philadelphia, P	Sun Oil Refiner	CUBIX Corpora	5/30/91
225.	NOx	EPA 20	Philadelphia, P	Sun Oil Refiner	CUBIX Corpora	5/30/91
225.	NOx	EPA 20	Philadelphia, P	Sun Oil Refiner	CUBIX Corpora	5/30/91
225.	NOx	EPA 20	Philadelphia, P	Sun Oil Refiner	CUBIX Corpora	5/30/91
225.	NOx	EPA 20	Philadelphia, P	Sun Oil Refiner	CUBIX Corpora	5/30/91
227.	NOx	EPA 7D	Croyden Gener	Philadelphia El	Gilbert/Commo	7/16/91
227.	NOx	EPA 7D	Croyden Gener	Philadelphia El	Gilbert/Commo	7/16/91
227.	NOx	EPA 7D	Croyden Gener	Philadelphia El	Gilbert/Commo	7/16/91
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
300.	NOx	SCAQMD 100.	Carson, CA	County Sanitati	Calscience Env	7/30/92
300.	NOx	SCAQMD 100.	Carson, CA	County Sanitati	Calscience Env	7/30/92
409	NOx	SDAPCD Meth	San Diego, CA	SDGE Division	SDAPCD	3/24/98
410	NOx	Method 7	San Diego, CA	SDGE Harbor	SDAPCD	12/14/95
412	NOx	Method 7	San Diego, CA	SDGE/32nd Str	SDAPCD	10/ 4/94

ID	Pollutant	Rating	Unit	Load	Manufacturer	Model
15.2	NOx	50	MW	100	General Electri	Frame 7B
223	NOx	55	MW	100	General Electri	MS 7001 13
225.	NOx	29	MW	62	Westinghouse	W301-G
225.	NOx	29	MW	75	Westinghouse	W301-G
225.	NOx	29	MW	86	Westinghouse	W301-G
225.	NOx	29	MW	91.7	Westinghouse	W301-G
225.	NOx	29	MW	71.3	Westinghouse	W301-G
225.	NOx	29	MW	97	Westinghouse	W301-G
227.	NOx	NR	NR	100	NR	NR
227.	NOx	NR	NR	100	NR	NR
227.	NOx	NR	NR	100	NR	NR
246.	NOx	25	MW	100	General Electri	NR
246.	NOx	29	MW	100	General Electri	NR
246.	NOx	29	MW	38	General Electri	NR
246.	NOx	29	MW	69	General Electri	NR
246.	NOx	29	MW	93	General Electri	NR
246.	NOx	25	MW	100	General Electri	NR
246.	NOx	25	MW	100	General Electri	NR
246.	NOx	25	MW	100	General Electri	NR
246.	NOx	25	MW	100	General Electri	NR
246.	NOx	25	MW	100	General Electri	NR
246.	NOx	29	MW	10	General Electri	NR
246.	NOx	29	MW	38	General Electri	NR
246.	NOx	29	MW	69	General Electri	NR
300.	NOx	7.2	MW	20.83	Solar Mars	NR
300.	NOx	7.2	MW	20.83	Solar Mars	NR
409	NOx	317	MMBtu/hr	76.2	General Electri	PG-5191
410	NOx	317	MMBtu/hr	70.3	General Electri	PG-5191
412	NOx	317	MMBtu/hr	76		PG-5191

ID	Pollutant	Turbine	Fuel Type	Application	Run 1 Conc R	Run 2 Conc R
15.2	NOx	General Electri	#2 Fuel Oil	Power generati	33300	40500
223	NOx	General Electri	#2 Fuel Oil	NR	37800	40200
225.	NOx	Westinghouse/	#2 Fuel Oil	Power Generati	32500	32500
225.	NOx	Westinghouse/	#2 Fuel Oil	Power Generati	38100	38700
225.	NOx	Westinghouse/	#2 Fuel Oil	Power Generati	43800	44500
225.	NOx	Westinghouse/	#2 Fuel Oil	Power Generati	47000	47000
225.	NOx	Westinghouse/	#2 Fuel Oil	Power Generati	36200	43000
225.	NOx	Westinghouse/	#2 Fuel Oil	Power Generati	50000	NR
227.	NOx	NR/NR/NR M	#2 Fuel Oil	NR	214700	223300
227.	NOx	NR/NR/NR M	#2 Fuel Oil	NR	214300	203900
227.	NOx	NR/NR/NR M	#2 Fuel Oil	NR	125800	129100
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	60000	61000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	76000	75000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	27000	28000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	47000	46000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	72000	73000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	66000	66000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	70000	67000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	70000	66000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	63000	66000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	63000	64000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	14000	13000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	28000	28000
246.	NOx	General Electri	#2 Fuel Oil	Electric generat	44000	45000
300.	NOx	Solar Mars/NR/	#2 Fuel Oil	NR	82800	NR
300.	NOx	Solar Mars/NR/	#2 Fuel Oil	NR	69900	NR
409	NOx	General Electri	#2 Fuel Oil	Gas turbine ge	46300	46400
410	NOx	General Electri	#2 Fuel Oil	Gas Turbine	45300	45300
412	NOx	/PG-5191/317	#2 Fuel Oil	Gas turbine	45630	45630

ID	Pollutant	Run 3 Conc R	Average	Conc R Averag	DL	SD
15.2	NOx	38400	37400	37400	NA	3
223	NOx	42500	40166.6666666	40200	NA	3
225.	NOx	32800	32600	32600	NA	3
225.	NOx	39500	38766.6666666	38800	NA	3
225.	NOx	45200	44500	44500	NA	3
225.	NOx	47500	47166.6666666	47200	NA	3
225.	NOx	48500	42566.6666666	42600	NA	3
225.	NOx	NR	50000	50000	NA	3
227.	NOx	194200	210733.333333	211000	NA	3
227.	NOx	189500	202566.666666	203000	NA	3
227.	NOx	130700	128533.333333	129000	NA	3
246.	NOx	61000	60666.6666666	60700	NA	3
246.	NOx	77000	76000	76000	NA	3
246.	NOx	27000	27333.3333333	27300	NA	3
246.	NOx	44000	45666.6666666	45700	NA	3
246.	NOx	72000	72333.3333333	72300	NA	3
246.	NOx	66000	66000	66000	NA	3
246.	NOx	68000	68333.3333333	68300	NA	3
246.	NOx	66000	67333.3333333	67300	NA	3
246.	NOx	67000	65333.3333333	65300	NA	3
246.	NOx	63000	63333.3333333	63300	NA	3
246.	NOx	13000	13333.3333333	13300	NA	3
246.	NOx	27000	27666.6666666	27700	NA	3
246.	NOx	45000	44666.6666666	44700	NA	3
300.	NOx	NR	82800	82800	NA	3
300.	NOx	NR	69900	69900	NA	3
409	NOx	45600	46100	46100	NA	3
410	NOx	45300	45300	45300	NA	3
412	NOx	45630	45630	45600	NA	3

ID	Pollutant	CountAConc	CountIbh	CountIbMMBtu	CountIbMW	CUnit
15.2	NOx	1	1	1	1	ppb
223	NOx	1	1	1	1	ppb
225.	NOx	1	1	1	1	ppb
225.	NOx	1	1	1	1	ppb
225.	NOx	1	1	1	1	ppb
225.	NOx	1	1	1	1	ppb
225.	NOx	1	1	1	1	ppb
225.	NOx	1	1	1	1	ppb
227.	NOx	1	1	1	0	ppb
227.	NOx	1	1	1	0	ppb
227.	NOx	1	1	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
300.	NOx	1	1	1	1	ppb
300.	NOx	1	1	1	1	ppb
409	NOx	1	0	1	0	ppb
410	NOx	1	0	1	0	ppb
412	NOx	1	0	1	0	ppb

ID	Pollutant	Control Device	Source EF
15.2	NOx	Water Injection	#Error
223	NOx	Water injection	#Error
225.	NOx	Water Injection	#Error
225.	NOx	Water Injection	#Error
225.	NOx	Water Injection	#Error
225.	NOx	Water Injection	#Error
225.	NOx	Water Injection	#Error
225.	NOx	Water Injection	#Error
227.	NOx	None	#Error
227.	NOx	None	#Error
227.	NOx	None	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
300.	NOx	None	#Error
300.	NOx	None	#Error
409	NOx	Water Injection	#Error
410	NOx	Water Injection	#Error
412	NOx	None	#Error

ID	Pollutant	Comm
15.2	NOx	F-Factor from CFR
223	NOx	Exhaust gas flowrate value presented in summary chart, probably calculated, not
225.	NOx	Unit # 2. Runs 1,2,3 of 12.
225.	NOx	Unit # 2. Runs 3,4,5 of 12.
225.	NOx	Unit # 2. Runs 7,8,9 of 12.
225.	NOx	Unit # 2. Runs 10,11,12 of 12.
225.	NOx	Unit # 1. Runs 1,2,3 of 4.
225.	NOx	Unit # 1. Run 4 of 4.
227.	NOx	Unit 11
227.	NOx	Unit 21
227.	NOx	Unit 22
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
300.	NOx	Turbine 1 - Diesel. Exhaust gas velocity and temperature are average of particula
300.	NOx	Turbine # 2 - Diesel. Exhaust gas velocity and temperature are average of metals
409	NOx	
410	NOx	Nox # are average of 6 samples
412	NOx	Nox # is average of 6 samples

ID	Pollutant	Run 1 O2	Run 2 O2	Run 3 O2	Test Rating
15.2	NOx	12.4	12.4	12.4	
223	NOx	15.4	15.3	15.2	0
225.	NOx	18	18.05	18.05	0
225.	NOx	17.7	17.62	17.62	0
225.	NOx	17.25	17.23	17.25	0
225.	NOx	17	17	16.95	0
225.	NOx	18	17.45	17.13	0
225.	NOx	16.95	NR	NR	0
227.	NOx	16.25	16.4	16.63	0
227.	NOx	16.33	16.4	16.73	0
227.	NOx	15.23	15.1	15.25	0
246.	NOx	15.13	14.97	15.28	
246.	NOx	14.95	14.88	14.85	
246.	NOx	17.37	17.26	17.33	
246.	NOx	15.9	16.05	16.07	
246.	NOx	14.77	14.72	14.71	
246.	NOx	15.37	14.85	14.65	
246.	NOx	14.75	15.11	14.95	
246.	NOx	14.98	14.86	15.17	
246.	NOx	14.54	14.71	15.28	
246.	NOx	14.51	14.96	14.9	
246.	NOx	18.45	18.68	18.42	
246.	NOx	17.48	17.25	18.47	
246.	NOx	16.58	16.23	16	
300.	NOx	17.28	NR	NR	0
300.	NOx	17.34	NR	NR	0
409	NOx	15.93	15.94	15.93	15
410	NOx	15.8	15.8	15.8	223
412	NOx	15.76	15.76	15.76	

ID	Pollutant	Comments	Standard Temp	Standard Temp
15.2	NOx		68	F
223	NOx		68	F
225.	NOx	Unit # 2. Runs 1,2,3 of 12.	68	F
225.	NOx	Unit # 2. Runs 4,5,6 of 12.	68	F
225.	NOx	Unit # 2. Runs 7,8,9 of 12.	68	F
225.	NOx	Unit # 2. Runs 10,11,12 of 12.	68	F
225.	NOx	Unit # 1. Runs 1,2,3 of 4.	68	F
225.	NOx	Unit # 1. Run 4 of 4.	68	F
227.	NOx	Unit 11. No info on make and model of turbine	68	F
227.	NOx	Unit 21. No info on make and model of turbine	68	F
227.	NOx	Unit 22. No info on make and model of turbine	68	F
246.	NOx	Unit 1 Distillate Oil	68	F
246.	NOx	Unit 7 Distillate Oil	68	F
246.	NOx	Unit 8 Distillate Oil.	68	F
246.	NOx	Unit 8 Distillate Oil.	68	F
246.	NOx	Unit 8 Distillate Oil	68	F
246.	NOx	Unit 2 Distillate Oil	68	F
246.	NOx	Unit 3 Distillate Oil	68	F
246.	NOx	Unit 4 Distillate Oil	68	F
246.	NOx	Unit 5 Distillate Oil	68	F
246.	NOx	Unit 6 Distillate Oil	68	F
246.	NOx	Unit 7 Distillate Oil.	68	F
246.	NOx	Unit 7 Distillate Oil.	68	F
246.	NOx	Unit 7 Distillate Oil.	68	F
300.	NOx	Turbine # 1	68	F
300.	NOx	Turbine # 2	68	F
409	NOx	Exhaust flow rate not available	68	F
410	NOx		68	F
412	NOx	load derived from #409	68	F

ID	Pollutant	Fuel Heating V	Fuel Heating V	Run 1 Gas Flov	Run 2 Gas Flo	Run 3 Gas Flo
15.2	NOx	NR	NR	363600	363600	363600
223	NOx	19680	Btu/lb	445544	357044	380576
225.	NOx	19313	Btu/lb	345251	394536	343930
225.	NOx	19313	Btu/lb	345835	341409	339008
225.	NOx	19313	Btu/lb	330269	332052	332784
225.	NOx	19313	Btu/lb	331252	331252	326855
225.	NOx	19313	Btu/lb	336182	328398	328492
225.	NOx	19313	Btu/lb	333529	NR	NR
227.	NOx	137720.7	Btu/gal	323186	334679	336084
227.	NOx	138005.1	Btu/gal	373508	367106	388583
227.	NOx	138036.8	Btu/gal	382376	367946	366803
246.	NOx	19274	Btu/lb	NR	NR	NR
246.	NOx	19382	Btu/lb	NR	NR	NR
246.	NOx	19403	Btu/lb	NR	NR	NR
246.	NOx	19403	Btu/lb	NR	NR	NR
246.	NOx	19403	Btu/lb	NR	NR	NR
246.	NOx	19406	Btu/lb	NR	NR	NR
246.	NOx	19378	Btu/lb	NR	NR	NR
246.	NOx	19307	Btu/lb	NR	NR	NR
246.	NOx	19433	Btu/lb	NR	NR	NR
246.	NOx	19353	Btu/lb	NR	NR	NR
246.	NOx	19382	Btu/lb	NR	NR	NR
246.	NOx	19382	Btu/lb	NR	NR	NR
246.	NOx	19382	Btu/lb	NR	NR	NR
300.	NOx	NR	NR	44438	NR	NR
300.	NOx	NR	NR	45426	NR	NR
409	NOx			NR	NR	NR
410	NOx			NR	NR	NR
412	NOx			NR	NR	NR

ID	Pollutant	MW	Run 1 % Moist	Run 2 % Moist	Run 3 % Moist	Run 1 Fuel Fac
15.2	NOx	46				9190
223	NOx	46				9271
225.	NOx	46				9190
225.	NOx	46				9190
225.	NOx	46				9190
225.	NOx	46				9190
225.	NOx	46				9190
225.	NOx	46				9190
227.	NOx	46				9190
227.	NOx	46				9190
227.	NOx	46				9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
246.	NOx	46	NR	NR	NR	9190
300.	NOx	46	5.0	NR		9190
300.	NOx	46	4,2	NR		9190
409	NOx	48				9190
410	NOx	46				9190
412	NOx	46				9190

ID	Pollutant	Runs	NDs	Expr5	Load1
15.2	NOx	3	0	2	100
223	NOx	3	0	2	100
225.	NOx	3	0	2	62
225.	NOx	3	0	2	75
225.	NOx	3	0	2	86
225.	NOx	3	0	2	91.7
225.	NOx	3	0	2	71.3
225.	NOx	1	0	2	97
227.	NOx	3	0	1	100
227.	NOx	3	0	1	100
227.	NOx	3	0	1	100
246.	NOx	3	0	2	100
246.	NOx	3	0	2	100
246.	NOx	3	0	2	38
246.	NOx	3	0	2	69
246.	NOx	3	0	2	93
246.	NOx	3	0	2	100
246.	NOx	3	0	2	100
246.	NOx	3	0	2	100
246.	NOx	3	0	2	100
246.	NOx	3	0	2	100
246.	NOx	3	0	2	10
246.	NOx	3	0	2	38
246.	NOx	3	0	2	69
300.	NOx	1	0	1	20.83
300.	NOx	1	0	1	20.83
409	NOx	3	0	2	76.2
410	NOx	3	0	2	70.3
412	NOx	3	0	1	76

ID	Pollutant	Flag Control Device Description	Run 1 Conc	Run 2 Conc
15.2	NOx	Steam/Water Injection	23100	28100
223	NOx	Steam/Water Injection	40500	42400
225.	NOx	Steam/Water Injection	66100	67300
225.	NOx	Steam/Water Injection	70200	69600
225.	NOx	Steam/Water Injection	70800	71500
225.	NOx	Steam/Water Injection	71100	71100
225.	NOx	Steam/Water Injection	73600	73500
225.	NOx	Steam/Water Injection	74700	NR
227.	NOx	No Control	272000	293000
227.	NOx	No Control	277000	267000
227.	NOx	No Control	131000	131000
246.	NOx	Steam/Water Injection	61400	60700
246.	NOx	Steam/Water Injection	75400	73500
246.	NOx	Steam/Water Injection	45100	45400
246.	NOx	Steam/Water Injection	55500	56000
246.	NOx	Steam/Water Injection	69300	69700
246.	NOx	Steam/Water Injection	70400	64400
246.	NOx	Steam/Water Injection	67200	68300
246.	NOx	Steam/Water Injection	69800	64500
246.	NOx	Steam/Water Injection	58400	62900
246.	NOx	Steam/Water Injection	58200	63600
246.	NOx	Steam/Water Injection	33700	34500
246.	NOx	Steam/Water Injection	48300	45300
246.	NOx	Steam/Water Injection	60100	56900
300.	NOx	No Control	135000	NR
300.	NOx	No Control	116000	NR
409	NOx	Steam/Water Injection	55000	55200
410	NOx	Steam/Water Injection	52400	52400
412	NOx	No Control	52400	52400

ID	Pollutant	Run 3 Conc	AConc	HHV
15.2	NOx	26700	25966.6666666	139
223	NOx	44000	42300	139
225.	NOx	67900	67100	139
225.	NOx	71100	70300	139
225.	NOx	73100	71800	139
225.	NOx	70900	71033.3333333	139
225.	NOx	75900	74333.3333333	139
225.	NOx	NR	74700	139
227.	NOx	268000	277666.666666	139
227.	NOx	268000	270666.666666	139
227.	NOx	136000	132666.666666	139
246.	NOx	64000	62033.3333333	139
246.	NOx	75100	74666.6666666	139
246.	NOx	44600	45033.3333333	139
246.	NOx	53700	55066.6666666	139
246.	NOx	68600	69200	139
246.	NOx	62300	65700	139
246.	NOx	67400	67633.3333333	139
246.	NOx	68000	67433.3333333	139
246.	NOx	70300	63866.6666666	139
246.	NOx	62000	61266.6666666	139
246.	NOx	30900	33033.3333333	139
246.	NOx	65600	53066.6666666	139
246.	NOx	54200	57066.6666666	139
300.	NOx	NR	135000	139
300.	NOx	NR	116000	139
409	NOx	54100	54766.6666666	139
410	NOx	52400	52400	139
412	NOx	52400	52400	139

AP-42 Chapter 3, Section 3.1 Emission Factor Query

Chemical Name:

- NOx
- PAHs
- PM-10
- PM-10 (Filterable)
- PM-condensibles
- PM-filterable
- Propylene oxide
- Selenium
- SO2
- Tetrachloroethylene
- TGNMO
- THC
- TMA

Fuel Type:

- Natural Gas
- #2 Fuel Oil
- Landfill Gas
- Digester Gas

Control Device:

- Steam/Water Injection & SCONOX
- Steam/Water Injection & CO Catalyst
- No HAP Controls
- All HAP Controls

Load:

- [x] All Loads
- [ ] 80 to 110
- [ ] < 80

Emission Units:

- [x] lb/MMBtu
- [ ] lb/hr
- [ ] lb/MW-hr
- [ ] ppb@15% O2
- [ ] lb/MMscf (gas turbines only)
- [ ] lb/1000gal (diesel turbines only)

View Facilities | View EF Inputs | EF Report | Done

Natural Gas

Emission Factor Report for NOx with Steam/Water Injection

16-Jan-03

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
435.2.3	Allison	501 KB5	3.5	81	1.11E-01	3	0	Water Injection
435.2.2	Allison	501 KB5	3.5	80	1.20E-01	3	0	Water Injection
435.2.1	Allison	501 KB5	3.5	96	1.02E-01	3	0	Water Injection
435.1.3	Allison	501 KB5	3.5	100	1.23E-01	3	0	Water Injection
435.1.2	Allison	501 KB5	3.5	100	1.30E-01	3	0	Water Injection
435.1.1	Allison	501 KB5	3.5	100	1.19E-01	3	0	Water Injection
226.6	Allison	501-KB	3	100	7.20E-02	3	0	None

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
226.7	Allison	501-KB	3	100	6.37E-02	3	0	None
226.5	Allison	501-KB	3	100	8.24E-02	3	0	None
226.4	Allison	501-KB	3	100	8.12E-02	3	0	None
226.3	Allison	501-KB	3	100	8.55E-02	3	0	None
226.2	Allison	501-KB	3	100	7.98E-02	3	0	None
226.1	Allison	501-KB	3	100	8.67E-02	3	0	None
238.6	Allison	501-KB5	4	80	1.19E-01	2	0	Lean Premix combustion and Water Injection
238.5	Allison	501-KB5	4	80	1.22E-01	2	0	Lean Premix combustion and Water Injection
244.6	Clark	DC-990	3.36	96	3.91E-01	3	0	None

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
208	Cooper Rolls	RB211	NR	100	5.86E-01	3	0	None
244.2	General Electric	3572 Serie	6.93	93	2.44E-01	3	0	None
444.3	General Electric	5191	317	98	1.06E-01	3	0	Water Injection
430.9.3	General Electric	5211	317	79.2	1.04E-01	3	0	None
430.1.1	General Electric	5221	299	92.4	9.20E-02	3	0	Water Injection
430.1.3	General Electric	5221	299	89	1.09E-01	3	0	Water Injection
430.1.2	General Electric	5221	299	88.9	5.91E-02	3	0	Water Injection
428.1.3	General Electric	5251	360	82.2	1.02E-01	3	0	Water Injection
428.2.3	General Electric	5251	360	80.8	1.20E-01	3	0	Water Injection

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
313.1.1	General Electric	Frame 3	7.7	100	7.28E-01	3	0	None
313.1.3	General Electric	Frame 3	7.7	75	6.29E-01	3	0	None
313.1.2	General Electric	Frame 3	7.7	50	5.11E-01	3	0	None
237.1	General Electric	Frame 3	8.46	93	5.36E-01	3	0	None
237.2	General Electric	Frame 3	8.46	63	4.65E-01	3	0	None
221.4	General Electric	G7111E	75	100	1.58E-01	3	0	Water injection for NOx
221.1	General Electric	G7111E	75	100	1.62E-01	3	0	Water injection for NOx
221.2	General Electric	G7111E	75	100	1.57E-01	3	0	Water injection for NOx
221.3	General Electric	G7111E	75	100	1.75E-01	3	0	Water injection for NOx

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
315.1	General Electric	LM1500	10.6	100	2.60E-01	3	0	None
315.2	General Electric	LM1500	10.6	25	6.88E-02	3	0	None
315.3	General Electric	LM1500	10.6	50	1.34E-01	3	0	None
315.4	General Electric	LM1500	10.6	75	1.83E-01	3	0	None
244.1	General Electric	LM-1500	7.46	100	2.75E-01	3	0	None
245	General Electric	LM-2500	216.5	100	2.16E-01	3	0	Water Injection for NOx control.
244.7	General Electric	M3122R	8.98	97	5.81E-01	3	0	None
246.14	General Electric	NR	29	100	2.42E-01	3	0	Water Injection for NOx control.
216.2	General Electric	NR	42.7	100	1.27E-02	3	0	Ammonia Injection and Selective

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
216.3	General Electric	NR	42.7	100	1.42E-02	3	0	Ammonia Injection and Selective
216.4	General Electric	NR	42.7	100	1.39E-02	1	0	Ammonia Injection and Selective
246.21	General Electric	NR	29	96	2.46E-01	3	0	Water Injection for NOx control.
246.20	General Electric	NR	29	69	1.49E-01	3	0	Water Injection for NOx control.
216.1	General Electric	NR	42.7	100	1.05E-02	3	0	Ammonia Injection and Selective
246.18	General Electric	NR	29	10	1.10E-01	3	0	Water Injection for NOx control.
246.13	General Electric	NR	29	69	1.62E-01	3	0	Water Injection for NOx control.
246.12	General Electric	NR	29	38	2.37E-01	3	0	Water Injection for NOx control.
246.11	General Electric	NR	29	10	1.59E-01	3	0	Water Injection for NOx control.

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
246.19	General Electric	NR	29	38	1.92E-01	3	0	Water Injection for NOx control.
444.2	General Electric	PG-5191	317	82	1.08E-01	3	0	Water Injection
432.2.3	General Electric	PG-5191	18.27	77.6	1.18E-01	3	0	Water Injection
444.1	General Electric	PG-5191	317	82	1.00E-01	3	0	Water Injection
432.2.2	General Electric	PG-5191	317	NA	5.32E-02	3	0	Water Injection
432.2.1	General Electric	PG-5191	317	87.1	1.08E-01	3	0	Water Injection
432.1	General Electric	PG-5191	317	78.5	8.55E-02	3	0	Water Injection
408	General Electric	PG-5191	317	57.1	1.17E-01	3	0	No Control
407	General Electric	PG-5191	317	75	1.01E-01	3	0	Water Injection

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
430.5.1	General Electric	PG-5211	317	86	9.98E-02	3	0	Water Injection
430.2.3	General Electric	PG-5211	317	77.2	9.91E-02	3	0	Water Injection
430.2.2	General Electric	PG-5211	317	81.2	1.24E-01	3	0	Water Injection
430.5.3	General Electric	PG-5211	317	76.2	1.30E-01	3	0	Water Injection
430.3.1	General Electric	PG-5211	317	88.6	1.11E-01	3	0	Water Injection
430.4.3	General Electric	PG-5211	317	77.2	1.24E-01	3	0	Water Injection
430.9.2	General Electric	PG-5211	317	79	7.61E-02	1	0	Water Injection
430.3.3	General Electric	PG-5211	317	84.5	8.43E-02	3	0	Water Injection
430.9.1	General Electric	PG-5211	317	80.6	9.31E-02	3	0	Water Injection

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
430.6.1	General Electric	PG-5211	317	83.7	1.23E-01	3	0	Water Injection
430.5.2	General Electric	PG-5211	317	85.4	1.25E-01	3	0	Water Injection
430.7.1	General Electric	PG-5211	317	76.5	9.96E-02	3	0	Water Injection
430.8.3	General Electric	PG-5211	317	74.3	1.24E-01	3	0	Water Injection
430.6.3	General Electric	PG-5211	317	74.9	1.39E-01	3	0	Water Injection
430.8.2	General Electric	PG-5211	317	80	1.07E-01	3	0	Water Injection
430.2.1	General Electric	PG-5211	317	69.6	1.24E-01	3	0	Water Injection
430.8.1	General Electric	PG-5211	317	80	9.30E-02	3	0	Water Injection
430.3.2	General Electric	PG-5211	317	86.8	1.19E-01	3	0	Water Injection

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
430.7.3	General Electric	PG-5211	317	76.9	1.49E-01	3	0	Water Injection
430.7.2	General Electric	PG-5211	317	77.3	8.48E-02	3	0	Water Injection
430.4.2	General Electric	PG-5211	317	58.2	1.31E-01	3	0	Water Injection
430.4.1	General Electric	PG-5211	317	78.2	1.12E-01	3	0	Water Injection
430.6.2	General Electric	PG-5211	317	77.2	9.00E-02	3	0	Water Injection
428.1.1	General Electric Co.	5251	360	84.72	9.20E-02	3	0	Water Injection
428.2.2	General Electric Co.	5251	360	89	8.56E-02	3	0	Water Injection
428.2.1	General Electric Co.	5251	360	84.6	1.14E-01	3	0	Water Injection
428.1.2	General Electric Co.	5251	360	85	1.19E-01	3	0	Water Injection

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
210.2	NR	NR	75	100	1.32E-01	3	0	None
210.3	NR	NR	75	100	1.25E-01	3	0	None
210.4	NR	NR	75	100	1.32E-01	3	0	None
243.5	NR	NR	9	75	9.23E-03	3	0	Water Injection and outlet of selective catalytic
212	NR	NR	27.3	100	1.01E-01	3	0	None
214.1	NR	NR	75	100	1.39E-01	3	0	Water injection for NOx
214.2	NR	NR	75	100	1.27E-01	3	0	Water injection for NOx
214.4	NR	NR	75	100	1.28E-01	3	0	Water injection for NOx
214.3	NR	NR	75	100	1.48E-01	3	0	Water injection for NOx

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
210.1	NR	NR	75	100	1.25E-01	3	0	None
243.2	NR	NR	9	75	1.19E-01	3	0	Water Injection and inlet of selective catalytic
243.4	NR	NR	9	100	1.50E-02	3	0	Water Injection and outlet of selective catalytic
243.3	NR	NR	9	50	9.85E-02	3	0	Water Injection and inlet of selective catalytic
243.1	NR	NR	9	100	1.62E-01	3	0	Water Injection and inlet of selective catalytic
243.6	NR	NR	9	50	8.34E-03	3	0	Water Injection and outlet of selective catalytic
441	Pratt & Whitney	FT-4A-7	266	73.5	1.75E-01	3	0	Steam Injection
446.1	Pratt & Whitney	FT4C-1-D	411	80	1.00E-01	3	0	Water Injection
425	Pratt & Whitney	FT4C-1-D	411	78.4	1.20E-01	3	0	Water Injection

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
446.2	Pratt & Whitney	FT4C-1-D	411	79.2	1.13E-01	3	0	Water Injection
219	Rolls Royce	1533-76G	9.32	100	2.02E-01	3	0	None
316.1.2	Rolls Royce	Avon	10.7	25	1.24E-01	3	0	None
316.1.1	Rolls Royce	Avon	10.7	100	2.36E-01	3	0	None
316.2.2	Rolls Royce	Spey	12.2	25	1.97E-01	3	0	None
316.2.1	Rolls Royce	Spey	12.2	100	5.75E-01	3	0	None
244.3	Solar	Centaur	2.57	93	5.30E-01	3	0	None
244.9	Solar	Centaur	2.61	106	6.80E-01	3	0	None
244.5	Solar	Centaur	2.61	94	7.42E-01	3	0	None

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
244.4	Solar	Centaur	2.61	97	7.09E-01	3	0	None
244.10	Solar	Centaur T-	3.09	91	4.23E-01	3	0	None
231	Solar	GCI-SB-K	.8	100	1.90E-01	3	0	None
317.1	Solar	Mars	10.9	100	6.06E-01	3	0	None
317.2	Solar	Mars	10.9	25	1.91E-01	3	0	None
314.3	Solar	Mars SoL	10.9	50	1.48E-01	3	0	Lean pre-mix (SoLoNOx)
314.2	Solar	Mars SoL	10.9	75	8.75E-02	3	0	Lean pre-mix (SoLoNOx)
314.1	Solar	Mars SoL	10.9	100	9.91E-02	3	0	Lean pre-mix (SoLoNOx)
314.4	Solar	Mars SoL	10.9	35	1.10E-01	3	0	Lean pre-mix (SoLoNOx)

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
244.8	Solar	Saturn	.75	92	1.96E-01	3	0	None
313.2.3	Solar	T12000	9.4	50	2.18E-01	3	0	None
203.7	Solar	T12000	NR	25	4.49E-01	1	0	None
313.2.2	Solar	T12000	9.4	25	1.24E-01	3	0	None
313.2.1	Solar	T12000	9.4	100	5.17E-01	3	0	None
203.1	Solar	T12000	9.40	75	7.53E-02	3	0	None
203.2	Solar	T12000	NR	100	1.11E-01	3	0	None
203.3	Solar	T12000	9.40	25	1.18E-01	3	0	None
313.2.4	Solar	T12000	9.4	75	3.92E-01	3	0	None

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
203.6	Solar	T12000	NR	50	6.48E-01	1	0	None
203.5	Solar	T12000	NR	75	5.35E-01	1	0	None
206.4	Solar	T14000	NR	25	3.66E-02	3	0	None
206.3	Solar	T14000	NR	50	3.58E-02	3	0	None
206.2	Solar	T14000	NR	100	6.01E-02	3	0	None
206.1	Solar	T14000	NR	75	4.31E-02	3	0	None
205	Solar	T14000	NR	100	5.97E-01	3	0	None
204.1	Solar	T14000	NR	75	6.98E-02	3	0	None
204.2	Solar	T14000	NR	100	7.54E-02	3	0	None

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
204.3	Solar	T14000	NR	40	9.88E-02	3	0	None
204.4	Solar	T14000	NR	50	5.70E-02	3	0	None
202.2	Solar Centaur	CDI-CB-C	2.86	100	4.39E-01	3	0	None
202.1	Solar Centaur	CDI-CB-C	2.86	88	4.57E-01	3	0	None
232.7	Solar Centaur	HT 5500	4.10	85	1.80E-01	3	0	None
232.3	Solar Centaur	HT 5500	4.10	95	2.73E-01	3	0	None
232.2	Solar Centaur	HT 5500	4.10	90	2.20E-01	3	0	None
232.1	Solar Centaur	HT 5500	4.10	85	1.83E-01	3	0	None
232.6	Solar Centaur	HT 5500	4.10	90	2.16E-01	3	0	None

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
232.5	Solar Centaur	HT 5500	4.10	95.1	9.68E-01	3	0	None
232.4	Solar Centaur	HT 5500	4.10	95.7	2.65E-01	3	0	None
209.1	Solar Centaur	T5500	NR	95	2.22E-01	3	0	None
209.2	Solar Centaur	T5500	NR	85	1.62E-01	3	0	None
209.3	Solar Centaur	T5500	NR	95	2.37E-01	3	0	None
209.4	Solar Centaur	T5500	NR	85	1.55E-01	3	0	None
211	Solar Mars	NR	10.89	100	6.20E-01	3	0	None
234	Solar Mars	NR	10.14	100	5.16E-01	3	0	None
203.4	Solar Mars	T12000	NR	100	6.13E-01	1	0	None

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
207.4	Solar Taurus	T7000	NR	85	1.91E-01	3	0	None
207.1	Solar Taurus	T7000	NR	97	3.27E-01	3	0	None
207.2	Solar Taurus	T7000	NR	95	3.31E-01	3	0	None
207.3	Solar Taurus	T7000	NR	90	2.78E-01	3	0	None
228.1	United Technologies	FT4C-1(D	50	100	1.46E-01	3	0	Water Injection for NOx
228.2	United Technologies	FT4C-1(D	50	100	1.48E-01	3	0	Water Injection for NOx
228.10	United Technologies	FT4C-1(D	50	100	1.70E-01	3	0	Water Injection for NOx
228.11	United Technologies	FT4C-1(D	50	100	1.61E-01	3	0	Water Injection for NOx

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
				Avg EF =	2.01E-01			
				Count =	168			
				Std Dev =	1.80E-01			
				RSD(%) =	89.2%			

ID	Pollutant	Run 1 Cc	Run 2 Cc	Run 3 Conc C	lbh1	lbh2	lbh3	lbhAvg
202.	NOx	78900	55100	85600	21.2	13.2	20.8	18.4
202.	NOx	67300	76800	76300	16.1	20.1	19.8	18.7
203.	NOx	18900	19600	19800	7.73	7.75	7.64	7.71
203.	NOx	28400	28900	28500	11.6	11.4	11	11.3
203.	NOx	27300	26700	26700	9.45	9.25	9.09	9.26
203.	NOx	150000	NR	NR	61.7	NR	NR	61.7
203.	NOx	131000	NR	NR	50.6	NR	NR	50.6
203.	NOx	150000	NR	NR	56.6	NR	NR	56.6
203.	NOx	98000	NR	NR	33.7	NR	NR	33.7
204.	NOx	17200	17200	16600	6.78	6.68	6.31	6.59
204.	NOx	19700	19300	19000	8.35	8.21	7.87	8.14
204.	NOx	21800	22800	21700	6.48	6.51	6.4	6.46
204.	NOx	13700	14200	14200	4.97	5.11	5.1	5.06
205	NOx	150680	152470	149050	64.9	63.1	65.5	64.5
206.	NOx	10500	10900	11100	4.09	4.33	4.3	4.24
206.	NOx	16900	15500	14200	7	6.14	5.8	6.31
206.	NOx	8700	8600	8600	3.23	3.16	3.16	3.18
206.	NOx	8500	8500	8500	2.79	2.77	2.78	2.78
207.	NOx	75400	75600	76300	17.8	17.9	18	17.9
207.	NOx	73900	73500	73500	16.5	16.4	16.4	16.4
207.	NOx	55100	55400	55600	11.5	11.5	11.6	11.5
207.	NOx	30100	33100	30800	5.12	5.63	5.24	5.33
208	NOx	145500	142600	145600	142	139	142	141
209.	NOx	53500	53100	51800	9.95	9.87	9.63	9.82
209.	NOx	24000	24600	25100	3.31	3.4	3.47	3.39
209.	NOx	53600	53800	54700	10.8	10.8	11	10.9
209.	NOx	25600	25200	25300	3.57	3.51	3.53	3.54
210.	NOx	34990	36200	35920	NR	NR	NR	NR
210.	NOx	36510	37420	37730	NR	NR	NR	NR
210.	NOx	34280	37000	36830	NR	NR	NR	NR
210.	NOx	38010	37700	38200	NR	NR	NR	NR
211	NOx	162000	161600	162900	9.95	9.93	NR	9.94
212	NOx	20400	20800	22100	28.1	29.4	31.2	29.6
214.	NOx	38260	40290	41430	124	128	136	129
214.	NOx	38130	36920	36420	117	116	115	116
214.	NOx	41250	43600	43190	119	127	125	124
214.	NOx	37960	36340	36450	123	118	115	119
216.	NOx	2210	3580	3620	3.44	5.6	5.63	4.89
216.	NOx	3660	3950	3780	5.67	6.16	5.83	5.89
216.	NOx	4100	4330	4300	6.33	6.6	6.55	6.49
216.	NOx	4120	NR	NR	6.36	NR	NR	6.36
219	NOx	36200	36300	36200	31.7	31.8	31.3	31.6
221.	NOx	46500	49000	46300	128	135	121	128
221.	NOx	46800	46600	48900	120	121	124	122
221.	NOx	49800	52600	50400	125	122	118	122
221.	NOx	48300	46100	45400	127	121	120	123
226.	NOx	20410	18910	19730	4.14	3.9	4.09	4.04
226.	NOx	18960	18100	18040	3.88	3.76	3.74	3.79

ID	Pollutant	lbMMBtu1	lbMMBtu2	lbMMBtu3	lbMMBtuAvg	lbMW1
202.	NOx	.44	.428	.503	.457	8.42
202.	NOx	.443	.439	.436	.439	5.63
203.	NOx	.0744	.0756	.076	.0753	1.1
203.	NOx	.112	.112	.109	.111	NR
203.	NOx	.12	.118	.117	.118	4.02
203.	NOx	.613	NR	NR	.613	NR
203.	NOx	.535	NR	NR	.535	NR
203.	NOx	.648	NR	NR	.648	NR
203.	NOx	.449	NR	NR	.449	NR
204.	NOx	.0746	.0685	.0663	.0698	NR
204.	NOx	.0769	.0753	.0741	.0754	NR
204.	NOx	.0983	.0994	.0986	.0988	NR
204.	NOx	.0557	.0576	.0577	.057	NR
205	NOx	.594	.584	.612	.597	NR
206.	NOx	.0415	.044	.0437	.0431	NR
206.	NOx	.0655	.0585	.0563	.0601	NR
206.	NOx	.0363	.0355	.0355	.0358	NR
206.	NOx	.0368	.0366	.0364	.0366	NR
207.	NOx	.332	.319	.329	.327	NR
207.	NOx	.332	.33	.33	.331	NR
207.	NOx	.276	.278	.279	.278	NR
207.	NOx	.185	.198	.19	.191	NR
208	NOx	.589	.578	.59	.586	NR
209.	NOx	.227	.225	.215	.222	NR
209.	NOx	.155	.164	.167	.162	NR
209.	NOx	.237	.238	.237	.237	NR
209.	NOx	.156	.154	.155	.155	NR
210.	NOx	.121	.128	.127	.125	NR
210.	NOx	.128	.133	.135	.132	NR
210.	NOx	.119	.129	.127	.125	NR
210.	NOx	.133	.132	.132	.132	NR
211	NOx	.617	.618	.626	.62	.914
212	NOx	.0982	.1	.106	.101	1.03
214.	NOx	.133	.138	.146	.139	1.65
214.	NOx	.13	.126	.124	.127	1.56
214.	NOx	.141	.152	.15	.148	1.59
214.	NOx	.133	.127	.124	.128	1.64
216.	NOx	.00731	.012	.0121	.0105	.0806
216.	NOx	.0122	.0133	.0126	.0127	.133
216.	NOx	.0138	.0145	.0144	.0142	.148
216.	NOx	.0139	NR	NR	.0139	.149
219	NOx	.203	.203	.201	.202	3.4
221.	NOx	.159	.171	.156	.162	1.71
221.	NOx	.153	.157	.162	.157	1.6
221.	NOx	.179	.175	.17	.175	1.67
221.	NOx	.166	.156	.153	.158	1.69
226.	NOx	.0901	.0833	.0868	.0867	1.38
226.	NOx	.0788	.0824	.0782	.0798	1.29

ID	Pollutant	lbMW2	lbMW3	lbMWAvg	Facility Name
202.	NOx	5.24	8.26	7.31	Algonquin Gas Transmission Com
202.	NOx	7.03	6.92	6.53	Algonquin Gas Transmission Com
203.	NOx	1.1	1.08	1.09	Pacific Gas Transmission Compan
203.	NOx	NR	NR	NR	Pacific Gas Transmission Compan
203.	NOx	3.94	3.87	3.94	Pacific Gas Transmission Compan
203.	NOx	NR	NR	NR	Pacific Gas Transmission Compan
203.	NOx	NR	NR	NR	Pacific Gas Transmission Compan
203.	NOx	NR	NR	NR	Pacific Gas Transmission Compan
203.	NOx	NR	NR	NR	Pacific Gas Transmission Compan
204.	NOx	NR	NR	NR	SoLoNOx Combustor Unit A - PGT
204.	NOx	NR	NR	NR	SoLoNOx Combustor Unit A - PGT
204.	NOx	NR	NR	NR	SoLoNOx Combustor Unit A - PGT
204.	NOx	NR	NR	NR	SoLoNOx Combustor Unit A - PGT
205	NOx	NR	NR	NR	PGT Compressor Station 6
206.	NOx	NR	NR	NR	PGT Compressor Station 6
206.	NOx	NR	NR	NR	PGT Compressor Station 6
206.	NOx	NR	NR	NR	PGT Compressor Station 6
206.	NOx	NR	NR	NR	PGT Compressor Station 6
207.	NOx	NR	NR	NR	Northwest Pipeline Corporation - R
207.	NOx	NR	NR	NR	Northwest Pipeline Corporation - R
207.	NOx	NR	NR	NR	Northwest Pipeline Corporation - R
207.	NOx	NR	NR	NR	Northwest Pipeline Corporation - R
208	NOx	NR	NR	NR	PGT Compressor Station 7 - Unit
209.	NOx	NR	NR	NR	Northwest Pipeline Corporation -
209.	NOx	NR	NR	NR	Northwest Pipeline Corporation -
209.	NOx	NR	NR	NR	Northwest Pipeline Corporation -
209.	NOx	NR	NR	NR	Northwest Pipeline Corporation -
210.	NOx	NR	NR	NR	Kern River Cogeneration Company
210.	NOx	NR	NR	NR	Kern River Cogeneration Company
210.	NOx	NR	NR	NR	Kern River Cogeneration Company
210.	NOx	NR	NR	NR	Kern River Cogeneration Company
211	NOx	.912	NR	.913	Pacific Gas Transmission Compan
212	NOx	1.08	1.14	1.08	Agrico Cogeneration Corporation
214.	NOx	1.71	1.81	1.72	Sycamore Cogeneration Company
214.	NOx	1.55	1.53	1.55	Sycamore Cogeneration Company
214.	NOx	1.69	1.67	1.65	Sycamore Cogeneration Company
214.	NOx	1.57	1.53	1.58	Sycamore Cogeneration Company
216.	NOx	.131	.132	.115	Coalinga Cogeneration Company -
216.	NOx	.144	.137	.138	Coalinga Cogeneration Company -
216.	NOx	.155	.153	.152	Coalinga Cogeneration Company -
216.	NOx	NR	NR	.149	Coalinga Cogeneration Company -
219	NOx	3.41	3.36	3.39	Columbia Gulf Transmission Comp
221.	NOx	1.8	1.61	1.71	Sycamore Cogeneration Company
221.	NOx	1.61	1.65	1.62	Sycamore Cogeneration Company
221.	NOx	1.63	1.57	1.62	Sycamore Cogeneration Company
221.	NOx	1.61	1.6	1.63	Sycamore Cogeneration Company
226.	NOx	1.3	1.36	1.35	South Vandenberg Power Plant
226.	NOx	1.25	1.25	1.26	South Vandenberg Power Plant

ID	Pollutant	Method	Location	Facility	Testing Compa	Date
202.	NOx	EPA 20	Hanover, NJ	Algonquin Gas	TRC Environm	11/13/90
202.	NOx	EPA 20	Hanover, NJ	Algonquin Gas	TRC Environm	11/13/90
203.	NOx	EPA 7E	Rosalia, WA	Pacific Gas Tra	CARNOT	9/21/95
203.	NOx	EPA 7E	Rosalia, WA	Pacific Gas Tra	CARNOT	9/21/95
203.	NOx	EPA 7E	Rosalia, WA	Pacific Gas Tra	CARNOT	9/21/95
203.	NOx	EPA 7E	Rosalia, WA	Pacific Gas Tra	CARNOT	11/14/94
203.	NOx	EPA 7E	Rosalia, WA	Pacific Gas Tra	CARNOT	11/14/94
203.	NOx	EPA 7E	Rosalia, WA	Pacific Gas Tra	CARNOT	11/14/94
203.	NOx	EPA 7E	Rosalia, WA	Pacific Gas Tra	CARNOT	11/14/94
204.	NOx	EPA 7E	Rosalia, WA	SoLoNOx Com	CARNOT	9/23/94
204.	NOx	EPA 7E	Rosalia, WA	SoLoNOx Com	CARNOT	9/23/94
204.	NOx	EPA 7E	Rosalia, WA	SoLoNOx Com	CARNOT	9/23/94
204.	NOx	EPA 7E	Rosalia, WA	SoLoNOx Com	CARNOT	9/23/94
205	NOx	EPA 20	Rosalia, Washi	PGT Compress	CARNOT	2/ 8/91
206.	NOx	EPA 7E/20	Rosalia, WA	PGT Compress	CARNOT	3/30/95
206.	NOx	EPA 7E/20	Rosalia, WA	PGT Compress	CARNOT	3/30/95
206.	NOx	EPA 7E/20	Rosalia, WA	PGT Compress	CARNOT	3/30/95
206.	NOx	EPA 7E/20	Rosalia, WA	PGT Compress	CARNOT	3/30/95
207.	NOx	EPA 20	Rossevelt, Klic	Northwest Pipel	AMTEST Air Q	8/18/93
207.	NOx	EPA 20	Rossevelt, Klic	Northwest Pipel	AMTEST Air Q	8/18/93
207.	NOx	EPA 20	Rossevelt, Klic	Northwest Pipel	AMTEST Air Q	8/18/93
207.	NOx	EPA 20	Rossevelt, Klic	Northwest Pipel	AMTEST Air Q	8/18/93
208	NOx	EPA 7E	Starbuck, WA	PGT Compress	CARNOT	6/ 3/93
209.	NOx	EPA 20	Willard, WA	Northwest Pipel	Am Test-Air Qu	9/27/94
209.	NOx	EPA 20	Willard, WA	Northwest Pipel	Am Test-Air Qu	9/27/94
209.	NOx	EPA 20	Willard, WA	Northwest Pipel	Am Test-Air Qu	9/27/94
209.	NOx	EPA 20	Willard, WA	Northwest Pipel	Am Test-Air Qu	9/27/94
210.	NOx	CARB 100	P.O. Box 8047	Kern River Cog	Engineering - S	3/ 9/93
210.	NOx	CARB 100	P.O. Box 8047	Kern River Cog	Engineering - S	3/ 9/93
210.	NOx	CARB 100	P.O. Box 8047	Kern River Cog	Engineering - S	3/ 9/93
210.	NOx	CARB 100	P.O. Box 8047	Kern River Cog	Engineering - S	3/ 9/93
211	NOx	EPA 20	Rosalia, WA	Pacific Gas Tra	CARNOT	12/ 1/90
212	NOx	CARB 1-100	San Joaquin, C	Agrico Cogener	Genesis Enviro	6/12/91
214.	NOx	CARB 100	P.O. Box 8059	Sycamore Cog	Engineering Sci	2/11/93
214.	NOx	CARB 100	P.O. Box 8059	Sycamore Cog	Engineering Sci	2/11/93
214.	NOx	CARB 100	P.O. Box 8059	Sycamore Cog	Engineering Sci	2/11/93
214.	NOx	CARB 100	P.O. Box 8059	Sycamore Cog	Engineering Sci	2/11/93
216.	NOx	CARB 100	P.O. Box 8107	Coalinga Coge	Engineering Sci	3/ 4/93
216.	NOx	CARB 100	P.O. Box 8107	Coalinga Coge	Engineering Sci	3/ 4/93
216.	NOx	CARB 100	P.O. Box 8107	Coalinga Coge	Engineering Sci	3/ 4/93
216.	NOx	CARB 100	P.O. Box 8107	Coalinga Coge	Engineering Sci	3/ 4/93
219	NOx	EPA 20	Rayne, LA	Columbia Gulf	Entropy Enviro	3/18/92
221.	NOx	CARB 100	Bakersfield, CA	Sycamore Cog	Engineering Sci	1/22/91
221.	NOx	CARB 100	Bakersfield, CA	Sycamore Cog	Engineering Sci	1/22/91
221.	NOx	CARB 100	Bakersfield, CA	Sycamore Cog	Engineering Sci	1/22/91
221.	NOx	CARB 100	Bakersfield, CA	Sycamore Cog	Engineering Sci	1/22/91
226.	NOx	EPA 20	Vandenberg Air	South Vandenb	Petro Chem En	5/11/93
226.	NOx	EPA 20	Vandenberg Air	South Vandenb	Petro Chem En	5/11/93

ID	Pollutant	Rating	Unit	Load	Manufacturer	Model
202.	NOx	2.86	MW	88	Solar Centaur	CDI-CB-C307
202.	NOx	2.86	MW	100	Solar Centaur	CDI-CB-C307
203.	NOx	9.40	MW	75	Solar	T12000
203.	NOx	NR	NR	100	Solar	T12000
203.	NOx	9.40	MW	25	Solar	T12000
203.	NOx	NR	NR	100	Solar Mars	T12000
203.	NOx	NR	NR	75	Solar	T12000
203.	NOx	NR	NR	50	Solar	T12000
203.	NOx	NR	NR	25	Solar	T12000
204.	NOx	NR	NR	75	Solar	T14000
204.	NOx	NR	NR	100	Solar	T14000
204.	NOx	NR	NR	40	Solar	T14000
204.	NOx	NR	NR	50	Solar	T14000
205	NOx	NR	NR	100	Solar	T14000
206.	NOx	NR	NR	75	Solar	T14000
206.	NOx	NR	NR	100	Solar	T14000
206.	NOx	NR	NR	50	Solar	T14000
206.	NOx	NR	NR	25	Solar	T14000
207.	NOx	NR	NR	97	Solar Taurus	T7000
207.	NOx	NR	NR	95	Solar Taurus	T7000
207.	NOx	NR	NR	90	Solar Taurus	T7000
207.	NOx	NR	NR	85	Solar Taurus	T7000
208	NOx	NR	NR	100	Cooper Rolls	RB211
209.	NOx	NR	NR	95	Solar Centaur	T5500
209.	NOx	NR	NR	85	Solar Centaur	T5500
209.	NOx	NR	NR	95	Solar Centaur	T5500
209.	NOx	NR	NR	85	Solar Centaur	T5500
210.	NOx	75	MW	100	NR	NR
210.	NOx	75	MW	100	NR	NR
210.	NOx	75	MW	100	NR	NR
210.	NOx	75	MW	100	NR	NR
211	NOx	10.89	MW	100	Solar Mars	NR
212	NOx	27.3	MW	100	NR	NR
214.	NOx	75	MW	100	NR	NR
214.	NOx	75	MW	100	NR	NR
214.	NOx	75	MW	100	NR	NR
214.	NOx	75	MW	100	NR	NR
216.	NOx	42.7	MW	100	General Electri	NR
216.	NOx	42.7	MW	100	General Electri	NR
216.	NOx	42.7	MW	100	General Electri	NR
216.	NOx	42.7	MW	100	General Electri	NR
219	NOx	9.32	MW	100	Rolls Royce	1533-76G
221.	NOx	75	MW	100	General Electri	G7111E
221.	NOx	75	MW	100	General Electri	G7111E
221.	NOx	75	MW	100	General Electri	G7111E
221.	NOx	75	MW	100	General Electri	G7111E
226.	NOx	3	MW	100	Allison	501-KB
226.	NOx	3	MW	100	Allison	501-KB

ID	Pollutant	Turbine	Fuel Type	Application	Run 1 Conc R	Run 2 Conc R
202.	NOx	Solar Centaur/	Natural Gas	NR	78900	55100
202.	NOx	Solar Centaur/	Natural Gas	NR	67300	76800
203.	NOx	Solar/T12000/9	Natural Gas	NR	18900	19600
203.	NOx	Solar/T12000/N	Natural Gas	NR	28400	28900
203.	NOx	Solar/T12000/9	Natural Gas	NR	27300	26700
203.	NOx	Solar Mars/T12	Natural Gas	NR	150000	NR
203.	NOx	Solar/T12000/N	Natural Gas	NR	131000	NR
203.	NOx	Solar/T12000/N	Natural Gas	NR	150000	NR
203.	NOx	Solar/T12000/N	Natural Gas	NR	98000	NR
204.	NOx	Solar/T14000/N	Natural Gas	NR	17200	17200
204.	NOx	Solar/T14000/N	Natural Gas	NR	19700	19300
204.	NOx	Solar/T14000/N	Natural Gas	NR	21800	22800
204.	NOx	Solar/T14000/N	Natural Gas	NR	13700	14200
205	NOx	Solar/T14000/N	Natural Gas	NR	150680	152470
206.	NOx	Solar/T14000/N	Natural Gas	NR	10500	10900
206.	NOx	Solar/T14000/N	Natural Gas	NR	16900	15500
206.	NOx	Solar/T14000/N	Natural Gas	NR	8700	8600
206.	NOx	Solar/T14000/N	Natural Gas	NR	8500	8500
207.	NOx	Solar Taurus/T	Natural Gas	Runs Gas Com	75400	75600
207.	NOx	Solar Taurus/T	Natural Gas	Runs Gas Com	73900	73500
207.	NOx	Solar Taurus/T	Natural Gas	Runs Gas Com	55100	55400
207.	NOx	Solar Taurus/T	Natural Gas	Runs Gas Com	30100	33100
208	NOx	Cooper Rolls/R	Natural Gas	NR	145500	142600
209.	NOx	Solar Centaur/	Natural Gas	NR	53500	53100
209.	NOx	Solar Centaur/	Natural Gas	NR	24000	24600
209.	NOx	Solar Centaur/	Natural Gas	NR	53600	53800
209.	NOx	Solar Centaur/	Natural Gas	NR	25600	25200
210.	NOx	NR/NR/75 MW	Natural Gas	NR	34990	36200
210.	NOx	NR/NR/75 MW	Natural Gas	NR	36510	37420
210.	NOx	NR/NR/75 MW	Natural Gas	NR	34280	37000
210.	NOx	NR/NR/75 MW	Natural Gas	NR	38010	37700
211	NOx	Solar Mars/NR/	Natural Gas	NR	162000	161600
212	NOx	NR/NR/27.3 M	Natural Gas	NR	20400	20800
214.	NOx	NR/NR/75 MW	Natural Gas	NR	38260	40290
214.	NOx	NR/NR/75 MW	Natural Gas	NR	38130	36920
214.	NOx	NR/NR/75 MW	Natural Gas	NR	41250	43600
214.	NOx	NR/NR/75 MW	Natural Gas	NR	37960	36340
216.	NOx	General Electri	Natural Gas	NR	2210	3580
216.	NOx	General Electri	Natural Gas	NR	3660	3950
216.	NOx	General Electri	Natural Gas	NR	4100	4330
216.	NOx	General Electri	Natural Gas	NR	4120	NR
219	NOx	Rolls Royce/15	Natural Gas	NR	36200	36300
221.	NOx	General Electri	Natural Gas	NR	46500	49000
221.	NOx	General Electri	Natural Gas	NR	46800	46600
221.	NOx	General Electri	Natural Gas	NR	49800	52600
221.	NOx	General Electri	Natural Gas	NR	48300	46100
226.	NOx	Allison/501-KB/	Natural Gas	NR	20410	18910
226.	NOx	Allison/501-KB/	Natural Gas	NR	18960	18100

ID	Pollutant	Run 3 Conc R	Average	Conc R Averag	DL	SD
202.	NOx	85600	73200	73200	NA	3
202.	NOx	76300	73466.6666666	73500	NA	3
203.	NOx	19800	19433.3333333	19400	NA	3
203.	NOx	28500	28600	28600	NA	3
203.	NOx	26700	26900	26900	NA	3
203.	NOx	NR	150000	150000	NA	3
203.	NOx	NR	131000	131000	NA	3
203.	NOx	NR	150000	150000	NA	3
203.	NOx	NR	98000	98000	NA	3
204.	NOx	16600	17000	17000	NA	3
204.	NOx	19000	19333.3333333	19300	NA	3
204.	NOx	21700	22100	22100	NA	3
204.	NOx	14200	14033.3333333	14000	NA	3
205	NOx	149050	150733.333333	151000	NA	3
206.	NOx	11100	10833.3333333	10800	NA	3
206.	NOx	14200	15533.3333333	15500	NA	3
206.	NOx	8600	8633.33333333	8630	NA	3
206.	NOx	8500	8500	8500	NA	3
207.	NOx	76300	75766.6666666	75800	NA	3
207.	NOx	73500	73633.3333333	73600	NA	3
207.	NOx	55600	55366.6666666	55400	NA	3
207.	NOx	30800	31333.3333333	31300	NA	3
208	NOx	145600	144566.666666	145000	NA	3
209.	NOx	51800	52800	52800	NA	3
209.	NOx	25100	24566.6666666	24600	NA	3
209.	NOx	54700	54033.3333333	54000	NA	3
209.	NOx	25300	25366.6666666	25400	NA	3
210.	NOx	35920	35703.3333333	35700	NA	3
210.	NOx	37730	37220	37200	NA	3
210.	NOx	36830	36036.6666666	36000	NA	3
210.	NOx	38200	37970	38000	NA	3
211	NOx	162900	162166.666666	162000	NA	3
212	NOx	22100	21100	21100	NA	3
214.	NOx	41430	39993.3333333	40000	NA	3
214.	NOx	36420	37156.6666666	37200	NA	3
214.	NOx	43190	42680	42700	NA	3
214.	NOx	36450	36916.6666666	36900	NA	3
216.	NOx	3620	3136.66666666	3140	NA	3
216.	NOx	3780	3796.66666666	3800	NA	3
216.	NOx	4300	4243.33333333	4240	NA	3
216.	NOx	NR	4120	4120	NA	3
219	NOx	36200	36233.3333333	36200	NA	3
221.	NOx	46300	47266.6666666	47300	NA	3
221.	NOx	48900	47433.3333333	47400	NA	3
221.	NOx	50400	50933.3333333	50900	NA	3
221.	NOx	45400	46600	46600	NA	3
226.	NOx	19730	19683.3333333	19700	NA	3
226.	NOx	18040	18366.6666666	18400	NA	3

ID	Pollutant	CountAConc	Countlbh	CountlbMMBtu	CountlbMW	CUnit
202.	NOx	1	1	1	1	ppb
202.	NOx	1	1	1	1	ppb
203.	NOx	1	1	1	1	ppb
203.	NOx	1	1	1	0	ppb
203.	NOx	1	1	1	1	ppb
203.	NOx	1	1	1	0	ppb
203.	NOx	1	1	1	0	ppb
203.	NOx	1	1	1	0	ppb
203.	NOx	1	1	1	0	ppb
204.	NOx	1	1	1	0	ppb
204.	NOx	1	1	1	0	ppb
204.	NOx	1	1	1	0	ppb
204.	NOx	1	1	1	0	ppb
205	NOx	1	1	1	0	ppb
206.	NOx	1	1	1	0	ppb
206.	NOx	1	1	1	0	ppb
206.	NOx	1	1	1	0	ppb
206.	NOx	1	1	1	0	ppb
207.	NOx	1	1	1	0	ppb
207.	NOx	1	1	1	0	ppb
207.	NOx	1	1	1	0	ppb
207.	NOx	1	1	1	0	ppb
208	NOx	1	1	1	0	ppb
209.	NOx	1	1	1	0	ppb
209.	NOx	1	1	1	0	ppb
209.	NOx	1	1	1	0	ppb
209.	NOx	1	1	1	0	ppb
210.	NOx	1	0	1	0	ppb
210.	NOx	1	0	1	0	ppb
210.	NOx	1	0	1	0	ppb
210.	NOx	1	0	1	0	ppb
211	NOx	1	1	1	1	ppb
212	NOx	1	1	1	1	ppb
214.	NOx	1	1	1	1	ppb
214.	NOx	1	1	1	1	ppb
214.	NOx	1	1	1	1	ppb
214.	NOx	1	1	1	1	ppb
216.	NOx	1	1	1	1	ppb
216.	NOx	1	1	1	1	ppb
216.	NOx	1	1	1	1	ppb
216.	NOx	1	1	1	1	ppb
219	NOx	1	1	1	1	ppb
221.	NOx	1	1	1	1	ppb
221.	NOx	1	1	1	1	ppb
221.	NOx	1	1	1	1	ppb
221.	NOx	1	1	1	1	ppb
226.	NOx	1	1	1	1	ppb
226.	NOx	1	1	1	1	ppb

ID	Pollutant	Control Device	Source EF
202.	NOx	None	#Error
202.	NOx	None	#Error
203.	NOx	None	#Error
203.	NOx	None	#Error
203.	NOx	None	#Error
203.	NOx	None	#Error
203.	NOx	None	#Error
203.	NOx	None	#Error
203.	NOx	None	#Error
204.	NOx	None	#Error
204.	NOx	None	#Error
204.	NOx	None	#Error
204.	NOx	None	#Error
205	NOx	None	#Error
206.	NOx	None	#Error
206.	NOx	None	#Error
206.	NOx	None	#Error
206.	NOx	None	#Error
207.	NOx	None	#Error
207.	NOx	None	#Error
207.	NOx	None	#Error
207.	NOx	None	#Error
208	NOx	None	#Error
209.	NOx	None	#Error
209.	NOx	None	#Error
209.	NOx	None	#Error
209.	NOx	None	#Error
210.	NOx	None	#Error
210.	NOx	None	#Error
210.	NOx	None	#Error
210.	NOx	None	#Error
211	NOx	None	#Error
212	NOx	None	#Error
214.	NOx	Water injection	#Error
214.	NOx	Water injection	#Error
214.	NOx	Water injection	#Error
214.	NOx	Water injection	#Error
216.	NOx	Ammonia Inject	#Error
216.	NOx	Ammonia Inject	#Error
216.	NOx	Ammonia Inject	#Error
216.	NOx	Ammonia Inject	#Error
219	NOx	None	#Error
221.	NOx	Water injection	#Error
221.	NOx	Water injection	#Error
221.	NOx	Water injection	#Error
221.	NOx	Water injection	#Error
226.	NOx	None	#Error
226.	NOx	None	#Error

ID	Pollutant	Comm
202.	NOx	
202.	NOx	
203.	NOx	
203.	NOx	
203.	NOx	
203.	NOx	
203.	NOx	
203.	NOx	
203.	NOx	
204.	NOx	Runs 4,5,6.Fuel factor, exhaust gas flowrate are O2 based.Heating value calculat
204.	NOx	Runs 1,2,3.Fuel factor, exhaust gas flowrate are O2 based.Heating value calculat
204.	NOx	Runs 10,11,12.Fuel factor, exhaust gas flowrate are O2 based.Heating value calc
204.	NOx	Runs 7,8,9.Fuel factor, exhaust gas flowrate are O2 based.Heating value calculat
205	NOx	Fuel factor given in scf (not dry) and O2 based. Exhaust gas flowrate calculated u
206.	NOx	Runs 4,5,6. Fuel factor is in scf (not dry) and O2 based at 68 F. Exhaust Gas flo
206.	NOx	Runs 1,2,3. Fuel factor is in scf (not dry) and O2 based at 68 F. Exhaust Gas flo
206.	NOx	Runs 7,8,9. Fuel factor is in scf (not dry) and O2 based at 68 F. Exhaust Gas flo
206.	NOx	Runs 10,11,12. Fuel factor is in scf (not dry) and O2 based at 68 F. Exhaust Gas
207.	NOx	Turbine #1
207.	NOx	Turbine #3
207.	NOx	Turbine #2
207.	NOx	Turbine #1
208	NOx	Fuel factor is O2 based at 68 F. Exhaust Gas flowrate calculated from O2 flow.
209.	NOx	Turbine 2
209.	NOx	Turbine 1
209.	NOx	Turbine 1
209.	NOx	Turbine 2
210.	NOx	Turbine A. Continuous emission monitoring.No ambient or stack conditions provi
210.	NOx	Turbine B
210.	NOx	Turbine C
210.	NOx	Turbine D. Raw data for D not included in report
211	NOx	Fuel factor at 60 F. Dry sample
212	NOx	Fuel factor and Heating value of Fuel given at 60 F
214.	NOx	
214.	NOx	
214.	NOx	
214.	NOx	
216.	NOx	Runs 1,2,3
216.	NOx	Runs 4,5,6
216.	NOx	Runs 7,8.9
216.	NOx	Run 10
219	NOx	
221.	NOx	Turbine # 1
221.	NOx	Turbine # 2
221.	NOx	Turbine # 3
221.	NOx	Turbine # 4
226.	NOx	Unit A
226.	NOx	Unit B

ID	Pollutant	Run 1 O2	Run 2 O2	Run 3 O2	Test Rating
202.	NOx	17	18.1	17.2	0
202.	NOx	17.6	17.1	17.1	0
203.	NOx	15.38	15.27	15.24	0
203.	NOx	15.38	15.27	15.24	0
203.	NOx	15.95	15.98	15.95	0
203.	NOx	15.58	NR	NR	0
203.	NOx	15.58	NR	NR	0
203.	NOx	15.87	NR	NR	0
203.	NOx	16.16	NR	NR	0
204.	NOx	15.94	15.5	15.52	0
204.	NOx	15.39	15.39	15.39	0
204.	NOx	16.13	15.97	16.17	0
204.	NOx	15.61	15.6	15.61	0
205	NOx	15.52	15.36	15.73	0
206.	NOx	15.46	15.57	15.43	0
206.	NOx	15.35	15.20	15.47	0
206.	NOx	15.74	15.69	15.69	0
206.	NOx	15.93	15.9	15.88	0
207.	NOx	16	15.8	15.9	0
207.	NOx	16.1	16.1	16.1	0
207.	NOx	16.6	16.6	16.6	0
207.	NOx	17.4	17.3	17.4	0
208	NOx	15.6	15.6	15.6	0
209.	NOx	16	16	15.9	0
209.	NOx	17.6	17.7	17.7	0
209.	NOx	16	16	15.9	0
209.	NOx	17.5	17.5	17.5	0
210.	NOx	14.69	14.83	14.81	0
210.	NOx	14.78	14.85	14.87	0
210.	NOx	14.7	14.7	14.64	0
210.	NOx	14.75	14.77	14.69	0
211	NOx	15.28	15.3	15.33	0
212	NOx	16.43	16.43	16.43	0
214.	NOx	14.78	14.67	14.86	0
214.	NOx	14.68	14.66	14.67	0
214.	NOx	14.67	14.80	14.76	0
214.	NOx	14.84	14.82	14.65	0
216.	NOx	14.48	14.54	14.53	0
216.	NOx	14.52	14.59	14.53	0
216.	NOx	14.57	14.56	14.56	0
216.	NOx	14.61	NR	NR	0
219	NOx	17.07	17.06	17.02	0
221.	NOx	14.7	14.8	14.6	0
221.	NOx	14.4	14.6	14.5	0
221.	NOx	15	14.5	14.6	0
221.	NOx	14.7	14.6	14.6	0
226.	NOx	15.98	15.97	15.96	0
226.	NOx	15.67	16.13	15.89	0

ID	Pollutant	Comments	Standard Temp	Standard Temp
202.	NOx		68	F
202.	NOx		68	F
203.	NOx	Exhaust Stack Obtained through Sampling Ports.	68	F
203.	NOx	12 Runs. Runs 7,8,9. Sampling at Turbine exhaust	68	F
203.	NOx	12 Runs. Runs 1,2,3. Fuel flow rate not dry. Previo	68	F
203.	NOx	One run Only. Unit previously listed as T14000	68	F
203.	NOx	One run Only. Unit previously listed as T14000	68	F
203.	NOx	One run Only. Unit previously listed as T14000	68	F
203.	NOx	One run Only. Unit previously listed as T14000. Te	68	F
204.	NOx	Runs 4, 5 and 6. Turbine type : simple cycle, unco	68	F
204.	NOx	Runs1, 2 and 3. Turbine Type : Simple Cycle, unc	68	F
204.	NOx	Runs 10, 11 and 12. Turbine type : Simple Cycle, u	68	F
204.	NOx	Runs 7, 8 and 9. Turbine type : simple cycle, unco	68	F
205	NOx		68	F
206.	NOx	Runs 4,5,6 of 12.	68	F
206.	NOx	Runs 1,2,3 of 12	68	F
206.	NOx	Runs 7,8,9 of 12	68	F
206.	NOx	Runs 10,11,12 of 12	68	F
207.	NOx	Turbine 4.Simple Cycle. Molecular weight of gas b	68	F
207.	NOx	Turbine 3.Simple Cycle. Molecular weight of gas b	68	F
207.	NOx	Turbine 2.Simple Cycle. Molecular weight of gas b	68	F
207.	NOx	Turbine 1.Simple Cycle. Molecular weight of gas b	68	F
208	NOx	Simple Cycle	68	F
209.	NOx	Turbine 2	68	F
209.	NOx	Turbine 1	68	F
209.	NOx	Turbine 1	60	F
209.	NOx	Turbine 2	68	F
210.	NOx	Turbine A. Reported ppb are measured values at	68	F
210.	NOx	Turbine B. Model and Manufacturer missing	68	F
210.	NOx	Turbine C. Model and Manufacturer missing	68	F
210.	NOx	Turbine D. Raw data for this turbine not included in	68	F
211	NOx	Gas analysis performed by Truesail Laboratories.	60	F
212	NOx	Model and Manufacturer missing	60	F
214.	NOx	Unit 1	68	F
214.	NOx	Unit 2	68	F
214.	NOx	Unit 3	68	F
214.	NOx	Unit 4	68	F
216.	NOx	Runs 1,2,3	68	F
216.	NOx	Runs 4,5,6	68	F
216.	NOx	Runs 7,8,9	68	F
216.	NOx	Runs 10,11,12	68	F
219	NOx	Report for engine included and introduced in Engin	68	F
221.	NOx	Turbine # 1	68	F
221.	NOx	Turbine # 2	68	F
221.	NOx	Turbine # 3	68	F
221.	NOx	Turbine # 4	68	F
226.	NOx	Unit A	68	F
226.	NOx	Unit B	68	F

ID	Pollutant	Fuel Heating V	Fuel Heating V	Run 1 Gas Flo	Run 2 Gas Flo	Run 3 Gas Flo
202.	NOx	NR	NR	37500	33600	33900
202.	NOx	NR	NR	33500	36500	36300
203.	NOx	1011	Btu/scf	57160	55220	53917
203.	NOx	1011	Btu/scf	57160	55220	53917
203.	NOx	1011	Btu/dcf	48387	48388	47587
203.	NOx	1028	Btu/scf	57454	NR	NR
203.	NOx	1028	Btu/scf	53936	NR	NR
203.	NOx	1028	Btu/scf	52706	NR	NR
203.	NOx	1028	Btu/scf	48034	NR	NR
204.	NOx	1012.26	Btu/dscf	55090	54240	53142
204.	NOx	1012.26	Btu/dscf	59222	59443	57899
204.	NOx	1012.36	Btu/dscf	41530	39879	41239
204.	NOx	1012.36	Btu/dscf	50715	50333	50198
205	NOx	1013	Btu/dscf	60213	57863	61368
206.	NOx	1018	Btu/scf	54438	55557	54102
206.	NOx	1018	Btu/scf	57893	55354	57118
206.	NOx	1018	Btu/scf	51844	51399	51306
206.	NOx	1018	Btu/scf	45883	45508	45650
207.	NOx	1044	Btu/dscf	33017.5	33017.5	33017.5
207.	NOx	1044	Btu/dscf	31258.3	31258.3	31258.3
207.	NOx	1044	Btu/dscf	29121.3	29121.3	29121.3
207.	NOx	1044	Btu/dscf	23786.3	23786.3	23786.3
208	NOx	1021	Btu/dscf	136300	136300	136500
209.	NOx	1046.1	Btu/scf	25983.8	25983.8	25983.8
209.	NOx	1045.9	Btu/scf	19294.5	19294.5	19294.5
209.	NOx	1045.9	Btu/scf	27606.7	27606.7	27606.7
209.	NOx	1046.1	Btu/scf	19480.2	19480.2	19480.2
210.	NOx	22925	Btu/dscf	NR	NR	NR
210.	NOx	22925	Btu/dscf	NR	NR	NR
210.	NOx	22925	Btu/dscf	NR	NR	NR
210.	NOx	22925	Btu/dscf	NR	NR	NR
211	NOx	1025	Btu/dscf	8453	8453	NR
212	NOx	911.9	Btu/dscf	189603	194519	194157
214.	NOx	21607	Btu/lb	453480	445028	458071
214.	NOx	21607	Btu/lb	429430	440835	439911
214.	NOx	21607	Btu/lb	402754	408611	404669
214.	NOx	21607	Btu/lb	454387	453348	441682
216.	NOx	22175	Btu/lb	217656	218592	217320
216.	NOx	22175	Btu/lb	216608	218073	215647
216.	NOx	22175	Btu/lb	215700	213118	212745
216.	NOx	22175	Btu/lb	215754	NR	NR
219	NOx	1021.17	Btu/dscf	122317	122357	120899
221.	NOx	18730.89	Btu/lb	385162	384998	366529
221.	NOx	18730.89	Btu/lb	358262	363372	354609
221.	NOx	18730.89	Btu/lb	351212	323780	325792
221.	NOx	18730.89	Btu/lb	366051	368089	368097
226.	NOx	NR	NR	28378	28787	28995
226.	NOx	NR	NR	28593	29066	28997

ID	Pollutant	MW	Run 1 % Moist	Run 2 % Moist	Run 3 % Moist	Run 1 Fuel Fac
202.	NOx	46				8710
202.	NOx	46				8710
203.	NOx	46				8710
203.	NOx	46				8710
203.	NOx	46				8710
203.	NOx	46				8710
203.	NOx	46				8710
203.	NOx	46				8710
203.	NOx	46				8700
204.	NOx	46				8619
204.	NOx	46				8619
204.	NOx	46				8619
204.	NOx	46				8619
205	NOx	46				8509.1
206.	NOx	46				8623
206.	NOx	46				8623
206.	NOx	46				8623
206.	NOx	46				8623
207.	NOx	46				8637
207.	NOx	46				8637
207.	NOx	46				8637
207.	NOx	46				8637
208	NOx	46				8606
209.	NOx	46				8325
209.	NOx	46				8547
209.	NOx	46				8547
209.	NOx	46				8325
210.	NOx	46				8634.03
210.	NOx	46				8634.03
210.	NOx	46				8634.03
210.	NOx	46				8634.03
211	NOx	46				8453
212	NOx	46				8495.97
214.	NOx	46				8526.36
214.	NOx	46				8526.36
214.	NOx	46				8526.36
214.	NOx	46				8526.36
216.	NOx	46				8517.09
216.	NOx	46				8517.09
216.	NOx	46				8517.09
216.	NOx	46				8517.09
219	NOx	46				8626
221.	NOx	46				8524.1
221.	NOx	46				8524.1
221.	NOx	46				8524.1
221.	NOx	46				8524.1
226.	NOx	46				8710
226.	NOx	46				8710

ID	Pollutant	Runs	NDs	Expr5	Load1
202.	NOx	3	0	1	88
202.	NOx	3	0	1	100
203.	NOx	3	0	1	75
203.	NOx	3	0	1	100
203.	NOx	3	0	1	25
203.	NOx	1	0	1	100
203.	NOx	1	0	1	75
203.	NOx	1	0	1	50
203.	NOx	1	0	1	25
204.	NOx	3	0	1	75
204.	NOx	3	0	1	100
204.	NOx	3	0	1	40
204.	NOx	3	0	1	50
205	NOx	3	0	1	100
206.	NOx	3	0	1	75
206.	NOx	3	0	1	100
206.	NOx	3	0	1	50
206.	NOx	3	0	1	25
207.	NOx	3	0	1	97
207.	NOx	3	0	1	95
207.	NOx	3	0	1	90
207.	NOx	3	0	1	85
208	NOx	3	0	1	100
209.	NOx	3	0	1	95
209.	NOx	3	0	1	85
209.	NOx	3	0	1	95
209.	NOx	3	0	1	85
210.	NOx	3	0	1	100
210.	NOx	3	0	1	100
210.	NOx	3	0	1	100
210.	NOx	3	0	1	100
211	NOx	3	0	1	100
212	NOx	3	0	1	100
214.	NOx	3	0	2	100
214.	NOx	3	0	2	100
214.	NOx	3	0	2	100
214.	NOx	3	0	2	100
216.	NOx	3	0	8	100
216.	NOx	3	0	8	100
216.	NOx	3	0	8	100
216.	NOx	1	0	8	100
219	NOx	3	0	1	100
221.	NOx	3	0	2	100
221.	NOx	3	0	2	100
221.	NOx	3	0	2	100
221.	NOx	3	0	2	100
226.	NOx	3	0	1	100
226.	NOx	3	0	1	100

ID	Pollutant	Flag Control Device Description	Run 1 Conc	Run 2 Conc
202.	NOx	No Control	119000	116000
202.	NOx	No Control	120000	119000
203.	NOx	No Control	20200	20500
203.	NOx	No Control	30400	30300
203.	NOx	No Control	32500	32000
203.	NOx	No Control	166000	NR
203.	NOx	No Control	145000	NR
203.	NOx	No Control	176000	NR
203.	NOx	No Control	122000	NR
204.	NOx	No Control	20500	18800
204.	NOx	No Control	21100	20700
204.	NOx	No Control	27000	27300
204.	NOx	No Control	15300	15800
205	NOx	No Control	165000	162000
206.	NOx	No Control	11400	12100
206.	NOx	No Control	18000	16000
206.	NOx	No Control	9950	9740
206.	NOx	No Control	10100	10000
207.	NOx	No Control	90800	87500
207.	NOx	No Control	90800	90300
207.	NOx	No Control	75600	76000
207.	NOx	No Control	50700	54200
208	NOx	No Control	162000	159000
209.	NOx	No Control	64400	63900
209.	NOx	No Control	42900	45400
209.	NOx	No Control	64500	64800
209.	NOx	No Control	44400	43700
210.	NOx	No Control	33200	35200
210.	NOx	No Control	35200	36500
210.	NOx	No Control	32600	35200
210.	NOx	No Control	36500	36300
211	NOx	No Control	170000	170000
212	NOx	No Control	26900	27500
214.	NOx	Steam/Water Injection	36900	38200
214.	NOx	Steam/Water Injection	36200	34900
214.	NOx	Steam/Water Injection	39100	42200
214.	NOx	Steam/Water Injection	37000	35300
216.	NOx	SCR	2030	3320
216.	NOx	SCR	3380	3690
216.	NOx	SCR	3820	4030
216.	NOx	SCR	3860	NR
219	NOx	No Control	55800	55800
221.	NOx	Steam/Water Injection	44200	47400
221.	NOx	Steam/Water Injection	42500	43600
221.	NOx	Steam/Water Injection	49800	48500
221.	NOx	Steam/Water Injection	46000	43200
226.	NOx	No Control	24500	22600
226.	NOx	No Control	21400	22400

ID	Pollutant	Run 3 Conc	AConc	HHV
202.	NOx	136000	123666.666666	1020
202.	NOx	118000	119000	1020
203.	NOx	20600	20433.3333333	1020
203.	NOx	29700	30133.3333333	1020
203.	NOx	31800	32100	1020
203.	NOx	NR	166000	1020
203.	NOx	NR	145000	1020
203.	NOx	NR	176000	1020
203.	NOx	NR	122000	1020
204.	NOx	18200	19166.6666666	1020
204.	NOx	20300	20700	1020
204.	NOx	27100	27133.3333333	1020
204.	NOx	15800	15633.3333333	1020
205	NOx	170000	165666.666666	1020
206.	NOx	12000	11833.3333333	1020
206.	NOx	15400	16466.6666666	1020
206.	NOx	9740	9810	1020
206.	NOx	9990	10030	1020
207.	NOx	90000	89433.3333333	1020
207.	NOx	90300	90466.6666666	1020
207.	NOx	76300	75966.6666666	1020
207.	NOx	51900	52266.6666666	1020
208	NOx	162000	161000	1020
209.	NOx	61100	63133.3333333	1020
209.	NOx	46300	44866.6666666	1020
209.	NOx	64500	64600	1020
209.	NOx	43900	44000	1020
210.	NOx	34800	34400	1020
210.	NOx	36900	36200	1020
210.	NOx	34700	34166.6666666	1020
210.	NOx	36300	36366.6666666	1020
211	NOx	173000	171000	1020
212	NOx	29200	27866.6666666	1020
214.	NOx	40500	38533.3333333	1020
214.	NOx	34500	35200	1020
214.	NOx	41500	40933.3333333	1020
214.	NOx	34400	35566.6666666	1020
216.	NOx	3350	2900	1020
216.	NOx	3500	3523.33333333	1020
216.	NOx	4000	3950	1020
216.	NOx	NR	3860	1020
219	NOx	55000	55533.3333333	1020
221.	NOx	43400	45000	1020
221.	NOx	45100	43733.3333333	1020
221.	NOx	47200	48500	1020
221.	NOx	42500	43900	1020
226.	NOx	23600	23566.6666666	1020
226.	NOx	21200	21666.6666666	1020

ID	Pollutant	Run 1 Cc	Run 2 Cc	Run 3 Conc C	lbh1	lbh2	lbh3	lbhAvg
226.	NOx	21230	21160	20530	4.25	4.24	4.11	4.2
226.	NOx	19410	20640	19480	3.97	4.26	3.94	4.06
226.	NOx	19160	19240	19080	3.81	3.79	3.78	3.79
226.	NOx	14460	14290	13870	2.86	2.82	2.78	2.82
226.	NOx	10360	10390	10410	2.09	2.08	2.08	2.08
228.	NOx	27550	27060	26790	47.7	44.8	45	45.8
228.	NOx	33280	32700	32150	52.1	51.9	49.3	51.1
228.	NOx	34100	34520	29500	65.1	66.5	56.9	62.8
228.	NOx	25100	25560	27750	44	40.6	43.7	42.8
231	NOx	35536	34939	34137	2.57	2.49	2.46	2.51
232.	NOx	24900	27000	29700	3.58	3.88	4.27	3.91
232.	NOx	42100	38400	41800	6.61	6.03	6.57	6.4
232.	NOx	67300	60700	61700	12.5	11.2	11.4	11.7
232.	NOx	62100	60700	59100	11.6	11.3	11	11.3
232.	NOx	567400	54000	51900	110	10.5	10.1	43.5
232.	NOx	44400	44100	44200	8.08	8.02	8.04	8.05
232.	NOx	26400	27800	27600	4.08	4.3	4.27	4.22
234	NOx	140200	142900	142800	74.4	73.9	73.8	74
237.	NOx	90000	89800	89700	50.6	50.7	50.8	50.7
237.	NOx	69300	68900	68500	30.9	30.9	30.9	30.9
238.	NOx	34030	31480	NR	6.29	5.61	NR	5.95
238.	NOx	30430	31280	NR	5.71	5.6	NR	5.65
243.	NOx	41810	42470	40770	NR	NR	NR	NR
243.	NOx	27980	27580	26580	NR	NR	NR	NR
243.	NOx	21260	21690	20670	NR	NR	NR	NR
243.	NOx	4310	3580	3530	2.1	1.76	1.75	1.87
243.	NOx	2030	2060	2270	.9	.916	1.02	.945
243.	NOx	1760	1900	1640	.662	.721	.63	.671
244.	NOx	43000	43000	43000	29.9	29.9	29.2	29.7
244.	NOx	83900	83500	83500	21.2	20.5	20.9	20.9
244.	NOx	53300	53400	53600	26.5	26.7	26.5	26.6
244.	NOx	79100	82100	82700	15.4	15.8	15.5	15.6
244.	NOx	111400	111000	110300	23.6	23.8	23.4	23.6
244.	NOx	110900	111800	112400	22	22.2	22.1	22.1
244.	NOx	74100	74200	74800	17	17.5	17.7	17.4
244.	NOx	83800	93600	92900	55.1	64.3	60	59.8
244.	NOx	36400	36400	36300	2.69	2.82	2.81	2.77
244.	NOx	108300	102300	96300	23	21.9	20.5	21.8
245	NOx	64100	65000	65300	51.6	51.5	52.1	51.7
246.	NOx	15000	16000	16000	NR	NR	NR	NR
246.	NOx	36000	36000	36000	NR	NR	NR	NR
246.	NOx	33000	33000	34000	NR	NR	NR	NR
246.	NOx	64000	66000	66000	NR	NR	NR	NR
246.	NOx	13000	12000	12000	NR	NR	NR	NR
246.	NOx	30000	31000	30000	NR	NR	NR	NR
246.	NOx	30000	30000	29000	NR	NR	NR	NR
246.	NOx	61000	65000	65000	NR	NR	NR	NR
313.	NOx	109970	111130	110060	62	63.8	63.4	63.1

ID	Pollutant	lbMMBtu1	lbMMBtu2	lbMMBtu3	lbMMBtuAvg	lbMW1
226.	NOx	.0848	.0879	.0838	.0855	1.42
226.	NOx	.0802	.0827	.0808	.0812	1.32
226.	NOx	.0834	.0818	.0819	.0824	1.27
226.	NOx	.0731	.0724	.0704	.072	.953
226.	NOx	.0625	.0643	.0643	.0637	.697
228.	NOx	.146	.151	.142	.146	.954
228.	NOx	.185	.154	.17	.17	1.04
228.	NOx	.181	.163	.139	.161	1.3
228.	NOx	.147	.146	.151	.148	.88
231	NOx	.193	.195	.181	.19	3.21
232.	NOx	.168	.182	.2	.183	1.03
232.	NOx	.227	.207	.225	.22	1.79
232.	NOx	.29	.262	.266	.273	3.21
232.	NOx	.268	.267	.26	.265	2.96
232.	NOx	2.44	.237	.228	.968	28.2
232.	NOx	.221	.215	.211	.216	2.19
232.	NOx	.172	.181	.186	.18	1.17
234	NOx	.516	.517	.515	.516	7.34
237.	NOx	.539	.536	.534	.536	6.43
237.	NOx	.469	.465	.462	.465	5.8
238.	NOx	.129	.116	NR	.122	1.97
238.	NOx	.12	.118	NR	.119	1.78
243.	NOx	.163	.165	.157	.162	NR
243.	NOx	.12	.12	.116	.119	NR
243.	NOx	.101	.0982	.0964	.0985	NR
243.	NOx	.0171	.014	.0138	.015	.233
243.	NOx	.00878	.00896	.00994	.00923	.133
243.	NOx	.0084	.009	.00763	.00834	.147
244.	NOx	.275	.275	.275	.275	4.01
244.	NOx	.424	.422	.422	.423	7.54
244.	NOx	.246	.242	.243	.244	4.11
244.	NOx	.521	.541	.528	.53	6.44
244.	NOx	.712	.709	.705	.709	9.32
244.	NOx	.748	.745	.733	.742	8.97
244.	NOx	.383	.393	.396	.391	5.27
244.	NOx	.569	.581	.594	.581	6.33
244.	NOx	.193	.198	.197	.196	3.9
244.	NOx	.713	.674	.654	.68	8.31
245	NOx	.218	.214	.215	.216	.238
246.	NOx	.123	.178	.176	.159	NR
246.	NOx	.252	.229	.231	.237	NR
246.	NOx	.153	.17	.162	.162	NR
246.	NOx	.234	.23	.263	.242	NR
246.	NOx	.117	.103	.109	.11	NR
246.	NOx	.193	.198	.184	.192	NR
246.	NOx	.166	.142	.138	.149	NR
246.	NOx	.249	.245	.243	.246	NR
313.	NOx	.715	.736	.734	.728	8.05

ID	Pollutant	lbMW2	lbMW3	lbMWAvg	Facility Name
226.	NOx	1.41	1.37	1.4	South Vandenberg Power Plant
226.	NOx	1.42	1.31	1.35	South Vandenberg Power Plant
226.	NOx	1.26	1.26	1.26	South Vandenberg Power Plant
226.	NOx	.94	.927	.94	South Vandenberg Power Plant
226.	NOx	.693	.693	.694	South Vandenberg Power Plant
228.	NOx	.896	.9	.917	City Utilities of Springfield - Southw
228.	NOx	1.04	.986	1.02	City Utilities of Springfield - Southw
228.	NOx	1.33	1.14	1.26	City Utilities of Springfield - Southw
228.	NOx	.812	.874	.855	City Utilities of Springfield - Southw
231	NOx	3.11	3.08	3.13	AMOCO Production Company
232.	NOx	1.11	1.23	1.12	NW Pipeline Corporation - Willard
232.	NOx	1.63	1.78	1.73	NW Pipeline Corporation - Willard
232.	NOx	2.88	2.93	3.01	NW Pipeline Corporation - Willard
232.	NOx	2.88	2.8	2.88	NW Pipeline Corporation - Willard
232.	NOx	2.69	2.59	11.2	NW Pipeline Corporation - Willard
232.	NOx	2.17	2.18	2.18	NW Pipeline Corporation - Willard
232.	NOx	1.23	1.23	1.21	NW Pipeline Corporation - Willard
234	NOx	7.29	7.28	7.3	Transcontinental Gas Pipeline Cor
237.	NOx	6.44	6.46	6.44	Tennessee Gas Pipeline - Compre
237.	NOx	5.8	5.8	5.8	Tennessee Gas Pipeline - Compre
238.	NOx	1.75	NR	1.86	SEKR Cogeneration Facility
238.	NOx	1.75	NR	1.76	SEKR Cogeneration Facility
243.	NOx	NR	NR	NR	Bonneville Pacific Cogeneration Pl
243.	NOx	NR	NR	NR	Bonneville Pacific Cogeneration Pl
243.	NOx	NR	NR	NR	Bonneville Pacific Cogeneration Pl
243.	NOx	.196	.194	.208	Bonneville Pacific Cogeneration Pl
243.	NOx	.136	.151	.14	Bonneville Pacific Cogeneration Pl
243.	NOx	.16	.14	.149	Bonneville Pacific Cogeneration Pl
244.	NOx	4.01	3.91	3.98	American Gas Association/B-3
244.	NOx	7.29	7.43	7.42	American Gas Association/B-19
244.	NOx	4.14	4.11	4.12	American Gas Association/B-6
244.	NOx	6.61	6.49	6.51	American Gas Association/B-8
244.	NOx	9.4	9.24	9.32	American Gas Association/B-9
244.	NOx	9.05	9.01	9.01	American Gas Association/B-11
244.	NOx	5.43	5.49	5.4	American Gas Association/B-12
244.	NOx	7.38	6.89	6.87	American Gas Association/B-16
244.	NOx	4.09	4.07	4.02	American Gas Association/B-17
244.	NOx	7.92	7.41	7.88	American Gas Association/B-18
245	NOx	.238	.241	.239	Proctor & Gamble Manufacturing C
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
246.	NOx	NR	NR	NR	Fayetteville Generation Plant
313.	NOx	8.29	8.23	8.19	NR

ID	Pollutant	Method	Location	Facility	Testing Compa	Date
226.	NOx	EPA 20	Vandenberg Air	South Vandenb	Petro Chem En	5/11/93
226.	NOx	EPA 20	Vandenberg Air	South Vandenb	Petro Chem En	5/11/93
226.	NOx	EPA 20	Vandenberg Air	South Vandenb	Petro Chem En	5/11/93
226.	NOx	EPA 20	Vandenberg Air	South Vandenb	Petro Chem En	5/11/93
226.	NOx	EPA 20	Vandenberg Air	South Vandenb	Petro Chem En	5/11/93
228.	NOx	EPA 20	301 East Centr	City Utilities of	Total Source A	8/ 6/91
228.	NOx	EPA 20	301 East Centr	City Utilities of	Total Source A	8/ 6/91
228.	NOx	EPA 20	301 East Centr	City Utilities of	Total Source A	8/ 6/91
228.	NOx	EPA 20	301 East Centr	City Utilities of	Total Source A	8/ 6/91
231	NOx	EPA 20	Morganza, LA	AMOCO Produ	Emission Testi	7/28/88
232.	NOx	EPA 20	Willard Compre	NW Pipeline C	AMTEST Air Q	8/20/93
232.	NOx	EPA 20	Willard Compre	NW Pipeline C	AMTEST Air Q	8/20/93
232.	NOx	EPA 20	Willard Compre	NW Pipeline C	AMTEST Air Q	8/20/93
232.	NOx	EPA 20	Willard Compre	NW Pipeline C	AMTEST Air Q	8/20/93
232.	NOx	EPA 20	Willard Compre	NW Pipeline C	AMTEST Air Q	8/20/93
232.	NOx	EPA 20	Willard Compre	NW Pipeline C	AMTEST Air Q	8/20/93
232.	NOx	EPA 20	Willard Compre	NW Pipeline C	AMTEST Air Q	8/20/93
234	NOx	EPA 7E and 20	Bear Creek, PA	Transcontinent	Scott Environm	1/ 7/92
237.	NOx	EPA 20	East Bernard,	Tennessee Ga	Technical Servi	1/31/90
237.	NOx	EPA 20	East Bernard,	Tennessee Ga	Technical Servi	1/31/90
238.	NOx	CARB 100	Bakersfield, CA	SEKR Cogener	Engineering Sci	1/11/93
238.	NOx	CARB 100	Bakersfield, CA	SEKR Cogener	Engineering Sci	1/11/93
243.	NOx	EPA 7E	Santa Maria, C	Bonneville Paci	Steiner Environ	2/26/92
243.	NOx	EPA 7E	Santa Maria, C	Bonneville Paci	Steiner Environ	2/26/92
243.	NOx	EPA 7E	Santa Maria, C	Bonneville Paci	Steiner Environ	2/26/92
243.	NOx	EPA 7E	Santa Maria, C	Bonneville Paci	Steiner Environ	2/26/92
243.	NOx	EPA 7E	Santa Maria, C	Bonneville Paci	Steiner Environ	2/26/92
243.	NOx	EPA 7E	Santa Maria, C	Bonneville Paci	Steiner Environ	2/26/92
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	7/13/85
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	1/29/88
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	1/22/86
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	10/ 2/86
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	4/29/86
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	6/30/86
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	2/26/86
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	2/ 1/88
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	12/ 8/87
244.	NOx	EPA 7E	NR	American Gas	Southwest Res	2/13/88
245	NOx	EPA 20	Sacramento, C	Proctor & Gam	Carnot	5/10/90
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
246.	NOx	EPA 20	Fayetteville, NC	Fayetteville Ge	Interpoll Labora	6/21/89
313.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 1/93

ID	Pollutant	Rating	Unit	Load	Manufacturer	Model
226.	NOx	3	MW	100	Allison	501-KB
226.	NOx	3	MW	100	Allison	501-KB
226.	NOx	3	MW	100	Allison	501-KB
226.	NOx	3	MW	100	Allison	501-KB
226.	NOx	3	MW	100	Allison	501-KB
228.	NOx	50	MW	100	United Technol	FT4C-1(DF)
228.	NOx	50	MW	100	United Technol	FT4C-1(DF)
228.	NOx	50	MW	100	United Technol	FT4C-1(DF)
228.	NOx	50	MW	100	United Technol	FT4C-1(DF)
231	NOx	.8	MW	100	Solar	GCI-SB-KATO
232.	NOx	4.10	MW	85	Solar Centaur	HT 5500
232.	NOx	4.10	MW	90	Solar Centaur	HT 5500
232.	NOx	4.10	MW	95	Solar Centaur	HT 5500
232.	NOx	4.10	MW	95.7	Solar Centaur	HT 5500
232.	NOx	4.10	MW	95.1	Solar Centaur	HT 5500
232.	NOx	4.10	MW	90	Solar Centaur	HT 5500
232.	NOx	4.10	MW	85	Solar Centaur	HT 5500
234	NOx	10.14	MW	100	Solar Mars	NR
237.	NOx	8.46	MW	93	General Electri	Frame 3
237.	NOx	8.46	MW	63	General Electri	Frame 3
238.	NOx	4	MW	80	Allison	501-KB5
238.	NOx	4	MW	80	Allison	501-KB5
243.	NOx	9	MW	100	NR	NR
243.	NOx	9	MW	75	NR	NR
243.	NOx	9	MW	50	NR	NR
243.	NOx	9	MW	100	NR	NR
243.	NOx	9	MW	75	NR	NR
243.	NOx	9	MW	50	NR	NR
244.	NOx	7.46	MW	100	General Electri	LM-1500
244.	NOx	3.09	MW	91	Solar	Centaur T-450
244.	NOx	6.93	MW	93	General Electri	3572 Series 3
244.	NOx	2.57	MW	93	Solar	Centaur
244.	NOx	2.61	MW	97	Solar	Centaur
244.	NOx	2.61	MW	94	Solar	Centaur
244.	NOx	3.36	MW	96	Clark	DC-990
244.	NOx	8.98	MW	97	General Electri	M3122R
244.	NOx	.75	MW	92	Solar	Saturn
244.	NOx	2.61	MW	106	Solar	Centaur
245	NOx	216.5	MW	100	General Electri	LM-2500
246.	NOx	29	MW	10	General Electri	NR
246.	NOx	29	MW	38	General Electri	NR
246.	NOx	29	MW	69	General Electri	NR
246.	NOx	29	MW	100	General Electri	NR
246.	NOx	29	MW	10	General Electri	NR
246.	NOx	29	MW	38	General Electri	NR
246.	NOx	29	MW	69	General Electri	NR
246.	NOx	29	MW	96	General Electri	NR
313.	NOx	7.7	MW	100	General Electri	Frame 3

ID	Pollutant	Turbine	Fuel Type	Application	Run 1 Conc R	Run 2 Conc R
226.	NOx	Allison/501-KB/	Natural Gas	NR	21230	21160
226.	NOx	Allison/501-KB/	Natural Gas	NR	19410	20640
226.	NOx	Allison/501-KB/	Natural Gas	NR	19160	19240
226.	NOx	Allison/501-KB/	Natural Gas	NR	14460	14290
226.	NOx	Allison/501-KB/	Natural Gas	NR	10360	10390
228.	NOx	United Technol	Natural Gas	NR	27550	27060
228.	NOx	United Technol	Natural Gas	NR	33280	32700
228.	NOx	United Technol	Natural Gas	NR	34100	34520
228.	NOx	United Technol	Natural Gas	NR	25100	25560
231	NOx	Solar/GCI-SB-	Natural Gas	NR	35536	34939
232.	NOx	Solar Centaur/	Natural Gas	NR	24900	27000
232.	NOx	Solar Centaur/	Natural Gas	NR	42100	38400
232.	NOx	Solar Centaur/	Natural Gas	NR	67300	60700
232.	NOx	Solar Centaur/	Natural Gas	NR	62100	60700
232.	NOx	Solar Centaur/	Natural Gas	NR	567400	54000
232.	NOx	Solar Centaur/	Natural Gas	NR	44400	44100
232.	NOx	Solar Centaur/	Natural Gas	NR	26400	27800
234	NOx	Solar Mars/NR/	Natural Gas	NR	140200	142900
237.	NOx	General Electri	Natural Gas	NR	90000	89800
237.	NOx	General Electri	Natural Gas	NR	69300	68900
238.	NOx	Allison/501-KB	Natural Gas	NR	34030	31480
238.	NOx	Allison/501-KB	Natural Gas	NR	30430	31280
243.	NOx	NR/NR/9 MW /	Natural Gas	Cogeneration	41810	42470
243.	NOx	NR/NR/9 MW /	Natural Gas	Cogeneration	27980	27580
243.	NOx	NR/NR/9 MW /	Natural Gas	Cogeneration	21260	21690
243.	NOx	NR/NR/9 MW /	Natural Gas	Cogeneration	4310	3580
243.	NOx	NR/NR/9 MW /	Natural Gas	Cogeneration	2030	2060
243.	NOx	NR/NR/9 MW /	Natural Gas	Cogeneration	1760	1900
244.	NOx	General Electri	Natural Gas	Gas Transmiss	43000	43000
244.	NOx	Solar/Centaur	Natural Gas	Gas Transmiss	83900	83500
244.	NOx	General Electri	Natural Gas	Gas Transmiss	53300	53400
244.	NOx	Solar/Centaur/2	Natural Gas	Gas Transmiss	79100	82100
244.	NOx	Solar/Centaur/2	Natural Gas	Gas Transmiss	111400	111000
244.	NOx	Solar/Centaur/2	Natural Gas	Gas Transmiss	110900	111800
244.	NOx	Clark/DC-990/3	Natural Gas	Gas Transmiss	74100	74200
244.	NOx	General Electri	Natural Gas	Gas Transmiss	83800	93600
244.	NOx	Solar/Saturn/.7	Natural Gas	Gas Transmiss	36400	36400
244.	NOx	Solar/Centaur/2	Natural Gas	Gas Transmiss	108300	102300
245	NOx	General Electri	Natural Gas	Cogeneration	64100	65000
246.	NOx	General Electri	Natural Gas	Electric generat	15000	16000
246.	NOx	General Electri	Natural Gas	Electric generat	36000	36000
246.	NOx	General Electri	Natural Gas	Electric generat	33000	33000
246.	NOx	General Electri	Natural Gas	Electric generat	64000	66000
246.	NOx	General Electri	Natural Gas	Electric generat	13000	12000
246.	NOx	General Electri	Natural Gas	Electric generat	30000	31000
246.	NOx	General Electri	Natural Gas	Electric generat	30000	30000
246.	NOx	General Electri	Natural Gas	Electric generat	61000	65000
313.	NOx	General Electri	Natural Gas	Gas Transmiss	109970	111130

ID	Pollutant	Run 3 Conc R	Average	Conc R Averag	DL	SD
226.	NOx	20530	20973.3333333	21000	NA	3
226.	NOx	19480	19843.3333333	19800	NA	3
226.	NOx	19080	19160	19200	NA	3
226.	NOx	13870	14206.6666666	14200	NA	3
226.	NOx	10410	10386.6666666	10400	NA	3
228.	NOx	26790	27133.3333333	27100	NA	3
228.	NOx	32150	32710	32700	NA	3
228.	NOx	29500	32706.6666666	32700	NA	3
228.	NOx	27750	26136.6666666	26100	NA	3
231	NOx	34137	34870.6666666	34900	NA	3
232.	NOx	29700	27200	27200	NA	3
232.	NOx	41800	40766.6666666	40800	NA	3
232.	NOx	61700	63233.3333333	63200	NA	3
232.	NOx	59100	60633.3333333	60600	NA	3
232.	NOx	51900	224433.333333	224000	NA	3
232.	NOx	44200	44233.3333333	44200	NA	3
232.	NOx	27600	27266.6666666	27300	NA	3
234	NOx	142800	141966.666666	142000	NA	3
237.	NOx	89700	89833.3333333	89800	NA	3
237.	NOx	68500	68900	68900	NA	3
238.	NOx	NR	32755	32800	NA	3
238.	NOx	NR	30855	30900	NA	3
243.	NOx	40770	41683.3333333	41700	NA	3
243.	NOx	26580	27380	27400	NA	3
243.	NOx	20670	21206.6666666	21200	NA	3
243.	NOx	3530	3806.66666666	3810	NA	3
243.	NOx	2270	2120	2120	NA	3
243.	NOx	1640	1766.66666666	1770	NA	3
244.	NOx	43000	43000	43000	NA	3
244.	NOx	83500	83633.3333333	83600	NA	3
244.	NOx	53600	53433.3333333	53400	NA	3
244.	NOx	82700	81300	81300	NA	3
244.	NOx	110300	110900	111000	NA	3
244.	NOx	112400	111700	112000	NA	3
244.	NOx	74800	74366.6666666	74400	NA	3
244.	NOx	92900	90100	90100	NA	3
244.	NOx	36300	36366.6666666	36400	NA	3
244.	NOx	96300	102300	102000	NA	3
245	NOx	65300	64800	64800	NA	3
246.	NOx	16000	15666.6666666	15700	NA	3
246.	NOx	36000	36000	36000	NA	3
246.	NOx	34000	33333.3333333	33300	NA	3
246.	NOx	66000	65333.3333333	65300	NA	3
246.	NOx	12000	12333.3333333	12300	NA	3
246.	NOx	30000	30333.3333333	30300	NA	3
246.	NOx	29000	29666.6666666	29700	NA	3
246.	NOx	65000	63666.6666666	63700	NA	3
313.	NOx	110060	110386.666666	110000	NA	3

ID	Pollutant	CountAConc	Countlbh	CountlbMMBtu	CountlbMW	CUnit
226.	NOx	1	1	1	1	ppb
226.	NOx	1	1	1	1	ppb
226.	NOx	1	1	1	1	ppb
226.	NOx	1	1	1	1	ppb
226.	NOx	1	1	1	1	ppb
228.	NOx	1	1	1	1	ppb
228.	NOx	1	1	1	1	ppb
228.	NOx	1	1	1	1	ppb
228.	NOx	1	1	1	1	ppb
231	NOx	1	1	1	1	ppb
232.	NOx	1	1	1	1	ppb
232.	NOx	1	1	1	1	ppb
232.	NOx	1	1	1	1	ppb
232.	NOx	1	1	1	1	ppb
232.	NOx	1	1	1	1	ppb
232.	NOx	1	1	1	1	ppb
232.	NOx	1	1	1	1	ppb
234	NOx	1	1	1	1	ppb
237.	NOx	1	1	1	1	ppb
237.	NOx	1	1	1	1	ppb
238.	NOx	1	1	1	1	ppb
238.	NOx	1	1	1	1	ppb
243.	NOx	1	0	1	0	ppb
243.	NOx	1	0	1	0	ppb
243.	NOx	1	0	1	0	ppb
243.	NOx	1	1	1	1	ppb
243.	NOx	1	1	1	1	ppb
243.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
244.	NOx	1	1	1	1	ppb
245	NOx	1	1	1	1	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
246.	NOx	1	0	1	0	ppb
313.	NOx	1	1	1	1	ppb

ID	Pollutant	Control Device	Source EF
226.	NOx	None	#Error
226.	NOx	None	#Error
226.	NOx	None	#Error
226.	NOx	None	#Error
226.	NOx	None	#Error
228.	NOx	Water Injection	#Error
228.	NOx	Water Injection	#Error
228.	NOx	Water Injection	#Error
228.	NOx	Water Injection	#Error
231	NOx	None	#Error
232.	NOx	None	#Error
232.	NOx	None	#Error
232.	NOx	None	#Error
232.	NOx	None	#Error
232.	NOx	None	#Error
232.	NOx	None	#Error
232.	NOx	None	#Error
234	NOx	None	#Error
237.	NOx	None	#Error
237.	NOx	None	#Error
238.	NOx	Lean Premix co	#Error
238.	NOx	Lean Premix co	#Error
243.	NOx	Water Injection	#Error
243.	NOx	Water Injection	#Error
243.	NOx	Water Injection	#Error
243.	NOx	Water Injection	#Error
243.	NOx	Water Injection	#Error
243.	NOx	Water Injection	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
244.	NOx	None	#Error
245	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
246.	NOx	Water Injection	#Error
313.	NOx	None	#Error

ID	Pollutant	Comm
226.	NOx	Unit C
226.	NOx	Unit D
226.	NOx	Unit E. Runs 1,2,3.
226.	NOx	Unit E. Runs 4,5,6.
226.	NOx	Unit E. Runs 7,8,9.
228.	NOx	Unit # 2-South
228.	NOx	Unit # 1 - North
228.	NOx	Unit # 1 - South
228.	NOx	Unit # 2-North
231	NOx	
232.	NOx	
232.	NOx	
232.	NOx	
232.	NOx	
232.	NOx	
232.	NOx	
232.	NOx	
232.	NOx	
234	NOx	
237.	NOx	
237.	NOx	
238.	NOx	Turbine 2
238.	NOx	Turbine 3
243.	NOx	Used 68 as default temperature.
243.	NOx	Used 68 as default temperature
243.	NOx	Used 68 as default temperature
243.	NOx	Used 68 as default temperature
243.	NOx	Used 68 as default temperature
243.	NOx	Used 68 as default temperature
244.	NOx	
244.	NOx	
244.	NOx	
244.	NOx	
244.	NOx	
244.	NOx	
244.	NOx	
244.	NOx	
244.	NOx	
244.	NOx	
245	NOx	4 runs performed, data from 1st 3 input.
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
246.	NOx	Exhaust Gas Flowrate missing
313.	NOx	Unit B.Exhaust gas flowrate calculated from Fuel Factor (O2)

ID	Pollutant	Run 1 O2	Run 2 O2	Run 3 O2	Test Rating
226.	NOx	15.46	15.67	15.58	0
226.	NOx	15.64	15.48	15.66	0
226.	NOx	15.91	15.79	15.84	0
226.	NOx	16.6	16.61	16.62	0
226.	NOx	17.3	17.39	17.38	0
228.	NOx	16.8	17	16.8	0
228.	NOx	17	16.3	16.8	0
228.	NOx	16.8	16.3	16.3	0
228.	NOx	17.2	17.1	16.9	0
231	NOx	16.9	17.0	16.8	0
232.	NOx	17.7	17.7	17.7	0
232.	NOx	16.9	16.9	16.9	0
232.	NOx	15.9	15.9	15.9	0
232.	NOx	15.9	16	16	0
232.	NOx	15.9	16	16	0
232.	NOx	16.6	16.5	16.4	0
232.	NOx	17.6	17.6	17.7	0
234	NOx	15	14.9	14.88	0
237.	NOx	17.27	17.26	17.25	0
237.	NOx	17.69	17.68	17.68	0
238.	NOx	15.22	15.03	NR	
238.	NOx	15.45	15.19	NR	
243.	NOx	15.46	15.45	15.39	
243.	NOx	15.96	16.04	16.05	
243.	NOx	16.43	16.21	16.35	
243.	NOx	15.54	15.48	15.47	
243.	NOx	15.99	16.02	16.05	
243.	NOx	16.45	16.42	16.34	
244.	NOx	17.5	17.5	17.5	
244.	NOx	16.6	16.6	16.6	
244.	NOx	16.2	16.1	16.1	
244.	NOx	17.6	17.6	17.5	
244.	NOx	17.5	17.5	17.5	
244.	NOx	17.68	17.64	17.57	
244.	NOx	16.7	16.8	16.8	
244.	NOx	17.7	17.4	17.5	
244.	NOx	16.8	16.9	16.9	
244.	NOx	17.6	17.6	17.7	
245	NOx	14.7	14.5	14.5	
246.	NOx	18.25	18.95	18.93	
246.	NOx	17.8	17.48	17.52	
246.	NOx	16.21	16.67	16.33	
246.	NOx	14.97	14.66	15.45	
246.	NOx	18.48	18.36	18.51	
246.	NOx	17.52	17.5	17.36	
246.	NOx	16.98	16.3	16.32	
246.	NOx	15.57	15.13	15.08	
313.	NOx	17.6	17.66	17.68	

ID	Pollutant	Comments	Standard Temp	Standard Temp
226.	NOx	Unit C	68	F
226.	NOx	Unit D	68	F
226.	NOx	Unit E. Runs 1,2,3 of 9	68	F
226.	NOx	Unit E. Runs 4,5,6 of 9	68	F
226.	NOx	Unit E. Runs 7,8,9 of 9	68	F
228.	NOx	Unit # 2 - South	68	F
228.	NOx	Unit # 1 - North	68	F
228.	NOx	Unit # 1 - South	68	F
228.	NOx	Unit # 2 - North	68	F
231	NOx		68	F
232.	NOx	Turbine 1, simple Cycle turbine	68	F
232.	NOx	Turbine 1, simple Cycle turbine	68	F
232.	NOx	Turbine 1, simple Cycle turbine	68	F
232.	NOx	Turbine 1, simple Cycle turbine	68	F
232.	NOx	Turbine 2, simple Cycle turbine	68	F
232.	NOx	Turbine 2, simple Cycle turbine	70	F
232.	NOx	Turbine 2, simple Cycle turbine	68	F
234	NOx		68	F
237.	NOx	Unit 1C	68	F
237.	NOx	Unit 1C	68	F
238.	NOx	"x"ed due to missing load information.	60	F
238.	NOx	"x"ed due to missing load information.	60	F
243.	NOx		68	F
243.	NOx		68	F
243.	NOx		68	F
243.	NOx		68	F
243.	NOx		68	F
243.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
244.	NOx		68	F
245	NOx		68	F
246.	NOx	Unit 7 NG.	68	F
246.	NOx	Unit 7 NG.	68	F
246.	NOx	Unit 7 NG.	68	F
246.	NOx	Unit 7 NG	68	F
246.	NOx	Unit 8 NG.	68	F
246.	NOx	Unit 8 NG.	68	F
246.	NOx	Unit 8 NG.	68	F
246.	NOx	Unit 8 NG	68	F
313.	NOx	Unit B	68	F

ID	Pollutant	Fuel Heating V	Fuel Heating V	Run 1 Gas Flov	Run 2 Gas Flov	Run 3 Gas Flov
226.	NOx	NR	NR	28006	28016	27982
226.	NOx	NR	NR	28558	28857	28271
226.	NOx	NR	NR	27773	27560	27709
226.	NOx	NR	NR	27642	27529	28048
226.	NOx	NR	NR	28128	27994	27893
228.	NOx	NR	NR	241937	231580	234483
228.	NOx	NR	NR	218652	221610	214391
228.	NOx	NR	NR	266702	269007	269382
228.	NOx	NR	NR	245146	221812	220169
231	NOx	NR	NR	10112	9945	10084
232.	NOx	940	Btu/dscf	20079.6	20079.6	20079.6
232.	NOx	940	Btu/dscf	21949.2	21949.2	21949.2
232.	NOx	940	Btu/dscf	25871.2	25871.2	25871.2
232.	NOx	940	Btu/dscf	26026.6	26026.6	26026.6
232.	NOx	939	Btu/dscf	27123.5	27123.5	27123.5
232.	NOx	939	Btu/dscf	25519.6	25519.6	25519.6
232.	NOx	939	Btu/dscf	21615.8	21615.8	21615.8
234	NOx	NR	NR	74144	72279	72186
237.	NOx	1058	Btu/dscf	78576	78891	79097
237.	NOx	1058	Btu/dscf	62399	62744	62983
238.	NOx	1043.63	Btu/dcuft	25453	24515	NR
238.	NOx	1049.63	Btu/dcuft	25827	24651	NR
243.	NOx	1020	Btu/cuft	NR	NR	NR
243.	NOx	1020	Btu/cuft	NR	NR	NR
243.	NOx	1020	Btu/cuft	NR	NR	NR
243.	NOx	1020	Btu/cuft	68088	68550	69288
243.	NOx	1020	Btu/cuft	61930	62130	62553
243.	NOx	1020	Btu/cuft	52601	53052	53655
244.	NOx	1071	Btu/scf	97183	97251	94893
244.	NOx	1035	Btu/scf	35323	34354	34938
244.	NOx	1027	Btu/scf	69374	69791	69032
244.	NOx	1035	Btu/scf	27193	26945	26166
244.	NOx	1019	Btu/scf	29571	29972	29664
244.	NOx	1022	Btu/scf	27720	27758	27425
244.	NOx	1026	Btu/scf	32032	32867	33025
244.	NOx	1020	Btu/scf	91940	95935	90260
244.	NOx	1010	Btu/scf	10315	10826	10823
244.	NOx	1029	Btu/scf	29738	29868	29680
245	NOx	993	Btu/scf	112495	110774	111597
246.	NOx	1028.2	Btu/scf @60F	NR	NR	NR
246.	NOx	1028.2	Btu/scf @60F	NR	NR	NR
246.	NOx	1028.2	Btu/scf @60F	NR	NR	NR
246.	NOx	1028.2	Btu/scf @60F	NR	NR	NR
246.	NOx	1028.2	Btu/scf @60F	NR	NR	NR
246.	NOx	1028.2	Btu/scf @60F	NR	NR	NR
246.	NOx	1028.2	Btu/scf @60F	NR	NR	NR
246.	NOx	1028.2	Btu/scf @60F	NR	NR	NR
313.	NOx	1038	Btu/scf	78838	80202	80507

ID	Pollutant	MW	Run 1 % Moist	Run 2 % Moist	Run 3 % Moist	Run 1 Fuel Fac
226.	NOx	46				8710
226.	NOx	46				8710
226.	NOx	46				8710
226.	NOx	46				8710
226.	NOx	46				8710
228.	NOx	46				8710
228.	NOx	46				8710
228.	NOx	46				8710
228.	NOx	46				8710
231	NOx	46				8710
232.	NOx	46				8638
232.	NOx	46				8638
232.	NOx	46				8638
232.	NOx	46				8638
232.	NOx	46				8631
232.	NOx	46				8631
232.	NOx	46				8631
234	NOx	46				8710
237.	NOx	46				8710
237.	NOx	46				8710
238.	NOx	46				8516.1
238.	NOx	46				8516.1
243.	NOx	46	NR	NR	NR	8510
243.	NOx	46	NR	NR	NR	8510
243.	NOx	46	NR	NR	NR	8510
243.	NOx	46	7.9	8	8.2	8510
243.	NOx	46	7.2	7	7.2	8510
243.	NOx	46	6.7	6.5	6.5	8510
244.	NOx	46	NR	NR	NR	8710
244.	NOx	46	4.7	4.7	4.7	8710
244.	NOx	46	6	5.9	6	8710
244.	NOx	46	5.9	5.9	6	8710
244.	NOx	46	4.5	4.5	4.5	8710
244.	NOx	46	4.7	4.7	4.6	8710
244.	NOx	46	4.6	4.5	4.5	8710
244.	NOx	46	4.6	5	5.1	8710
244.	NOx	46	4.8	4.6	4.6	8710
244.	NOx	46	3.6	3.6	3.5	8710
245	NOx	46	NR	NR	NR	8466
246.	NOx	46	NR	NR	NR	8710
246.	NOx	46	NR	NR	NR	8710
246.	NOx	46	NR	NR	NR	8710
246.	NOx	46	NR	NR	NR	8710
246.	NOx	46	NR	NR	NR	8710
246.	NOx	46	NR	NR	NR	8710
246.	NOx	46	NR	NR	NR	8710
246.	NOx	46	NR	NR	NR	8710
313.	NOx	46	NR	NR	NR	8607

ID	Pollutant	Runs	NDs	Expr5	Load1
226.	NOx	3	0	1	100
226.	NOx	3	0	1	100
226.	NOx	3	0	1	100
226.	NOx	3	0	1	100
226.	NOx	3	0	1	100
228.	NOx	3	0	2	100
228.	NOx	3	0	2	100
228.	NOx	3	0	2	100
228.	NOx	3	0	2	100
231	NOx	3	0	1	100
232.	NOx	3	0	1	85
232.	NOx	3	0	1	90
232.	NOx	3	0	1	95
232.	NOx	3	0	1	95.7
232.	NOx	3	0	1	95.1
232.	NOx	3	0	1	90
232.	NOx	3	0	1	85
234	NOx	3	0	1	100
237.	NOx	3	0	1	93
237.	NOx	3	0	1	63
238.	NOx	2	0	5	80
238.	NOx	2	0	5	80
243.	NOx	3	0	2	100
243.	NOx	3	0	2	75
243.	NOx	3	0	2	50
243.	NOx	3	0	3	100
243.	NOx	3	0	3	75
243.	NOx	3	0	3	50
244.	NOx	3	0	1	100
244.	NOx	3	0	1	91
244.	NOx	3	0	1	93
244.	NOx	3	0	1	93
244.	NOx	3	0	1	97
244.	NOx	3	0	1	94
244.	NOx	3	0	1	96
244.	NOx	3	0	1	97
244.	NOx	3	0	1	92
244.	NOx	3	0	1	106
245	NOx	3	0	2	100
246.	NOx	3	0	2	10
246.	NOx	3	0	2	38
246.	NOx	3	0	2	69
246.	NOx	3	0	2	100
246.	NOx	3	0	2	10
246.	NOx	3	0	2	38
246.	NOx	3	0	2	69
246.	NOx	3	0	2	96
313.	NOx	3	0	1	100

ID	Pollutant	Flag Control Device Description	Run 1 Conc	Run 2 Conc
226.	NOx	No Control	23000	23900
226.	NOx	No Control	21800	22500
226.	NOx	No Control	22700	22200
226.	NOx	No Control	19800	19700
226.	NOx	No Control	17000	17500
228.	NOx	Steam/Water Injection	39600	40900
228.	NOx	Steam/Water Injection	50300	41900
228.	NOx	Steam/Water Injection	49100	44300
228.	NOx	Steam/Water Injection	40000	39700
231	NOx	No Control	52400	52900
232.	NOx	No Control	45900	49800
232.	NOx	No Control	62100	56600
232.	NOx	No Control	79400	71600
232.	NOx	No Control	73300	73100
232.	NOx	No Control	670000	65000
232.	NOx	No Control	60900	59100
232.	NOx	No Control	47200	49700
234	NOx	No Control	140000	141000
237.	NOx	No Control	146000	146000
237.	NOx	No Control	127000	126000
238.	NOx	Lean Pre-Mix & Water Injection	35300	31600
238.	NOx	Lean Pre-Mix & Water Injection	32900	32300
243.	NOx	Steam/Water Injection	45300	46000
243.	NOx	Steam/Water Injection	33400	33500
243.	NOx	Steam/Water Injection	28100	27300
243.	NOx	Steam/Water Injection & SCR	4740	3900
243.	NOx	Steam/Water Injection & SCR	2440	2490
243.	NOx	Steam/Water Injection & SCR	2330	2500
244.	NOx	No Control	74600	74600
244.	NOx	No Control	115000	115000
244.	NOx	No Control	66900	65600
244.	NOx	No Control	141000	147000
244.	NOx	No Control	193000	193000
244.	NOx	No Control	203000	202000
244.	NOx	No Control	104000	107000
244.	NOx	No Control	155000	158000
244.	NOx	No Control	52400	53700
244.	NOx	No Control	194000	183000
245	NOx	Steam/Water Injection	61000	59900
246.	NOx	Steam/Water Injection	33400	48400
246.	NOx	Steam/Water Injection	68500	62100
246.	NOx	Steam/Water Injection	41500	46000
246.	NOx	Steam/Water Injection	63700	62400
246.	NOx	Steam/Water Injection	31700	27900
246.	NOx	Steam/Water Injection	52400	53800
246.	NOx	Steam/Water Injection	45200	38500
246.	NOx	Steam/Water Injection	67500	66500
313.	NOx	No Control	197000	202000

ID	Pollutant	Run 3 Conc	AConc	HHV
226.	NOx	22800	23233.3333333	1020
226.	NOx	21900	22066.6666666	1020
226.	NOx	22200	22366.6666666	1020
226.	NOx	19100	19533.3333333	1020
226.	NOx	17400	17300	1020
228.	NOx	38600	39700	1020
228.	NOx	46300	46166.6666666	1020
228.	NOx	37800	43733.3333333	1020
228.	NOx	40900	40200	1020
231	NOx	49100	51466.6666666	1020
232.	NOx	54800	50166.6666666	1020
232.	NOx	61700	60133.3333333	1020
232.	NOx	72800	74600	1020
232.	NOx	71200	72533.3333333	1020
232.	NOx	62500	265833.333333	1020
232.	NOx	58000	59333.3333333	1020
232.	NOx	50900	49266.6666666	1020
234	NOx	140000	140333.333333	1020
237.	NOx	145000	145666.666666	1020
237.	NOx	126000	126333.333333	1020
238.	NOx	NR	33450	1020
238.	NOx	NR	32600	1020
243.	NOx	43700	45000	1020
243.	NOx	32300	33066.6666666	1020
243.	NOx	26800	27400	1020
243.	NOx	3840	4160	1020
243.	NOx	2760	2563.33333333	1020
243.	NOx	2120	2316.66666666	1020
244.	NOx	74600	74600	1020
244.	NOx	115000	115000	1020
244.	NOx	65900	66133.3333333	1020
244.	NOx	144000	144000	1020
244.	NOx	191000	192333.333333	1020
244.	NOx	199000	201333.333333	1020
244.	NOx	108000	106333.333333	1020
244.	NOx	161000	158000	1020
244.	NOx	53500	53200	1020
244.	NOx	178000	185000	1020
245	NOx	60200	60366.6666666	1020
246.	NOx	47900	43233.3333333	1020
246.	NOx	62800	64466.6666666	1020
246.	NOx	43900	43800	1020
246.	NOx	71400	65833.3333333	1020
246.	NOx	29600	29733.3333333	1020
246.	NOx	50000	52066.6666666	1020
246.	NOx	37400	40366.6666666	1020
246.	NOx	65900	66633.3333333	1020
313.	NOx	202000	200333.333333	1020

ID	Pollutant	Run 1 Cc	Run 2 Cc	Run 3 Conc C	lbh1	lbh2	lbh3	lbhAvg
313.	NOx	63050	62100	61010	28.6	29.1	28.4	28.7
313.	NOx	84550	84380	84530	42.8	41.1	43.1	42.3
313.	NOx	129190	129130	129060	52	51.5	51.5	51.7
313.	NOx	18100	18640	18420	3.78	4.02	4.35	4.05
313.	NOx	37780	38380	38980	10.6	11.2	11.7	11.2
313.	NOx	90690	87320	86380	34.6	32.9	33	33.5
314.	NOx	25120	26340	25880	10.3	11.2	11.1	10.9
314.	NOx	20780	21030	NA	8.39	8.41	NA	8.4
314.	NOx	35190	34510	NA	12	11.9	NA	12
314.	NOx	20140	20110	NA	6.37	6.46	NA	6.42
315.	NOx	43740	45820	46200	36.4	36.7	37.2	36.8
315.	NOx	5720	5310	5330	2.29	2.42	2.58	2.43
315.	NOx	18210	16410	17160	12	9.85	9.82	10.6
315.	NOx	26230	25730	24960	18.6	18.6	17.8	18.3
316.	NOx	43900	43490	45140	37.7	37.6	36.5	37.3
316.	NOx	17800	17800	18100	9.84	9.81	10.4	10
316.	NOx	119200	114770	112150	78.5	75.3	72.8	75.5
316.	NOx	26060	26750	26280	12.1	13.1	12.6	12.6
317.	NOx	159650	161510	161180	65.8	67.5	67.1	66.8
317.	NOx	33940	34230	34630	9.21	9.41	9.59	9.4
407	NOx	22700	22500	22200	NR	NR	NR	NR
408	NOx	29500	29500	29500	NR	NR	NR	NR
425	NOx	23200	25700	25100	NR	NR	NR	NR
428.	NOx	21600	21600	21600	NR	NR	NR	NR
428.	NOx	25300	25300	25300	NR	NR	NR	NR
428.	NOx	21200	21500	21000	NR	NR	NR	NR
428.	NOx	24600	24600	24600	NR	NR	NR	NR
428.	NOx	18200	18200	18200	NR	NR	NR	NR
428.	Nox	24700	25200	25500	NR	NR	NR	NR
430.	NOx	23500	23500	23500	NR	NR	NR	NR
430.	NOx	16250	16250	16250	NR	NR	NR	NR
430.	NOx	24700	25000	25200	NR	NR	NR	NR
430.	NOx	28810	28810	28810	NR	NR	NR	NR
430.	NOx	33750	33750	33750	NR	NR	NR	NR
430.	NOx	24030	24030	24030	NR	NR	NR	NR
430.	NOx	27120	27120	27120	NR	NR	NR	NR
430.	NOx	27680	27680	27680	NR	NR	NR	NR
430.	NOx	20570	20570	20570	NR	NR	NR	NR
430.	NOx	25900	25900	25900	NR	NR	NR	NR
430.	NOx	33930	33930	33930	NR	NR	NR	NR
430.	NOx	28980	28980	28980	NR	NR	NR	NR
430.	NOx	25720	25720	25720	NR	NR	NR	NR
430.	NOx	25680	25680	25680	NR	NR	NR	NR
430.	NOx	29650	29650	29650	NR	NR	NR	NR
430.	NOx	30400	30400	30400	NR	NR	NR	NR
430.	NOx	22200	22200	22200	NR	NR	NR	NR
430.	NOx	32100	32100	32100	NR	NR	NR	NR
430.	NOx	23200	23200	23200	NR	NR	NR	NR

ID	Pollutant	lbMMBtu1	lbMMBtu2	lbMMBtu3	lbMMBtuAvg	lbMW1
313.	NOx	.505	.519	.508	.511	7.43
313.	NOx	.633	.616	.637	.629	7.41
313.	NOx	.522	.512	.516	.517	5.53
313.	NOx	.119	.122	.131	.124	1.61
313.	NOx	.209	.22	.225	.218	2.26
313.	NOx	.402	.387	.388	.392	4.91
314.	NOx	.0943	.102	.101	.0991	.945
314.	NOx	.0873	.0877		.0875	1.03
314.	NOx	.147	.148		.148	2.2
314.	NOx	.11	.11		.11	1.67
315.	NOx	.263	.257	.26	.26	3.43
315.	NOx	.0647	.0687	.0729	.0688	.864
315.	NOx	.149	.127	.127	.134	2.26
315.	NOx	.184	.186	.179	.183	2.34
316.	NOx	.239	.24	.23	.236	3.52
316.	NOx	.123	.121	.127	.124	3.68
316.	NOx	.596	.576	.553	.575	6.43
316.	NOx	.19	.205	.197	.197	3.97
317.	NOx	.595	.611	.611	.606	6.04
317.	NOx	.19	.19	.193	.191	3.38
407	NOx	.0986	.102	.101	.101	NR
408	NOx	.117	.117	.117	.117	NR
425	NOx	.114	.125	.121	.12	NR
428.	NOx	.092	.092	.092	.092	NR
428.	NOx	.119	.119	.119	.119	NR
428.	NOx	.104	.102	.0998	.102	NR
428.	NOx	.114	.114	.114	.114	NR
428.	NOx	.0856	.0856	.0856	.0856	NR
428.	Nox	.12	.12	.119	.12	NR
430.	NOx	.092	.092	.092	.092	NR
430.	NOx	.0591	.0591	.0591	.0591	NR
430.	NOx	.11	.107	.109	.109	NR
430.	NOx	.124	.124	.124	.124	NR
430.	NOx	.124	.124	.124	.124	NR
430.	NOx	.0991	.0991	.0991	.0991	NR
430.	NOx	.111	.111	.111	.111	NR
430.	NOx	.119	.119	.119	.119	NR
430.	NOx	.0843	.0843	.0843	.0843	NR
430.	NOx	.112	.112	.112	.112	NR
430.	NOx	.131	.131	.131	.131	NR
430.	NOx	.124	.124	.124	.124	NR
430.	NOx	.0998	.0998	.0998	.0998	NR
430.	NOx	.125	.125	.125	.125	NR
430.	NOx	.13	.13	.13	.13	NR
430.	NOx	.123	.123	.123	.123	NR
430.	NOx	.09	.09	.09	.09	NR
430.	NOx	.139	.139	.139	.139	NR
430.	NOx	.0996	.0996	.0996	.0996	NR

ID	Pollutant	lbMW2	lbMW3	lbMWAvg	Facility Name
313.	NOx	7.56	7.38	7.46	NR
313.	NOx	7.12	7.46	7.33	NR
313.	NOx	5.48	5.48	5.5	NR
313.	NOx	1.71	1.85	1.72	NR
313.	NOx	2.38	2.49	2.38	NR
313.	NOx	4.67	4.68	4.75	NR
314.	NOx	1.03	1.02	.998	NR
314.	NOx	1.03	NA	1.03	NR
314.	NOx	2.18	NA	2.19	NR
314.	NOx	1.69	NA	1.68	NR
315.	NOx	3.46	3.51	3.47	NR
315.	NOx	.913	.974	.917	NR
315.	NOx	1.86	1.85	1.99	NR
315.	NOx	2.34	2.24	2.31	NR
316.	NOx	3.51	3.41	3.48	NR
316.	NOx	3.67	3.89	3.75	NR
316.	NOx	6.17	5.97	6.19	NR
316.	NOx	4.3	4.13	4.13	NR
317.	NOx	6.19	6.16	6.13	NR
317.	NOx	3.45	3.52	3.45	NR
407	NOx	NR	NR	NR	SDGE NTC GT
408	NOx	NR	NR	NR	SDGE (MCRD/NTC)
425	NOx	NR	NR	NR	SDGE Naval Station GT
428.	NOx	NR	NR	NR	SDGE Miramar
428.	NOx	NR	NR	NR	SDGE Miramar
428.	NOx	NR	NR	NR	SDGE Miramar
428.	NOx	NR	NR	NR	SDGE Miramar
428.	NOx	NR	NR	NR	SDGE Miramar
428.	Nox	NR	NR	NR	SDGE Miramar
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA
430.	NOx	NR	NR	NR	SDGE KMA

ID	Pollutant	Method	Location	Facility	Testing Compa	Date
313.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 1/93
313.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 1/93
313.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 1/93
313.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 1/93
313.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 1/93
313.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 1/93
314.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 7/93
314.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 7/93
314.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 7/93
314.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 7/93
315.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 6/93
315.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 6/93
315.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 6/93
315.	NOx	EPA 7E/20	NR	NR/NR	Carnot	12/ 6/93
316.	NOx	EPA 7E/20	NR	NR/NR	Carnot	11/15/93
316.	NOx	EPA 7E/20	NR	NR/NR	Carnot	11/15/93
316.	NOx	EPA 7E/20	NR	NR/NR	Carnot	11/15/93
316.	NOx	EPA 7E/20	NR	NR/NR	Carnot	11/15/93
317.	NOx	EPA 7E/20	NR	NR/NR	Carnot	11/18/93
317.	NOx	EPA 7E/20	NR	NR/NR	Carnot	11/18/93
407	NOx	SDAPCD Meth	Neville Rd	SDGE NTC GT	SDAPCD	3/18/98
408	NOx	Method 7	San Diego, CA	SDGE (MCRD/	SDAPCD	1/10/96
425	NOx	SDAPCD Meth	San Diego, CA	SDGE Naval St	SDAPCD	4/15/97
428.	NOx	Method 7	San Diego, CA	SDGE Miramar	SDAPCD	3/22/95
428.	NOx	Method 7	San Diego, CA	SDGE Miramar	SDAPCD	3/ 6/96
428.	NOx	SDAPCD Meth	San Diego, CA	SDGE Miramar	SDAPCD	4/22/97
428.	NOx	Method 7	San Diego, CA	SDGE Miramar	SDAPCD	3/15/94
428.	NOx	Method 7	San Diego, CA	SDGE Miramar	SDAPCD	3/ 6/96
428.	Nox	Method 7	San Diego, CA	SDGE Miramar	SDAPCD	4/24/97
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	5/24/95
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	3/27/96
430.	NOx	SDAPCD Meth	San Diego, CA	SDGE KMA	SDAPCD	4/17/97
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/12/94
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/19/95
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/16/96
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/26/94
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	5/10/95
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/16/96
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/12/94
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/19/95
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	5/ 1/96
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/26/94
430.	NOx	Method 7	San Diego, CA	SDGE KMA/Sa	SDAPCD	5/10/95
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	5/ 1/96
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	5/17/94
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	4/26/95
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	5/15/96
430.	NOx	Method 7	San Diego, CA	SDGE KMA	SDAPCD	5/10/94

ID	Pollutant	Rating	Unit	Load	Manufacturer	Model
313.	NOx	7.7	MW	50	General Electri	Frame 3
313.	NOx	7.7	MW	75	General Electri	Frame 3
313.	NOx	9.4	MW	100	Solar	T12000
313.	NOx	9.4	MW	25	Solar	T12000
313.	NOx	9.4	MW	50	Solar	T12000
313.	NOx	9.4	MW	75	Solar	T12000
314.	NOx	10.9	MW	100	Solar	Mars SoLoNOx
314.	NOx	10.9	MW	75	Solar	Mars SoLoNOx
314.	NOx	10.9	MW	50	Solar	Mars SoLoNOx
314.	NOx	10.9	MW	35	Solar	Mars SoLoNOx
315.	NOx	10.6	MW	100	General Electri	LM1500
315.	NOx	10.6	MW	25	General Electri	LM1500
315.	NOx	10.6	MW	50	General Electri	LM1500
315.	NOx	10.6	MW	75	General Electri	LM1500
316.	NOx	10.7	MW	100	Rolls Royce	Avon
316.	NOx	10.7	MW	25	Rolls Royce	Avon
316.	NOx	12.2	MW	100	Rolls Royce	Spey
316.	NOx	12.2	MW	25	Rolls Royce	Spey
317.	NOx	10.9	MW	100	Solar	Mars
317.	NOx	10.9	MW	25	Solar	Mars
407	NOx	317	MMBtu/hr	75	General Electri	PG-5191
408	NOx	317	MMBtu/hr	57.1	General Electri	PG-5191
425	NOx	411	MMBtu/hr	78.4	Pratt & Whitney	FT4C-1-DF
428.	NOx	360	MMBtu/hr	84.72	General Electri	5251
428.	NOx	360	MMBtu/hr	85	General Electri	5251
428.	NOx	360	MMBtu/hr	82.2	General Electri	5251
428.	NOx	360	MMBtu/hr	84.6	General Electri	5251
428.	NOx	360	MMBtu/hr	89	General Electri	5251
428.	Nox	360	MMBtu/hr	80.8	General Electri	5251
430.	NOx	299	MMBtu/hr	92.4	General Electri	5221
430.	NOx	299	MMBtu/hr	88.9	General Electri	5221
430.	NOx	299	MMBtu/hr	89	General Electri	5221
430.	NOx	317	MMBtu/hr	69.6	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	81.2	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	77.2	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	88.6	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	86.8	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	84.5	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	78.2	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	58.2	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	77.2	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	86	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	85.4	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	76.2	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	83.7	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	77.2	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	74.9	General Electri	PG-5211
430.	NOx	317	MMBtu/hr	76.5	General Electri	PG-5211

ID	Pollutant	Turbine	Fuel Type	Application	Run 1 Conc R	Run 2 Conc R
313.	NOx	General Electri	Natural Gas	Gas Transmiss	63050	62100
313.	NOx	General Electri	Natural Gas	Gas Transmiss	84550	84380
313.	NOx	Solar/T12000/9	Natural Gas	Gas Transmiss	129190	129130
313.	NOx	Solar/T12000/9	Natural Gas	Gas Transmiss	18100	18640
313.	NOx	Solar/T12000/9	Natural Gas	Gas Transmiss	37780	38380
313.	NOx	Solar/T12000/9	Natural Gas	Gas Transmiss	90690	87320
314.	NOx	Solar/Mars SoL	Natural Gas	Gas Transmiss	25120	26340
314.	NOx	Solar/Mars SoL	Natural Gas	Gas Transmiss	20780	21030
314.	NOx	Solar/Mars SoL	Natural Gas	Gas Transmiss	35190	34510
314.	NOx	Solar/Mars SoL	Natural Gas	Gas Transmiss	20140	20110
315.	NOx	General Electri	Natural Gas	Gas Transmiss	43740	45820
315.	NOx	General Electri	Natural Gas	Gas Transmiss	5720	5310
315.	NOx	General Electri	Natural Gas	Gas Transmiss	18210	16410
315.	NOx	General Electri	Natural Gas	Gas Transmiss	26230	25730
316.	NOx	Rolls Royce/Av	Natural Gas	Gas Transmiss	43900	43490
316.	NOx	Rolls Royce/Av	Natural Gas	Gas Transmiss	17800	17800
316.	NOx	Rolls Royce/Sp	Natural Gas	Gas Transmiss	119200	114770
316.	NOx	Rolls Royce/Sp	Natural Gas	Gas Transmiss	26060	26750
317.	NOx	Solar/Mars/10.	Natural Gas	Gas Transmiss	159650	161510
317.	NOx	Solar/Mars/10.	Natural Gas	Gas Transmiss	33940	34230
407	NOx	General Electri	Natural Gas	Generator	22700	22500
408	NOx	General Electri	Natural Gas	Gas turbine ge	29500	29500
425	NOx	Pratt & Whitney	Natural Gas	Generator	23200	25700
428.	NOx	General Electri	Natural Gas	Generator	21600	21600
428.	NOx	General Electri	Natural Gas	Generator	25300	25300
428.	NOx	General Electri	Natural Gas	Generator	21200	21500
428.	NOx	General Electri	Natural Gas	Generator	24600	24600
428.	NOx	General Electri	Natural Gas	Gernerator	18200	18200
428.	Nox	General Electri	Natural Gas	Generator	24700	25200
430.	NOx	General Electri	Natural Gas	Cogeneration	23500	23500
430.	NOx	General Electri	Natural Gas	Cogeneration	16250	16250
430.	NOx	General Electri	Natural Gas	Generator	24700	25000
430.	NOx	General Electri	Natural Gas	Cogeneration	28810	28810
430.	NOx	General Electri	Natural Gas	Cogeneration	33750	33750
430.	NOx	General Electri	Natural Gas	Cogeneration	24030	24030
430.	NOx	General Electri	Natural Gas	Cogeneration	27120	27120
430.	NOx	General Electri	Natural Gas	Cogeneration	27680	27680
430.	NOx	General Electri	Natural Gas	Cogeneration	20570	20570
430.	NOx	General Electri	Natural Gas	Cogeneration	25900	25900
430.	NOx	General Electri	Natural Gas	Cogeneration	33930	33930
430.	NOx	General Electri	Natural Gas	Cogeneration	28980	28980
430.	NOx	General Electri	Natural Gas	Cogeneration	25720	25720
430.	NOx	General Electri	Natural Gas	Cogeneration	25680	25680
430.	NOx	General Electri	Natural Gas	Cogeneration	29650	29650
430.	NOx	General Electri	Natural Gas	Cogeneration	30400	30400
430.	NOx	General Electri	Natural Gas	Cogeneration	22200	22200
430.	NOx	General Electri	Natural Gas	Cogeneration	32100	32100
430.	NOx	General Electri	Natural Gas	Cogeneration	23200	23200

ID	Pollutant	Run 3 Conc R	Average	Conc R Averag	DL	SD
313.	NOx	61010	62053.3333333	62100	NA	3
313.	NOx	84530	84486.6666666	84500	NA	3
313.	NOx	129060	129126.666666	129000	NA	3
313.	NOx	18420	18386.6666666	18400	NA	3
313.	NOx	38980	38380	38400	NA	3
313.	NOx	86380	88130	88100	NA	3
314.	NOx	25880	25780	25800	NA	3
314.	NOx	NA	20905	20900	NA	3
314.	NOx	NA	34850	34800	NA	3
314.	NOx	NA	20125	20100	NA	3
315.	NOx	46200	45253.3333333	45300	NA	3
315.	NOx	5330	5453.33333333	5450	NA	3
315.	NOx	17160	17260	17300	NA	3
315.	NOx	24960	25640	25600	NA	3
316.	NOx	45140	44176.6666666	44200	NA	3
316.	NOx	18100	17900	17900	NA	3
316.	NOx	112150	115373.333333	115000	NA	3
316.	NOx	26280	26363.3333333	26400	NA	3
317.	NOx	161180	160780	161000	NA	3
317.	NOx	34630	34266.6666666	34300	NA	3
407	NOx	22200	22466.6666666	22500	NA	3
408	NOx	29500	29500	29500	NA	3
425	NOx	25100	24666.6666666	24700	NA	3
428.	NOx	21600	21600	21600	NA	3
428.	NOx	25300	25300	25300	NA	3
428.	NOx	21000	21233.3333333	21200	NA	3
428.	NOx	24600	24600	24600	NA	3
428.	NOx	18200	18200	18200	NA	3
428.	Nox	25500	25133.3333333	25100	NA	3
430.	NOx	23500	23500	23500	NA	3
430.	NOx	16250	16250	16200	NA	3
430.	NOx	25200	24966.6666666	25000	NA	3
430.	NOx	28810	28810	28800	NA	3
430.	NOx	33750	33750	33800	NA	3
430.	NOx	24030	24030	24000	NA	3
430.	NOx	27120	27120	27100	NA	3
430.	NOx	27680	27680	27700	NA	3
430.	NOx	20570	20570	20600	NA	3
430.	NOx	25900	25900	25900	NA	3
430.	NOx	33930	33930	33900	NA	3
430.	NOx	28980	28980	29000	NA	3
430.	NOx	25720	25720	25700	NA	3
430.	NOx	25680	25680	25700	NA	3
430.	NOx	29650	29650	29600	NA	3
430.	NOx	30400	30400	30400	NA	3
430.	NOx	22200	22200	22200	NA	3
430.	NOx	32100	32100	32100	NA	3
430.	NOx	23200	23200	23200	NA	3

ID	Pollutant	CountAConc	Countlbh	CountlbMMBtu	CountlbMW	CUnit
313.	NOx	1	1	1	1	ppb
313.	NOx	1	1	1	1	ppb
313.	NOx	1	1	1	1	ppb
313.	NOx	1	1	1	1	ppb
313.	NOx	1	1	1	1	ppb
313.	NOx	1	1	1	1	ppb
314.	NOx	1	1	1	1	ppb
314.	NOx	1	1	1	1	ppb
314.	NOx	1	1	1	1	ppb
314.	NOx	1	1	1	1	ppb
315.	NOx	1	1	1	1	ppb
315.	NOx	1	1	1	1	ppb
315.	NOx	1	1	1	1	ppb
315.	NOx	1	1	1	1	ppb
316.	NOx	1	1	1	1	ppb
316.	NOx	1	1	1	1	ppb
316.	NOx	1	1	1	1	ppb
316.	NOx	1	1	1	1	ppb
317.	NOx	1	1	1	1	ppb
317.	NOx	1	1	1	1	ppb
407	NOx	1	0	1	0	ppb
408	NOx	1	0	1	0	ppb
425	NOx	1	0	1	0	ppb
428.	NOx	1	0	1	0	ppb
428.	NOx	1	0	1	0	ppb
428.	NOx	1	0	1	0	ppb
428.	NOx	1	0	1	0	ppb
428.	NOx	1	0	1	0	ppb
428.	Nox	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb
430.	NOx	1	0	1	0	ppb

ID	Pollutant	Control Device	Source EF
313.	NOx	None	#Error
313.	NOx	None	#Error
313.	NOx	None	#Error
313.	NOx	None	#Error
313.	NOx	None	#Error
313.	NOx	None	#Error
314.	NOx	Lean pre-mix (	#Error
314.	NOx	Lean pre-mix (	#Error
314.	NOx	Lean pre-mix (	#Error
314.	NOx	Lean pre-mix (	#Error
315.	NOx	None	#Error
315.	NOx	None	#Error
315.	NOx	None	#Error
315.	NOx	None	#Error
316.	NOx	None	#Error
316.	NOx	None	#Error
316.	NOx	None	#Error
316.	NOx	None	#Error
317.	NOx	None	#Error
317.	NOx	None	#Error
407	NOx	Water Injection	#Error
408	NOx	No Control	#Error
425	NOx	Water Injection	#Error
428.	NOx	Water Injection	#Error
428.	NOx	Water Injection	#Error
428.	NOx	Water Injection	#Error
428.	NOx	Water Injection	#Error
428.	NOx	Water Injection	#Error
428.	Nox	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error
430.	NOx	Water Injection	#Error