BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

Petroleum Refinery Emissions Inventory Guidelines

July 2020

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Executive Summary

Petroleum refineries and their support facilities are complex facilities with hundreds of thousands of sources of air pollutants. The District currently estimates and tracks emissions from permitted and formally permit exempt sources.

To ensure a consistent approach to estimating emissions is used by the Bay Area petroleum refineries and their support facilities, guidance is required.

Petroleum refineries and support facilities within the Bay Area should estimate and report emissions of criteria pollutants, toxic air contaminants, and greenhouse gases for all continuous, intermittent, predictable, or 40 CFR 68.168 reportable accidental air releases resulting from petroleum refinery processes at stationary sources at a petroleum refinery or support facility.

These guidelines describe the emission estimation methodologies that have been reviewed and approved by the District to be used when calculating emissions, outline quality assurance and quality control measures to follow to ensure quality data, and provide report formats to follow when submitting emission inventories for District and the public's review.

By following these guidelines, petroleum refinery and support facility emission inventories should be:

- comprehensive (include all emission activities and sources),
- comparable (follows same conventions and procedures used by all refineries),
- robust (data quality is high and follows proper quality assurance and quality controls procedures),
- verifiable (all documentation required to replicate estimates is maintained and available for review), and
- transparent (methodologies used and rationale are stipulated).

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Deleted: (2) all air releases from cargo carriers (e.g. ships and trains), excluding motor vehicles, that load or unload materials at a petroleum refinery including emissions from such carriers while operating within the District or within California Coastal Waters.¶
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Table of Contents

Acronyms, Definitions, and Terms

Accuracy	The maximum deviation of a value from its true value.
AP-42	U.S. EPA AP 42, *Compilation of Air Pollutant Emission Factors*
ARB (or CARB)	California Air Resources Board
BAAQMD	Bay Area Air Quality Management District
Bias	The systematic or persistent distortion of a measurement process which causes error in one direction (either positive or negative)
BTU	British thermal unit
CAPCOA	California Air Pollution Control Officers Association
CATEF	California Air Toxics Emission Factors
CEM	continuous emission monitor
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents, usually expressed in metric tons
DSCF	dry, standard cubic foot
EEPPR	U.S. EPA *Emission Estimation Protocol for Petroleum Refineries*
EPA	United States Environmental Protection Agency
GHG	greenhouse gas
HAP	hazardous air pollutant
Heavy liquid	liquids with an initial boiling point greater than or equal to 150 degrees Celsius (302 degrees Fahrenheit)
lb	pounds
LDAR	leak detection and repair
LOD	limit of detection
NO_X	oxides of nitrogen
Parametric monitor	any monitoring device or system required by District permit condition or regulation to monitor the operational parameters of either a source or an abatement device. Parametric monitors may record temperature, gauge pressure, flowrate, pH, hydrocarbon breakthrough, or other factors
PFD	process flow diagram
P&ID	piping and instrumentation diagram
PM	particulate matter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
PM_{10}	particulate matter less than 10 microns in diameter
ppm	parts per million
ppmv	parts per million, by volume
ppmw	parts per million, by weight
Precision	A measure of mutual agreement among individual measurements of the same property usually under prescribed similar conditions.
Representativeness	The degree in which data accurately and precisely represents a characteristic of a population, parameter variation at a sampling point, a process condition, or an environmental condition
QA	quality assurance
QC	quality control
SCF	standard cubic foot
SO_2	sulfur dioxide
TAC	toxic air contaminant
TDS	total dissolved solids
VOC	volatile organic compounds

Section 1: Introduction

This guidance document describes methodologies for calculating and reporting petroleum refinery and support facility emission inventories that have been reviewed and approved by District staff. While alternative methodologies may be proposed to the District for acceptance, the methodologies set forth in this guidance are presumptively the most accurate and valid, and so should be used until this guidance is revised to reflect a different methodology.

These guidelines include District staff recommendations made in the District report entitled *Refinery Emissions Inventory Guidelines: An Assessment of EPA Document Emission Estimation Protocol for Petroleum Refineries* (dated September 2013).

The District staff report reviewed the document entitled *Emission Estimation Protocol for Petroleum Refineries* (version 2.1.1, May 2011) by the staff of the District. The *Emission Estimation Protocol for Petroleum Refineries* (EEPPR) was prepared by RTI International for U.S. EPA to provide guidance to petroleum refineries on how to calculate emission inventories, for the purpose of satisfying EPA's 2011 information collection request. The EEPPR was revised in April 2015.

The EEPPR is divided into several chapters covering common emission categories at refineries. Each chapter contains several options for calculating emissions, and ranks those options in order of preference. Staff reviewed the chapters to see how the various calculation methods compare to the way the District typically calculates emissions. For each chapter, staff prepared a summary report and provided recommendations on which method(s) in the EEPPR, if any, should be used by the District.

These guidelines incorporate staff recommendations as well input from the regulated entities and the public.

Section 2: Overriding Principles

An emission inventory is a compilation of estimates of emission estimates from individual and aggregated activities and sources. When estimating emissions, not all methodologies are equal nor result in the same quality or reliability of estimate. Often, there are multiple methodologies that may be employed. However, using a methodology that has a greater degree of reliability (certainty) of an estimate typically costs more (in time, money, and resources) and may not be cost-effective if resulting emission estimates are low or a greater degree of certainty is not needed. Typical methods for estimating emissions compared to their relative costs are shown in Figure 2.1.

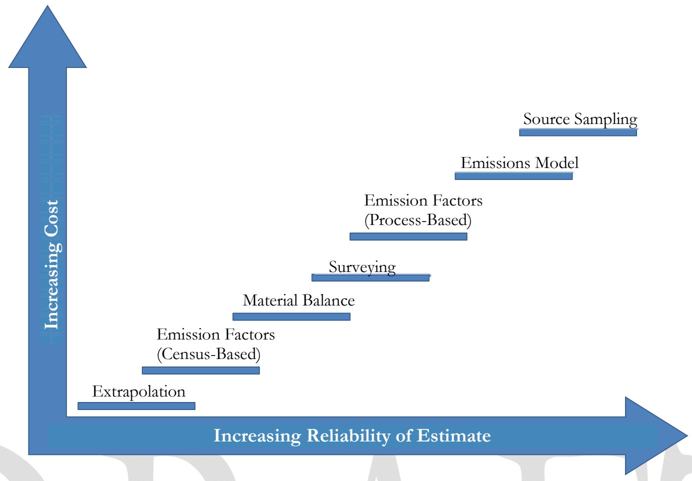

Figure 2.1 Emission estimation methodologies
(Source: Solomon, *Emission Inventories,* EPA)

As Figure 2.1 shows, source sampling (e.g. source tests, continuous emission monitor, etc.) has the greatest degree of reliability but also costs the most while extrapolation has the least degree of reliability but costs the least. From their inherent nature, the least reliable methods typically overestimate emissions due to the conservative assumptions made in their development.

As the purpose of emission inventories is for accurate emissions rather than a conservative maximum as often used in permit evaluations, these guidelines require using the most reliable method available and rank methods (shown in Figure 2.2) accordingly.

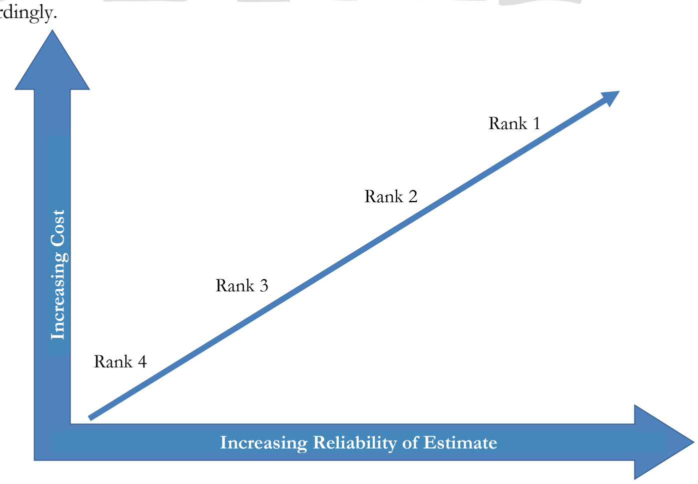

Figure 2.2 Emission estimation methodology rankings

When using the higher ranking emission estimation method, the following overriding principles should be considered when doing any type of emission calculation:

- Direct measurement is preferable to calculated emissions.
- Continuous measurement is preferable to periodic testing.
- Periodic source testing should be representative of typical source operation (unless intentionally testing for atypical conditions). If multiple source tests are available for the same source, source tests covering the inventory period should be used whenever available unless the source test represents atypical operation.
- Emission factors that are based on source testing should be updated as processes change.
- Use default emission factors only when other data is not available. While it is desirable to avoid using default emission factors, it is impractical to directly measure or test all sources for all pollutants under all operating scenarios. However, such factors will not capture emission trends over time, due to changing operation.
- When multiple default emission factors are available for a given criteria pollutant/toxic air contaminant, use the following order of preference:
  1. CATEF*,
  2. EEPPR,
  3. AP-42.

  Emission factors from sources other than those listed above, such as from EPA's National Emissions Inventory (NEI), may be acceptable. However, such emission factors should be reviewed and approved by the District, on a case-by-case basis, and incorporated into the District-approved default emission factors list of Appendix A.

  *In the absence of source-specific emission factor data, the District will apply the most representative emissions factors as provided in these guidelines, including the mean or maximum California Air Toxics Emission Factors ("CATEF") where appropriate, with the exception of CATEF that are based on the limit of detection of TAC emissions (identified as having a detect ratio of 0.00). With the exception of emission factors for those sources and their listed pollutants identified in Appendix D of the Hot Spots Inventory Guidelines, refineries and the District will apply half of the lowest representative published value in cases where the most representative emission factor is CATEF based on the limit of detection of TACs. For those sources and their listed pollutants identified in Appendix D of the Hot Spots Inventory Guidelines, maximum CATEF will be applied in the absence of source-specific emission factor data. Tables A-1 and A-2 of Appendix A provide emission factors from CATEF following this guidance.

Section 3: Source-Specific Emission Calculation Procedures

The section outlines source-specific guidance for broad categories of emission-producing sources and activities. However, a petroleum refinery is a complex facility with thousands of activities and hundreds of thousands of components that may cause emissions. Therefore, it is not practical to list guidance for every activity and/or source that may emit. Nevertheless, although these guidelines may not provide guidance for a specific emission-producing activity and/or source, a facility is still required to estimate and report emissions for that activity and/or source. For those cases, those activities and/or sources, the facility should contact the District's Engineering Division for clarification on how to estimate emission. Those activities and/or sources should be identified within the submitted emission inventory as not covered by these guidelines. If warranted, the procedures of Section 10 (Guidelines Revision Procedure) may be followed to update the guidelines.

All emission inventories should include estimates of air emissions from activities including from all continuous, intermittent, predictable, or accidental air releases resulting from petroleum refinery processes at stationary sources at a petroleum refinery or support facility.

Accidental air releases are unanticipated emissions required to be reported in a risk management plan per 40 CFR 68.168.

Emissions occurring from incidental office activities (i.e. use of organic compound-containing permanent markers) are not required to be estimated.

All emission inventories shall include estimates for all toxic air contaminants (TACs) that appear in Table 2-5-1 of District Regulation 2, Rule 5 and that have been demonstrated, as judged by the District, to be emitted from a refinery source category unless a relevant refinery can demonstrate, as approved by the District, that a particular TAC cannot be emitted by that refinery. The District will use the following evidence to demonstrate that a pollutant has been emitted from a refinery source category:

1. District data (studies, sampling, or measurements);
2. Peer-reviewed published literature by scientific bodies or government agencies such as EPA and CARB;
3. Facility-specific process or equipment data; or
4. Validated measurement data of similar equipment.

Refineries shall submit proposed speciation data to the District. In approving speciation data, the District will review the proposed data submitted by every refinery and any data the District has collected and shall then apply the following hierarchy of speciation data, on a per-pollutant basis:

1. Site-, process-, and equipment-specific data, reviewed and approved by the District.
2. Site-, process-, and stream-specific data, reviewed and approved by the District.
3. Site- and stream-specific data, reviewed and approved by the District.
4. Stream-specific data from similar processes or equipment at other refineries within the same corporate family, reviewed and approved by the District.
5. Default process- and stream-specific data compiled by the District from Bay Area refinery data, or District sampling.
6. Peer-reviewed published studies on similar processes, equipment and streams, reviewed and approved by the District.
7. Peer-reviewed industry literature on similar processes, equipment and streams, reviewed and approved by the District.

If a refinery disagrees with the District's determination that a TAC may be emitted from the refinery, the refinery may present a technical demonstration supporting its position. When evaluating such a technical demonstration for approval by the District, the District will accept the following technical demonstrations:

1. It is not possible for a pollutant to be emitted due to either process chemistry, equipment configuration, or equipment operation; or
2. A previous pollutant demonstration, used as evidence that the pollutant is emitted, is no longer valid; or
3. A previous pollutant demonstration, used as evidence that the pollutant is emitted, was invalid.

Refineries and the District may rely on source-specific testing of TAC emissions from refinery sources. In the case of a source test that is unable to detect a particular TAC, if the test is based on the lowest limit of detection currently achievable, as approved by the District, the District will include in the refinery emissions inventory half of the approved test's limit of detection for that particular TAC. Refineries desiring to report lower emissions for a TAC that is unable to be detected by a source test may (1) demonstrate that the TAC is not present, as described above, or (2) optimize the source test methodology, in consultation with the District to lower the limit of detection.

To aid comprehension and implementation, each section contains the following headings with section-specific information.

Approved Methods

Specifies the District-approved emission estimation methodologies and their ranking in relation to each other. Emission inventories should employ the highest ranking methodology **for which data is available** (i.e. if emissions can be estimated using a Rank 2 and Rank 4 method, emissions should be estimated using the Rank 2 method).

District-approved default emission factors that may not exist or may differ from one published by either ARB or EPA are listed with the technical basis in Appendix A.

Data Needs and Supporting Documentation

Lists data required to estimate emissions per listed emission estimation methodologies. Details documentation that a facility should maintain in order to estimate emissions using a specific method. At a minimum, the listed documentation should be included in the facility's quality assurance program.

Several sections list a requirement to maintain information and/or calculations in a spreadsheet. This is to allow the District to review and verify underlying information. However, due to either the complexity or quantity of information, a spreadsheet may not function as well. Therefore, refineries may use a non-spreadsheet-based software program for calculations provided that the underlying equations can be reviewed and the programs validated and approved by the District on a case by case basis. Any such software program must be made available to the District, must allow a static copy with a timestamp to be made, and include the minimum functionality that a spreadsheet would offer.

Reports

Lists reports required elsewhere (District, ARB, EPA, etc.) that may be used in estimating emissions.

Definitions

Includes section-specific definitions that are either important or may differ from another section.

Key Factors

Enumerates significant assumptions/premises used in an emission estimation methodology (e.g. a single source test result is representative of normal, continuous operation).

Section 3.1: Greenhouse Gas Emissions

All emission inventories should include estimates of greenhouse gas emissions from all activities including from all continuous, intermittent, predictable, or accidental air releases resulting from petroleum refinery processes at stationary sources at a petroleum refinery or support facility.

Bay Area petroleum refineries and support facilities currently estimate and report greenhouse gas emissions to two regulatory agencies: the California Air Resources Board (ARB) and the U.S. EPA. However, greenhouse gas emissions occurring from marine (e.g. transit, maneuvering, hoteling, pumping, etc.) and rail (hauling, switching) activities are not required to be reported by either Title 17 California Code of Regulations (CCR) Sections 95100 through 95158 or 40 CFR Part 98.

For sources and activities required to be reported by Title 17 CCR §95113, greenhouse gas emissions should be calculated in a manner consistent with California Air Resources Board requirements as contained in §95113 of the Mandatory Greenhouse Gas Emissions Reporting Rule.

However, greenhouse gas emissions should be estimated and reported on an individual source basis. When emissions from multiple sources are aggregated (i.e. using same analyzer, meter, etc.), aggregated emissions may be by apportioned to individual sources by fuel gas throughput or firing rate.

Regardless of any exemptions (e.g. certain pilot lights, emergency generators, portable equipment, marine vessels, rail cars, etc.) listed in either 40 CFR Part 98 or Title 17 CCR §95113, refineries should report emissions from sources or activities that meet one of the categories listed above.

Therefore, although some information from greenhouse gas inventories submitted to ARB and to EPA may be replicated in inventories submitted to the District, those inventories are not sufficient by themselves. In some cases, the inventories may differ for certain sources as discussed in the section below.

Approved Methods

Refineries and support facilities should identify within submitted emissions inventories any source or activity included in the inventory that is not included within the facility's Title 17 CCR §95113 report for that year. When possible, emissions inventories should include a summary of greenhouse gas emissions from sources not included in that year's Title 17 CCR §95113 report. This will allow a reconciliation of facility-wide greenhouse gas emissions as listed in a District emissions inventory that may differ from the greenhouse gas emissions listed in a Title 17 CCR §95113 report.

For sources exempted or not covered in Title 17 CCR Title 17 CCR §95113, greenhouse gas emissions should be estimated using the highest ranked methodology for which data is available listed in Table 3.1-1.

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Table 3.1-1: Summary of Approved Greenhouse Gas Emission Estimate Methodologies

Rank	Approved Measurement or Method	Application
1	Direct measurement (CEM) for both flow rate and gas composition	Stationary fuel combustion sources Electricity generation and cogeneration units Hydrogen plants Marine activities Rail activities Loading operations
2	Direct measurement (CEMS) for gas composition Use of F factors	Stationary fuel combustion sources Hydrogen plants Marine activities Rail activities Loading operations
3A	Fuel analysis/mass balance	Stationary fuel combustion sources Electricity generation and cogeneration units Hydrogen plants Marine activities Rail activities Loading operations
3B	Source-specific stack testing to calculate source specific emission correlations or factors	Stationary fuel combustion sources Electricity generation and cogeneration units Hydrogen plants Marine activities Rail activities Fugitive emissions
4	Default emission factors	All

Rank 4 – Default Emission Factors

40 CFR Part 98 Subpart C lists equations for calculating CO_2 emissions from greenhouse gases using default emission factors. These equations are acceptable to be used. However, when estimating emissions using these equations, annual averages (e.g. fuel usages, heat content, carbon content, etc.) should not be used. These calculations should be done on an hourly basis and if not available, on a daily basis. The reason for doing this is because multiplying an average by an average may overestimate or underestimate emissions. Although this error may be small for routine operation, this may not be the case for startup and shutdown activities.

Data Needs and Supporting Documentation

The following data is required to estimate greenhouse gas emissions. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.1-2: Data Needs and Documentation by Greenhouse Gas Emissions Estimate Method

Measurement Method	Data Needed	Supporting Documentation
Direct measurement (CEM) for both flow rate and gas composition	Pollutant concentrations, pressure, temperature, and moisture content	Instrumentation records
Direct measurement (CEMS) for gas composition Use of F factors	Fuel usage	Fuel records Flow meter readings
Fuel analysis/mass balance	Heat content of fuel	Lab analysis Instrumentation data
Source-specific stack testing to calculate source specific emission correlations or factors	Throughput	Throughput records
Default emission factors	Production quantities	Production records

Reports
Title 40 Code of Federal Regulations Part 98 reports
Title 17 California Code of Regulations Sections 95100 – 95158 reports

Definitions

Greenhouse gas	a single air pollutant made up of a combination of the following six constituents: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, expressed as CO_2 equivalent emissions (CO_2e)

Key Factors
None

Section 3.2: Fugitive Emission Leaks

Equipment leaks (also known as fugitive emissions) occur throughout the refinery or support facility at various equipment components, including valves, flanges, pumps, compressors, relief valves, etc.

Approved Methods

Fugitive equipment leak emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.2-1.

When using Rank Method 3 or 4 (use of default average emission factors) for non-monitored components in heavy liquid service, use average emission factors developed through the Air District Heavy Liquid Study or, if not finalized, use the interim emission factors identified in Table A-3 of Appendix A.

Table 3.2-1: Summary of Approved Equipment Leak Emission Estimate Methods

Rank	Measurement Method	Correlation Equations or Emission Factor	Compositional Analysis Data[1,2]
1	Direct measurement (bagging)	Not necessary	Speciation of collected gas samples
2	EPA Method 21	Correlation Equation[3]	1. Site-, process-, and equipment-specific data, reviewed and approved by the District. 2. Site-, process-, and stream-specific data, reviewed and approved by the District. 3. Site- and stream-specific data, reviewed and approved by the District. 4. Stream-specific data from similar processes or equipment at other refineries within the same corporate family, reviewed and approved by the District. 5. Default process- and stream-specific data compiled by the District from Bay Area refinery data, or District sampling. 6. Peer-reviewed published studies on similar processes, equipment and streams, reviewed and approved by the District. 7. Peer-reviewed industry literature on similar processes, equipment and streams, reviewed and approved by the District.
3	No monitoring; facility-specific component counts	Default average emission factors[4]	
4	No monitoring; default process component counts[5]	Default average factors[4]	

Notes:

1. The letters represent ranking sublevels. For example, Rank 2a consists of using the correlation equation to estimate the total VOC emissions and using process-specific and equipment-specific process fluid concentration data to estimate speciated emissions.
2. Emission inventories shall utilize refinery data and organic compound emission factors developed through the Heavy Liquid Study and apply District-approved speciation data to estimate equipment leak ("fugitive") TAC emissions from components handling heavy liquid streams. Emission inventories shall also apply District-approved speciation data to estimate equipment leak ("fugitive") TAC emissions from components handling gas and light liquid streams.
3. CAPCOA 1999 *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* – Table IV-3a (Method 3)
4. Table A-3 of Appendix A. The District is currently conducting a study of refinery heavy liquid emission rates and expected to finish by the end of 2019. Average emission factors for non-monitored heavy liquid components will be updated based on the study results.
5. Default process component counts estimated using the multipliers in Table 3.2-2. For process units other than those listed in Table 3.2-2, consult with the Air District.

Table 3.2-2: Heavy Liquid Multipliers

Process Unit	Heavy Liquid Multipliers(1)			
	Valves	Pumps	Pressure Relief Devices	Connectors
Crude distillation	1.13	0.93	2.40	1.07
Alkylation (sulfuric acid)	0.00	0.00	0.00	0.45
Alkylation (HF)	0.21	0.62	0.09	0.14
Catalytic reforming	0.22	0.17	0.00	0.16
Hydrocracking	0.47	0.55	0.00	0.37
Hydrotreating/hydrorefining	0.79	0.86	2.00	0.83
Catalytic cracking	1.58	1.00	1.44	1.19
Thermal cracking (visbreaking)	0.53	0.86	5.00	0.83
Thermal cracking (coking)	0.81	0.92	2.00	1.06
Hydrogen plant	0.00	51.43(2)	0.00	0.00
Product blending	0.44	1.00	0.38	0.71
Sulfur plant	0.88	0.38	1.00	0.39
Vacuum distillation	4.14	6.00	4.00	7.88
Full-range distillation	0.13	0.14	0.25	0.21
Isomerization	0.26	0.56	0.40	0.49
Polymerization	0.23	0.33	2.33	0.30
MEK dewaxing	0.12	0.34	3.00	0.12
Other lube oil processes	1.99	3.20	3.33	6.74

Notes:
1. Derived using counts listed in EPA's "*Emission Estimation Protocol for Petroleum Refineries*", Version 3– Table 2-5.
2. Refineries should use the actual count of heavy liquid pumps in hydrogen plants.

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the following data and supporting documentation are required to estimate mass emissions from equipment leaks and quality assure emission estimates.

Table 3.2-3: Data Needs and Documentation by Equipment Leak Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Direct Measurement	Mass emissions	Source test report
EPA Method 21	Component screening values	Leak Detection and Repair (LDAR) database
	Component types	
	Background screening values	
	Screening date	
	Speciation by stream service	Lab analyses
	Repair history	Work Orders
	Calibration sheet	Calibration Gas Certifications
No monitoring facility-specific component counts	Component inventory (type, count)	LDAR database
No monitoring; default process component counts	Component inventory (type, count)	LDAR database

Reports

District Regulation 8, Rule 18 annual inventory report

Definitions

The following definitions apply when estimating emissions per this section.

Heavy Liquid Organic liquids having an ASTM D1078-98 or D86 initial boiling point greater than 302 degrees Fahrenheit

LDAR Leak Detection and Repair

Key Factors

The following premises are used in this section.

Item	Key Factor
Correlation Equations	Correlation equations represent mass emissions from entire range of components and operating ranges.
Heavy Liquid Service Components	Distribution of heavy liquid service components are similar to those included in EPA's "*Emission Estimation Protocol for Petroleum Refineries*", Version 3 – Table 2-5

Section 3.3: Storage Tanks

Emissions from storage tanks depend on the storage tank type, tank dimensions and characteristics, stored materials, and activity.

Emissions should be estimated for all:

- External floating roof tanks
- Internal floating roof tanks
- Geodesic dome roof tanks, and
- Fixed roof tanks vented to the atmosphere
- Fixed roof tanks vented to a control device

Emissions from fixed roof tanks that are abated by a combustion-based control device (e.g. thermal oxidizer, furnace, etc.) should be estimated using the procedures listed here and apply an abatement efficiency to the tank emissions.

Emissions generated by the combustion-based control device should be estimated per the procedures outlined in Section 3.4 (Stationary Combustion).

Storage tank emissions should be calculated and itemized for the following emission activities:

Routine:

- Standing losses (emissions occurring through diurnal changes)
- Working losses (emissions occurring through liquid movement)
- Stock changes (change of service)
- Tank landings
- Tank degassing
- Tank cleaning

Non-Routine:

- Leaking pontoons
- Non-routine pressure relief device venting

Emission estimates should account for seasonal and stock changes. At a minimum, emissions should be estimated on a monthly basis and then aggregated on annual basis.

Approved Methods

Storage tank emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.3-1.

Table 3.3-1: Summary of Approved Storage Tank Emission Estimate Methods

Rank	Measurement Method	Application	Compositional Analysis Data
1	Direct measurement	Covered and vented storage tanks	Constituent concentration and flow rate
2	Tank-specific modeling[1]	All petroleum liquid storage tanks	Stored material properties (e.g. lab analyses, crude assays)
3	Tank-specific modeling[1]	All petroleum liquid storage tanks	Default composition profiles

Notes:

1. Using the equations listed in Chapter 7.1 (Organic Liquid Storage Tanks) of U.S. EPA's *Compilation of Air Pollutant Emission Factors* (AP-42), dated November 2006.

When estimating emissions using Rank 2 methodology, the U.S. EPA TANKS software program should not be used as it is no longer supported and has known issues (e.g. TANKS does not treat temperature as a variable for fixed roof tank working losses, TANKS does not allow for elevated liquid stock bulk temperature for non-heated tanks, does not account for liquid heel when computing fixed-roof tank working capacity, etc.). When using Rank 2 methodology, the equations listed in Chapter 7.1 of U.S. EPA's *Compilation of Air Pollution Emission Factors* (AP-42) should be used directly.

However, although Chapter 7.1 of AP-42 provides default material properties, ambient conditions (temperature, wind speed, solar insolation), and tank fittings; facilities should use site-specific, tank-specific, and material-specific data rather than the defaults listed in Chapter 7.1 to the extent specific data are available.

When estimating emissions from tanks subject to the primary and secondary seal requirements of Regulation 8, Rule 5 using the equations of Chapter 7.1 of AP-42, the rim seal loss factors for "tight-fitting seals" listed in the Background Document (*Emission Factor Documentation for AP-42 Section 7.1,* September 2006) may be used, provided the seals were in compliance with Regulation 8, Rule 5 seal gap requirements.

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the following data are required to estimate mass emissions from storage tanks. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.3-2 Data Needs and Documentation by Storage Tank Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Direct Measurement	Constituent concentration and data	Source test results
Tank-specific modeling	Tank type and dimensions	Design drawings
	Stored liquid properties (vapor pressure, API gravity, etc.) and constituent concentrations	Crude assays (for crude tanks) Lab analyses
	Tank condition/fitting information	Installation records Maintenance records Turnaround reports (if turnaround included installation/modification of a tank)
	Stored material throughputs	Flow meter or stored material level records
	Ambient conditions (temperature, wind speed)	Onsite meteorological records
	Stock changes	Stock change records
	Degassing information	Degassing records, source test results

Reports

District Regulation 8, Rule 5 reports

Definitions

Crude Assay a laboratory test of petroleum crude oil that provides a detailed hydrocarbon analysis data

Key Factor

The following significant premises are used in this section.

Item	Key Factor
Monthly averages	Monthly average emission estimates adequately represent daily changes in temperature, wind speed, and stored materials

Section 3.4: Stationary Combustion

Stationary combustion emissions occur throughout the refinery or support facility at various combustion sources, including process heaters, boilers, CO boilers, internal combustion engines and combustion turbines.

Approved Methods

Stationary combustion emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4-1.

Table 3.4-1: Summary of Approved Stationary Combustion Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Direct measurement (CEM for flow rate and gas composition)	Unlimited	CEM must be District approved
2	Direct measurement (CEM for gas composition) Use of F factors	Use with calculated F factors	CEMs must be District approved Calculated F factor must trend fuel properties[2].
3A	Fuel analysis/mass balance	GHG, SO_2, TAC, HAP emissions for uncontrolled sources	Fuel analysis must be in sufficient detail for materials where the pollutant of interest is not regulated (e.g. calculating SO_2 emissions using regulated sulfur content of CARB diesel, PG&E pipeline quality natural gas, etc.). Conversion and destruction efficiency must be supported and District approved.
3B	Source-specific stack testing to calculate source specific emission correlations or factors	Unlimited (GHG, TAC, HAP, Criteria Pollutants)	District approved source test representative of normal or maximum operation. Data substitution not allowed[1].
4	Default emission factors[3]		Default emission factors reflect fuel type and quality as well as source type and configuration.

Notes:
1. Actual emissions are required. Therefore, data substitution (e.g., as allowed for NOx emissions in Regulation 9, Rule 10) is not acceptable.
2. Fuel properties must be determined at a minimum of quarterly for each period of F factor calculation.
3. For internal combustion engines, ARB or EPA-certified emissions factors may be used.

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the following data is required to estimate mass emissions from stationary combustion sources. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.4-2: Data Needs and Documentation by Stationary Combustion Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Direct measurement (CEM)	CEM data - Pollutant concentrations - Oxygen content - Flue gas flowrate - Flue gas moisture content (if measured on wet basis) - Flue gas temperature[1] - Flue gas pressure[1]	CEM certification and periodic accuracy testing
		Spreadsheet with CEM data (pollutant concentrations, oxygen content, flue gas flowrate, moisture content, temperature, pressure)
		Spreadsheet with mass emissions
Direct measurement (CEM using F factor)	CEM data - Pollutant concentrations - Oxygen content	CEM certification and periodic accuracy testing
		Spreadsheet with CEM data
		Spreadsheet with calculated mass emissions
	Operational parameters - Fuel flowrate - Fuel temperature - Fuel pressure	Spreadsheet with operational parameters (flowrate, temperature, pressure)
	Fuel properties - Higher heating value - Fuel gas composition	Periodic fuel gas lab analysis results[2]
		Fuel gas composition[2]
	F Factor	Spreadsheet with F factor calculation (using fuel gas composition)[2]
Fuel analysis/mass balance	Operational parameters - Fuel flowrate - Fuel temperature - Fuel pressure	Spreadsheet with parameters (raw fuel gas flowrate, fuel gas composition, conversion or destruction efficiency used)
		Spreadsheet with calculated mass emissions
	Fuel properties	Periodic fuel gas analysis[2]
		Fuel gas composition[2]
	Stoichiometric analysis	Documentation of stoichiometric (mass balance) basis
	Destruction data	Documentation of basis for species destruction (if assuming less than 100 percent emissions of species)
Source-specific stack testing to calculate source specific emission correlations or factors	Stack parameters - Oxygen content - Flue gas temperature - Flue gas pressure - Exhaust flowrate	Spreadsheet with stack parameters
		Spreadsheet with calculated mass emissions
	Operational parameters[4] - Fuel flowrate - Fuel temperature - Fuel pressure - Fire box temperature	Spreadsheet of operating parameters
	Source test results	Summary of source test report (including all operating parameters and test results)
Default emission factors	Operational parameters - Fuel flowrate - Fuel temperature - Fuel pressure	Spreadsheet with parameters (raw fuel gas flowrate, temperature, pressure)
		Spreadsheet with calculated mass emissions

Approved Method	Needed Data	Supporting Documentation
	Fuel properties - Higher heating value	Periodic fuel gas lab analysis results[2]
	Emission factor	Documentation of emission factor applicability determination (e.g. emission factor assumptions or constraints, range of applicability, and confirmation that source operation is consistent with the applicability of the specified default emission factor)

Notes:
1. Required if the refinery has the capability of recording these parameters.
2. For fuels other than natural gas, CARB diesel, or CARB gasoline
3. All required spreadsheets must be in format that data can be analyzed by the District.
4. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal or maximum operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. The minimum source operation data is listed. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions when there are more than one default emission factors.

Reports

Regulation 1-522 reports

Definitions

None

Key Factors

The following significant premises are used in this section.

Item	Key Factor
F-factor	Combustion exhaust gas flow rates can be estimated via calculation
Source test	Source test results represent emission rates during non-test periods

Section 3.5: Process Vents

Typically, vent gases are collected and routed to a vapor recovery or fuel gas system. This section is for estimating emissions from vent gasses that are not collected. There are calculation methods specific to several different process units.

Section 3.5.1 – Catalytic Cracking Units

Approved Methods

Catalytic cracking unit emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.1-1.

Table 3.5.1-1: Summary of Approved Catalytic Cracking Unit Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Continuous gas composition analyzer with engineering estimates (e.g., air blast rate, regenerator exhaust gas, etc.)	Use with calculated exhaust gas flow rate	Monitors must be District approved.
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved
4	Source tests with measured process rates		District approved source test representative of normal or maximum operation.
5A	Source test (PM) and speciation of metal HAPs/TACs within catalyst fines with measured process rates	Metal HAPs/TACs	District approved source test representative of normal or maximum operation
5B	Default emission factors with measured process rates		

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.1-2: Data Needs and Documentation by Catalytic Cracking Unit Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Unit design, process, permitting and ancillary equipment information	Piping and Instrumentation Diagrams (P&IDs) Process Flow Diagrams (PFDs)
	Emissions measurement method	
	Unit and method changes, volume of feed material, coke burn rate	Throughput records
Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point (NO_X, SO_2, CO)	CEM data - Pollutant concentrations - Oxygen content - Flue gas flowrate - Flue gas moisture content - Flue gas temperature[1] - Flue gas pressure[1]	CEMS certification and periodic accuracy testing Spreadsheet with CEM data (pollutant concentrations, oxygen content, flue gas flowrate, moisture content, temperature, pressure) Spreadsheet with calculated mass emissions
Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point (PM)	COM data - Opacity readings - Oxygen content - Flue gas flowrate - Flue gas moisture content Opacity/PM correlation	Correlation used to derive PM emissions from COM COM certification and periodic accuracy testing Spreadsheet with COM data (raw flue gas flowrate, moisture content, temperature, pressure, opacity readings, factors used to convert opacity to PM and mass emissions Spreadsheet with calculated mass emissions
Source tests with measured process rates (if no COM correlation available) (PM)	Source specific emission factor Process throughput Operational parameters	Source test report summary with operating parameters[2], concentrations speciated by PM_{10} filterable, PM_{10} condensable, $PM_{2.5}$ filterable, and $PM_{2.5}$ condensable. Spreadsheet with raw flue gas flowrate, moisture content, temperature, pressure, opacity readings, factors used for each PM species, and mass emissions Spreadsheet with calculated mass emissions
Source tests with measured process rates (GHG, VOC, HAPs, TACs)	Source specific emission factor Process throughput Operational parameters	Source test report summary with operating data[2], concentrations speciated by HAP/TAC. Spreadsheet including daily CCU feed in barrels, maximum and minimum flowrate for the day, stack gas flowrate, moisture content, temperature, pressure, emission factor used, and mass emissions Spreadsheet with calculated mass emissions
Source test (PM) and speciation of metal HAPs/TACs within catalyst fines with measured process rates	Source specific emission factor Process throughput Operational parameters Catalyst fines metals speciation	Source test report summary with operating data, concentrations of total PM_{10} Catalyst fines speciation report summary Spreadsheet including daily CCU feed in barrels, and calculated mass emissions
Default emission factors	Process throughput	Process throughput records

Notes:
1. Required if the refinery has the capability of recording these parameters
2. All required spreadsheets must be in format that data can be analyzed by the District.
3. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal or maximum operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. If source operation data is listed, this is the minimum required. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.

Reports

None

Definitions
None

Key Factors
None

Section 3.5.2 – Fluid Coking Units

Approved Methods
Fluid coking unit emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.2-1.

Table 3.5.2-1: Summary of Approved Catalytic Cracking Unit Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Continuous gas composition analyzer with engineering estimates (e.g. air blast rate, composition monitor)	Use with calculated exhaust gas flow rate	Monitors must be District approved
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved
4	Source tests with measured process rates		District approved source test representative of normal or maximum operation.
5	Default emission factors with measured process rates		

Data Needs and Supporting Documentation
Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.2-2: Data Needs and Documentation by Fluid Coking Unit Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Unit design, process, permitting and ancillary equipment information	Piping and Instrumentation Diagrams (P&IDs) Process Flow Diagrams (PFDs)
	Unit and method changes, volume of feed material	Throughput records
Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point (NO_X, SO_2, CO)	CEM data - Pollutant concentrations - Oxygen content - Flue gas flowrate - Flue gas moisture content - Flue gas temperature[1] - Flue gas pressure[1]	CEMS certification and periodic accuracy testing Spreadsheet with CEM data (raw flue gas flowrate, moisture content, temperature, pressure, emission concentration readings, and mass emissions) Spreadsheet with mass emissions
Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point (PM)	COM data - Opacity readings - Oxygen content - Flue gas flowrate - Flue gas moisture content Opacity/PM correlation	Correlation used to derive PM emissions from COM COM certification and periodic accuracy testing Spreadsheet with COM data (raw flue gas flowrate, moisture content, temperature, pressure, opacity readings), factors used to convert opacity to PM Spreadsheet with calculated mass emissions

Approved Method	Needed Data	Supporting Documentation
Source tests with measured process rates (if no COM correlation available) (PM)	Source specific emission factor Process throughput Operational parameters	Source test report summary with operating parameters[2], concentrations speciated by PM_{10} filterable, PM_{10} condensable, $PM_{2.5}$ filterable, and $PM_{2.5}$ condensable.
		Basis for emission factors
		Spreadsheet with raw flue gas flowrate, moisture content, temperature, pressure, opacity readings, factors used for each PM species, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions (each PM species)
GHG, VOC, HAPs, TACs: (Source tests)	Source specific emission factor Process throughput Operational parameters	Source test report summary with operating data, concentrations speciated by HAP/TAC.
		Basis for emission factors
		Spreadsheet including daily fluid coking unit feed in barrels, maximum and minimum flowrate for the day, stack gas flowrate, moisture content, temperature, pressure, emission factor used, and mass emissions
		Spreadsheet with calculated mass emissions
GHG, VOC, HAPs, TACs: (Default emission factors)	Process throughput Operational parameters	Spreadsheet showing for each decoking cycle, coke drum coke and water mass, the mass of steam generated, coke drum overhead temperature, the default emission factor used, and mass emissions
		Spreadsheet with calculated mass emissions

Notes:
1. Required if the refinery has the capability of recording these parameters
2. All required spreadsheets must be in format that data can be analyzed by the District.
3. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal or maximum operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. If source operation data is listed, this is the minimum required. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.

Reports

None

Definitions

None

Key Factors

None

Section 3.5.3 – Delayed Coking Units

Approved Methods

Fluid coking unit emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.3-1.

Table 3.5.3-1: Summary of Approved Delayed Coking Unit Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved
3	Source tests with measured process rates		District approved source test representative of normal or maximum operation.
4	Default emission factors with measured process rates		

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions.

Table 3.5.2-2: Data Needs and Documentation by Delayed Coking Unit Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Unit design, process, permitting and ancillary equipment information	Piping and Instrumentation Diagrams (P&IDs) Process Flow Diagrams (PFDs)
	Unit and method changes, coke production, overhead line temperature and pressure when vent opened, volume of feed material	Throughput records
Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point (NO_X, SO_2, CO)	CEM data - Pollutant concentrations - Oxygen content - Flue gas flowrate - Flue gas moisture content - Temperature and pressure[1]	CEMS certification and periodic accuracy testing
		Spreadsheet with CEM data (raw flue gas flowrate, moisture content, temperature, pressure, emission concentration readings)
		Spreadsheet with mass emissions
Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point (PM)	COM data - Opacity readings - Oxygen content - Flue gas flowrate - Flue gas moisture content Opacity/PM correlation	Correlation used to derive PM emissions from COM
		COM certification and periodic accuracy testing
		Spreadsheet with raw flue gas flowrate, moisture content, temperature, pressure, opacity readings, factors used to convert opacity to PM and mass emissions
		Spreadsheet with mass emissions
Source tests with measured process rates (if no COM correlation available) (PM)	Source specific emission factor Process throughput Operational parameters	Source test report summary with operating parameters[2], concentrations speciated by PM_{10} filterable, PM_{10} condensable, $PM_{2.5}$ filterable, and $PM_{2.5}$ condensable
		Basis for emission factors used in emission calculation
		Spreadsheet with raw flue gas flowrate, moisture content, temperature, pressure, opacity readings, factors used for each PM species, and mass emissions
		Spreadsheet with mass emissions (for each PM species)
Source tests (GHG, VOC, HAPs, TACs)	Source specific emission factor Process throughput Operational parameters	Source test report summary with operating data, concentrations speciated by HAP/TAC
		Basis for emission factors used in emission calculation

Approved Method	Needed Data	Supporting Documentation
	- Bulk coke bed density - Internal height of coking unit - Coke drum outage - Water height - Temperature of vessel overhead line - Number of decoking cycles	Spreadsheet including daily feed, maximum and minimum flowrate for the day, stack gas flowrate, moisture content, temperature, pressure, emission factor used, and mass emissions
		Spreadsheet with calculated mass emissions
Default emission factors (GHG, VOC, HAPs, TACs)	Emission factor Process throughput Operational parameters - Bulk coke bed density - Internal height of coking unit - Coke drum outage - Water height - Temperature of vessel overhead line - Number of decoking cycles	Spreadsheet showing for each decoking cycle, coke drum coke and water mass, the mass of steam generated, coke drum overhead temperature, the default emission factor used, and mass emissions.
		Spreadsheet with calculated mass emissions

Notes:
1. Required if the refinery has the capability of recording these parameters
2. All required spreadsheets must be in format that data can be analyzed by the District.
3. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal or maximum operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. If source operation data is listed, this is the minimum required. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.

Reports
None

Definitions
None

Key Factors
None

Section 3.5.4 – Catalytic Reforming Units

Approved Methods
Catalytic reforming unit emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.4-1.

Table 3.5.4-1: Summary of Approved Catalytic Reforming Unit Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Source tests with measured process rates		District approved source test representative of normal or maximum operation
2	Default emission factors with measured process rates		Default emission factors

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.4-2 Data Needs and Documentation by Catalytic Reforming Unit Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Unit design, process, permitting and ancillary equipment information	Piping and Instrumentation Diagrams Process Flow Diagrams
	Unit and method changes, volume of feed material	Work orders/ capital expenditure requests Turnaround reports Throughput records
Source tests with measured or calculated process rates (VOC, HAPs, TACs)	Source specific emission factor Process throughput Operational parameters	Calculation spreadsheets Lab analysis reports Source test reports
Default emission factors (VOC, HAPs, TACs)	Process throughput Operational parameters Default emission factors	Calculation spreadsheets Lab analysis reports

Reports

None

Definitions

None

Key Factors

None

Section 3.5.5 – Sulfur Recovery Plants

Approved Methods

Sulfur recovery plant emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.5-1.

Table 3.5.5-1: Summary of Approved Sulfur Recovery Plant Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Continuous gas composition analyzer with engineering estimates for flow rates	Use with calculated flow rates	Monitors must be District approved
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved
4	Source tests with measured process rates		District approved source test representative of normal or maximum operation.
5	Default emission factors with measured process rates		

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.5-2 Data Needs and Documentation by Sulfur Recovery Plant Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information	Piping and Instrumentation Diagrams Process Flow Diagrams
	One Time: Selected Emissions Measurement Method	Calculation spreadsheet
	Annually: Unit and Method Changes, Volume of Feed Material	Work orders/ capital expenditure requests Turnaround reports Throughput records
Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point (SO_2)	CEM data - Pollutant concentrations - Oxygen content - Flue gas flowrate - Flue gas moisture content - Flue gas temperature[1] - Flue gas pressure[1]	CEM certification and periodic accuracy testing Spreadsheet with CEM data (raw flue gas flowrate, moisture content, temperature, pressure, emission concentration readings)
Continuous gas composition analyzer with engineering estimate for flow rate	CEM data - Pollutant concentrations - Oxygen content - Flue gas moisture content - Flue gas temperature[1] - Flue gas pressure[1] Feed H_2S flow rate and concentration Air or oxygen feed rate to sulfur plant burner Quantity of recovered sulfur	CEM certification and periodic accuracy testing Spreadsheet with CEM data Sulfur plant feed records Sulfur plant burner oxygen records
Engineering calculation (GHG)	Feed Stream(s) Hydrocarbon content	Lab analysis reports
Source tests with measured or calculated process rates (CO, NO_X, VOC, HAPs, TACs)	Speciated emission factors Process throughput Operational parameters	Source test reports Lab analysis reports Throughput records Operational records Calculation spreadsheets
Default emission factors (CO, NO_X, VOC, HAPs, TACs)	Default emission factors Process throughput Operational parameters	Calculation spreadsheets Throughput records Operational records
Notes: 1. Required if the refinery has the capability of recording these parameters		

Reports

None

Definitions

None

Key Factors

None

Section 3.5.6 – Other Miscellaneous Process Vents

Section 3.5.6.1 – Hydrogen Plant Vents

Approved Methods

Hydrogen plant vent emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.6.1-1.

Table 3.5.6.1-1: Summary of Approved Hydrogen Plant Vent Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Continuous gas composition analyzer with engineering estimates		Monitors must be District approved
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved.
4	Source tests with measured process rates		District approved source test representative of normal or maximum operation.
5	Default emission factors with measured process rates		

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.6.1-2 Data Needs and Documentation by Hydrogen Plant Vent Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Unit design, process, permitting and ancillary equipment information	Piping and Instrumentation Diagrams Process Flow Diagrams
	Unit and method Changes, Hydrogen production	Hydrogen production records Throughput records
Source tests with measured or calculated process rates (GHG, VOC, HAPs, TACs)	Source specific emission factor Hydrogen production Operational parameters	Source test reports Lab analysis reports Throughput records Operational parameters Calculation spreadsheets

Reports

None

Definitions

None

Key Factors

None

Section 3.5.6.2 – Asphalt Plant Vents

Approved Methods

Asphalt plant vent emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.6.2-1.

Table 3.5.6.2-1: Summary of Approved Asphalt Plant Vent Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Continuous gas composition analyzer with engineering estimates (for vent gas flow rate)		Monitors must be District approved
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved.
4	Source tests with measured process rates		District approved source test representative of normal or maximum operation.
5	Default emission factors with measured process rates		

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.6.2-2 Data Needs and Documentation by Asphalt Plant Vent Emission Estimate Method

Approved Measurement Method	Needed Data	Supporting Documentation
All methods	Unit design, process, permitting and ancillary equipment information	Piping and Instrumentation Diagrams Process Flow Diagrams
	Unit and method changes, quantity of asphalt processed, thermal oxidizer fuel rate	Throughput records Thermal oxidizer fuel flow records
Source tests with measured or calculated process rates (PM, VOC, HAPs, TACs)	Speciated emission factors	Source test reports Lab analysis reports Calculation spreadsheets
Default emission factors (PM, VOC, HAPs, TACs)	Throughput	Throughput records Calculation spreadsheets

Reports

None

Definitions

None

Key Factors

None

Section 3.5.6.3 – Coke Calcining

Approved Methods

Coke calcining emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.6.3-1.

Table 3.5.6.3-1: Summary of Approved Coke Calcining Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal or maximum operation.
5	Default emission factors with measured process rates		
Notes: 1. Fuel properties must be determined quarterly for each period of F factor calculation.			

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.6.3-2 Data Needs and Documentation by Coke Calcining Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Unit design, process, permitting and ancillary equipment information	Piping and Instrumentation Diagrams Process Flow Diagrams
	Unit and method changes, quantity of coke processed, thermal oxidizer fuel rate	Throughput records Thermal oxidizer fuel flow records
Source tests with measured or calculated process rates (HAPs, TACs)	Speciated emission factors Throughput	Source test reports Lab analysis reports Calculation spreadsheets
Default emission factors (HAPs, TACs)	Default emission factors Throughput	Calculation spreadsheets

Reports

None

Definitions

None

Key Factors

None

Section 3.5.6.4 – Blowdown Systems

Approved Methods

Blowdown systems may be either "controlled" or "uncontrolled". Gases from "controlled" blowdown systems are routed to either: recovery, a fuel gas system, or a flare. Gases from "uncontrolled" blowdown systems are vented to atmosphere. Emissions from "controlled" blowdown systems are accounted for in other sections.

"Uncontrolled" blowdown system emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.6.4-1.

Table 3.5.6.4-1: Summary of Approved Blowdown System Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer (with continuous vent gas flow measurement)	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Continuous gas composition analyzer (with engineering estimates)		Monitors are District approved
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling is District approved.
4	Source tests with measured process rates		District approved source test representative of normal or maximum operation
5	Default emission factors (based on total refinery feed[1]) with measured process rates		

Notes:
1. Table 5-12 (*Default Emission Factors for Blowdown Systems*), *U.S.* EPA Emissions Estimation Protocol for Petroleum Refineries, April 2015

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.6.4-2 Data Needs and Documentation by Blowdown System Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Event information (composition, volume) Disposition of blowdown	
Continuous gas composition analyzer (with continuous vent gas flow measurement)	Gas composition Vent gas flow rate	Composition analyzer records Vent gas flow rate records
Continuous gas composition analyzer (with engineering estimates)	Gas composition F factor	Composition analyzer records F factor calculation
Occasional grab sample (with continuous vent gas flow measurement)	Gas composition Vent gas flow rate	Lab analysis results Vent gas flow rate records
Occasional grab sample (with engineering estimates)	Gas composition F factor	Lab analysis results F factor calculation
Source tests or process calculations with measured or calculated process rates (VOC, HAPs, TACs)	Source test results	Spreadsheet with calculated mass emissions
	Speciated emission factors	Lab analysis reports, source test reports
Default emission factors	Total refinery feed[1]	Refinery feed records

Notes:
1. Per Table 5-12 of the EPPR, total refinery feed is required to estimate emissions using default emission factors

Reports

None

Definitions
None

Key Factors
None

Section 3.5.6.5 – Vacuum Producing Systems

Approved Methods
Vacuum producing system emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5.6.5-1.

Table 3.5.6.5-1: Summary of Approved Vacuum Producing System Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer (with continuous vent gas flow measurement)	Unlimited. Provides accurate emission rates	Monitors must be District approved
2	Continuous gas composition analyzer (with engineering estimates)		Monitors must be District approved
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved
4	Source tests with measured process rates		District approved source test representative of normal or maximum operation.
5	Default emission factors with measured process rates		

Data Needs and Supporting Documentation
Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.5.6.4-2 Data Needs and Documentation by Vacuum Producing System Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Unit design. Process, Permitting and Ancillary Equipment Information	Piping and Instrumentation Diagrams Process Flow Diagrams
	Unit and method changes, quantity of vacuum unit feed, vent gas and/or condensed liquid composition.	Throughput records Lab analysis reports
Source tests, samples, or process calculations with measured or calculated process rates) (VOC, HAPs, TACs)	Speciated emission factors Throughput Operational parameters	Source test reports Lab analysis reports Calculation spreadsheets
Default emission factors (VOC)	Default emission factor Throughput	Calculation spreadsheets

Reports
None

Definitions
None

Key Factors
None

Section 3.6: Flares

Refinery and support facility flares are routinely a source of emissions from continuous pilot and purge gas. Most refinery and support facility flares are also a source of emissions when vent gas is directed to the flares for malfunctions, unplanned shutdowns, startups, and scheduled shutdowns and turnarounds. There are also a select number of flares at a facility that are dedicated abatement devices that are routinely used to control emissions from sources such as a tank or marine terminal.

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There has been a recent effort to standardize the reporting of flare emissions. The refineries were notified of this standardization in January, 2015, for implementation in the 2015 annual update. Pilot and purge gas emissions are reported as combustion emissions at the flare source number. Emissions due to vent gas combustion are reported in the fugitive source S-32110. For inventory purposes, all flare emissions need to be included, regardless of whether they are reportable events or whether or not the flare is subject to Regulations 12-11 or 12-12. Emissions must include criteria pollutants, greenhouse gases (GHGs), toxic air contaminants (TACs) and hazardous air pollutants (HAPs).

Approved Methods

Flare emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.6-1.

Table 3.6-1: Summary of Approved Flare Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Continuous composition monitoring (or manual sampling at least once every 3 hours during flaring events) and continuous flow rate monitoring of the gas sent to the flare	Any flare event where the vent gas exceeds the 12-11 sampling requirement (330 scfm for any consecutive 15-minute period)	Base SO_2 emissions on total sulfur content of vent gas. The Reg. 12-11-401.9 98% destruction efficiency may be used for inventory purposes if flares combust high heat content vent gas and are properly operated for high temperature optimum combustion (93% for flexi-gas flares or flares combusting < 300 Btu/scf vent gas).
2	Continuous flow rate monitoring and daily or weekly compositional analysis	Any flare event where the vent gas is below the 12-11 sampling requirement trigger	Sampling and/or compositional analysis must be representative of combusted vent gas for the flaring duration.
3	Continuous flow rate and heating value monitoring	Purge and pilot gas	Heating value monitoring not required if natural gas is used.
4	Engineering calculations	Any flare not subject to 12-11 and/or 12-12 or for which composition or flow data is not available	Process operating data monitored as needed.
5	Emission factors based on energy consumption	PM, NO_X, CO, GHG emissions	
6	Default emission factors based on refinery or process throughput	Use if no other method applies	

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the following data is required to estimate mass emissions from flares. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.6-2: Data Needs and Documentation by Flare Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All methods	Flare System Drawings and Specifications	An overall drawing for each flare system that shows the configuration, the flare description and source numbers, vent gas meter locations, purge gas meter locations, pilot gas meter locations, sulfur monitors, and sampling systems.
		Flare design specification that includes information to determine flare rating and vent gas velocities.
	Vent Gas Composition	Spreadsheet(s) or other auditable system that shows results of all vent gas sampling
		Vent gas composition compilation that was the basis for the emission calculations.
	Event Information	Spreadsheet(s) or other auditable system that shows the raw vent gas flowrates and durations that were the basis for the total vent gas quantity.
Continuous composition monitoring (or manual sampling at least once every 3 hours during flaring events) and continuous flow rate monitoring of the gas sent to the flare	Vent Gas Flowrate	Spreadsheet(s) or other auditable system that shows raw vent gas flowrate, temperatures and pressures, and calculated vent gas flowrate
	Destruction and Combustion Efficiency	Basis for combustion efficiency and destruction efficiency used in emissions calculation, including operating data that demonstrates flares are properly operated if high efficiencies (greater than 95 percent) are used.
	Mass Emissions	Spreadsheet(s) or other auditable system with mass emissions
Continuous flow rate monitoring and daily or weekly compositional analysis	Vent Gas Flowrate	Spreadsheet(s) or other auditable system that shows raw vent gas flowrate, temperatures and pressures, and calculated vent gas flowrate
	Destruction and Combustion Efficiency	Basis for combustion efficiency and destruction efficiency used in emissions calculation, including operating data that demonstrates flares are properly operated if high efficiencies (greater than 95 percent) are used.
Continuous flow rate and heating value monitoring	Pilot Gas Flowrate	Spreadsheet(s) or other auditable system that shows raw pilot gas flowrate, temperatures and pressures, and calculated gas flowrate
	Purge Gas Flowrate	Spreadsheet(s) or other auditable system that shows raw purge gas flowrate, temperatures and pressures, and calculated gas flowrate
	Destruction and Combustion Efficiency	Basis for combustion efficiency and destruction efficiency used in emissions calculation, including operating data that demonstrates flares are properly operated at high temperatures (if high efficiencies are used).

Approved Method	Needed Data	Supporting Documentation
	Gas Composition if other than natural gas	Gas composition from each sample and a compilation that was the basis for the heating value used in the emission calculations.
Engineering calculations	Vent Gas Flowrate	Spreadsheet(s) or other auditable system that shows raw vent gas flowrate, temperatures and pressures, and calculated vent gas flowrate
	Vent Gas Composition	Vent gas composition from each process that was evaluated and a compilation that was the basis for the emission calculations.
	Destruction and Combustion Efficiency	Basis for combustion efficiency and destruction efficiency used in emissions calculation, including operating data that demonstrates flares are properly operated at high temperatures (if high efficiencies are used)
Emission factors based on energy consumption	Vent Gas Flowrate	Spreadsheet(s) or other auditable system that shows raw vent gas flowrate, temperatures and pressures, and calculated vent gas flowrate
	Vent Gas Composition	Vent gas composition and basis that was used to derive the vent gas LHV (or other unit that is the basis of the emission factors) used in the emission calculations
	Emission Factors	Basis for the energy consumption based emission factors used in the emission calculations
Default emission factors based on refinery or process throughput	Process Unit Specification	Design drawings or specifications that demonstrate the unit capacity that was the basis of the emission calculation.
	Emission Factors	Basis for the unit capacity based emission factors used in the emission calculations
	Throughput	Throughput records Spreadsheet(s) or other auditable system with calculated mass emissions

Reports

The following reports and records are associated with this section.

BAAQMD Regulation 12, Rule 11, Flare Monitoring at Petroleum Refineries.

- Regulation 12-11-401, Flare Data Reporting Requirements: Monthly report showing hourly flaring data.
- Regulation 12-11-402, Flow Verification Report. Semiannual report verifying accuracy of vent gas flow monitoring.

BAAQMD Regulation 12, Rule 12, Flares at Petroleum Refineries.

- Regulation 12-12-401 and 12-12-404, Flare Minimization Plans (FMP). Initial and annual updates of FMP.
- Regulation 12-12-405, Notification of Flaring. Written notification when vent gas exceeds 500,000 SCF in a calendar day.
- Regulation 12-12-406, Determination and Reporting of Cause. A report indicating the cause and prevention of a flaring event.

Definitions

The following definitions apply when estimating emissions according to this section.

Vent Gas Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

Key Factors

The following significant premises are used in this section.

Item	Key Factor
Total Flare Emissions	Emissions from flares include all vent gas combusted at the flares plus emissions from pilot and purge gas combustion.
Total Vent Gas Flow	There are no provisions to bypass the vent gas flow monitors.

Section 3.7: Wastewater

Wastewater systems consist of a variety of components, including collection systems, weirs, oil-water separators, flotation units, biological treatment and polishing. Because of Regulation 8, Rule 8 and federal Benzene Waste NESHAP requirements, many of the components (equalization tanks, oil-water separators, flotation units) are enclosed and/or abated, and therefore, can be measured directly (through either periodic EPA Method 21 monitoring or source tests). Therefore, emissions may be estimated based on monitoring data or emission factors for controlled equipment. Emissions from open units can be calculated using predictive modeling or emission factors.

Approved Methods

Wastewater emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.7-1.

Table 3.7-1: Summary of Approved Wastewater Emission Estimate Methods

Rank	Measurement Method or Emission Factor	Application
1	Direct measurement	Covered and vented units
2A	Predictive modeling with site-specific factors and biodegradation rates followed by validation	Uncovered units
2B	Predictive modeling with site-specific factors and biodegradation rates	Uncovered units
2C	Predictive modeling with site-specific factors	Uncovered units
3A	Engineering estimates based on wastewater treatment plant load	Uncovered units
3B	Engineering estimates based on crude throughput	Uncovered units

Data Needs and Supporting Documentation

The following data is required to estimate mass emissions from wastewater sources. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.7-2: Data Needs and Documentation by Wastewater Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Direct measurement	Constituent load and speciation of collected gas samples	Lab analysis reports, field data sheets Flow rates
Predictive modeling with site-specific factors and biodegradation rates followed by validation	Constituent load and speciation of process wastewaters Site-specific biodegradation rates Model validation by a direct measurement method	Lab analysis reports Flow rate/throughput records Model assumptions, equations, and calculations Direct measurement records
Predictive modeling with site-specific factors and biodegradation rates	Constituent load and speciation of process wastewaters Site-specific biodegradation rates	Flow rates Model assumptions, equations, and calculations
Predictive modeling with site-specific factors	Constituent load and speciation of process wastewaters	Flow rates Model assumptions, equations, and calculations
Engineering estimates based on wastewater treatment plant load	Constituent load and speciation of process wastewaters	Throughput records
Engineering estimates based on crude throughput	Crude throughput	Throughput records

Reports

None

Definitions

None

Key Factors

The following premises are used in this section.

Item	Key Factor
Crude throughput	Wastewater emissions are linear proportional to crude throughput

Section 3.8: Cooling Towers

This section is for estimating POC, HAP, chlorine and particulate emissions from cooling towers. Organic contaminants are introduced into the cooling water through leaks in heat exchangers and condensers, and then stripped out of the cooling water to the atmosphere.

Emissions of precursor organic compounds (POCs) and toxic air contaminants (TACs) result when leaks occur in heat exchangers or condensers served by cooling towers. Particulate matter (PM_{10}) emissions result due to stripping in the cooling tower and drift loss.

Approved Methods

Cooling tower emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.8-1.

Table 3.8-1: Summary of Approved Cooling Tower Emission Estimate Methods

Rank	Measurement Method or Emission Factor	Compositional Analysis Data
1	Direct water measurement (continuous)	Speciated lab analysis (POC[1], TAC[1], TDS[2])
2	Direct water measurement (periodic)	Speciated lab analysis (POC[1], TAC[1], TDS[2])
3	Default emission factors	Default PM_{10}[3], POC[4], and TAC[5] emission factors

Notes:

[1] Site-specific and source-specific POC and TAC emissions shall be estimated using Equation 8-5 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

[2] If TDS concentration in cooling tower water is monitored, site-specific and source-specific PM_{10} emissions shall be estimated using Equation 8-9 assuming EF_{Drift} of 1,700 lb/MMgal from Table 8-5 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015. Else, PM_{10} emissions shall be estimated using Equation 8-8 and 8-9 assuming EF_{Drift} of 1,700 lb/MMgal from Table 5 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

[3] PM_{10} emissions shall be estimated using default emission factors for EF_{Unc} provided in Table 8-5 in Equation 8-10 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

[4] POC emissions shall be estimated using default emission factors for EF_{Unc} provided in Table 8-5 in Equation 8-6 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

[5] TAC emissions shall be estimated using default emission factors for EF_{Unc} provided in Table 8-5 and the average percent by weight of TACs provided in Table A-1 of Appendix A for process unit streams served by the cooling tower in Equation 8-7 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

If Rank 1 or 2 is used, consecutive monitoring events can be used to estimate emissions by assigning each measurement to half of the time period between monitoring/sampling events.

Data Needs and Supporting Documentation

The following data is required to estimate mass emissions from cooling towers. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.8-2 Data Needs and Documentation by Cooling Tower Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Direct water measurement (continuous)	POC, TAC, TDS concentrations	Continuous analyzer readings
	Cooling tower water recirculation rate	Continuous measurements from pump flow rate curves, rotameters, or similar methods
Direct water measurement (periodic)	POC, TAC, TDS concentrations	Periodic cooling tower water sampling logs containing monitoring info such as date, time, and sampling location.
		Lab results for cooling tower water samples for POC and TAC If TDS monitored, site-specific & source-specific lab results for TDS in cooling tower water. If TDS is not monitored, site-specific & source-specific lab results/District approved analyzer readings for parameter (conductivity, etc.) monitored to estimate TDS concentration in cooling tower water.
		Emission calculations for POC and TAC based on lab results. If TDS monitored, emission calculations for PM_{10} based on lab results. If TDS not monitored, emission calculations for PM_{10} and supporting assumptions.
	Length of time of monitoring period	Assume measured concentration has occurred for half of the time period since the last sampling date; if a leak occurs, then add the time period it takes to repair the leak
	Cooling tower water flow recirculation rates	Continuous measurements from pump flow rate curves, rotameters, or APCO-approved methods
	Cooling tower water flow recirculation rates	PFDs showing process units, heat exchangers/condensers served by the cooling tower
Default emission factors	Emission factors	Emission calculation for VOC, TAC, and TDS
	Cooling tower water flow recirculation rate	Continuous measurements from pump flow rate curves, rotameters, or APCO-approved methods

Reports

Regulation 11, Rule 10

Definitions

TDS the quantity of dissolved material in a given volume of water

Key Factors

Measured concentrations during periodic sampling occurred half of the time between sampling events.

Section 3.9: Loading Operations

Organic and HAP/TAC emissions result from the loading of liquids into drums, trucks, railcars, and marine vessels. Loading operations may occur with or without vapor recovery.

Approved Methods

Loading operation emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.9-1.

Table 3.9-1: Summary of Approved Loading Operations Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1A	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates.	Monitors must be District approved
1B	Continuous gas total hydrocarbon (THC) analyzer and continuous vent gas flow measurement, HAP/TAC speciation from periodic sampling	Unlimited with representative sampling	Monitors must be District approved
1C	Continuous gas non-methane organic compound (NMOC) analyzer and continuous vent gas flow measurement, HAP/TAC/methane speciation from periodic sampling	Unlimited with representative sampling	Monitors must be District approved
2	Direct measurement of speciated organic compounds by EPA Method 18 (or District-approved alternative) (Site specific emissions factor) and loading rate or loading volume	Unlimited with representative source test	District approved source test representative of normal or maximum/worst-case operation
3	Direct measurement of non-methane or total organic compounds by EPA Method 25, Method 25A, Method 25B, or District-approved alternative (site-specific emission factor) and loading rate or loading volume	Use calculated emissions factors based on loaded liquid composition	District approved source test representative of normal or maximum/worst-case operation
4	Default emission factors with loading rate or loading volume		

Loading Operations without Vapor Recovery

Emissions from loading operations without vapor recovery should be estimated using the methods above. For the Rank 3 and 4 methods, use the equations and methodology explained in Section 9.3 and Section 9.4 of EPA's *Emission Estimation Protocol for Petroleum Refineries* (version 3, April 2015).

Loading Operations with Vapor Recovery

Organic compound emissions may be recovered through a vapor recovery system and sent to either: a refinery fuel gas system, a flare, a thermal oxidizer, a carbon abatement, or returned to process. Depending on the destination of the recovered compounds, emissions may be double-counted (i.e. estimated per loading operations and included as combustion emissions), if not properly accounted.

If the capture of a loading operation is not one hundred percent (i.e. use of capture hood), emissions generated from loading operations are emitted through two streams: a captured stream that is sent to a final destination (e.g. fuel gas system, thermal oxidizer, etc.) and a fugitive stream (emitted at the operation). The amount of emissions in each stream is dependent on the vapor recovery capture efficiency as shown in Equations 3.9-1 through 3.9-3.

$$Captured\ emissions = uncontrolled\ emissions\ x\ capture\ effienciy \qquad \text{[Equation 3.9-1]}$$

$$Fugitve\ Emissions = uncontrolled\ emissions\ x\ (1 - \ capture\ effienciy) \qquad \text{[Equation 3.9-2]}$$

$$Total\ Emissions = \ captured\ emissions + fugitive\ Emissions \qquad \text{[Equation 3.9-3]}$$

Depending on the destination, captured emissions may be: emitted as an equipment leak (e.g. valves, connectors, etc.), combusted (e.g. fuel gas system, flare, etc.), abated (e.g. thermal oxidizer, carbon, etc.) or returned to a process (e.g. condensers).

Equipment leak emissions should be accounted for using the methods listed in Section 3.2. Combustion emissions should be accounted for using the methods listed in Section 3.4 (non-flare combustion) or Section 3.6 (flares). Abated emissions should be estimated using the methods listed in this section and an abatement efficiency as determined through a District-approved source test (such test should be representative of normal or worst-case operation). Captured emissions returned to process should be estimated using a relevant section of these guidelines (i.e. process vent section if process has a stack, Section 3.3 if returned to a tank, etc.).

To properly account for both captured and fugitive emissions and prevent potentially double-counting of emissions, the following procedures should be used based upon the degree of capture and the destination of recovered vapors.

Table 3.9-2: Procedure for Estimating Emissions from Loading Operation with Vapor Recovery

Destination	Capture Efficiency	Procedure for Loading Operation Emissions
Fuel gas system	100 percent	Estimate equipment leak emissions per Section 3.2 Estimate combustion emissions per Section 3.4
	<100 percent	Estimate fugitive emissions per this section Estimate equipment leak emissions per Section 3.2 Estimate combustion emissions per Section 3.4
Flare	100 percent	Estimate equipment leak emissions per Section 3.2 Estimate flare combustion emissions per Section 3.6
	<100 percent	Estimate fugitive emissions per this section Estimate equipment leak emissions per Section 3.2 Estimate flare combustion emissions per Section 3.6
Thermal oxidizers	100 percent	Estimate abated emissions per this section, multiply by a source test-determined abatement efficiency Estimate equipment leak emissions per Section 3.2
	<100 percent	Estimate fugitive emissions per this section Estimate abated emissions per this section, multiply by a source test-determined abatement efficiency Estimate equipment leak emissions per Section 3.2
Carbon abatement	100 percent	Estimate abated emissions per this section multiply by a source test-determined abatement efficiency Estimate equipment leak emissions per Section 3.2
	<100 percent	Estimate fugitive emissions per this section Estimate abated emissions per this section multiply by a source test-determined abatement efficiency Estimate equipment leak emissions per Section 3.2
Returned to process	100 percent	Estimate equipment leak emissions per Section 3.2

		Estimate tank emissions per Section 3.3
	<100 percent	Estimate fugitive emissions per this section Estimate equipment leak emissions per Section 3.3 Estimate tank emissions per Section 3.3

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from the loading operations is summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.9-3: Data Needs and Documentation by Loading Operation Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Continuous compositional and flow measurement	CEM data - Pollutant concentrations - Oxygen content - Vent gas flowrate - Vent gas moisture content - Vent gas temperature[1] - Vent gas pressure[1]	CEMS certification and periodic accuracy testing
		Spreadsheet with CEM data (raw flue gas flowrate, oxygen content, moisture content, temperature, pressure, emission concentrations)
		Spreadsheet with mass emissions
Continuous THC and flow measurement	Analyzer data - Pollutant concentrations - Oxygen content - Vent gas flowrate - Vent gas moisture content - Vent gas temperature[1] - Vent gas pressure[1]	Analyzer certification and periodic accuracy testing
		Spreadsheet with analyzer data (hydrocarbon readings, flowrate , oxygen content, moisture content, temperature, pressure)
		Spreadsheet with mass emissions
	Speciated emission factors	Documentation for basis of emission factor (e.g. assumptions or constraints, range of applicability, and confirmation that source operation is consistent with the applicability of the specified emission factor)
		Emission factor calculations
Direct measurement of speciated organic compounds by EPA Method 18 or District-approved alternative (Site specific emissions factor) and loading rate or loading volume	Material type and loading data	Spreadsheet with daily loading rate, emissions factor, and mass emissions
	Loading volume	Loading records including material loaded, material properties, and total material loaded
		Loading rate used in emission calculation
	Speciated emission factors	Documentation for basis of emission factor (e.g. assumptions or constraints, range of applicability, and confirmation that source operation is consistent with the applicability of the specified emission factor)
		Emission factors used in emission calculations.
	Source test results Operating parameters	Summary of source test report including all operating parameters and test results
Direct measurement of non-methane or total organic compounds by EPA Method 25, Method	Material type and loading data	Spreadsheet with daily loading rate, emissions factor, and mass emissions
	Loading volume	Loading records including material loaded, material properties, and total material loaded
		Loading rate used in emission calculation

Approved Method	Needed Data	Supporting Documentation
25A, Method 25B, or District-approved alternative (site-specific emission factor) and loading rate or loading volume	Speciated emission factors	Documentation for basis of emission factor (e.g. assumptions or constraints, range of applicability, and confirmation that source operation is consistent with the applicability of the specified emission factor)
		Emission factors used in emission calculations.
	Source Test	Source test report including all operating parameters and test results
Default emission factors	Material type and loading data	Spreadsheet with daily loading rate, emissions factor, and mass emissions
	Loading rate or loading volume	Loading records including material loaded, material properties, and total material loaded
	Speciated emission factors	Documentation for basis of emission factor (if other than AP-42)

Notes:

1. All required spreadsheets must be in format that data can be analyzed by the District.
2. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal or maximum operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. The minimum source operation data is listed. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.

Reports
None

Definitions
None

Key Factors
None

Section 3.10: Fugitive Dust

This section provides particulate emission calculations for three operations at petroleum refineries and support facilities:

- roads (paved and unpaved),
- FCCU catalyst handling, and
- coke handling and storage.

Only fugitive dust emissions created by business-related activities need to be reported. Examples of business-related activities include:

- truck deliveries or receipts of feedstocks, chemicals, catalysts, or products, or
- contractor equipment (e.g. vacuum trucks, de-coking vehicles, etc.), or
- front-loaders, cranes, or graders.

Approved Methods

Emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.10-1.

Table 3.10-1: Summary of Approved Fugitive Dust Emission Estimate Methods

Source	Rank	Measurement Method
Paved road	1	Calculated emission factor[1] (measured silt loading)
	2	Calculated emission factor[1] (default silt loading content)
Unpaved road	1	Calculated emission factor[2] (measured silt loading)
	2	Calculated emission factor[2] (default silt loading)
FCCU catalyst handling	1	Calculated emission factor[3] (measured silt and moisture content)
	2	Calculated emission factor[3] (default silt and moisture content)
Petroleum coke handling	1	Calculated emission factor[3] (measured silt and moisture content)
	2	Calculated emission factor[3] (default silt and moisture content)
Stock piles	1	Calculated emission factor[4]

Notes:
1. Use Equation 1 of Section 13.2.1.3 of AP-42 (U.S. EPA, 1995a)
2. Use Equation 1a of Section 13.2.2.2. of AP-42 (U.S. EPA, 1995a)
3. Use Equation 1 of Section 13.2.4.3 of AP-42 (U.S. EPA, 1995a)
4. Use Equations 1 through 7 of Section 13.2.5 of AP-42 (U.S. EPA, 1995a)

Where coke or sulfur is stored and handled in an enclosed system, an abatement efficiency may be applied. The abatement efficiency should account for both capture and control of fugitive dust.

If silt loading and/or moisture content data is not available, the default values listed in Table 3.10-2 should be used.

Table 3.10-2: Default Values for Fugitive Dust Emission Estimate Methodologies

Source	Variable Description	Units	Activity	Default Value
Paved road	Silt loading	g/m^2	Coke or sulfur pit	70
			Other	10
Unpaved road	Silt loading	%	All	7
FCCU catalyst handling "drops"	Silt content	%	FCCU	50
	Moisture content	%		8
FCU or calcined coke "drops"	Silt content	%	Fluid Coker	5
	Moisture content	%		8
Delayed coking unit coke "drops"	Silt content	%	Delayed Coking	5
	Moisture content	%		10
Flexicoking or petroleum coke ash	Silt content	%	Flexicoking	13
	Moisture content	%		7

To estimate emissions occurring from paved and unpaved roads, the total vehicle miles traveled is required. However, it may not be practical to track every vehicle to every location visited within a refinery or support facility.

The following methods may be used to estimate vehicle miles traveled by vehicle type for vehicles where vehicle miles traveled are not tracked. The total vehicle miles traveled is the summation of all individual vehicle miles traveled.

Table 3.10-3: Methods for Estimating Vehicle Miles Traveled

Vehicle	Travel Location	VMT Estimation Method
Facility vehicle	Never leaves facility	For each vehicle, subtract the odometer reading at the beginning of the year from the odometer reading at the end of the year
	Leaves facility	For each vehicle, multiply the difference in odometer readings at the beginning and end of the year by an estimated percentage of vehicle miles traveled while onsite.
Employee-owned vehicle (Used for Work Purposes)	Leaves facility	For each employee, estimate the distance between the facility entry/exit gate and their jobsite (e.g. office, parking lot, etc.), multiply by two for the round trip, and multiply by an estimated number of days worked
Contractor vehicle (Non-routine)[1]	Never leaves facility during job	For each vehicle, subtract the odometer reading at the beginning of the job from the odometer reading at the end of the job
	Leaves facility during job	For each vehicle, multiply the difference in odometer readings at the beginning and end of the job by an estimated percentage of vehicle miles traveled while onsite.
Contractor vehicle (Routine)[2]	Leaves facility after job	For each vehicle, estimate the distance between the facility contractor entry/exit gate and the jobsite (e.g. truck loading rack, office, etc.) and multiply by two for the round trip.

Notes:
1. Vehicles onsite for a specific project (e.g. turnaround, maintenance, etc.) and mileage may be tracked.
2. Vehicles onsite as normal part of business (e.g. crude oil truck deliveries, sulfur trucks, gasoline trucks, etc.)

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Data Needs and Supporting Documentation

The following data is required to estimate mass emissions from activities creating fugitive dust. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.10-4: Data Needs and Documentation by Fugitive Dust Emission Estimate Method

Source	Measurement Method	Needed Data	Supporting Documentation
Paved road	Calculated emission factor (measured silt loading)	Road surface silt loading Average weight of vehicles Vehicle miles traveled	Silt loading test results Weight calculations Odometer logs/VMT calculations
	Calculated emission factor (default silt loading content)	Average weight of vehicles Vehicle miles traveled	Weight calculations Odometer logs/VMT calculations
Unpaved road	Calculated emission factor (measured silt loading)	Road surface silt loading Average weight of vehicles Vehicle miles traveled	Silt loading test results Weight calculations Odometer logs/VMT calculations
	Calculated emission factor (default silt loading)	Average weight of vehicles Vehicle miles traveled	Weight calculations Odometer logs/VMT calculations
FCCU catalyst handling	Calculated emission factor (measured silt, moisture content)	Mean wind speed Material moisture content Quantity of material transferred	Meteorological records Moisture test results Throughput records
	Calculated emission factor (default silt and moisture content)	Mean wind speed Quantity of material transferred	Meteorological records Throughput records
Petroleum coke handling	Calculated emission factor (measured silt, moisture content)	Mean wind speed Material moisture content Quantity of material transferred	Meteorological records Moisture test results Throughput records
	Calculated emission factor (default silt and moisture content)	Mean wind speed Quantity of material transferred	Meteorological records Throughput records
Stock piles	Calculated emission factor	Mean and fastest recorded wind speed Pile surface area	Meteorological records Surface area calculations

Reports

None

Definitions

Silt any particulate, including but not limited to catalyst, coal, coke, or sulfur with a particle size less than 75 micrometers in diameter as measured by a No. 200 sieve

Vehicle miles traveled number of miles traveled by vehicles

Key Factors

The following key premises are used in this section.

Item	Key Factor
Silt loading	Average silt loading is between 0.04 - 570 grains/square foot
Mean vehicle weight	Mean vehicle weight is between 2.0 - 42 tons
Mean vehicle speed	Mean vehicle speed is between 1 - 55 miles per hour
Vehicle miles traveled	Estimated vehicle miles traveled
Average vehicle weight	Estimated average vehicle weight is representative of actual average vehicle weight

Section 3.11: Startup and Shutdown

Much of the emission estimates included in this guideline are for normal facility operation. This section is intended to capture emissions from the non-routine emissions that occur during abnormal operation. Key non-routine operation is during Startup and Shutdown, when there can be discharges to atmosphere that normally do not occur. However, the EPA ICR states that it is beyond the scope of the ICR protocol to provide methods of estimating emissions during all possible startup or shutdown scenarios or events. This is true for this guideline section as well. The sole emission estimate for this section, as in the ICR, is for vessel depressurization. If there are other startup, shutdown or non-routine events that merit inclusion in this guideline, this addition will be included in a future version. However, if there are any non-routine events that cause emissions during Startup or Shutdown, provisions are available to identify these and estimate the emissions.

Deleted: refinery

Vessels can be depressurized at any time that the process is no longer in operation, often for maintenance or inspection. To perform internal maintenance on a vessel, or to perform the periodic inspections required by ASME or other codes, vessels need to be purged of process materials and made suitable for safe vessel entry. Most of the vessel content is usually directed to a vapor recovery system where the gas is reprocessed, used for fuel gas, or flared. Organic and HAP/TAC emissions result from the final steps of vessel depressurization where the residual fluids are discharged to atmosphere. Often the vessel will be pressured and depressured repeatedly with inerts (i.e., nitrogen) to prevent hazardous environments when the vessel is made safe with the proper breathing air for vessel entry. The vessel discharge to atmosphere could be due to vessel pressures being too low to drive the materials for any more recovery, or the residual materials are of no value, or the residual material is so rich in inert gas that it will not combust or will affect the fuel gas system in a detrimental manner.

This section covers all startup/shutdown emissions, regardless of whether the emissions are generated at the equipment site or if the emissions are collected in a blowdown system and generated remotely. This section does not include emissions that are covered in other sections (e.g., emissions sent to a combustion device or a flare).

Approved Methods

Two methods are approved to estimate emissions from Process Vessel Depressurization, one for a vessel containing only gas and one for vessels that also contain a liquid "heel".

Table 3.11-1: Summary of Approved Process Vessel Depressurization Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1A[1]	Engineering estimate based on ideal gas law	Vessels in gas service	May underestimate emissions if solid material in the vessel absorbs gas during process conditions and desorbs at startup/shutdown conditions.
1B[2]	Engineering estimate based on all residual liquids (the liquid "heel") vaporizing[3]	Vessels in liquid service	Assumes the mass of the "heel" will be large in comparison to the mass in the gas phase.
1C	Engineering estimate based on both the ideal gas law and the liquid "heel"[3]	Vessels in very volatile liquid service	Use for gasoline and similar volatile materials[4]

Notes:
1. EPA Emissions Estimation Protocol for Petroleum Refineries, April 2015, Section 11.1, Gaseous Process Vessel Depressurization and Purging
2. EPA Emissions Estimation Protocol for Petroleum Refineries, April 2015, Section 11.2, Liquid Process Vessel Depressurization and Purging
3. Estimates may subtract any organic compounds recovered and not combusted
4. As recommended in Section 11.2, Liquid Process Vessel Depressurization and Purging

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from startup and shutdown operations are summarized below. This information will be added to the Startup/Shutdown spreadsheet that accompanies this guideline. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.11-2: Data Needs and Documentation by Process Vessel Depressurization Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
All Methods	Vessel Information	Equipment description including tag number, service, and content.
		Design drawings with sufficient information to determine equipment volume and void fraction.
	Event Information	Event information including purpose, notification, duration, steps taken prior to release to atmosphere, and process conditions prior to release to atmosphere.
		Operating procedures for depressurizing event.
		Operator log showing process parameters prior to release to atmosphere.
	Gas Composition for each vessel	Documentation of the gas composition for each vessel that was the basis of the emission estimate (e.g., material balance, flash calculations, sample analyses, or source test reports).
	Liquid Volume and Composition for each vessel (if applicable)	The liquid "heel" volume and the basis or assumption used to determine the volume
		Documentation of the liquid composition for each vessel that was the basis of the emission estimate (e.g., material balance, flash calculations, sample analyses, or source test reports)
	Abatement Device (devices not included in other sections)	Owner Information (if different from facility owner)
		Abatement Device Permit to Operate
		Design drawings with sufficient information to determine destruction efficiency
		Operator log showing process parameters during service.
		Source test report and date of submission to District (if basis for destruction efficiency used in emission calculations)

Deleted: refinery

Records/Reports

The following reports and records are associated with this section.

BAAQMD Regulation 8, Rule 10, Process Vessel Depressurization

- Regulation 8-10-401, Reporting: Annual report due February 1 of each year.
- Regulation 8-10-503, Records: Content of annual report.

Definitions

The following definitions apply when estimating emissions per this section.

Vessel any equipment that is vented to atmosphere including equipment such as a process pressure vessel, a reactor, a column, or a storage tank. Any piping or other ancillary equipment that is vented to atmosphere, whether associated with the vessel or independently depressured to atmosphere is also included in this section.

Key Factors

The following key premises are used in this section.

Item	Key Factor
Vessel depressurization	No emissions to atmosphere occur through pressure relief devices.

Section 3.12: Malfunctions/Upsets

During malfunction/upset events, emissions may be significantly higher than the emissions that occur under normal operating conditions. Three malfunction/upset events scenarios are addressed in this section:

- Control device malfunction
- Process vessel over pressurization
- Liquid spills

Specific malfunction/upset events that require emission estimates are shown below. This list is not intended to be an exhaustive list.

- Any instance when a control or abatement device is bypassed or is not functioning properly.
- Any instance when a fuel gas treatment system or a sulfur recovery plant if offline or is not operating at normal efficiencies.
- Any instance where a flare is over-steamed.
- Any instance where the operating conditions of a flare do not satisfy 40 CFR 60.18 (e.g., BTU content, exit velocities).
- Any instance when a spill or other similar release occurs.

Specific events that are not covered by this section are shown below:

- Leaks identified by the facility LDAR program (as long as the leaks do not cause a liquid puddle). Covered in Section 3.2.
- Flare emissions when the flare operating conditions satisfy the design requirements of 40 CFR 60.18. Covered in Section 3.6.
- Storage tank emissions from unintentional tank roof landings. Covered in Section 3.3.

Approved Methods

Emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.12-1.

Deleted: refinery

Table 3.12-1: Summary of Approved Malfunction/Upset Events Emission Estimate Methods

Rank	Measurement Method	Applicability	Qualifications
1	Direct measurement (CEM for both flow rate and gas composition)	Unlimited (CEM-monitored operation)	CEM must be District approved CEM monitoring range must include uncontrolled emission levels
2	Emission calculations (specified multiplier derived from normal control device efficiency)	Control Device Malfunction	Multiplier = 1/(1-normal efficiency)
	Emission calculations (relief device flow rate)	Vessel Overpressurization (discharged to atmosphere)	Also applies to discharges recovered to fuel gas or sent to flare if not accounted for in another section (e.g., if default emission factors are used)
	Emission calculations (mass transfer coefficients[1] and liquid properties)		
	Calculations (assume all materials in spill emitted to the atmosphere)		

Notes:
1. As listed in Section 12.3 *Spills* of the EEPPR, mass transfer coefficients provided in Appendix B, *Wastewater Treatment System Equations*, Section B.2.1, *Oil Water Separators*

Data Needs and Supporting Documentation

Depending on the approved measurement method used, the data required to estimate mass emissions from malfunction/upset events are summarized below. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.12-2: Data Needs and Documentation by Malfunction/Upset Event Emission Estimate Method

Event	Approved Method	Needed Data	Supporting Documentation
Control Device Malfunction (separate documentation for each control device)	Direct measurement (CEMS)	CEM data - Pollutant concentrations - Oxygen content - Flue gas flowrate - Flue gas moisture content - Flue gas temperature[1] - Flue gas pressure[1]	CEMS certification and periodic accuracy testing
			Spreadsheet with CEM data (pollutant concentrations, raw flue gas flowrate, moisture content, temperature, pressure, and mass emissions)
			Spreadsheet for each control device with description of event including date and duration, mass emissions summarized by event, and mass emissions totalized for year
	Calculations	Uncontrolled mass emissions Controlled emission multiplier	Spreadsheet for each control device with description of event including date and duration, normal daily controlled emissions, controlled emissions multiplier, and mass emissions
Vessel Overpressurization	Calculations	Event data	Spreadsheet with description of event including vessel, date and duration, vessel or process unit source number, sonic or subsonic flow, mach number, vent outlet description and cross-sectional area, vessel pressure and temperature, gas molecular weight, and mass emissions
			Spreadsheet with mass emissions
		Gas Composition	Documentation of basis of composition used

Event	Approved Method	Needed Data	Supporting Documentation
			Spreadsheet with details of physical or thermal properties derived from gas composition (e.g., MW, k values [$k=C_p/C_v$])
		Emission Points	Description of emission point
			Basis for emission reductions if emissions not direct to atmosphere (e.g., if emissions are reduced by flaring, amount of reductions and basis for destruction efficiency of flare)
Liquid Spills	Calculations	Event data	Spreadsheet with description of event including spill origin and date, equipment or process unit source number, liquid description, temperature and vapor pressure, and mass emissions
		Total spill duration, volume and mass	Spreadsheet detailing for each spill the volume and mass of the liquid and the duration of the spill.
		Liquid Composition	Documentation of basis of composition used
			Spreadsheet with details of physical or thermal properties derived from liquid composition
		Mass Transfer Coefficients	Spreadsheet with the detailed calculations resulting in the mass transfer coefficient used in the emissions calculations

Reports
A report of each malfunction or upset event and the emission impacts of each event.

Definitions
None

Key Factors
None

Section 3.13: Miscellaneous Sources

In addition to the major category of emission producing sources discussed in other sections, there are several relatively infrequent and/or minor activities at petroleum refineries and support facilities. These include:

- non-retail gasoline and diesel dispensing facilities,
- equipment painting (architectural coatings and paint booths),
- abrasive blasting
- solvent degreasers
- soil remediation, and
- ground water remediation.

Section 3.13.1: Non-Retail Gasoline and Diesel Dispensing Facility

Petroleum refineries and support facilities employ a fleet of vehicles (maintenance trucks, cranes, etc.) that require fueling onsite. Fueling is often done at non-retail gasoline and diesel dispensing facilities. Emissions from dispensing facilities subject to California vapor recovery requirements may be overestimated if using the loading loss equation of EPA's AP-42 Section 5.2 (Transportation and Marketing of Petroleum Liquids). For these activities, emissions should be estimated using emission factors developed by the California Air Resources Board.

Approved Methods

Emissions shall be estimated by using the method as listed in Table 3.13.1-1.

Table 3.13.1-1: Summary of Approved Non-Retail Gasoline and Diesel Dispensing Facility Emission Estimate Methods

Rank	Measurement Method	Applicability	Compositional Analysis Data
1A	Default Emission Factors[1] (gasoline)	Subject to California vapor recovery requirements	a. Facility-specific material speciation b. Corporate-specific speciation c. Default speciation profiles
1B	Loading Loss Equation[2] (temperature measurements)	All facilities	a. Facility-specific material speciation b. Corporate-specific speciation c. Default speciation profiles
2	Loading Loss Equation[2] (assumed temperature)	All facilities	a. Facility-specific material speciation b. Corporate-specific speciation c. Default speciation profiles

Notes:
1. ARB default emission factors
2. Loading loss equation from AP-42 Section 5.2

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Rank 1A - Default Emission Factors

The California Air Resources Board and the California Air Pollution Control Officers Association have published default emission factors to be used for gasoline dispensing facilities. These emission factors differ depending on the vapor recovery configuration used (e.g. no vapor recovery, Phase I vapor recovery, Phase I and Phase II vapor recovery systems predating enhanced vapor recovery or enhanced Phase I and Phase II vapor recovery systems).

Table 3.13.1-2: Summary of Default Gasoline Dispensing Emission Factors

Tank Type	Vapor Recovery Configuration	TOC Emission Factors (1,2) (lbs/1000 gallons)					
		Loading	**Breathing**	**Refueling**	**Spillage**	**Permeation**	**Total**
Aboveground	Pre-EVR Phase I Only	0.42	2.1	8.4	0.61	0.062	11.592
	Phase I and II	0.42	0.0053	0.63	0.24	0.009	1.3043
Underground	EVR Phase I Only	0.084	0.21	8.4	0.61	0.062	9.366
	EVR Phase I and II						
	ORVR vehicles	0.084	0.025	0.021	0.24	0.009	0.379
	Non-ORVR vehicles	0.084	0.025	0.42	0.24	0.009	0.778

Notes:
1. CAPCOA Air Toxics "Hot Spots" Program "Gasoline Service Station Industrywide Risk Assessment Guidelines", November 1997
2. California Environmental Protection Agency Air Resources Board "Revised Emission Factors for Gasoline Marketing Operations at California Gasoline Dispensing Facilities", December 23, 2013

Data Needs and Supporting Documentation

The following data is required to estimate mass emissions from fuel dispensing activities. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.13.1-2 Data Needs and Documentation by Non-Retail Dispensing Facility Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Default Emission Factors	Material (e.g. gasoline, diesel, etc.) throughput	Throughput records
	Material (e.g. gasoline, diesel, etc.) speciation	Lab analyses
	Vapor recovery configuration	
	Abatement efficiency	Source test reports
Loading Loss Equation (temperature measurements)	Temperature of bulk liquid loaded	Temperature records
	True vapor pressure of liquid	
	Material loaded	
	Amount of material loaded	Throughput records
Loading Loss Equation (assumed temperature)	Assumed temperature	Basis for assumed temperature
	True vapor pressure	
	Material loaded	
	Amount of material loaded	Throughput records

Reports

BAAQMD Regulation 8, Rule 7 (Gasoline Dispensing Facilities)

Definitions

Phase I vapor recovery of gasoline vapors displaced from storage tanks when cargo tank trucks make gasoline deliveries
Phase II vapor recovery systems that control the vapors displaced from the vehicle fuel tanks during refueling
Loading emissions occurring when a cargo tank truck unloads fuel the storage tanks
Breathing emissions from the storage tank vent pipe due to temperature and pressure changes within the storage tank vapor space
Refueling emissions at the vehicle/nozzle interface
Spillage emissions occurring from spills during vehicle fueling
EVR enhanced vapor recovery
ORVR onboard refueling vapor recovery

Key Factors

The following key premises are used in this section.

Item	Key Factor
Default Emission Factor	Emission factor is representative of emissions

Section 3.13.2: Architectural or Equipment Painting

Occasionally, equipment or buildings may be painted (for aesthetic or corrosion protection reasons). Emissions should be estimated from all painting of process equipment (e.g. storage tanks, process vessels, piping, pumps, process units, etc.) whether by petroleum refinery or support facility staff or third party contractors.

Approved Methods

Emissions from painting activities should be estimated using a material balance (Table 3.13.2-1) and assuming that 100 percent of organic compounds are emitted unless it can be demonstrated otherwise.

Table 3.13.2-1: Summary of Architectural or Equipment Painting Emission Estimate Methodologies

Rank	Measurement Method	Compositional Analysis Data
1	Material balance	Coating characterization including POC and NPOC content

Data Needs and Supporting Documentation

The following data is required to estimate mass emissions from painting activities. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.13.2-2 Data Needs and Documentation by Painting Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Material balance	Material (e.g. solvent, paint, etc.) usages	Usage records Purchase and disposal records Work orders
	Material characteristics	Material Safety Data Sheets

Reports

None

Definitions

Architectural Coating A coating applied to stationary structures and their appurtenances at the site of installation, to portable buildings at the site of installation, to pavements, or to curbs.

Appurtenances Any accessory to a stationary structure coated at the site of installation, whether installed or detached, including but not limited to: bathroom and kitchen fixtures; cabinets; concrete forms; doors; elevators; fences; hand railings; heating equipment, air conditioning equipment, and other fixed mechanical equipment or stationary tools; lampposts; partitions; pipes and piping systems; rain gutters and downspouts; stairways, fixed ladders, catwalks, and fire escapes; and window screens.

Key Factor

The following key premises are used in this section.

Item	Key Factor
Evaporation rate	100% of volatiles evaporate and are emitted to atmosphere

Section 3.13.3: Abrasive Blasting

Abrasive blasting is the cleaning or preparing of a surface by forcibly propelling a stream of abrasive material against the surface using sand, glass bead, aluminum oxide, grit, slag, garnet, steel shot, slag, walnut shells, and others.

Abrasive blasting may be confined or unconfined and is used to:

- Remove rust, scale, and paint;
- Roughen surfaces in preparation for bonding, painting or coating;
- Remove burr, and/or
- Develop a matte surface finish.

In a petroleum refinery or support facility, abrasive blasting is mainly used for cleaning and painting of aboveground storage tanks or building and removing rust or other debris from pressure vessels, furnaces, boilers, etc.

Approved Methods

Emissions shall be estimated by using the method as listed in Table 3.13.3-1.

Table 3.13.3-1: Summary of Approved Abrasive Blasting Emission Estimate Methods

Rank	Measurement Method	Compositional Analysis Data
1	Default Emission Factors	Abrasive characterization

Data Needs and Supporting Documentation

The following data is required to estimate mass emissions from abrasive blasting activities. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.13.3-2 Data Needs and Documentation by Abrasive Blasting Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Default Emission Factors	Abrasive usage	Abrasive usage records
	Abrasive characteristics	Material Safety Data Sheets
	Abatement efficiencies (capture efficiency and control efficiency), if available	Capture efficiency calculation Source test reports

Reports

None

Definitions

None

Key Factors

The following key premises are used in this section.

Item	Key Factor
Default Emission Factor	Emission factor is representative of emissions

Section 3.13.4: Solvent Degreaser

Solvent degreasers are typically used in maintenance shops to clean tools and parts. Emissions from solvent degreasers are required to be estimated.

Approved Methods

Emissions from solvent degreasers should be estimated by multiplying the net solvent usage by the density of the solvent and assuming the solvent to be 100 percent volatile and emitted to the atmosphere.

Data Needs and Supporting Documentation

The following data is required to estimate mass emissions from solvent degreaser activities. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.13.4-1 Data Needs and Documentation by Solvent Degreaser Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Material balance	Solvent usage	Solvent usage records
	Solvent characteristics	Material Safety Data Sheets

Reports

None

Definitions

None

Key Factors

The following key premises are used in this section.

Item	Key Factor
Evaporation rate	100% of solvent is emitted to atmosphere

Section 3.13.5: Soil Remediation

Soil remediation is the process of removing pollutants from soil contaminated either accidentally (e.g. spills, leaking underground storage tanks, etc.) or intentionally (historical dumping or burying of barrels).

Contaminated soil may be decontaminated using soil vapor extraction (either venting of soil or applying a vacuum) or soil excavation where contaminated soil may be aerated and/or sent offsite for treatment.

Exhaust air from decontamination activities is typically directed to a carbon abatement system or to a thermal oxidizer.

Emissions from all temporary or permanent soil and soil excavation activities should be estimated as well as emissions created by any abatement devices (e.g. thermal oxidizer).

Approved Methods

Emissions shall be estimated by using the method listed in Table 3.13.5-1.

Table 3.13.5-1: Summary of Soil Remediation Emission Estimate Methods

Rank	Measurement Method	Compositional Analysis Data
1	Material balance	a. Pollutant plume characterization (lab analysis) b. Available lab analysis

Data Needs and Supporting Documentation

The following data is required to estimate mass emissions from soil vapor extraction activities. The following supporting documentation should be maintained per the approved method used to estimate emissions and quality assure emission estimates.

Table 3.13.5-2 Data Needs and Documentation by Soil Remediation Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Material balance	Influent concentrations	Lab analysis
	Influent flow rate	Equipment design specifications (e.g. vacuum blower maximum capacity)
	Abatement device efficiency	Source test results

Reports

District Regulation 8, Rule 40 (Aeration of Contaminated Soil and Removal of Underground Storage Tanks)

- Report – Removal or Replacement of Tanks (Reg. 8-40-401)
- Report – Excavation of Contaminated Soil (Reg. 8-40-402)
- Report – Aeration of Soil (Reg. 8-40-403)
- Report – Contaminated Soil Excavation During Organic Liquid Service Pipeline Repairs (Reg. 8-40-404)
- Report – Contaminated Soil Excavations Unrelated to Underground Storage Tank Activities (Reg. 8-40-405)

District Regulation 8, Rule 47 (Air Stripping and Soil Vapor Extraction Operations)

- Report – Superfund Amendments and Reauthorization Act Sites (Reg. 8-47-401)
- Report – Less than 1 Pound per Day Petition (Reg. 8-47-402)

Definitions

None.

Key Factors
The following key premises are used in this section.

Item	Key Factor
Stripped contaminants	100% of contaminants are stripped from the soil

Section 3.13.6: Groundwater Remediation (Air Stripping)

Like contaminated soil, groundwater may become contaminated and require remediation.
Ground water is typically remediation via air stripping where water is sprayed inside a packed tower or aeration tank and air is forced, countercurrent to the water flow. Volatile contaminants are transferred from contaminated water to air.

Approved Methods
Emissions shall be estimated by using the method listed in Table 3.13.6-1.

Table 3.12.6-1: Summary of Soil Remediation or Soil Excavation Emission Estimate Methods

Rank	Measurement Method	Compositional Analysis Data
1	Material balance	a. Water analysis b. Available lab analysis

Data Needs and Supporting Documentation
The following data is required to estimate mass emissions from air stripping activities. The following supporting documentation should be maintained according to the approved method used to estimate emissions and quality assure emission estimates.

Table 3.13.6-2 Data Needs and Documentation by Air Stripping Emission Estimate Method

Approved Method	Needed Data	Supporting Documentation
Material balance	Influent concentrations (TOC, individual TACs)	Lab analysis
	Influent flow rate	Equipment design specifications (e.g. air stripping blower maximum capacity)
	Abatement device efficiency	Source test results

Reports
District Regulation 8, Rule 47 (Air Stripping and Soil Vapor Extraction Operations)

- Report – Superfund Amendments and Reauthorization Act Sites (Reg. 8-47-401)
- Report – Less than 1 Pound per Day Petition (Reg. 8-47-402)

Definitions
None

Key Factors
The following key premises are used in this section.

Item	Key Factor
Contaminant transfer	100 percent of contaminants are stripped from contaminated water

Section 3.13.7: Contractor Operations

Emissions from petroleum refinery or support facility stationary sources resulting from contractor operations at a petroleum refinery or support facility should be included in that facility's emission inventory using the guidance provided in these guidelines.

The following are examples of contractor operations for which emissions are required to be estimated and reported:

- De-coking
- Catalyst replacement
- Vessel cleaning
- Tank cleaning/degassing
- Hydroblasting
- Tank painting
- Pipeline pigging
- Refractory conditioning

Emissions occurring from stationary sources that are temporarily located on site to perform tasks at refineries, but are permitted to other entities are not required to be estimated unless those emissions were estimated and included in a previous emissions inventory for the facility. If a facility has questions regarding what emissions may have been previously estimated and included in a previous emissions inventory, the facility should contact the Air District.

However, emissions occurring from stationary sources permitted to a petroleum refinery or support facility that result from the use of temporarily-located stationary sources permitted to other entities are required to be estimated.

Depending on the activity, emissions from contractor operations may be reported with another source category. For example, emissions from tank cleaning may be included with the operational emissions of the specific tank being cleaned.

For contractor operations that do not fit one of the categories listed within these guidelines, emissions may be estimated using District-approved engineering calculations and/or methodologies.

Example

During the course of the year, a petroleum refinery degassed and cleaned a stationary storage tank permitted to the petroleum refinery. Prior to cleaning, a natural gas-fired thermal oxidizer permitted to a third party was brought onsite to abate emissions from the stationary storage tank. Emissions from this thermal oxidizer have never been included in a previous emissions inventory for the petroleum refinery. In this case, emissions generated from combusting of supplemental natural gas at the thermal oxidizer are not required to be estimated. However, emissions generated by the storage tank should be estimated per the methodologies and procedures described in the preceding sections.

Section 3.14: Emission Calculation Spreadsheets

For consistency and comparison purposes and to aid in identifying assumptions and methodologies used, emission inventories prepared according to these guidelines shall use the emission estimation spreadsheet templates listed in Appendix B according to the appropriate methodology used.

Section 4: Procedure for Revising Emission Factor, Methodology, or Ranking

Over time, emission estimation procedures are refined as understanding, techniques, and monitoring equipment improve. Therefore, it may become necessary to revise an approved emission factor, methodology, or ranking.

In such cases, the procedures outlined in this section shall be followed before revising a default emission factor, methodology, or ranking listed in Section 3. However, the lists below are not all inclusive.

The procedures for revising the guidelines itself are listed in Section 10 (Guidelines Revision Procedure). Section 10 addresses the process for identifying when the guidelines should be changed. This section addresses the process of revising an emission estimation methodology.

Section 4.1: Emission Factor Revision

The District may revise an approved emission factor if any of the following occurs:

- underlying data used to develop the emission factor is discredited
- underlying methodology used to develop the emission factor is discredited
- underlying methodology used to develop the emission factor is revised
- an improved methodology to develop an emission becomes available
- better quality data becomes available

The District will exercise its expertise when reviewing and approving emission factors. The emission factor that has the highest degree of confidence and representativeness will be chosen if multiple emission factors are available.

Section 4.2: Emission Estimation Methodology Revision

The District may revise an approved emission estimation methodology if any of the following occurs:

- an approved methodology is discredited
- previously unavailable technology and/or predictive modeling becomes available
- previously unknown pollutant and/or emission source is identified

The District will exercise its expertise when reviewing and approving emission estimation methodologies. The methodology that results in the highest quality of data will be chosen if multiple methodologies are available.

Section 4.3: Ranking Revision

The District may revise the ranking of an approved emission estimation methodology if any of the following occurs:

- an approved methodology is discredited
- previously unavailable technology and/or predictive modeling becomes available
- previously unknown pollutant and/or emission source is identified

The District will exercise its expertise when reviewing and ranking approved emission estimation methodologies. The methodologies that result in the highest quality of data will be ranked higher.

Section 5: Data Usage and Calculations

All data and calculations used to develop an emission inventory should be consistent and follow the proscribed steps listed in the following sections.

Section 5.1: Limit of Detection or Accuracy

All calculations that rely on source test results or instrumentation data should reflect the limitations and/or accuracy of the data source and should not represent a greater degree of accuracy, precision, resolution, or confidence level than warranted.

Definitions

Accuracy – how close a measurement is to the "true" (actual value).

Precision – how close two or more measurements are to each other under the same conditions, regardless of whether those measurements are accurate or not. Precision is a measure of the spread of different readings and reflects the reproducibility of a measurement.

Resolution – the smallest discernible change in the parameter of interest that can be registered by a particular instrument.

Confidence interval – designates the bounds within which a parameter is expected to lie.

Range – the extent over which an instrument can reliably function within the confines of its specification.

Error – the amount by which an assumed value deviates from its true value, error is closely associated with

Examples of accuracy and precision are shown in Figure 5.1.1.

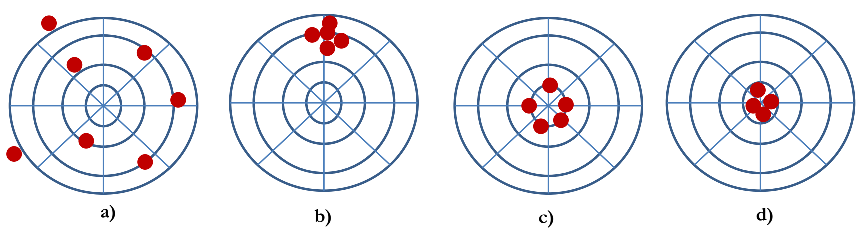

Figure 5.1.1 Example of a) not accurate, not precise, b) not accurate, precise, c) accurate, not precise d) accurate, precise.

Calculation results of two or more measurements should not be more precise than the measurements.

Section 5.1.1 – Limit of Detection

The Limit of Detection (LOD) is the smallest amount of a substance that an analytical method can reliably distinguish from zero.

The Limit of Quantification (LOQ) is the minimum concentration or amount of an analyte that a method can measure with a specified degree of precision.

The following procedures should be used when calculating using data from an analytical test (e.g. source test, GC analysis, calorimeter, etc.).

When several individually reported measurements are averaged to generate a single composite reported value, the averaging should be conducted and reported according to the following methodology:

- If all measured values are below the LOD, then the value reported shall be reported as less than the value represented by the LOD and one half of the LOD should be used in all calculations.

- If all measured values fall above the LOD, the reported value will be the average of the individually reported values. The average of the individually reported values should be used in all calculations.

- If at least one value is below the LOD, then one half of the LOD will be used in place of the below the LOD value to calculate the average of the individually reported values. The average should then be used in all calculations.

If a pollutant has **never** been demonstrated (by BAAQMD, EPA, ARB, other agencies, third parties, etc.) to be emitted from a source-category, then it is not reasonable to use half the LOD. However, if a source category has demonstrated emissions of a pollutant but the specific source has not, then half the LOD should be used. The rationale being that the source has the potential to emit the pollutant, but may not indicate levels above the LOD based on the scale of the monitoring instrument/test method used.

All emission inventories shall include estimates for all toxic air contaminants (TACs) that appear in Table 2-5-1 of District Regulation 2, Rule 5 and that have been demonstrated, as judged by the District, to be emitted from a refinery source category unless a relevant refinery can demonstrate, as approved by the District, that a particular TAC cannot be emitted by that refinery. The District will use the following evidence to demonstrate that a pollutant has been emitted from a refinery source category:

1. District data (studies, sampling, or measurements);
2. Peer-reviewed published literature by scientific bodies or government agencies such as EPA and CARB;
3. Facility-specific process or equipment data; or
4. Validated measurement data of similar equipment.

Refineries shall submit proposed speciation data to the District. In approving speciation data, the District will review the proposed data submitted by every refinery and any data the District has collected and shall then apply the following hierarchy of speciation data, on a per-pollutant basis:

1. Site-, process-, and equipment-specific data, reviewed and approved by the District.
2. Site-, process-, and stream-specific data, reviewed and approved by the District.
3. Site- and stream-specific data, reviewed and approved by the District.
4. Stream-specific data from similar processes or equipment at other refineries within the same corporate family, reviewed and approved by the District.
5. Default process- and stream-specific data compiled by the District from Bay Area refinery data, or District sampling.
6. Peer-reviewed published studies on similar processes, equipment and streams, reviewed and approved by the District.

7. Peer-reviewed industry literature on similar processes, equipment and streams, reviewed and approved by the District.

If a refinery disagrees with the District's determination that a TAC may be emitted from the refinery, the refinery may present a technical demonstration supporting its position. When evaluating such a technical demonstration for approval by the District, the District will accept the following technical demonstrations:

1. It is not possible for a pollutant to be emitted due to either process chemistry, equipment configuration, or equipment operation; or
2. A previous pollutant demonstration, used as evidence that the pollutant is emitted, is no longer valid; or
3. A previous pollutant demonstration, used as evidence that the pollutant is emitted, was invalid.

Refineries and the District may rely on source-specific testing of TAC emissions from refinery sources. In the case of a source test that is unable to detect a particular TAC, if the test is based on the lowest limit of detection currently achievable, as approved by the District, the District will include in the refinery emissions inventory half of the approved test's limit of detection for that particular TAC. Refineries desiring to report lower emissions for a TAC that is unable to be detected by a source test may (1) demonstrate that the TAC is not present, as described above, or (2) optimize the source test methodology, in consultation with the District to lower the limit of detection.

When ascertaining if a pollutant is required to be reported for a source category, it is not intended that an extensive literature search be conducted by a reporting facility to prove that a pollutant has never been emitted from a source category. Rather, reporting facilities may perform a cursory review of existing publicly available databases such as the California Air Toxics Emission Factors (CATEF) database. The District will review publicly available databases as well as other information (e.g. source test reports, agency databases, etc.) and alert reporting facilities if a pollutant is required to be reported.

Facilities desiring to report lower emissions from measurements below the limit of detection may:

1) demonstrate that a pollutant is not present, or
2) optimize the source test methodology to lower the limit of detection

Pollutant Not Present Demonstration
A pollutant may not be present because:

- the pollutant cannot be emitted (i.e. impossible to be emitted due to process chemistry, etc.)
- a previous pollutant demonstration is no longer valid
- a previous emission demonstration was invalid

A previous pollutant demonstration may no longer be valid if the previous source test, where a pollutant was measured above the limit of detection, was conducted on a source that is substantially different (in configuration and/or process) than the current source category and where the pollutant of concern may no longer be emitted. For example, a source test conducted on an engine combusting gasoline containing lead or MTBE.

One reason a previous emission demonstration may be invalid is if there were an error in the source test methodology or analyzer equipment and the pollutant was retroactively found to not have been measured above the limit of detection.

Source Test Optimization

Facilities can optimize the source test methodology to lower the limit of detection. Such optimization can include using more accurate instrumentation, higher tolerance calibration gases, etc. Facilities seeking to optimize a source test methodology should contact the District's Source Test Section for guidance.

Examples

Table 5.1-1 lists examples of the three situations discussed above, provides what the reported average should be, and lists the average to use in calculations. In all examples, the LOD is 2.

Table 5.1-1: Example Measurement Values

	Measured Value			Reported Value			Reported	Average to Use in
Example	**Run A**	**Run B**	**Run C**	**Run A**	**Run B**	**Run C**	**Average**	**Calculations**
1	1.5	0.5	1.7	<2	<2	<2	<2	1
2	12.0	10.0	14.0	12.0	10.0	14.0	12.0	12.0
3	6.0	7.0	8.0	6.0	7.0	8.0	7.0	7.0
4	0.8	16.0	13.0	<2	16.0	13.0	10.0*	10.0
5	0.8	0.8	3.0	<2	<2	3.0	1.7*	1.7

Note:
* Analyte was less than the detection in some, but not all samples

All emission inventories shall include estimates for all toxic air contaminants (TACs) that appear in Table 2-5-1 of District Regulation 2, Rule 5 and that have been demonstrated, as judged by the District, to be emitted from a refinery source category unless a relevant refinery can demonstrate, as approved by the District, that a particular TAC cannot be emitted by that refinery. The District will use the following evidence to demonstrate that a pollutant has been emitted from a refinery source category:

1. District data (studies, sampling, or measurements);
2. Peer-reviewed published literature by scientific bodies or government agencies such as EPA and CARB;
3. Facility-specific process or equipment data; or
4. Validated measurement data of similar equipment.

Refineries shall submit proposed speciation data to the District. In approving speciation data, the District will review the proposed data submitted by every refinery and any data the District has collected and shall then apply the following hierarchy of speciation data, on a per-pollutant basis:

1. Site-, process-, and equipment-specific data, reviewed and approved by the District.
2. Site-, process-, and stream-specific data, reviewed and approved by the District.
3. Site- and stream-specific data, reviewed and approved by the District.
4. Stream-specific data from similar processes or equipment at other refineries within the same corporate family, reviewed and approved by the District.
5. Default process- and stream-specific data compiled by the District from Bay Area refinery data, or District sampling.
6. Peer-reviewed published studies on similar processes, equipment and streams, reviewed and approved by the District.
7. Peer-reviewed industry literature on similar processes, equipment and streams, reviewed and approved by the District.

If a refinery disagrees with the District's determination that a TAC may be emitted from the refinery, the refinery may present a technical demonstration supporting its position. When evaluating such a technical demonstration for approval by the District, the District will accept the following technical demonstrations:

1. It is not possible for a pollutant to be emitted due to either process chemistry, equipment configuration, or equipment operation; or
2. A previous pollutant demonstration, used as evidence that the pollutant is emitted, is no longer valid; or
3. A previous pollutant demonstration, used as evidence that the pollutant is emitted, was invalid.

Refineries and the District may rely on source-specific testing of TAC emissions from refinery sources. In the case of a source test that is unable to detect a particular TAC, if the test is based on the lowest limit of detection currently achievable, as approved by the District, the District will include in the refinery emissions inventory half of the approved test's limit of detection for that particular TAC. Refineries desiring to report lower emissions for a TAC that is unable to be detected by a source test may (1) demonstrate that the TAC is not present, as described above, or (2) optimize the source test methodology, in consultation with the District to lower the limit of detection.

Section 5.1.2 – Instrumentation/Methodology Accuracy

Calculations that use data from instrumentation (e.g. flow meters, thermocouples, etc.) shall be based upon the accuracy, precision, and resolution of the instrumentation and methodology employed. Calculations that involve values below the detection limit of the instrument (includes instrument accuracy, accuracy limit of an instrument and methodology) should account for the accuracy limit of the instrument and method.

At a minimum, uncertainty should be accounted for in reported emissions from sources that meet the following criteria:

- emissions attributed to uncertainty exceed 50 percent of total emissions, or
- emissions attributed to uncertainty are greater than 1000 pounds, or
- uncertainty is equal to or greater than 10 percent.

The complete expression of a quantitative measurement consists of two values: the measured quantity (V) and the associated uncertainty (e.g. accuracy, limit of detection, error, etc.).

Source test data is generally reported in one of two styles:

1) Parameter value = V ± U (**V may never be less than U**)
2) Parameter value = <U, or more informatively:
Parameter value = ½ U ± ½ U

The most proper way to report all data is in the style of the first equation. However, if a quantitative result is reported as below LOD (<LOD), then it may be rewritten as ½ LOD ± ½ LOD.

For measurements below the limit of detection of an instrument/methodology, emission inventories should use one-half the limit of detection when estimating emissions with those measurements.

The following examples provide guidance for how data should be reported when calculated from two or more parameters and where one or more parameters are below the LOD.

Example 1: Only One Parameter below a LOD

Mass = conversion factor (k) x volumetric flow rate x pollutant concentration

Flow rate = Q (standard accuracy on value established)

Concentration = ½ LOD_{CEM} ± ½ LOD_{CEM} (concentration below LOD of CEM)

In this example, the lower bound on mass rate emissions is zero but the upper bound is:

Mass ≤ (k)(Q)(LOD_{CEM}).

Therefore, the reported mass should be: Mass = ½ (k)(Q)(LOD_{CEM}) ± ½ (k)(Q)(LOD_{CEM})

Example 2: Two Parameters below the LODs

Mass = conversion factor (k) x volumetric flow rate x pollutant concentration

Flow rate = ½ LOD_{Flow} ± ½ LOD_{Flow} (flow rate below LOD of flow meter)

Concentration = ½ LOD_{CEM} ± ½ LOD_{CEM} (concentration below LOD of CEM)

In this example, the lower bound on mass rate emissions is zero but the upper bound is:

Mass ≤ (k)(LOD_{Flow})(LOD_{CEM}).

Therefore, the reported mass should be: Mass = ½ (k)(LOD_{Flow})(LOD_{CEM}) ± ½ (k)(LOD_{Flow})(LOD_{CEM})

Example 3:
A cooling tower has a permit condition limiting total hydrocarbons in the water to less than 40 ppmv. A continuous total hydrocarbon analyzer is used to verify compliance with the limit. The analyzer routinely reads less than 1 ppmv.

The analyzer has a scale of 100 ppmv, an instrumentation accuracy of ± 5 percent of scale and a resolution of 1 ppmv. The analyzer is calibrated weekly to ± 10 percent of scale (an LOD of 10 ppmv).

For this analyzer, the accuracy of the instrument is ± 5 ppmv (5 percent of scale) and the accuracy of the calibration is ± 10 ppmv (10 percent of scale). The District source test division views the two errors as co-dependent and therefore the uncertainties are additive. In this case, the total uncertainty (accuracy of instrument and accuracy of calibration) is 15 percent or ± 15 ppmv.
Therefore, an instrument reading of less than 15 ppmv may be either an actual emission or attributed to instrumentation/method inaccuracy. If a heat exchanger had a hydrocarbon leak of less than 15 ppmv (e.g. 5 ppmv), the analyzer may have an instrument reading of anywhere between 0 ppmv to 15 ppmv.

In this example, any reading below 10 ppmv should be reported as "<15 ppmv" or "½ 15 ppmv ± ½ 15 ppmv".

For the purposes of an emissions inventory, emissions should be estimated using one-half of the LOD whenever the instrument lists a reading less than 15 ppmv . If a facility desires to use lower values, the facility should use either an instrument with a smaller scale, dual range scale, better accuracy or a more accurate calibration method.

Example 4:
During a calibration, the analyzer in the above example is found to have drifted by 20 percent since it was last calibrated (the prior week). In this case, the accuracy is 25 percent or 25 ppmv.

Emissions for this period should be estimated assuming that the first half of the previous week, the total uncertainty was ±10 ppmv and the second half of the week the total uncertainty was ± 25 ppmv. For emissions calculations, a value of 5 ppmv should be used during the first half of the week whenever the analyzer recorded readings less than 10 ppmv and a value of 12.5 ppmv during the second half of the week whenever the analyzer recorded readings less than 25 ppmv.

Section 5.2: Calculations Involving Averages

Whenever possible, all calculations shall be made on an individual basis rather than on an averaged basis. For equipment whose emissions may vary greatly on an hourly basis and that use either a continuous emissions monitor or a parametric monitor (e.g. flowmeter, temperature, oxygen, pressure, etc.) to estimate emissions, calculations shall be done on an hourly basis whenever possible. Such equipment includes process units, combustion devices (e.g. boilers, furnaces, heaters, etc.), and equipment which had a startup, shutdown, or malfunction during a reporting year. At a minimum, emissions should be estimated on an hourly basis for those sources that had a startup, shutdown, or malfunction during the reporting year or whose emissions varied by more than 15 percent on an hourly basis. This will prevent either underestimating or overestimating emissions and will lead to more accurate emission inventories.

Section 5.3: Data Substitution

When compiling data to be used in an emission inventory, a facility may discover that some or all of the data necessary to estimate emissions from a source or activity is missing.

A missing data period is defined as a time period when a piece of data is:

- not collected, or
- invalid, or
- collected while the measurement device is not in compliance with applicable quality-assurance requirements (e.g. District field accuracy test, relative accuracy test audit, etc.).

When data is missing, there are circumstances where it is appropriate to substitute other data for the missing data. However, there are circumstances where it is not. Whenever missing data is substituted with other data, it should be identified as such (e.g. a unique identifier), have the data substitution method cited, and the justification for the data substitution (e.g. following procedure listed in 40 CFR 75.33, etc.).

If all of the data that is necessary to estimate emissions using a specific method is missing, that method may not be used and a lower ranking emission method may be required.

For example, if a furnace stack has a continuous emission monitor that was inoperative for the entire inventory year, then it may be required to use source test results rather than continuous data to estimate emissions from that furnace.

The following sections outline the procedures that should be followed when data is missing for only a partial portion of an inventory year.

Section 5.3.1 –Continuous Emission Monitor (CEM)

Unless otherwise required by an applicable regulation or an alternative procedure has been approved by the District, missing data from CEMs should following the data substitution procedures listed in of 40 CFR Part 75 (Continuous Emission Monitoring), Subpart D (Missing Data Substitution Procedures).

The procedures outlined in 40 CFR 75 Subpart D are based on the percent of data available and the duration of the missing data period. Depending on the data availability and duration of missing data, substituted data may be based on either: the average of the hour before and hour after the missing period, some percentile (e.g. 90^{th}, 95^{th}, etc.) reading recorded in a given number of hours (e.g. 720 hours, 2160 hours, etc.), or the maximum (or minimum for O_2 or H_2O meters) potential reading.

An example of the different scenario-based procedures for missing data from SO_2 CEMs is shown in Table 5.3.1-1

Table 5.3.1-1: SO_2 CEM – Data Substitution Procedures [40 CFR 75.33(b)]

Data Availability (percent)	**Missing Period** (hours)	**Data Substitution Procedure**
Availability ≥ 95	≤ 24	Substitute the average of the hourly readings recorded by the CEM for the hour before and the hour after the missing period
	> 24	Substitute the greater of: • the 90th percentile hourly reading recorded by the CEM during the previous 720 quality-assured monitor operating hours; or • the average of the hourly readings recorded by the CEM for the hour before and the hour after the missing period
90.0 ≤ Availability < 95	≤ 8	Substitute the average of the hourly readings recorded by the CEM for the hour before and the hour after the missing data period
	> 8	Substitute the greater of: • the 95th percentile hourly reading recorded by the CEM during the previous 720 quality-assured monitor operating hours; or • the average of the hourly readings recorded by the CEM for the hour before and the hour after the missing period
80.0 ≤ Availability < 90	> 0	Substitute for that hour of missing data period the maximum hourly reading recorded by the CEM during the previous 720 quality-assured monitor operating hours.
Availability < 80	> 0	Substitute for that hour of the missing data period the maximum potential reading, as defined in 40 CFR Part 75, Subpart D Appendix A, Section 2.1.1.1.

For transparency purposes and to ensure that the proper substitution method was used, whenever data is substituted it should be identified and include the specific method used and a citation for the data substitution method used.

Example (data availability = 93 percent)

Hour	**CEM Reading** (ppmv)	**CEM Reading with Substituted Data** (ppmv)	**Method**	**Data Substitution Method Citation**
07:00	100	100	CEM	CEM
08:00	50	50	CEM	CEM
09:00	Missing	125*	Average**	40 CFR 75.33(b)(2)(i)
10:00	Missing	125*	Average **	40 CFR 75.33(b)(2)(i)
11:00	200	200	CEM	CEM
12:00	85	85	CEM	CEM
*Substituted data ** Average of hour before and hour after readings				

Section 5.3.2 – Parametric Monitor

As defined in District Regulation 1, a parametric monitor is "any monitoring device or system required by District permit condition or regulation to monitor the operational parameters of either a source or an abatement device.

Parametric monitors may record temperature, gauge pressure, flowrate, pH, hydrocarbon breakthrough, or other factors."

Per District Regulation 1-523, the petroleum refineries are required to "maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications and the District Manual of Procedures."

In addition, the petroleum refineries are required to report all parametric monitor periods of inoperation greater than 24 continuous hours and periods of inoperation cannot exceed 15 consecutive days per incident or 30 calendar days per consecutive 12-month period.

Therefore, data availability of a parametric monitor should not be lower than 92 percent (335 days per year).

However, when using data from a parametric monitor to estimate emissions, the following data substitution procedure should be used.

Table 5.3.2-1: Data Substitution Procedures for Parametric Monitors

Data Availability (percent)	**Missing Period** (hours)	**Data Substitution Procedure**
Availability ≥ 95	≤ 24	Substitute the average of the hourly readings recorded by the monitor for the hour before and the hour after the missing period
	> 24	Substitute the greater of: • the 90th percentile hourly reading recorded by the monitor during the previous 720 quality-assured monitor operating hours; or • the average of the hourly readings recorded by the monitor for the hour before and the hour after the missing period
90.0 ≤ Availability < 95	≤ 8	Substitute the average of the hourly readings recorded by the monitor for the hour before and the hour after the missing data period
	> 8	Substitute the greater of: • the 95th percentile hourly reading recorded by the monitor during the previous 720 quality-assured monitor operating hours; or • the average of the hourly readings recorded by the monitor for the hour before and the hour after the missing period
80.0 ≤ Availability < 90	> 0	Substitute for that hour of missing data period the maximum hourly reading recorded by the monitor during the previous 720 quality-assured monitor operating hours
Availability < 80	> 0	Substitute for that hour of the missing data period the maximum potential reading

Section 5.3.3 –Non-CEM, Non-Parametric Monitor

Instrumentation that is neither a CEM nor a parametric monitor is not required to meet minimum calibration and/or maintenance requirements. Therefore, the reliability and data quality of data results may be suspect.

For these instruments, the data substitution procedures of Table 5.3.3-1 should be used.

Table 5.3.3-1: Data Substitution Procedures for Non-CEM/Non-Parametric Monitors

Data Availability (percent)	**Data Substitution Procedure**
Availability ≥ 90	Substitute for each missing value with the best available estimate of the parameter, based on all available process data.
80.0 ≤ Availability < 90	Substitute for each missing value with the highest/lowest value recorded for the parameter during the given data year that would result in a conservative (e.g. maximum) emission estimate
Availability < 80	Substitute for each missing value with the highest/lowest value recorded for the parameter within the past five years of records that would result in a conservative (e.g. maximum) emission estimate

Section 5.4: Conventions

To ensure consistency, this section outlines conventions regarding significant figures, rounding, standard conditions, and conversion factors.

Section 5.4.1 – Significant Figures

The following list District-accepted conventions regarding significant figures:

- All non-zero digits (1-9) are significant
- All zeros between non-zero digits are always significant
- For numbers that do not contain decimal points, the trailing zeros may or may not be significant. In this situation, the number of significant figures is ambiguous.
- For numbers that do contain decimal points, the trailing zeros are significant.
- If a number is less than 1, zeros that follow the decimal point and are before a non-zero digit are not significant.

Any number based on calculations and/or measurements should have the same number of significant figures as the least precise measurement or number that went into it. The number of significant digits retained should be such that accuracy is neither sacrificed nor exaggerated.

Example

2.18 tons NO_X + 4.1 tons NO_X + 8.967 tons NO_X = 15.2 tons NO_X <u>NOT</u> 15.247 tons NO_X

The reason total NO_X is reported as15.2 tons and not 15.247 tons is because:

2.18 tons NO_X may be any value between 2.175 and 2.184,
4.1 tons NO_X may be any value between 4.050 and 4.149, and
Total NO_X may be any value between 15.192 tons or 15.300

Section 5.4.2 – Rounding

All calculations (intermediate and final) should carry the same number of significant figures as the least precise number.

When calculations are conducted by a software program (e.g. Microsoft Excel), software functions that either round (e.g. "Round" in Excel) or truncate (e.g. "Truncate" in Excel) should not be used in any calculations.

When rounding in manual calculations, the following procedure should be used:

- **For both calculations and measurements:** If the first digit to be discarded is less than five, the last digit retained should not be changed.
- **For both calculations and measurements** When the first digit to be discarded is greater than five, or if it is a five followed by at least one digit greater than 0, the last figure retained should be increased by one unit.
- **For calculations**: When the first digit is exactly five, followed only by zeros, the last digit retained should be rounded upward.
- **For measurements**: When the first digit is exactly five, followed only by zeros, the last digit retained should be rounded upward if it is an odd number, but no adjustment made if it is an even number.

Examples (Two Significant Figures)

Rounding Convention	Example	Rounding Off (Calculations)	Rounding Off (Measurements)
First digit to be discarded is less than five.	1.24	1.2	1.2
First digit to be discarded is greater than five	1.26	1.3	1.3
First digit to be discarded is exactly five	1.25	1.3	1.2
	1.35	1.4	1.4

Temperature Rounding

When rounding converted measurements, the resulting number should reflect the accuracy and precision of the original measurement.

For example, temperature is typically expressed in degrees Fahrenheit as whole numbers. When converting to Celsius, temperature should be converted to the nearest 0.5 degree Celsius. This is because the magnitude of a degree Celsius is approximately twice the size of a degree Fahrenheit (as shown in the equations below), and rounding to the nearest Celsius would reduce the precision of the original measurement.

Temperature conversion equations: $°F = \frac{9}{5}(°C) + 32$ $°C = \frac{5}{9}(°F - 32)$

Section 5.4.3 –Standard Conditions

Emissions and any intermediate calculations should be converted to standard conditions as defined in Regulation 1. Standard conditions are those listed in Table 5.4-1.

Table 5.4-1: Standard Conditions

Parameter	Standard
Temperature	70 degrees Fahrenheit (20 degrees Celsius)
Pressure	14.7 psi (760.00 mm Hg)
Oxygen	20.95%
Molar Volume	386.9ft^3/lb-mole

Example

To correct sampling volumes (V_s) to District standard (V_{std}) conditions, the following equation is used:

$V_{std} = (V_s)(P_{atm}/P_{std})(T_{std}/T_{atm})$

where:

V_{std} = volume of gas sampled, corrected to the District's standard pressure and standard temperature
V_s = volume of gas sampled at atmospheric pressure (Patm) and temperature (Tatm)
T_{std} = District standard temperature (Kelvin)
P_{std} = District standard pressure (mm Hg)
T_{atm} = average atmospheric temperature during sampling (Kelvin)
P_{atm} = average atmospheric pressure during sampling (mm Hg)

Example

A natural gas-fired furnace has a CO stack reading of 30 ppm at 9.7% O_2. To find the CO concentration at 0% O_2 (to convert to mass emissions), the following equation is used.

$$CO_{std} = (CO_{stack})\left(\frac{20.95\% O_2 - 0\% O_2}{20.95\%\ O_2 - Stack\ \%\ O_2}\right) = (30\ ppm)\left(\frac{20.95\%\ O_2 - 0\%\ O_2}{20.95\% - 9.7\% O_2}\right) = 56\ ppm\ CO\ at\ 0\%\ O_2$$

Section 5.3.4 –Conversion Factors

Conversion is a multi-step process that involves multiplication or division by a numerical factor, selection of the correct number of significant figures (following procedures listed in Section 5.3.1), and rounding (following procedures listed in Section 5.3.2).

All calculations involving heating value shall be based on the higher heating value of fuel.

To minimize conversion errors and aid in comparing reported emissions, the conversion factors listed in Table 5.4-2 should be used for all emission calculations.

Table 5.4-2: Conversion Factors

Multiply	By	To Obtain		Multiply	By	To Obtain
Mass						
kilogram	2.2046	pound		pound	0.4536	kilogram
ounce	28.349	gram				
	0.0625	pound				
Power						
horsepower (boiler)	33,479	Btu/hr				
horsepower (U.S.)	2542.5	Btu/hr				
	0.7457	kilowatts				
Volume						
bbl	42	gallons				

Section 6: Quality Assurance and Quality Control

To ensure accurate emission inventories, quality assurance (preventing deficiencies) and quality control (identifying deficiencies) procedures should be implemented when developing and reviewing emission inventories.

Implementing quality assurance and quality control processes and procedures will have the following goals:

- Instill confidence in emission estimates
- Improve accuracy of emission estimates
- Improve assessment of emissions on air quality
- Improve transparency of estimates
- Provide an estimation of uncertainty, and
- Provide documentation of quality assurance and quality control activities.

Section 6.1: Quality Assurance

Quality assurance is a set of activities for ensuring quality in the process of developing an emission inventory. Quality assurance aims to prevent deficiencies with a focus on the process used to develop an emission inventory. Quality assurance is a proactive process.

Section 6.1.1 – Quality Assurance Program

Each facility that submits an emission inventory should have and follow a quality assurance program when developing an emission inventory. At a minimum, the program should include three general types of procedures:

- standard operating procedures,
- error identification and correction techniques, and
- data quality assessments.

Standard operating procedures should include organization planning, personnel training, project planning, and the development of step-by-step procedures for technical tasks.

Error finding procedures should include techniques for finding and correcting inconsistencies and errors including identification of potential error sources, location of checkpoints for optimal problem detection, and a provision for timely response when problems occur.

Data quality assessments should include accuracy checks (e.g. calibrations, instrument accuracy, source test accuracy, range, etc.), uncertainty calculations (e.g. error propagation, accuracy, etc.), and any other method for determining the quality of data used in the inventory.

When developing an emission inventory quality assurance program, a facility should:

- analyze the system to identify its components,
- estimate the potential for error and identify the errors having the greatest impact on inventory results, and
- develop techniques for the control and correction of errors.

An example outline of a quality assurance program is included in Appendix C.

Reporting facilities are not required to have comprehensive, individualized quality assurance procedures for each source. Rather it is intended that facilities will have procedures that may be used for all sources and source categories.

Section 6.1.2 –Accuracy

Per Section 5.1.1 (Limit of Detection), calculations involving values below the limit of detection should be adjusted based on the values of the specific test runs. When doing so, each inventory shall identify the adjustment and the limit of detection of the specific source test.

Per Section 5.1.2 (Instrumentation Accuracy), calculations involving values below the accuracy of the instrument should use the accuracy limit of the instrumentation. For assurance and transparency purposes, each inventory shall identify where calculations used values at the accuracy limit and note the accuracy limit.

Per District Regulation 1, parametric monitors are required to be maintained and calibrated according to manufacturer's specifications. Therefore, each emission inventory that uses data from a parametric or other monitor should include a table that lists all monitors used and for each parametric monitor: the accuracy, resolution, manufacturer-recommend calibration and maintenance schedule (e.g. daily, weekly, monthly, semi-annual, annual, etc.).

Example – Parametric Monitors

Parameter	Instrument	Facility ID	Accuracy	Resolution	Manufacturer-Recommendations	
					Calibration Frequency	Maintenance Frequency
Temperature	Rosemount 3114P temperature transmitter	PI 108.789	±0.14°F (0.08 °C)	0.01°F (0.01 °C)	60 months(1)	As needed
.	.	.	.	.	.	.
.	.	.	.	.	.	.
.	.	.	.	.	.	.

Notes: 1. Calculated using manufacturer-provided calibration frequency equation listed in Section 3.14.1 of Reference Manual 00809-0100-4021, Rev GD May 2015

Section 6.1.3 –Error Prevention

Wherever possible, errors should be eliminated or minimized in the development of an emission inventory.

Typical error source categories include:

- missing or duplicate emission sources
- errors in locating sources (e.g. not all sources identified or source incorrectly attributed to another facility)
- divergent time frames (inclusion of non-inventory year emissions or exclusion of inventory year emissions)
- emission factor reliability
- instrumentation error
- calculation errors
- data entry errors

Each facility submitting an emission inventory should have in place processes, techniques, and procedures for preventing errors.

Section 6.2: Quality Control

Quality control is a set of activities for ensuring quality in a completed emission inventory. Quality control aims to identify and correct deficiencies and measures the performance of the process of developing an emission inventory. Quality control is a reactive process.

Section 6.2.1 – Methods

The following are examples of quality control methods that can be used by facilities to review the efficacy of a quality assurance program:

- Reality checks (e.g. are numbers reasonable? Do they make sense?)
- Peer review (e.g. independent review of calculations, assumptions, and documentation by person with a moderate to high level of technical expertise)
- Sample calculation (e.g. replication of calculations)
- Computerized or automated data checks (check for data format errors, range checks, look-up tables)
- Sensitivity analysis (identify which parameters and errors have largest effect on results)
- Emission estimation validation
- Statistical checks (identify outliers)
- Independent audit

Employing standardized checklists to monitor:

- Data collection
- Data calculations
- Evaluation of data reasonableness
- Evaluation of data completeness
- Data coding and recording
- Data tracking

Example quality control activities include:

- Comparison of emissions to previous inventories
- Using checklists to ensure that all inventory development requirements are met
- Determining outliers by using computer-aided, graphical, or other reviews
- Conducting accuracy checks

Section 6.2.2 – Error Detection and Correction

Each facility submitting an emission inventory should have in place processes, techniques, and procedures for detecting and correcting errors.

Techniques to detect and correct errors may include:

- Peer review
- System audit of quality assurance system

Section 6.3: Uncertainty Analysis

Each inventory calculation involving an emission factor, instrumentation data, source test, or other information that has the potential for uncertainty (degree of accuracy and precision of data) should include a minimum and maximum error range for each point of uncertainty as well as an error propagation (total uncertainty) value for those sources that have estimated post-control emissions equal to or more than 10 tons (on a single pollutant basis).

Each inventory should include for each source in the inventory that emits equal to or more than 10 tons per year, a table of the parameters used to calculate emissions for that source with the method used to determine the value of the parameter and uncertainty values for the parameter.

Each emission inventory should include total errors on an individual source basis as well as a refinery-wide basis.

Sources of uncertainty include:

- Assumptions and methods
- Input data (measured values have errors, non-representative emission factors, lack of data, etc.)
- Calculation errors

District Regulation 1, Section 522 requires CEMS to be calibrated daily and maintain accuracies to within specified values. District Regulation 1, Section 523 requires facilities to maintain and calibrate all parametric monitors in accordance with applicable manufacturer's specifications and keep records of all tests, calibrations, adjustments and maintenance. All District-approved source tests are required to following the District's Manual of Procedures, which outlines the minimum accuracy criteria of various test methods. Within the basis of agency-supplied (BAAQMD, ARB, EPA, etc.) default emission factors are listed either the confidence interval or accuracies.

Within each refinery's Title V permit are standard conditions that require the refineries to report any non-compliance within 10 days of discovery as well require the responsible official to certify compliance with all applicable rules and regulations to the best of their knowledge.

It is expected that each refinery can readily obtain and compile accuracies for all CEMS, parametric monitors, and source tests used in a submitted emission inventory.

However, for instruments that are not CEMs or parametric monitors, there are no regulatory-required maintenance or accuracy requirements. As such, compilation and reporting of accuracies from these instruments may be difficult. As such, refineries may have until the third submitted emission inventory to report accuracies for these instruments. In the interim, unless data is available, total uncertainty calculations involving these instruments should treat these instruments as being 100 percent accurate.

To reduce the amount of effort required to identify and obtain uncertainties for individual parameters, the following assumptions may be made:

Item	Qualification	Uncertainty
CEMS	Complies with Regulation 1-522	± 20 percent
District source test result	Valid test (passed quality assurance checks)	± 20 percent
Default emission factor	Uncertainty not listed	None

Total Uncertainty –Error Propagation

Depending on the emission estimation methodology, multiple parameters may be either added (or subtracted) or multiplied (or divided) together. Each of these parameters may have an associated uncertainty. The total uncertainty associated with an emission estimate will depend on whether estimation parameters are added (or subtracted) or multiplied (or divided) and whether the uncertainties are related (dependent) or unrelated (independent) to each other.

Total uncertainty should be calculated using an error propagation equation (see Equation 6.1.3-1 through 6.1.3-4):

Uncertainty Propagation for a Sum (or Difference)

Unrelated Uncertainty Parameters

$$U(abs)_{X+Y+\cdots N} = \sqrt{U_X^2 + U_Y^2 + \cdots U_N^2} \qquad \text{[Equation 6.1.3-1]}$$

Where:
U(abs) = the absolute uncertainty
U_i = the uncertainty of parameter "i"

Related Uncertainty Parameters (Two Parameters)

$$U(abs)_{Correlated X+Y} = \sqrt{U_X^2 + U_Y^2 + 2r(U_X + U_Y)} \qquad \text{[Equation 6.1.3-2]}$$

Where:
U(abs) = the absolute uncertainty
U_i = the uncertainty of parameter "i"
r = the correlation coefficient between U_X and U_Y

Related Uncertainty Parameters (More Than Two Parameters)
When the uncertainties of more than two parameters are related, a Monte Carlo approach is preferred, if data is available.

Uncertainty Propagation for a Product (or Quotient)

Unrelated Uncertainty Parameters

$$U(rel)_{X\times Y\times\ldots\times N} = U(rel)_{X\div Y\div\ldots\div N} = \sqrt{\left(\frac{U_X}{X}\right)^2 + \left(\frac{U_Y}{Y}\right)^2 + \cdots + \left(\frac{U_N}{N}\right)^2} \qquad \text{[Equation 6.1.3-3]}$$

Related Uncertainty Parameters (Two Parameters)

$$U(rel)_{Correlated X\times Y} = \sqrt{\left(\frac{U_X}{X}\right)^2 + \left(\frac{U_Y}{Y}\right)^2 + 2r\left(\frac{U_X}{X} + \frac{U_Y}{Y}\right)} \qquad \text{[Equation 6.1.3-4]}$$

Related Uncertainty Parameters (More Than Two Parameters)
When the uncertainties of more than two parameters are related, a Monte Carlo approach is preferred, if data is available.

Example

CO emissions from a furnace are estimated using the following equation:

$$CO(lb/hour) = \frac{CO(ppm)}{1{,}000{,}000} x \frac{20.95\%\, O_2 - \%\, O_2}{20.95\%\, O_2} x \frac{28.01\frac{lb}{lb-mol}}{385.3\frac{scf}{lb-mol}} x \frac{(T°F+459.67)}{(68+459.67)} x \frac{fuel\ flow\ (scf) x\ HHV \left(\frac{Btu}{scf}\right) x \left(\frac{1\ MMBtu}{1{,}000{,}000\ Btu}\right)}{F-Factor\ (dscf/MMBtu)}$$

where:
CO = CO concentration measured using a continuous emission monitor (CEM)
O_2 = O_2 percentage measured using a CEM,
T = temperature measured using a thermocouple
Fuel flow is measured is flow meter,
HHV = higher heating value measured using a calorimeter
F-Factor = volume of combustion components per unit of heat content determined through a gas chromatograph analysis

In this example, there are several instances where errors may be introduced into the final calculation. These include the CO and O_2 CEMs, thermocouple, fuel flow meter, calorimeter, and GC analysis.

Table 6.3-1 lists example uncertainty values for each error-introducing parameter and a total error value.

Table 6.3-1: Example Uncertainty Analysis of CO Emissions from a Furnace

Parameter	**Units**	**Method**	**Uncertainty**	
			(%)	(absolute value)
Fuel flow	scf	Meter	± 2%	± 100 scf
Higher heat value	Btu/scf	Meter	± 10%	± 50 Btu/scf
CO	ppm	CEM	± 10%	± 5 ppm
O_2	%	CEM	± 5%	± 0.5%
Fuel analysis F-factor	dscf/MMBtu	GC	± 1%	± 100 scf/MMBtu
Temperature	°F	Thermocouple	± 5%	± 50 °F
		Total Error	**~± 16%**	

In this example, CO emissions would have a total uncertainty of ± 16%. This total error on both a percentile and absolute basis should be included in the inventory along with the final CO emissions (e.g. CO = 24 tons ± 3.8 tons (± 16%).

In addition to furnace listed in Table 6.1-1, a refinery has one other source of CO emissions whose emissions are 18 tons ± 2.2 tons (± 12%). In this case, the total refinery CO emissions are 42 tons ± 8.4 tons (± 20%).

Total Uncertainty –Monte Carlo Method

If uncertainties are large, have a non-normal distribution, complex algorithms, or correlations exist and uncertainties vary with time; a Monte Carlo simulation may be required rather than Equation 6.1.3-1. The Monte Carlo method requires understanding the shape of the probability density function (PDF) of the equation The PDF is the range and likelihood of possible values and includes the mean, width, and shape (e.g. normal, log-normal, Weibul, Gamma, uniform, triangular, fractile….).

The Monte Carlo method requires:

- selecting random values of input parameters from their PDF,
- calculating the corresponding emissions,

- repeating many times,
- plotting the results to form a PDF of the result, and
- estimating a mean and uncertainty from the PDF of the results.

Section 6.4: Documentation

All quality assurance and quality control activities, especially changes made as a result of these activities, should be documented and records kept onsite for the benefit of future preparers and District staff.

Each inventory should have a quality assurance report that includes the following information:

- Procedures used
- Technical approach used to implement quality assurance plan
- Any calculation sheets and quality assurance/quality control checklists
- Dates of each audit, and the names of the reviewers
- Responses to quality assurance/quality control audits
- Results of quality assurance activities, including problems found, correction actions, and recommendations
- Discussion of the inventory quality

Every submitted emission inventory should include a quality assurance section with a checklist that identifies the measures taken to ensure the accuracy and reliability of the inventory.

Section 6.5: Quality Assurance Plan

Each facility submitting an emission inventory should have and follow a quality assurance plan when developing the emission inventory.

Each quality assurance plan should include the following elements:

- A description of specific quality assurance and quality control procedures and responsibilities
- Identify a Quality Assurance Coordinator
- Restate the data quality objectives and data quality indicators
- Determine resources needed to implement the quality assurance plan
- Identify authority and responsibility for quality assurance/quality control plan implementation
- Techniques for identifying sources of pollutants
- Data acquisition
- Data validation and usability

Data quality indicators include:

- Representativeness
- Precision
- Bias
- Detectability
- Completeness

- Comparability

Techniques for identifying sources of pollutants may include:

- Documents and tools
- Existing inventories
- Source tests
- Compliance data
- Compliance reports (e.g. risk management reports, accidents/spills, etc.)
- Permits
- Risk assessments

At a minimum, each quality assurance plan should have the sections identified in Table 6.5-1.

Table 6.5-1: Quality Assurance Plan Components

Section	Includes
Policy Statement	Declaration of facility's commitment
Introduction	
Quality Assurance Program Summary	Data flow and points where quality control procedures will be applied
Technical Work Plan	Resources, documentation schedule
Quality Assurance/Quality Control Procedures	Techniques, checkpoints
Inventory Preparation and Quality Assurance/Quality Control Activities	Roles and responsibilities, personnel, reality checks, peer review, sensitivity checks, etc.
Corrective Action Mechanisms	
References	

As the District expects facilities to already employ numerous quality assurance processes that may be referenced, each quality assurance plan is not expected to exceed 20 pages.

To allow for time for facilities to develop a quality assurance plan in conjunction with the initial emissions inventory, a detailed quality assurance plan is not required for the initial emissions inventory. However, facilities should provide a a narrative on what quality assurance steps were used when developing the initial emissions inventory.

Section 7: Inventory Usage for Regulatory Compliance

The principle purpose of emission inventories is to track and characterize emissions from petroleum refineries over time. Attempts to compare emission inventory results to existing or previous regulations, permit conditions, or other metrics should be done carefully with a comprehensive understanding of how the inventory was developed and the underlying basis of the regulation under comparison.

Section 7.1: Regulatory Basis

Data used in an inventory report prepared according to these guidelines may also be used to determine compliance with District, California, or Federal regulations. However, emissions results should not be used to determine compliance with a regulation unless the underlying estimation methodologies are understood and determined to be the same, similar, or allowed by the regulation.

When developing regulations, concerns other than actual emissions totals are considered such as startup, shutdown, and malfunction allowances. Therefore, regulations may have different definitions of "hour", "day", "annual", or "year" as well as data substitution allowances. Therefore, unless these definitions are understood, emissions inventories should not be used to justify an assertion of non-compliance on the part of the facility.

As the purpose of the inventory is to report actual emissions as accurately as possible, reported emissions totals may differ from emissions reported per a specific regulation or permit condition requirement.

For example, a refinery's NO_X emissions reported in an emissions inventory may differ from NO_X emissions reported per District Regulation 9, Rule 10. As compliance with Regulation 9, Rule 10 is based on an average of all furnaces subject to Regulation 9, Rule 10; Regulation 9, Rule 10 includes allowances for various operating scenarios (data substitution) and excludes emissions from startup and shutdown periods. However, the emission inventory does not include such allowances and should reflect actual emissions. In this case, NO_X emissions reported in an inventory may differ (higher or lower) than those reported per Regulation 9, Rule 10. In this case, it is not appropriate to use emission inventory reported NO_X emissions as a demonstration of non-compliance with Regulation 9, Rule 10.

Therefore, emissions results should not be used to determine compliance with a regulation unless it is clearly demonstrated that the methodology used to derive the results are the same as the methodology used in the regulation.

Section 7.2: Regulatory Comparisons

When emissions appear to exceed an applicable limit and whenever possible, emission inventories should identify all emissions limits applicable to facility equipment and include a comparison of emissions totals in the inventory to applicable emission limits. The emission inventory shall identify and include a statement for any emission limit that has a different basis (i.e. methodology, averaging period, definition, etc.) than the inventory. Such comparisons and statements may prevent unwarranted comparisons and faulty conclusions from occurring.

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Section 8: Report Formats

To aid reader comprehension and increase efficiency of the District review, emission inventories prepared according to these guidelines should be consistent in how results are reported. An example of an approved format that follows the guidance listed within this section is included in Appendix D.

Section 8.1: Public Version and Confidential Version

Petroleum refineries should submit both a public version and a confidential version of the emission inventory. The two versions shall be identical except that confidential data should be redacted from the public version. The confidential version shall have all confidential information clearly identified. A section at the at the beginning of the confidential version shall summarize all confidential information and have specific statements as to how each information should be considered confidential per California Government Code Section 6250 – 6270 (“California Public Records Act”).

The District may differ in its interpretation of what information is considered confidential at which time the District will notify the affected facility and may require a re-submittal of both a revised public version and revised confidential version of the emission inventory.

Section 8.2: Physical and Digital Copies

Refineries and support facilities shall submit both physical and digital copies of the emissions inventory. Digital copies of the emissions inventory shall include some supporting documentation (intermediate and final calculations, source test results, CEM/analyzer readings, speciation data) as well as a list of supporting documentation available upon request. This list should identify the supporting documentation (with unique facility identifiers) by source category, affected sources, approved method, and data needs. Once used in an emission inventory, supporting documentation should be “frozen” and not subject to further change unless the District is notified and an updated emission inventory and list are provided. Supporting documentation should be retained for no less than five years from data entry. For longer periods, it is in a facility’s interest to maintain supporting documentation for the initial emissions inventory as well as any inventory in which a new source, pollutant, or methodological change occurred.

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Digital copies do not need to include entire source test reports if the District already has a copy of the source test. In such cases, the emissions inventory should include a source test results summary sheet with District reference number. Digital copies should include the entire source test report for non-District notified source tests. Digital copies should include supporting data and calculations in a spreadsheet-based software program (e.g. Microsoft Excel). Refineries may use a non-spreadsheet-based software program for calculations provided that the underlying equations can be reviewed and the programs validated and approved by the District on a case by case basis.

Section 8.3: Emissions Summaries

Each emission inventory shall include summaries of criteria pollutant, greenhouse gases, and toxic air contaminant emissions on a facility-wide, source category, and District source basis. Facility-wide, source category, and District source summaries shall be in tabular forms while source category and District source summaries shall also be in a graphic form.

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Facility-wide emissions summaries should be reported on a quantity basis (e.g. tons). Source-category and District source emissions summaries should be reported on a quantity (e.g. tons) and percentile basis (e.g. percentage of total emissions).

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Table 8.3.1 includes an example of a facility-wide criterial pollutant and greenhouse gases emissions summary in tabular form.

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Table 8.3.1 Example Facility-Wide Emissions Summary – Criteria Pollutants and Greenhouse Gases

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Facility-Wide Annual Emissions (tons)						
NO_X	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	GHGs (metric tons)
100	**200**	**400**	**800**	**50**	**25**	**1,000,000**

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Table 8.3.2 includes source categories for which emissions summaries should be reported.

Table 8.3.2 Source-Category Emissions Summary – Criteria Pollutants and Greenhouse Gases

	Annual Emissions (tons)						
Category	NO_X	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	GHGs*
Fugitive Emission Leaks							
Storage Tanks							
Stationary Combustion (All)							
Boilers							
Engines							
Furnaces & Process Heaters							
Gas Turbines & HRSGs							
Thermal Oxidizer(s)							
Process Vents (All)							
Catalytic Reformer(s)							
Delayed Coking Unit(s)							
Fluid Coking Unit/CO Boiler(s)							
Fluid Catalytic Cracking Unit							
Hydrogen Plant(s)							
Sulfur Plant(s)/Sulfur Recovery Unit(s)							
Flares							
Pilot/Purge							
Process Gas							
Wastewater							
Heat Exchanger Leaks/Cooling Towers							
Mobile Stationary Sources							
Turnaround Activities							
Startups/Shutdowns							
Malfunctions/Upsets							
Accidents/Spills							
Total							
* metric tons							

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Table 8.3.3 includes an example of a criteria pollutant and greenhouse gases emissions summary for District sources.

Table 8.3.3 Example Source-Category Emissions Summary – Criteria Pollutants and Greenhouse Gases

Source #	Description	Permit Status	New Source Review Status	Annual Emissions (tons)						
				NO_X	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	GHGs
S-1	Crude Unit	Permit	Grandfathered							
S-2	Crude Unit Furnace	Permit	NSR							
S-3	Diesel Tank	Exempt	Grandfathered							
.	.	.	.							
.	.	.	.							
			Total (tons)							

Table 8.3.4 lists an example of a District source emissions summary on a percentile basis.

Table 8.3.4 Example Source-Category Emissions Summary Percentile Basis– Criteria Pollutants and Greenhouse Gases

Source #	Description	Permit Status	New Source Review Status	Annual Emissions (% of total)						
				NO_X	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	GHGs
S-1	Crude Unit	Permit	Grandfathered							
S-2	Crude Unit Furnace	Permit	NSR							
S-3	Diesel Tank	Exempt	Grandfathered							
.	.	.	.							
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			Total (%)	**100**	**100**	**100**	**100**	**100**	**100**	**100**

Figure 8.3.1 shows examples of source category emission summaries in graphic form.

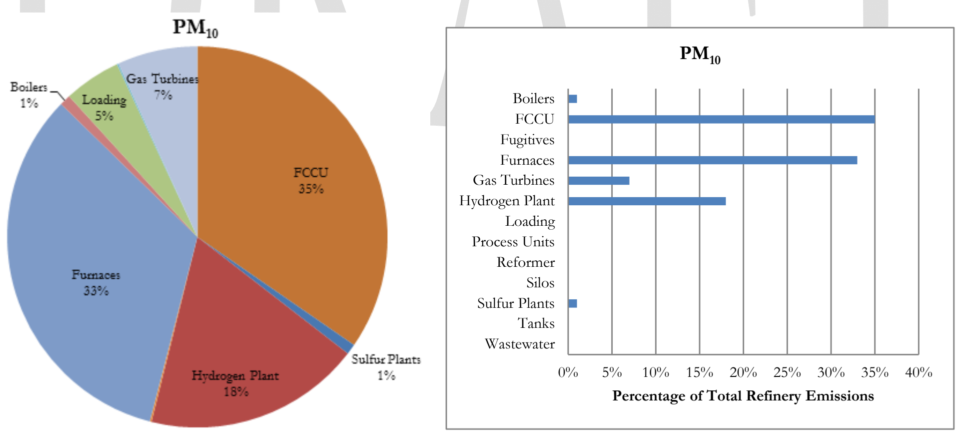

Figure 8.3.1 Example source category PM_{10} emission summary in graphic forms

Section 8.4: Emission Comparisons

Each emission inventory should include a comparison of emission totals (facility-wide and source category) to the first submitted inventory as well as year on year comparison to previous inventories.

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Section 8.4.1 – Comparison to First Inventory

Each inventory shall include a comparison of inventory totals to the first inventory with specific reasons for any totals that exceed the first inventory.

Table 8.4.1 includes an example of a facility-wide criterial pollutant and greenhouse gases emissions summary in tabular form.

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Table 8.4.1 Facility-Wide Emissions Summary – Criteria Pollutants and Greenhouse Gases

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Year	**Facility-Wide Annual Emissions** (tons)						
	NO_X	**SO_2**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**GHGs** (metric tons)

Section 8.4.2 – Comparison to Previous Inventory and Historical Trend Lines

Each inventory shall include a comparison to the previous inventory that includes emission totals in tons as well as the percentile difference between the two. The inventory shall include a trend line of emissions totals over time as reported in the current and previous inventories. Each comparison or trend line may include a notation for any changes in emissions calculation methodology that may account for emission trends over time.

Section 9: Timeline for Emission Estimation Methodology or Data Revision

Periodically, emission estimation methodologies may be revised or new pollutants may be required to be reported. Such changes may require that new parameters be recorded that were previously not being recorded.

If an emission estimation methodology is revised or a new pollutant is required to be reported and new data that was not previously being recorded is required, the facility may report the relevant emissions using the revised methodology or for the new pollutant for the following inventory report covering the complete calendar year when such new data is available.

For example, if a new pollutant is required to be reported in mid-2016 and the new pollutant requires data not currently being recorded, the facility may report emissions for the new pollutant in the 2018 inventory report covering the calendar year 2017 facility emissions. However, if the facility has the capability and records required to calculate emissions for the new pollutant, emissions totals for the new pollutant shall be reported in the 2017 year inventory report.

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Section 10: Guidelines Revision Procedure

The goal of the procedures described in this Section is to provide for transparency, consistency, and stakeholder participation when these Guidelines need to be revised.

Section 10.1: Revision Requirement

These Guidelines may be revised under the following circumstances:

- a new emission estimation methodology is developed,
- an existing methodology is changed,
- an acceptable methodology is discredited,
- the accuracy of an existing methodology is revised, requiring a change in ranking,
- a previously unknown pollutant is identified,
- a new regulated pollutant is added, or
- editorial additions and/or corrections.

Section 10.2: Revision Procedure

The following steps will be followed in considering revisions to these Guidelines:

Step 1: Identification of Proposed Revision
Step 2: Notification of Interested Stakeholders
Step 3: Review and Respond to Stakeholder Comments
Step 4: Publish Revised Guidelines

Section 10.2.1 – Identification of Proposed Revision

A proposed revision to these Guidelines may be identified by either:

- District personnel,
- Formal request by an interested stakeholder, or
- A scheduled review by the District occurring at least once every five years.

Formal requests by stakeholders should be in written form directed to the Engineering Division and should:

- identify the proposed revision,
- explain why the revision is appropriate, and
- include suggested revised text.

The District will review any formal requests for revision and determine whether the steps in Section 10.2 should be followed to revise the Guidelines.

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Section 10.2.2 – Notification of Interested Stakeholders

If the District determines a Guidelines revision is warranted, the District will notify interested stakeholders that a revision is appropriate and will:

- identify the pertinent section(s) of the Guidelines proposed for revision;
- explain the reason for the proposed revision. This explanation may group proposed changes in categories as appropriate,
- include proposed Guidelines language change, and
- request comments on the proposed revision.

Section 10.2.3 – Comment Review

After the close of the comment period (presumptively 60 calendar days), the District will consider all comments received and, as appropriate, revise the proposed Guidelines text and respond to comments received.

Section 10.2.4 – Publication of Revised Guidelines

Once the Guidelines have been revised, the District will publish the Guidelines on the District's website.

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Section 10.2.5 – Adoption of Revised Guidelines¶
Once the revised guidelines have been published on the District's website, the revised guidelines are considered adopted and should be used by affected facilities. ¶

Section 11: Emission Inventory Review Criteria

While reviewing an emission inventory; the District will determine if an emission inventory is:

- satisfactory,
- requires minor revision,
- requires major revision, or
- must be rejected.

Although it is not possible to list every situation that may result in an emission inventory from requiring revision or being rejected, the following sections outline the major criteria that the District will apply during its review.

These represent minimum measures (i.e. an inventory that does not meet the criteria will result in rejection but an inventory that meets the criteria is not automatically accepted).

Section 11.1: Completeness

The District will determine if emissions from all emission-causing activities and sources are included within the inventory. The District will determine if all pollutants are included in the inventory.

Section 11.2: Methodology

The District will review the emission estimation methodologies that were used and verify that the highest ranking method for which data is available was used. An emission inventory may be rejected if the highest ranking method was not used, if the methodology used is not identified, or the District cannot determine the methodology used.

Section 11.3: Data Quality

The District will review the underlying quality of the data used to estimate emissions. In this review, the District may review the quality assurance and quality control measures implemented by the facility to ensure data quality.

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Section 11.4: Documentation

The District will review all supporting documentation (either submitted with an inventory or retained onsite) and determine if there is documentation to support any assumptions, methodologies, or other metrics used in developing the emission inventory.

Section 11.5: Timing

The District may reject an emission inventory if a facility does not submit an inventory by the regulatory deadline or delays in response to District enquiries regarding an emission inventory.

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Inventory Usage for Regulatory Compliance

Bay Area Air Quality Management District. 2013. Regulation 9 (Inorganic Gaseous Pollutants), Rule 10 (Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries). Amended October 16, 2013.

APPENDIX A

Default Emission Factors

This section lists Air District-approved default emission factors.

Table A-1: Default Toxic Air Contaminant Emission Factors

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Asphalt Prod., Blowing	1	VOC	Hydrogen Sulfide	4.26E-04	lbs/ton processed	1
Asphalt Prod., Diesel	1	Metals	Arsenic	2.77E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Beryllium	5.54E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Cadmium	1.62E-06	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Chromium (Hex)	5.17E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Chromium (Total)	3.41E-06	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Copper	1.66E-06	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Lead	2.77E-06	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Manganese	1.61E-05	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Mercury	7.05E-08	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Nickel	2.77E-06	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Selenium	2.77E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	Metals	Zinc	2.44E-05	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Acenaphthene	9.53E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Acenaphthylene	6.35E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Anthracene	3.79E-08	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Benzo(a)anthracene	9.00E-08	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Benzo(a)pyrene	4.45E-09	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Benzo(b)fluoranthene	2.49E-08	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Benzo(g,h,i)perylene	2.65E-09	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Benzo(k)fluoranthene	8.47E-09	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Chrysene	4.08E-08	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Dibenz(a,h)anthracene	2.65E-09	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Fluoranthene	2.28E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Fluorene	1.22E-06	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Indeno(1,2,3-cd)pyrene	2.65E-09	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Naphthalene	7.94E-05	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Phenanthrene	8.47E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	PAH	Pyrene	1.75E-07	lbs/ton production	2
Asphalt Prod., Diesel	1	VOC	Benzene	1.56E-02	lbs/ton production	1
Asphalt Prod., Diesel	1	VOC	Formaldehyde	1.98E-04	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Arsenic	1.20E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Beryllium	1.63E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Cadmium	1.63E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Chromium (Hex)	1.20E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Chromium (Total)	9.15E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Copper	1.45E-06	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Lead	4.04E-06	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Manganese	1.08E-06	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Mercury	7.83E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Nickel	7.65E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Selenium	1.75E-06	lbs/ton production	2
Asphalt Prod., Diesel	2	Metals	Zinc	1.39E-05	lbs/ton production	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Asphalt Prod., Diesel	2	PAH	Acenaphthene	3.06E-08	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Acenaphthylene	4.19E-08	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Anthracene	2.53E-08	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Benzo(a)anthracene	9.14E-09	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Benzo(a)pyrene	3.49E-10	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Benzo(b)fluoranthene	1.18E-08	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Benzo(g,h,i)perylene	5.32E-10	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Benzo(k)fluoranthene	2.63E-09	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Chrysene	1.67E-09	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Dibenz(a,h)anthracene	3.15E-10	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Fluoranthene	1.29E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Fluorene	4.73E-07	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Indeno(1,2,3-cd)pyrene	3.06E-10	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Naphthalene	1.40E-05	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Phenanthrene	1.08E-06	lbs/ton production	2
Asphalt Prod., Diesel	2	PAH	Pyrene	8.60E-08	lbs/ton production	2
Asphalt Prod., Diesel	2	VOC	Benzene	5.00E-04	lbs/ton production	3
Asphalt Prod., Diesel	2	VOC	Formaldehyde	3.30E-04	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Arsenic	8.02E-06	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Beryllium	4.01E-06	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Cadmium	4.41E-05	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Chromium (Total)	8.42E-05	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Copper	1.32E-04	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Lead	2.19E-03	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Manganese	1.64E-03	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Mercury	8.02E-07	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Nickel	3.81E-04	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Selenium	8.02E-06	lbs/ton production	2
Asphalt Prod., Diesel	3	Metals	Zinc	4.62E-03	lbs/ton production	2
Asphalt Prod., Diesel	3	VOC	Benzene	3.05E-04	lbs/ton production	1
Asphalt Prod., Natural Gas	1	Metals	Arsenic	5.25E-08	lbs/ton production	3
Asphalt Prod., Natural Gas	1	Metals	Beryllium	1.06E-07	lbs/ton production	3
Asphalt Prod., Natural Gas	1	Metals	Cadmium	1.78E-06	lbs/ton production	1
Asphalt Prod., Natural Gas	1	Metals	Chromium (Hex)	4.47E-07	lbs/ton production	1
Asphalt Prod., Natural Gas	1	Metals	Chromium (Total)	9.92E-07	lbs/ton production	1
Asphalt Prod., Natural Gas	1	Metals	Copper	3.27E-06	lbs/ton production	1
Asphalt Prod., Natural Gas	1	Metals	Lead	4.36E-06	lbs/ton production	1
Asphalt Prod., Natural Gas	1	Metals	Manganese	2.00E-05	lbs/ton production	1
Asphalt Prod., Natural Gas	1	Metals	Mercury	1.08E-05	lbs/ton production	1
Asphalt Prod., Natural Gas	1	Metals	Nickel	3.99E-07	lbs/ton production	3
Asphalt Prod., Natural Gas	1	Metals	Selenium	5.25E-08	lbs/ton production	3
Asphalt Prod., Natural Gas	1	Metals	Zinc	1.30E-05	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Acenaphthene	6.40E-07	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Acenaphthylene	1.53E-06	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Anthracene	1.88E-07	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Benzo(a)anthracene	9.64E-09	lbs/ton production	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Asphalt Prod., Natural Gas	1	PAH	Benzo(a)pyrene	1.04E-09	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Benzo(b)fluoranthene	1.48E-09	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Benzo(e)pyrene	3.83E-09	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Benzo(g,h,i)perylene	1.29E-09	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Benzo(k)fluoranthene	2.34E-09	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Chrysene	1.55E-09	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Dibenz(a,h)anthracene	9.84E-10	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Fluoranthene	4.56E-07	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Fluorene	1.72E-06	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Indeno(1,2,3-cd)pyrene	1.16E-09	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Naphthalene	2.48E-05	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Phenanthrene	2.45E-06	lbs/ton production	1
Asphalt Prod., Natural Gas	1	PAH	Pyrene	8.39E-07	lbs/ton production	1
Asphalt Prod., Natural Gas	1	SVOC	Ethylbenzene	2.74E-05	lbs/ton production	1
Asphalt Prod., Natural Gas	1	VOC	Acetaldehyde	5.32E-05	lbs/ton production	1
Asphalt Prod., Natural Gas	1	VOC	Benzene	8.98E-05	lbs/ton production	1
Asphalt Prod., Natural Gas	1	VOC	Formaldehyde	2.57E-04	lbs/ton production	1
Asphalt Prod., Natural Gas	1	VOC	Hydrogen Sulfide	2.91E-04	lbs/ton production	3
Asphalt Prod., Natural Gas	1	VOC	Methyl Chloroform	2.87E-06	lbs/ton production	1
Asphalt Prod., Natural Gas	1	VOC	Toluene	4.32E-05	lbs/ton production	1
Asphalt Prod., Natural Gas	1	VOC	Xylene (Total)	4.26E-05	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Arsenic	3.46E-06	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Beryllium	1.48E-07	lbs/ton production	3
Asphalt Prod., Oil	1	Metals	Cadmium	7.70E-07	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Chromium (Hex)	4.30E-07	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Chromium (Total)	1.05E-05	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Copper	7.19E-06	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Lead	2.87E-06	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Manganese	6.54E-05	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Mercury	4.92E-06	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Nickel	1.27E-04	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Selenium	2.92E-06	lbs/ton production	1
Asphalt Prod., Oil	1	Metals	Zinc	1.11E-04	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Acenaphthene	3.06E-07	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Acenaphthylene	5.26E-07	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Anthracene	5.74E-08	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Benzo(a)anthracene	1.11E-08	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Benzo(a)pyrene	1.84E-09	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Benzo(b)fluoranthene	2.10E-09	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Benzo(g,h,i)perylene	1.20E-09	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Benzo(k)fluoranthene	3.72E-10	lbs/ton production	3
Asphalt Prod., Oil	1	PAH	Chrysene	3.72E-10	lbs/ton production	3
Asphalt Prod., Oil	1	PAH	Dibenz(a,h)anthracene	3.72E-10	lbs/ton production	3
Asphalt Prod., Oil	1	PAH	Fluoranthene	3.57E-08	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Fluorene	6.58E-07	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Indeno(1,2,3-cd)pyrene	3.72E-10	lbs/ton production	3

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Asphalt Prod., Oil	1	PAH	Naphthalene	3.08E-05	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Phenanthrene	6.64E-07	lbs/ton production	1
Asphalt Prod., Oil	1	PAH	Pyrene	5.62E-08	lbs/ton production	1
Asphalt Prod., Oil	1	VOC	Benzene	3.34E-04	lbs/ton production	1
Asphalt Prod., Oil	1	VOC	Formaldehyde	3.92E-04	lbs/ton production	1
Asphalt Prod., Truck Load	1	VOC	Hydrogen Sulfide	1.13E-01	lbs/ton charged	1
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:4D 2378	4.27E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:4D Total	4.27E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:5D 12378	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:5D Total	8.54E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:6D 123478	2.70E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:6D 123678	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:6D 123789	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:6D Total	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:7D 1234678	6.07E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:7D Total	6.07E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Dioxin:8D	7.42E-09	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:4F 2378	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:4F Total	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:5F 12378	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:5F 23478	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:5F Total	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:6F 123478	1.73E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:6F 123678	1.73E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:6F 123789	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:6F 234678	2.70E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:6F Total	2.70E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:7F 1234678	2.70E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:7F 1234789	4.27E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:7F Total	3.37E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Dioxin/Furan	Furan:8F	8.77E-10	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Arsenic	6.12E-05	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Barium	1.69E-03	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Beryllium	3.36E-05	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Cadmium	5.22E-05	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Chromium (Total)	2.19E-04	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Cobalt	3.37E-04	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Copper	8.43E-04	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Lead	3.14E-04	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Magnesium	1.45E-03	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Manganese	5.06E-04	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Mercury	2.40E-05	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Nickel	1.69E-04	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Selenium	2.78E-04	lbs/ton	2
Boiler, Coal/Natural Gas	1	Metals	Zinc	3.37E-03	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Acenaphthene	1.10E-07	lbs/ton	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Boiler, Coal/Natural Gas	1	PAH	Acenaphthylene	1.16E-06	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Anthracene	2.24E-07	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Benzo(a)anthracene	8.76E-08	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Benzo(a)pyrene	2.91E-07	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Benzo(b)fluoranthene	1.21E-07	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Benzo(e)pyrene	1.86E-07	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Benzo(g,h,i)perylene	7.44E-07	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Benzo(k)fluoranthene	1.84E-07	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Dibenz(a,h)anthracene	1.09E-06	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Fluorene	2.15E-06	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Indeno(1,2,3-cd)pyrene	6.57E-07	lbs/ton	2
Boiler, Coal/Natural Gas	1	PAH	Phenanthrene	4.03E-06	lbs/ton	2
Boiler, Coal/Natural Gas	1	SVOC	1,2-Dichlorobenzene	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	SVOC	2-Chloronaphthalene	4.73E-08	lbs/ton	3
Boiler, Coal/Natural Gas	1	SVOC	Ethylbenzene	7.77E-05	lbs/ton	1
Boiler, Coal/Natural Gas	1	SVOC	Perylene	7.40E-08	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	1,1,1-Trichloroethane	1.59E-04	lbs/ton	1
Boiler, Coal/Natural Gas	1	VOC	1,1,2,2-Tetrachloroethane	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	1,1,2-Trichloroethane	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	1,1-Dichloroethane	4.69E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	1,1-Dichloroethene	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	2-Chloroethyl vinyl Ether	9.65E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	2-Hexanone	1.75E-05	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Acetone	2.22E-03	lbs/ton	1
Boiler, Coal/Natural Gas	1	VOC	Benzene	9.75E-05	lbs/ton	1
Boiler, Coal/Natural Gas	1	VOC	Bromodichloromethane	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Bromoform	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Bromomethane	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Carbon disulfide	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Carbon Tetrachloride	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Chlorobenzene	4.82E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Chloroethane	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Chloroform	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Chloromethane	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Dibromochloromethane	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Dichloromethane	3.06E-03	lbs/ton	1
Boiler, Coal/Natural Gas	1	VOC	Formaldehyde	4.51E-01	lbs/ton	1
Boiler, Coal/Natural Gas	1	VOC	Methyl Ethyl Ketone	9.45E-05	lbs/ton	1
Boiler, Coal/Natural Gas	1	VOC	Styrene	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Tetrachloroethene	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Toluene	1.05E-03	lbs/ton	1
Boiler, Coal/Natural Gas	1	VOC	Trichloroethene	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Trichlorofluoromethane	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	vinyl Acetate	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	vinyl Chloride	4.66E-06	lbs/ton	3
Boiler, Coal/Natural Gas	1	VOC	Xylene (Total)	4.33E-04	lbs/ton	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin/Furan:Total	3.62E-10	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:4D 2378	1.74E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:4D Total	1.74E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:5D 12378	2.19E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:5D Total	2.19E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:6D 123478	2.68E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:6D 123678	2.57E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:6D 123789	2.46E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:6D Total	4.31E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:7D 1234678	9.40E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:7D Total	9.40E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Dioxin:8D	1.41E-10	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:4F 2378	9.07E-12	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:4F Total	9.07E-12	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:5F 12378	1.72E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:5F 23478	1.04E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:5F Total	1.71E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:6F 123478	1.33E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:6F 123678	1.22E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:6F 123789	1.47E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:6F 234678	1.26E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:6F Total	1.47E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:7F 1234678	2.37E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:7F 1234789	1.47E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:7F Total	2.37E-11	lbs/ton	2
Boiler, Coke/Coal	1	Dioxin/Furan	Furan:8F	6.15E-11	lbs/ton	2
Boiler, Coke/Coal	1	Halogens	HCl	1.47E-01	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Arsenic	7.14E-06	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Beryllium	5.20E-07	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Cadmium	7.35E-07	lbs/ton	2
Boiler, Coke/Coal	1	Metals	Chromium (Hex)	6.42E-07	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Chromium (Total)	2.33E-05	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Copper	1.76E-05	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Lead	3.66E-06	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Manganese	5.92E-05	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Mercury	1.73E-06	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Nickel	3.92E-04	lbs/ton	1
Boiler, Coke/Coal	1	Metals	Selenium	3.60E-05	lbs/ton	2
Boiler, Coke/Coal	1	Metals	Zinc	4.96E-05	lbs/ton	1
Boiler, Coke/Coal	1	PAH	Acenaphthene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Acenaphthylene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Anthracene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Benzo(a)anthracene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Benzo(a)pyrene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Benzo(b)fluoranthene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Benzo(e)pyrene	2.62E-08	lbs/ton	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Boiler, Coke/Coal	1	PAH	Benzo(g,h,i)perylene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Benzo(k)fluoranthene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Chrysene	5.32E-08	lbs/ton	1
Boiler, Coke/Coal	1	PAH	Dibenz(a,h)anthracene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Fluoranthene	4.71E-08	lbs/ton	1
Boiler, Coke/Coal	1	PAH	Fluorene	1.45E-07	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Indeno(1,2,3-cd)pyrene	2.62E-08	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Naphthalene	2.22E-06	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Phenanthrene	8.00E-07	lbs/ton	2
Boiler, Coke/Coal	1	PAH	Pyrene	1.57E-07	lbs/ton	1
Boiler, Coke/Coal	1	SVOC	2-Methylnaphthalene	1.51E-07	lbs/ton	3
Boiler, Coke/Coal	1	SVOC	Perylene	1.20E-08	lbs/ton	3
Boiler, Coke/Coal	1	VOC	Formaldehyde	4.78E-03	lbs/ton	1
Boiler, Distillate	1	PAH	Acenaphthene	1.13E-03	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Acenaphthylene	2.38E-04	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Anthracene	8.49E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Benzo(a)anthracene	9.93E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Benzo(a)pyrene	2.20E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Benzo(b)fluoranthene	2.11E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Benzo(e)pyrene	1.52E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Benzo(g,h,i)perylene	2.77E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Benzo(k)fluoranthene	7.03E-04	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Chrysene	1.01E-04	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Dibenz(a,h)anthracene	2.72E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Fluoranthene	7.12E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Fluorene	2.78E-04	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Indeno(1,2,3-cd)pyrene	2.18E-05	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Naphthalene	2.78E+00	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Phenanthrene	9.80E-04	lbs/1000 gallons	2
Boiler, Distillate	1	PAH	Pyrene	1.16E-04	lbs/1000 gallons	2
Boiler, Distillate	1	SVOC	2-Chloronaphthalene	9.05E-06	lbs/1000 gallons	3
Boiler, Distillate	1	SVOC	2-Methylnaphthalene	1.40E-04	lbs/1000 gallons	1
Boiler, Distillate	1	SVOC	Ethylbenzene	6.35E-04	lbs/1000 gallons	3
Boiler, Distillate	1	SVOC	Perylene	1.26E-05	lbs/1000 gallons	3
Boiler, Distillate	1	VOC	Benzene	2.54E-03	lbs/1000 gallons	1
Boiler, Distillate	1	VOC	Formaldehyde	1.75E+00	lbs/1000 gallons	2
Boiler, Distillate	1	VOC	Hexane	5.15E-04	lbs/1000 gallons	3
Boiler, Distillate	1	VOC	Propylene	1.71E-03	lbs/1000 gallons	1
Boiler, Distillate	1	VOC	Toluene	1.50E-03	lbs/1000 gallons	1
Boiler, Distillate	1	VOC	Xylene (Total)	6.35E-04	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:4D 2378	2.73E-10	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:4D Total	1.44E-09	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:5D 12378	1.31E-10	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:5D Total	4.06E-09	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:6D 123478	1.31E-10	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:6D 123678	3.68E-10	lbs/1000 gallons	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:6D 123789	3.68E-10	lbs/1000 gallons	1
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:6D Total	4.38E-09	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:7D 1234678	3.12E-09	lbs/1000 gallons	1
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:7D Total	2.33E-09	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Dioxin:8D	7.50E-08	lbs/1000 gallons	1
Boiler, Fuel oil	2	Dioxin/Furan	Furan:4F 2378	8.16E-10	lbs/1000 gallons	1
Boiler, Fuel oil	2	Dioxin/Furan	Furan:4F Total	1.27E-09	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Furan:5F 12378	1.31E-10	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Furan:5F 23478	1.31E-10	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Furan:5F Total	2.30E-09	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Furan:6F 123478	3.64E-10	lbs/1000 gallons	1
Boiler, Fuel oil	2	Dioxin/Furan	Furan:6F 123678	2.73E-10	lbs/1000 gallons	1
Boiler, Fuel oil	2	Dioxin/Furan	Furan:6F 123789	1.31E-10	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Furan:6F 234678	5.51E-10	lbs/1000 gallons	1
Boiler, Fuel oil	2	Dioxin/Furan	Furan:6F Total	4.33E-10	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Furan:7F 1234678	1.44E-09	lbs/1000 gallons	1
Boiler, Fuel oil	2	Dioxin/Furan	Furan:7F 1234789	1.31E-10	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Furan:7F Total	1.57E-09	lbs/1000 gallons	3
Boiler, Fuel oil	2	Dioxin/Furan	Furan:8F	7.15E-09	lbs/1000 gallons	1
Boiler, Fuel oil	2	Metals	Antimony	2.21E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Arsenic	3.64E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Barium	2.80E-02	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Beryllium	3.35E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Cadmium	5.02E-02	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Chromium (Hex)	1.21E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Chromium (Total)	6.85E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Cobalt	3.33E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Copper	1.95E-02	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Lead	3.62E-02	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Manganese	5.47E-01	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Mercury	1.43E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Molybdenum	7.05E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Nickel	4.70E-01	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Phosphorus	3.74E-02	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Selenium	4.49E-02	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Silver	1.85E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Thallium	1.86E-03	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	vanadium	1.13E-01	lbs/1000 gallons	2
Boiler, Fuel oil	2	Metals	Zinc	1.09E+00	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Acenaphthene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Acenaphthylene	1.83E-04	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Anthracene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Benzo(a)anthracene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Benzo(a)pyrene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Benzo(b)fluoranthene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Benzo(b+k)fluoranthene	4.15E-06	lbs/1000 gallons	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Boiler, Fuel oil	2	PAH	Benzo(e)pyrene	2.66E-06	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Benzo(g,h,i)perylene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Benzo(k)fluoranthene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Chrysene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Dibenz(a,h)anthracene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Fluoranthene	9.64E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Fluorene	8.59E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Indeno(1,2,3-cd)pyrene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Naphthalene	5.09E-02	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Phenanthrene	3.46E-04	lbs/1000 gallons	2
Boiler, Fuel oil	2	PAH	Pyrene	8.51E-05	lbs/1000 gallons	2
Boiler, Fuel oil	2	SVOC	2-Chloronaphthalene	8.15E-09	lbs/1000 gallons	3
Boiler, Fuel oil	2	SVOC	2-Methylnaphthalene	7.99E-05	lbs/1000 gallons	1
Boiler, Fuel oil	2	SVOC	Ethylbenzene	1.42E-03	lbs/1000 gallons	1
Boiler, Fuel oil	2	SVOC	Perylene	1.89E-08	lbs/1000 gallons	3
Boiler, Fuel oil	2	VOC	1,3-Butadiene	4.48E-04	lbs/1000 gallons	3
Boiler, Fuel oil	2	VOC	Acetaldehyde	2.31E-03	lbs/1000 gallons	1
Boiler, Fuel oil	2	VOC	Benzene	5.17E-01	lbs/1000 gallons	2
Boiler, Fuel oil	2	VOC	Chloroform	2.39E-03	lbs/1000 gallons	3
Boiler, Fuel oil	2	VOC	Formaldehyde	4.92E-01	lbs/1000 gallons	2
Boiler, Fuel oil	2	VOC	Propylene	1.06E-02	lbs/1000 gallons	3
Boiler, Fuel oil	2	VOC	Toluene	7.30E-03	lbs/1000 gallons	1
Boiler, Fuel oil	2	VOC	Xylene (Total)	9.28E-03	lbs/1000 gallons	1
Boiler, Ref. Gas	1	Metals	Arsenic	7.04E-04	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Beryllium	1.55E-04	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Cadmium	2.38E-03	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Chromium (Hex)	8.35E-05	lbs/MMcf	3
Boiler, Ref. Gas	1	Metals	Chromium (Total)	1.28E-02	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Copper	6.30E-03	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Lead	2.42E-03	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Manganese	2.39E-03	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Mercury	1.35E-04	lbs/MMcf	3
Boiler, Ref. Gas	1	Metals	Nickel	5.59E-03	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Selenium	2.06E-03	lbs/MMcf	1
Boiler, Ref. Gas	1	Metals	Zinc	3.42E+00	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Acenaphthene	5.88E-06	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Acenaphthylene	1.25E-06	lbs/MMcf	3
Boiler, Ref. Gas	1	PAH	Anthracene	2.28E-05	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Benzo(a)anthracene	1.83E-05	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Benzo(a)pyrene	3.42E-06	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Benzo(b)fluoranthene	6.76E-06	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Benzo(g,h,i)perylene	3.85E-06	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Benzo(k)fluoranthene	1.25E-06	lbs/MMcf	3
Boiler, Ref. Gas	1	PAH	Chrysene	3.42E-06	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Dibenz(a,h)anthracene	1.25E-06	lbs/MMcf	3
Boiler, Ref. Gas	1	PAH	Fluoranthene	4.25E-05	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Boiler, Ref. Gas	1	PAH	Fluorene	9.78E-06	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Indeno(1,2,3-cd)pyrene	1.25E-06	lbs/MMcf	3
Boiler, Ref. Gas	1	PAH	Naphthalene	2.06E-04	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Phenanthrene	5.64E-05	lbs/MMcf	1
Boiler, Ref. Gas	1	PAH	Pyrene	5.98E-05	lbs/MMcf	1
Boiler, Ref. Gas	1	SVOC	Phenol	2.18E-03	lbs/MMcf	1
Boiler, Ref. Gas	1	VOC	Acetaldehyde	3.97E-03	lbs/MMcf	1
Boiler, Ref. Gas	1	VOC	Benzene	2.06E-01	lbs/MMcf	1
Boiler, Ref. Gas	1	VOC	Formaldehyde	1.60E-02	lbs/MMcf	1
Boiler, Ref. Gas	1	VOC	Hydrogen Sulfide	2.97E-02	lbs/MMcf	3
Boiler, Ref. Gas	1	VOC	Toluene	8.40E-01	lbs/MMcf	1
Boiler, Ref. Gas	2	Halogens	HCl	1.42E-01	lbs/MMcf	3
Boiler, Ref. Gas	2	Metals	Arsenic	3.57E-03	lbs/MMcf	1
Boiler, Ref. Gas	2	Metals	Beryllium	1.07E-04	lbs/MMcf	3
Boiler, Ref. Gas	2	Metals	Cadmium	2.70E-04	lbs/MMcf	3
Boiler, Ref. Gas	2	Metals	Chromium (Hex)	8.35E-05	lbs/MMcf	3
Boiler, Ref. Gas	2	Metals	Chromium (Total)	2.46E-03	lbs/MMcf	1
Boiler, Ref. Gas	2	Metals	Copper	5.30E-03	lbs/MMcf	1
Boiler, Ref. Gas	2	Metals	Lead	3.01E-03	lbs/MMcf	1
Boiler, Ref. Gas	2	Metals	Manganese	1.43E-01	lbs/MMcf	1
Boiler, Ref. Gas	2	Metals	Mercury	1.35E-04	lbs/MMcf	3
Boiler, Ref. Gas	2	Metals	Nickel	1.97E-02	lbs/MMcf	1
Boiler, Ref. Gas	2	Metals	Selenium	3.30E-01	lbs/MMcf	1
Boiler, Ref. Gas	2	Metals	Zinc	9.89E-02	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Acenaphthene	1.23E-05	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Acenaphthylene	1.42E-04	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Anthracene	3.49E-05	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Benzo(a)anthracene	1.07E-05	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Benzo(a)pyrene	9.95E-07	lbs/MMcf	3
Boiler, Ref. Gas	2	PAH	Benzo(b)fluoranthene	1.54E-04	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Benzo(e)pyrene	2.13E-05	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Benzo(g,h,i)perylene	9.95E-07	lbs/MMcf	3
Boiler, Ref. Gas	2	PAH	Benzo(k)fluoranthene	3.05E-05	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Chrysene	9.72E-05	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Dibenz(a,h)anthracene	3.02E-06	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Fluoranthene	1.52E-04	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Fluorene	8.29E-05	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Indeno(1,2,3-cd)pyrene	4.86E-06	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Naphthalene	1.55E-03	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Phenanthrene	3.06E-04	lbs/MMcf	1
Boiler, Ref. Gas	2	PAH	Pyrene	6.66E-05	lbs/MMcf	1
Boiler, Ref. Gas	2	SVOC	2-Methylnaphthalene	1.30E-04	lbs/MMcf	1
Boiler, Ref. Gas	2	SVOC	Ethylbenzene	5.50E-02	lbs/MMcf	3
Boiler, Ref. Gas	2	SVOC	Perylene	9.95E-07	lbs/MMcf	3
Boiler, Ref. Gas	2	SVOC	Phenol	2.63E-03	lbs/MMcf	1
Boiler, Ref. Gas	2	VOC	1,1,1-Trichloroethane	2.78E-02	lbs/MMcf	3

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Boiler, Ref. Gas	2	VOC	1,2-Dichloroethane	8.85E-01	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Acetaldehyde	5.75E-01	lbs/MMcf	1
Boiler, Ref. Gas	2	VOC	Ammonia	3.21E+00	lbs/MMcf	1
Boiler, Ref. Gas	2	VOC	Benzene	4.07E-02	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Carbon Tetrachloride	5.15E-03	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Chloroform	2.49E-02	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Cyanide	5.35E-03	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Formaldehyde	1.93E+00	lbs/MMcf	1
Boiler, Ref. Gas	2	VOC	Hydrogen Sulfide	2.97E-02	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Methylene Chloride	1.05E+00	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Tetrachloroethene	5.65E-03	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Toluene	4.80E-02	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Trichloroethene	3.01E-03	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Trichlorofluoromethane	4.26E-03	lbs/MMcf	3
Boiler, Ref. Gas	2	VOC	Xylene (Total)	5.50E-02	lbs/MMcf	3
Catalytic Reformer	1	Dioxin/Furan	Dioxin:4D 2378	4.80E-12	lbs/1000 Barrels	3
Catalytic Reformer	1	Dioxin/Furan	Dioxin:4D Total	4.80E-12	lbs/1000 Barrels	3
Catalytic Reformer	1	Dioxin/Furan	Dioxin:5D 12378	4.19E-11	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Dioxin:5D Total	1.11E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Dioxin:6D 123478	3.73E-11	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Dioxin:6D 123678	9.10E-12	lbs/1000 Barrels	3
Catalytic Reformer	1	Dioxin/Furan	Dioxin:6D 123789	1.22E-11	lbs/1000 Barrels	3
Catalytic Reformer	1	Dioxin/Furan	Dioxin:6D Total	3.99E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Dioxin:7D 1234678	2.19E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Dioxin:7D Total	4.33E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Dioxin:8D	7.95E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:4F 2378	7.22E-11	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:4F Total	8.42E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:5F 12378	1.46E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:5F 23478	3.41E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:5F Total	1.59E-09	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:6F 123478	3.29E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:6F 123678	3.35E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:6F 123789	1.68E-11	lbs/1000 Barrels	3
Catalytic Reformer	1	Dioxin/Furan	Furan:6F 234678	3.81E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:6F Total	2.45E-09	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:7F 1234678	9.15E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:7F 1234789	2.59E-10	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:7F Total	1.52E-09	lbs/1000 Barrels	1
Catalytic Reformer	1	Dioxin/Furan	Furan:8F	3.14E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Dioxin:4D 2378	3.60E-12	lbs/1000 Barrels	3
Catalytic Reformer	2	Dioxin/Furan	Dioxin:4D Total	3.60E-12	lbs/1000 Barrels	3
Catalytic Reformer	2	Dioxin/Furan	Dioxin:5D 12378	3.26E-12	lbs/1000 Barrels	3
Catalytic Reformer	2	Dioxin/Furan	Dioxin:5D Total	3.26E-12	lbs/1000 Barrels	3
Catalytic Reformer	2	Dioxin/Furan	Dioxin:6D 123478	7.90E-12	lbs/1000 Barrels	3
Catalytic Reformer	2	Dioxin/Furan	Dioxin:6D 123678	1.12E-11	lbs/1000 Barrels	3

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Catalytic Reformer	2	Dioxin/Furan	Dioxin:6D 123789	7.90E-12	lbs/1000 Barrels	3
Catalytic Reformer	2	Dioxin/Furan	Dioxin:6D Total	8.65E-11	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Dioxin:7D 1234678	1.19E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Dioxin:7D Total	1.92E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Dioxin:8D	8.37E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:4F 2378	4.12E-12	lbs/1000 Barrels	3
Catalytic Reformer	2	Dioxin/Furan	Furan:4F Total	2.82E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:5F 12378	3.37E-11	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:5F 23478	6.64E-11	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:5F Total	4.47E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:6F 123478	7.44E-11	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:6F 123678	9.99E-11	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:6F 123789	9.10E-12	lbs/1000 Barrels	3
Catalytic Reformer	2	Dioxin/Furan	Furan:6F 234678	1.96E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:6F Total	7.39E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:7F 1234678	2.90E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:7F 1234789	1.73E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:7F Total	5.40E-10	lbs/1000 Barrels	1
Catalytic Reformer	2	Dioxin/Furan	Furan:8F	1.48E-10	lbs/1000 Barrels	1
Coke Calcining	1	Dioxin/Furan	Dioxin:4D 2378	1.32E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:4D other	2.99E-10	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:5D 12378	1.35E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:5D other	1.02E-10	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:6D 123478	1.57E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:6D 123678	2.04E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:6D 123789	1.50E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:6D other	8.96E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:7D 1234678	2.18E-10	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:7D other	1.90E-10	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Dioxin:8D	2.76E-09	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:4F 2378	1.63E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:4F other	2.15E-10	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:5F 12378	1.50E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:5F 23478	1.46E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:5F other	1.79E-10	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:6F 123478	2.71E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:6F 123678	3.13E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:6F 123789	1.20E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:6F 234678	2.04E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:6F other	2.36E-10	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:7F 1234678	1.76E-10	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:7F 1234789	2.99E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:7F other	5.16E-11	lbs/ton coke	2
Coke Calcining	1	Dioxin/Furan	Furan:8F	2.86E-10	lbs/ton coke	2
Coke Calcining	1	Metals	Antimony	4.79E-05	lbs/ton coke	2
Coke Calcining	1	Metals	Arsenic	4.92E-06	lbs/ton coke	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Coke Calcining	1	Metals	Barium	2.46E-05	lbs/ton coke	2
Coke Calcining	1	Metals	Beryllium	2.43E-06	lbs/ton coke	2
Coke Calcining	1	Metals	Cadmium	9.84E-06	lbs/ton coke	2
Coke Calcining	1	Metals	Chromium (Hex)	7.17E-07	lbs/ton coke	2
Coke Calcining	1	Metals	Chromium (Total)	2.09E-05	lbs/ton coke	2
Coke Calcining	1	Metals	Copper	9.84E-06	lbs/ton coke	2
Coke Calcining	1	Metals	Lead	9.27E-05	lbs/ton coke	2
Coke Calcining	1	Metals	Manganese	7.63E-05	lbs/ton coke	2
Coke Calcining	1	Metals	Mercury	1.12E-04	lbs/ton coke	2
Coke Calcining	1	Metals	Nickel	1.76E-04	lbs/ton coke	2
Coke Calcining	1	Metals	Phosphorus	4.92E-04	lbs/ton coke	2
Coke Calcining	1	Metals	Selenium	4.92E-06	lbs/ton coke	2
Coke Calcining	1	Metals	Silver	1.72E-05	lbs/ton coke	2
Coke Calcining	1	Metals	Thallium	7.38E-05	lbs/ton coke	2
Coke Calcining	1	Metals	Zinc	1.63E-04	lbs/ton coke	2
Coke Calcining	1	PAH	Acenaphthene	1.64E-08	lbs/ton coke	2
Coke Calcining	1	PAH	Acenaphthylene	2.81E-08	lbs/ton coke	2
Coke Calcining	1	PAH	Anthracene	1.97E-08	lbs/ton coke	2
Coke Calcining	1	PAH	Benzo(a)anthracene	1.02E-08	lbs/ton coke	2
Coke Calcining	1	PAH	Benzo(a)pyrene	8.25E-09	lbs/ton coke	2
Coke Calcining	1	PAH	Benzo(b)fluoranthene	8.25E-09	lbs/ton coke	2
Coke Calcining	1	PAH	Benzo(g,h,i)perylene	8.25E-09	lbs/ton coke	2
Coke Calcining	1	PAH	Benzo(k)fluoranthene	8.25E-09	lbs/ton coke	2
Coke Calcining	1	PAH	Chrysene	1.84E-08	lbs/ton coke	2
Coke Calcining	1	PAH	Dibenz(a,h)anthracene	8.25E-09	lbs/ton coke	2
Coke Calcining	1	PAH	Fluoranthene	4.30E-08	lbs/ton coke	2
Coke Calcining	1	PAH	Fluorene	6.61E-08	lbs/ton coke	2
Coke Calcining	1	PAH	Indeno(1,2,3-cd)pyrene	8.25E-09	lbs/ton coke	2
Coke Calcining	1	PAH	Naphthalene	3.14E-06	lbs/ton coke	2
Coke Calcining	1	PAH	Phenanthrene	2.15E-07	lbs/ton coke	2
Coke Calcining	1	PAH	Pyrene	3.23E-08	lbs/ton coke	2
Coke Calcining	1	VOC	Acetaldehyde	1.02E-03	lbs/ton coke	1
Coke Calcining	1	VOC	Benzene	3.24E-04	lbs/ton coke	1
Coke Calcining	1	VOC	Formaldehyde	3.60E-04	lbs/ton coke	2
Coke Calcining	1	VOC	Toluene	5.34E-05	lbs/ton coke	1
Coke Calcining	1	VOC	Xylene (m,p)	3.09E-05	lbs/ton coke	1
Coke Calcining	1	VOC	Xylene (o)	2.17E-05	lbs/ton coke	3
FCCU, Refinery gas	1	Halogens	HCl	5.29E-01	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	Metals	Arsenic	4.18E-04	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Beryllium	3.33E-05	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Cadmium	8.47E-05	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Chromium (Hex)	2.96E-05	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Chromium (Total)	5.04E-04	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Copper	1.21E-03	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Lead	5.76E-04	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Manganese	7.93E-04	lbs/ 1000 barrels	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
FCCU, Refinery gas	1	Metals	Mercury	2.94E-04	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Nickel	1.04E-02	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Selenium	1.58E-03	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	Metals	Zinc	4.04E-03	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	PAH	Acenaphthene	4.90E-07	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Acenaphthylene	3.53E-07	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Anthracene	1.13E-06	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Benzo(a)anthracene	5.23E-07	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Benzo(a)pyrene	1.29E-07	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	PAH	Benzo(b)fluoranthene	1.06E-06	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Benzo(e)pyrene	4.54E-07	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Benzo(g,h,i)perylene	1.29E-07	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	PAH	Benzo(k)fluoranthene	3.65E-07	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Chrysene	2.56E-06	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Dibenz(a,h)anthracene	1.29E-07	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	PAH	Fluoranthene	4.50E-06	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Fluorene	1.92E-06	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Indeno(1,2,3-cd)pyrene	1.29E-07	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	PAH	Naphthalene	4.62E-05	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	PAH	Phenanthrene	1.15E-05	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	PAH	Pyrene	2.48E-06	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	VOC	Carbon disulfide	5.60E-04	lbs/1000 Barrels	4
FCCU, Refinery gas	1	VOC	Hydrogen cyanide	7.00E+00	lbs/1000 Barrels	4
FCCU, Refinery gas	1	Dioxin/Furan	Pentachlorodibenzofurans	5.50E-10	lbs/1000 Barrels	4
FCCU, Refinery gas	1	Dioxin/Furan	Hexachlorodibenzofuran	1.10E-09	lbs/1000 Barrels	4
FCCU, Refinery gas	1	Dioxin/Furan	Heptachlorodibenzo-p-dioxin	9.40E-10	lbs/1000 Barrels	4
FCCU, Refinery gas	1	SVOC	2-Methylnaphthalene	2.26E-06	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	SVOC	Ethylbenzene	1.02E-02	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	SVOC	Perylene	1.29E-07	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	SVOC	Phenol	2.27E-04	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	VOC	Acetaldehyde	1.29E-02	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	VOC	Acrolein	1.00E-03	lbs/1000 Barrels	4
FCCU, Refinery gas	1	VOC	Ammonia	2.02E-01	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	VOC	Benzene	1.49E-02	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	VOC	Bromomethane	2.10E-03	lbs/1000 Barrels	4
FCCU, Refinery gas	1	VOC	1,3-Butadiene	3.30E-05	lbs/1000 Barrels	4
FCCU, Refinery gas	1	VOC	Carbonyl Sulfide	8.35E-02	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	VOC	Cyanide	3.55E-02	lbs/ 1000 barrels	1
FCCU, Refinery gas	1	VOC	Formaldehyde	4.91E-02	lbs/ 1000 barrels	2
FCCU, Refinery gas	1	VOC	Hydrogen Sulfide	7.70E-02	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	VOC	Methylene Chloride	6.70E-03	lbs/1000 Barrels	4
FCCU, Refinery gas	1	VOC	Toluene	8.80E-03	lbs/ 1000 barrels	3
FCCU, Refinery gas	1	VOC	Trichlorofluoromethane	2.40E-03	lbs/1000 Barrels	4
FCCU, Refinery gas	1	VOC	Xylene (Total)	2.03E-02	lbs/ 1000 barrels	1
Heater, Natural Gas	1	PAH	Acenaphthene	1.39E-06	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Acenaphthylene	1.21E-05	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Heater, Natural Gas	1	PAH	Anthracene	1.61E-06	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Benzo(a)anthracene	1.96E-06	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Benzo(a)pyrene	9.80E-07	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Benzo(b)fluoranthene	5.40E-07	lbs/MMcf	3
Heater, Natural Gas	1	PAH	Benzo(g,h,i)perylene	1.25E-06	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Benzo(k)fluoranthene	9.90E-07	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Chrysene	1.39E-06	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Dibenz(a,h)anthracene	9.17E-07	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Fluoranthene	1.19E-05	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Fluorene	4.59E-06	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Indeno(1,2,3-cd)pyrene	1.17E-06	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Naphthalene	1.12E-03	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Phenanthrene	3.37E-05	lbs/MMcf	1
Heater, Natural Gas	1	PAH	Pyrene	5.60E-06	lbs/MMcf	1
Heater, Natural Gas	1	SVOC	Ethylbenzene	1.13E-03	lbs/MMcf	3
Heater, Natural Gas	1	VOC	Acetaldehyde	1.40E-02	lbs/MMcf	1
Heater, Natural Gas	1	VOC	Benzene	1.12E-02	lbs/MMcf	1
Heater, Natural Gas	1	VOC	Formaldehyde	7.40E-02	lbs/MMcf	1
Heater, Natural Gas	1	VOC	Propylene	2.35E-01	lbs/MMcf	1
Heater, Natural Gas	1	VOC	Toluene	2.95E-02	lbs/MMcf	1
Heater, Natural Gas	1	VOC	Xylene (Total)	1.43E-02	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Acenaphthene	7.53E-06	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Acenaphthylene	5.88E-05	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Anthracene	1.04E-05	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Benzo(a)anthracene	9.57E-06	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Benzo(a)pyrene	6.07E-06	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Benzo(b)fluoranthene	2.63E-06	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Benzo(g,h,i)perylene	4.13E-07	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Benzo(k)fluoranthene	1.46E-06	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Chrysene	7.91E-07	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Dibenz(a,h)anthracene	5.05E-08	lbs/MMcf	3
Heater, Natural/Ref. Gas	1	PAH	Fluoranthene	1.80E-05	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Fluorene	6.48E-04	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Indeno(1,2,3-cd)pyrene	4.56E-07	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Naphthalene	2.31E-03	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Phenanthrene	2.06E-04	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	PAH	Pyrene	1.25E-05	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	SVOC	Phenol	1.72E-03	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	VOC	Acetaldehyde	1.47E-02	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	VOC	Benzene	9.70E-03	lbs/MMcf	3
Heater, Natural/Ref. Gas	1	VOC	Formaldehyde	4.33E-02	lbs/MMcf	1
Heater, Natural/Ref. Gas	1	VOC	Propylene	5.50E-03	lbs/MMcf	3
Heater, Natural/Ref. Gas	1	VOC	Toluene	1.21E-02	lbs/MMcf	3
Heater, Natural/Ref. Gas	1	VOC	Xylene (Total)	1.39E-02	lbs/MMcf	3
Heater, Oil	1	Dioxin/Furan	Dioxin:4D 2378	1.49E-10	lbs/1000 gallons	3
Heater, Oil	1	Dioxin/Furan	Dioxin:5D 12378	1.49E-10	lbs/1000 gallons	3

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Heater, Oil	1	Dioxin/Furan	Dioxin:6D 123478	1.49E-10	lbs/1000 gallons	3
Heater, Oil	1	Dioxin/Furan	Dioxin:6D 123678	2.99E-09	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Dioxin:6D 123789	4.78E-09	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Dioxin:7D 1234678	1.33E-08	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Dioxin:8D	4.68E-08	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Furan:4F 2378	8.93E-08	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Furan:5F 12378	1.49E-10	lbs/1000 gallons	3
Heater, Oil	1	Dioxin/Furan	Furan:5F 23478	1.49E-10	lbs/1000 gallons	3
Heater, Oil	1	Dioxin/Furan	Furan:6F 123478	1.92E-08	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Furan:6F 123678	6.12E-09	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Furan:6F 123789	1.49E-10	lbs/1000 gallons	3
Heater, Oil	1	Dioxin/Furan	Furan:6F 234678	8.76E-09	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Furan:7F 1234678	1.95E-08	lbs/1000 gallons	1
Heater, Oil	1	Dioxin/Furan	Furan:7F 1234789	1.49E-10	lbs/1000 gallons	3
Heater, Oil	1	Dioxin/Furan	Furan:8F	1.04E-08	lbs/1000 gallons	1
Heater, Oil	1	Metals	Arsenic	8.62E-04	lbs/1000 gallons	2
Heater, Oil	1	Metals	Beryllium	8.66E-05	lbs/1000 gallons	2
Heater, Oil	1	Metals	Cadmium	1.23E-03	lbs/1000 gallons	2
Heater, Oil	1	Metals	Chromium (Hex)	3.13E-04	lbs/1000 gallons	2
Heater, Oil	1	Metals	Chromium (Total)	2.74E-03	lbs/1000 gallons	2
Heater, Oil	1	Metals	Copper	4.58E-03	lbs/1000 gallons	2
Heater, Oil	1	Metals	Lead	5.48E-04	lbs/1000 gallons	2
Heater, Oil	1	Metals	Manganese	2.22E-03	lbs/1000 gallons	2
Heater, Oil	1	Metals	Mercury	2.83E-05	lbs/1000 gallons	2
Heater, Oil	1	Metals	Nickel	4.09E-01	lbs/1000 gallons	2
Heater, Oil	1	Metals	Selenium	6.59E-03	lbs/1000 gallons	2
Heater, Oil	1	Metals	Zinc	1.22E-02	lbs/1000 gallons	2
Heater, Oil	1	PAH	Acenaphthene	2.99E-06	lbs/1000 gallons	2
Heater, Oil	1	PAH	Acenaphthylene	1.37E-07	lbs/1000 gallons	2
Heater, Oil	1	PAH	Anthracene	7.41E-08	lbs/1000 gallons	2
Heater, Oil	1	PAH	Benzo(a)anthracene	1.12E-05	lbs/1000 gallons	2
Heater, Oil	1	PAH	Benzo(a)pyrene	1.84E-07	lbs/1000 gallons	2
Heater, Oil	1	PAH	Benzo(b)fluoranthene	1.15E-06	lbs/1000 gallons	2
Heater, Oil	1	PAH	Benzo(e)pyrene	7.73E-07	lbs/1000 gallons	2
Heater, Oil	1	PAH	Benzo(g,h,i)perylene	5.57E-06	lbs/1000 gallons	2
Heater, Oil	1	PAH	Benzo(k)fluoranthene	6.81E-08	lbs/1000 gallons	2
Heater, Oil	1	PAH	Chrysene	2.92E-05	lbs/1000 gallons	2
Heater, Oil	1	PAH	Dibenz(a,h)anthracene	5.09E-06	lbs/1000 gallons	2
Heater, Oil	1	PAH	Fluoranthene	2.48E-06	lbs/1000 gallons	2
Heater, Oil	1	PAH	Fluorene	1.67E-04	lbs/1000 gallons	2
Heater, Oil	1	PAH	Indeno(1,2,3-cd)pyrene	5.12E-06	lbs/1000 gallons	2
Heater, Oil	1	PAH	Naphthalene	1.11E-03	lbs/1000 gallons	2
Heater, Oil	1	PAH	Phenanthrene	6.02E-05	lbs/1000 gallons	2
Heater, Oil	1	PAH	Pyrene	2.14E-06	lbs/1000 gallons	2
Heater, Oil	1	SVOC	2-Chloronaphthalene	1.17E-05	lbs/1000 gallons	1
Heater, Oil	1	SVOC	2-Methylnaphthalene	3.60E-05	lbs/1000 gallons	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Heater, Oil	1	SVOC	Perylene	7.41E-08	lbs/1000 gallons	1
Heater, Oil	1	VOC	1,3-Butadiene	9.45E-03	lbs/1000 gallons	3
Heater, Oil	1	VOC	Acetaldehyde	2.69E-04	lbs/1000 gallons	3
Heater, Oil	1	VOC	Benzene	8.74E-03	lbs/1000 gallons	2
Heater, Oil	1	VOC	Chloroform	4.18E-03	lbs/1000 gallons	3
Heater, Oil	1	VOC	Formaldehyde	3.84E-03	lbs/1000 gallons	2
Heater, Oil	1	VOC	Propylene	7.35E-03	lbs/1000 gallons	3
Heater, Oil	1	VOC	Toluene	4.84E-03	lbs/1000 gallons	3
Heater, Oil	1	VOC	Xylene (Total)	9.30E-03	lbs/1000 gallons	3
Heater, Ref. Gas	1	Halogens	HCl	8.13E-01	lbs/MMcf	5
Heater, Ref. Gas	1	Metals	Antimony	4.55E-04	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Arsenic	8.39E-04	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Barium	3.91E-03	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Beryllium	1.46E-05	lbs/MMcf	3
Heater, Ref. Gas	1	Metals	Cadmium	5.96E-04	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Chromium (Hex)	1.28E-03	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Chromium (Total)	1.16E-03	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Cobalt	2.13E-04	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Copper	5.71E-03	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Lead	2.47E-03	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Manganese	4.63E-03	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Mercury	2.41E-04	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Nickel	4.95E-03	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Phosphorus	3.52E-04	lbs/MMcf	3
Heater, Ref. Gas	1	Metals	Selenium	4.95E-03	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Silver	9.69E-04	lbs/MMcf	1
Heater, Ref. Gas	1	Metals	Thallium	1.83E-05	lbs/MMcf	3
Heater, Ref. Gas	1	Metals	Zinc	1.46E-02	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Acenaphthene	4.08E-06	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Acenaphthylene	4.00E-06	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Anthracene	5.83E-06	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Benzo(a)anthracene	2.02E-05	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Benzo(a)pyrene	5.19E-05	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Benzo(b)fluoranthene	2.51E-05	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Benzo(e)pyrene	1.25E-06	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Benzo(g,h,i)perylene	1.11E-06	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Benzo(k)fluoranthene	1.47E-05	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Chrysene	1.88E-06	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Dibenz(a,h)anthracene	1.79E-07	lbs/MMcf	3
Heater, Ref. Gas	1	PAH	Fluoranthene	8.71E-06	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Fluorene	1.66E-05	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Indeno(1,2,3-cd)pyrene	6.06E-05	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Naphthalene	4.74E-04	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Phenanthrene	5.20E-05	lbs/MMcf	1
Heater, Ref. Gas	1	PAH	Pyrene	6.29E-06	lbs/MMcf	1
Heater, Ref. Gas	1	SVOC	2-Methylnaphthalene	7.80E-05	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Heater, Ref. Gas	1	SVOC	Ethylbenzene	1.77E-02	lbs/MMcf	1
Heater, Ref. Gas	1	SVOC	Perylene	1.76E-07	lbs/MMcf	3
Heater, Ref. Gas	1	SVOC	Phenol	4.63E-03	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Acetaldehyde	5.18E-02	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Ammonia	1.42E-01	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Benzene	4.76E-02	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Carbonyl Sulfide	4.56E-01	lbs/MMcf	3
Heater, Ref. Gas	1	VOC	Cyanide	2.66E-03	lbs/MMcf	3
Heater, Ref. Gas	1	VOC	Formaldehyde	9.93E-02	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Hydrogen Sulfide	8.05E-02	lbs/MMcf	6
Heater, Ref. Gas	1	VOC	Propylene	2.05E-03	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Toluene	8.39E-02	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Xylene (m,p)	3.49E-03	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Xylene (o)	8.80E-03	lbs/MMcf	1
Heater, Ref. Gas	1	VOC	Xylene (Total)	4.16E-02	lbs/MMcf	1
Heater, Ref. Gas	2	Halogens	HCl	8.13E-01	lbs/MMcf	1
Heater, Ref. Gas	2	Metals	Arsenic	8.39E-04	lbs/MMcf	7
Heater, Ref. Gas	2	Metals	Beryllium	1.46E-05	lbs/MMcf	8
Heater, Ref. Gas	2	Metals	Cadmium	5.96E-04	lbs/MMcf	8
Heater, Ref. Gas	2	Metals	Chromium (Hex)	1.28E-03	lbs/MMcf	8
Heater, Ref. Gas	2	Metals	Chromium (Total)	1.16E-03	lbs/MMcf	8
Heater, Ref. Gas	2	Metals	Copper	5.71E-03	lbs/MMcf	8
Heater, Ref. Gas	2	Metals	Lead	9.02E-04	lbs/MMcf	1
Heater, Ref. Gas	2	Metals	Manganese	1.98E-03	lbs/MMcf	1
Heater, Ref. Gas	2	Metals	Mercury	2.41E-04	lbs/MMcf	8
Heater, Ref. Gas	2	Metals	Nickel	5.87E-03	lbs/MMcf	1
Heater, Ref. Gas	2	Metals	Selenium	1.99E-03	lbs/MMcf	1
Heater, Ref. Gas	2	Metals	Zinc	8.61E-03	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Acenaphthene	1.95E-04	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Acenaphthylene	8.14E-05	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Anthracene	3.22E-04	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Benzo(a)anthracene	1.31E-04	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Benzo(a)pyrene	4.68E-05	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Benzo(b)fluoranthene	3.22E-04	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Benzo(e)pyrene	1.80E-04	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Benzo(g,h,i)perylene	2.64E-05	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Benzo(k)fluoranthene	1.01E-04	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Chrysene	4.76E-04	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Dibenz(a,h)anthracene	1.63E-05	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Fluoranthene	7.73E-04	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Fluorene	1.99E-03	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Indeno(1,2,3-cd)pyrene	2.69E-05	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Naphthalene	1.25E-02	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Phenanthrene	1.52E-03	lbs/MMcf	1
Heater, Ref. Gas	2	PAH	Pyrene	9.37E-04	lbs/MMcf	1
Heater, Ref. Gas	2	SVOC	2-Methylnaphthalene	2.29E-03	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Heater, Ref. Gas	2	SVOC	Ethylbenzene	4.73E-02	lbs/MMcf	3
Heater, Ref. Gas	2	SVOC	Perylene	1.62E-05	lbs/MMcf	1
Heater, Ref. Gas	2	SVOC	Phenol	2.23E-02	lbs/MMcf	1
Heater, Ref. Gas	2	VOC	1,1,1-Trichloroethane	2.90E-02	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	1,2-Dichloroethane	9.25E-01	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Acetaldehyde	5.05E-02	lbs/MMcf	1
Heater, Ref. Gas	2	VOC	Ammonia	2.76E+00	lbs/MMcf	1
Heater, Ref. Gas	2	VOC	Benzene	2.14E-01	lbs/MMcf	1
Heater, Ref. Gas	2	VOC	Carbon Tetrachloride	5.40E-03	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Carbonyl Sulfide	9.05E-01	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Chloroform	2.60E-02	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Cyanide	4.64E-03	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Formaldehyde	1.88E+00	lbs/MMcf	1
Heater, Ref. Gas	2	VOC	Hydrogen Sulfide	8.05E-02	lbs/MMcf	6
Heater, Ref. Gas	2	VOC	Methylene Chloride	1.09E+00	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Tetrachloroethene	5.90E-03	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Toluene	4.09E-02	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Trichloroethene	2.57E-02	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Trichlorofluoromethane	4.45E-03	lbs/MMcf	3
Heater, Ref. Gas	2	VOC	Xylene (Total)	4.73E-02	lbs/MMcf	3
ICE, Diesel (Prime)	1	PAH	Acenaphthene	8.67E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Acenaphthylene	1.32E-03	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Anthracene	2.89E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Benzo(a)anthracene	9.69E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Benzo(a)pyrene	4.77E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Benzo(b)fluoranthene	1.92E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Benzo(g,h,i)perylene	8.30E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Benzo(k)fluoranthene	6.92E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Chrysene	2.28E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Dibenz(a,h)anthracene	5.07E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Fluoranthene	5.84E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Fluorene	1.81E-03	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Indeno(1,2,3-cd)pyrene	6.61E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Naphthalene	1.85E-02	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Phenanthrene	5.76E-03	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	PAH	Pyrene	5.60E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	VOC	Acetaldehyde	3.47E-03	lbs/1000 gallons	1
ICE, Diesel (Prime)	1	VOC	Benzene	1.01E-01	lbs/1000 gallons	1
ICE, Diesel (Prime)	1	VOC	Formaldehyde	2.63E-02	lbs/1000 gallons	2
ICE, Diesel (Prime)	1	VOC	Propylene	3.85E-01	lbs/1000 gallons	1
ICE, Diesel (Prime)	1	VOC	Toluene	3.74E-02	lbs/1000 gallons	1
ICE, Diesel (Prime)	1	VOC	Xylene (Total)	2.68E-02	lbs/1000 gallons	1
ICE, Diesel (Prime)	4	PAH	Acenaphthene	2.04E-02	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Acenaphthylene	1.47E-02	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Anthracene	2.56E-03	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Benzo(a)anthracene	6.75E-04	lbs/1000 gallons	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
ICE, Diesel (Prime)	4	PAH	Benzo(a)pyrene	5.83E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Benzo(b)fluoranthene	1.63E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Benzo(b+k)fluoranthene	1.46E-06	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Benzo(g,h,i)perylene	1.55E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Benzo(k)fluoranthene	6.22E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Chrysene	7.33E-05	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Dibenz(a,h)anthracene	1.44E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Fluoranthene	2.70E-03	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Fluorene	1.05E-02	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Indeno(1,2,3-cd)pyrene	1.32E-04	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Naphthalene	1.58E-01	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Phenanthrene	2.31E-02	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	PAH	Pyrene	1.44E-03	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	SVOC	Benzaldehyde	1.26E-02	lbs/1000 gallons	1
ICE, Diesel (Prime)	4	VOC	1,3-Butadiene	2.71E-03	lbs/1000 gallons	3
ICE, Diesel (Prime)	4	VOC	Acetaldehyde	1.07E-01	lbs/1000 gallons	1
ICE, Diesel (Prime)	4	VOC	Benzene	1.22E-01	lbs/1000 gallons	1
ICE, Diesel (Prime)	4	VOC	Formaldehyde	3.35E-01	lbs/1000 gallons	2
ICE, Diesel (Prime)	4	VOC	Propylene	3.58E-01	lbs/1000 gallons	1
ICE, Diesel (Prime)	4	VOC	Toluene	5.50E-02	lbs/1000 gallons	1
ICE, Diesel (Prime)	4	VOC	Xylene (m,p)	2.16E-02	lbs/1000 gallons	1
ICE, Diesel (Prime)	4	VOC	Xylene (o)	1.05E-02	lbs/1000 gallons	3
ICE, Diesel (Prime)	4	VOC	Xylene (Total)	3.59E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Acenaphthene	4.71E-04	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Acenaphthylene	1.09E-03	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Anthracene	1.79E-04	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Benzo(a)anthracene	5.03E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Benzo(a)pyrene	1.81E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Benzo(b)fluoranthene	7.96E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Benzo(g,h,i)perylene	3.89E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Benzo(k)fluoranthene	1.56E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Chrysene	1.06E-04	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Dibenz(a,h)anthracene	4.12E-07	lbs/1000 gallons	3
ICE, Diesel (Emergency or Standby)	1	PAH	Fluoranthene	3.73E-04	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Fluorene	1.28E-03	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Indeno(1,2,3-cd)pyrene	2.89E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Naphthalene	1.63E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Phenanthrene	3.96E-03	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	PAH	Pyrene	2.90E-04	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	VOC	Acetaldehyde	3.47E-03	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	VOC	Benzene	1.01E-01	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	VOC	Formaldehyde	1.32E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	VOC	Propylene	3.85E-01	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	VOC	Toluene	3.74E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	1	VOC	Xylene (Total)	2.68E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Acenaphthene	3.14E-03	lbs/1000 gallons	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
ICE, Diesel (Emergency or Standby)	4	PAH	Acenaphthylene	4.07E-03	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Anthracene	8.48E-04	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Benzo(a)anthracene	2.34E-04	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Benzo(a)pyrene	1.81E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Benzo(b)fluoranthene	8.66E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Benzo(b+k)fluoranthene	7.05E-07	lbs/1000 gallons	3
ICE, Diesel (Emergency or Standby)	4	PAH	Benzo(g,h,i)perylene	4.94E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Benzo(k)fluoranthene	3.28E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Chrysene	5.30E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Dibenz(a,h)anthracene	5.50E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Fluoranthene	1.33E-03	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Fluorene	5.52E-03	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Indeno(1,2,3-cd)pyrene	4.63E-05	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Naphthalene	5.44E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Phenanthrene	9.47E-03	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	PAH	Pyrene	9.02E-04	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	SVOC	Benzaldehyde	1.26E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	VOC	1,3-Butadiene	2.71E-03	lbs/1000 gallons	3
ICE, Diesel (Emergency or Standby)	4	VOC	Acetaldehyde	1.07E-01	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	VOC	Benzene	1.22E-01	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	VOC	Formaldehyde	1.16E-01	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	VOC	Propylene	3.58E-01	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	VOC	Toluene	5.50E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	VOC	Xylene (m,p)	2.16E-02	lbs/1000 gallons	1
ICE, Diesel (Emergency or Standby)	4	VOC	Xylene (o)	1.05E-02	lbs/1000 gallons	3
ICE, Diesel (Emergency or Standby)	4	VOC	Xylene (Total)	3.59E-02	lbs/1000 gallons	1
ICE, Natural Gas	1	PAH	Acenaphthene	7.17E-04	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Acenaphthylene	7.59E-03	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Anthracene	2.56E-04	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Benzo(a)anthracene	7.78E-05	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Benzo(a)pyrene	3.55E-05	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Benzo(b)fluoranthene	3.27E-04	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Benzo(g,h,i)perylene	1.03E-04	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Benzo(k)fluoranthene	5.30E-04	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Chrysene	9.64E-05	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Dibenz(a,h)anthracene	1.09E-05	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Fluoranthene	2.50E-04	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Fluorene	1.69E-04	lbs/MMcf	3
ICE, Natural Gas	1	PAH	Indeno(1,2,3-cd)pyrene	1.20E-04	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Naphthalene	1.22E-01	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Phenanthrene	8.93E-04	lbs/MMcf	1
ICE, Natural Gas	1	PAH	Pyrene	1.23E-04	lbs/MMcf	1
ICE, Natural Gas	1	VOC	Acetaldehyde	3.99E+00	lbs/MMcf	1
ICE, Natural Gas	1	VOC	Benzene	1.21E+00	lbs/MMcf	1
ICE, Natural Gas	1	VOC	Formaldehyde	2.87E+01	lbs/MMcf	1
ICE, Natural Gas	1	VOC	Propylene	1.87E+01	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
ICE, Natural Gas	1	VOC	Toluene	4.12E-01	lbs/MMcf	1
ICE, Natural Gas	1	VOC	Xylene (m,p)	8.63E-02	lbs/MMcf	1
ICE, Natural Gas	1	VOC	Xylene (o)	4.94E-02	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Acenaphthene	1.94E-03	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Acenaphthylene	1.45E-02	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Anthracene	1.84E-03	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Benzo(a)anthracene	2.94E-04	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Benzo(a)pyrene	1.15E-04	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Benzo(b)fluoranthene	2.37E-04	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Benzo(g,h,i)perylene	1.95E-04	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Benzo(k)fluoranthene	1.03E-04	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Chrysene	3.10E-04	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Dibenz(a,h)anthracene	1.25E-05	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Fluoranthene	9.95E-04	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Fluorene	6.91E-03	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Indeno(1,2,3-cd)pyrene	1.69E-04	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Naphthalene	7.65E-02	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Phenanthrene	7.07E-03	lbs/MMcf	1
ICE, Natural Gas	2	PAH	Pyrene	1.79E-03	lbs/MMcf	1
ICE, Natural Gas	2	SVOC	Ethylbenzene	1.16E-02	lbs/MMcf	1
ICE, Natural Gas	2	VOC	1,3-Butadiene	1.04E-01	lbs/MMcf	1
ICE, Natural Gas	2	VOC	Acetaldehyde	8.83E-01	lbs/MMcf	1
ICE, Natural Gas	2	VOC	Benzene	1.91E+00	lbs/MMcf	1
ICE, Natural Gas	2	VOC	Formaldehyde	2.35E+00	lbs/MMcf	1
ICE, Natural Gas	2	VOC	Propylene	1.60E+01	lbs/MMcf	1
ICE, Natural Gas	2	VOC	Toluene	1.07E+00	lbs/MMcf	1
ICE, Natural Gas	2	VOC	Xylene (m,p)	4.41E-01	lbs/MMcf	1
ICE, Natural Gas	2	VOC	Xylene (o)	2.17E-01	lbs/MMcf	1
ICE, Natural Gas	2	VOC	Xylene (Total)	6.02E-02	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Acenaphthene	1.51E-04	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Acenaphthylene	5.25E-04	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Anthracene	1.19E-04	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Benzo(a)anthracene	5.88E-05	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Benzo(a)pyrene	9.20E-07	lbs/MMcf	3
ICE, Natural Gas	3	PAH	Benzo(b)fluoranthene	4.09E-05	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Benzo(g,h,i)perylene	7.54E-06	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Benzo(k)fluoranthene	7.83E-06	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Chrysene	1.43E-05	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Dibenz(a,h)anthracene	9.20E-07	lbs/MMcf	3
ICE, Natural Gas	3	PAH	Fluoranthene	2.91E-04	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Fluorene	4.36E-04	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Indeno(1,2,3-cd)pyrene	7.17E-06	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Naphthalene	2.51E-02	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Phenanthrene	1.85E-03	lbs/MMcf	1
ICE, Natural Gas	3	PAH	Pyrene	1.87E-04	lbs/MMcf	1
ICE, Natural Gas	3	SVOC	Ethylbenzene	7.11E-02	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
ICE, Natural Gas	3	VOC	1,3-Butadiene	3.67E-01	lbs/MMcf	1
ICE, Natural Gas	3	VOC	Acetaldehyde	5.29E-01	lbs/MMcf	1
ICE, Natural Gas	3	VOC	Benzene	2.18E-01	lbs/MMcf	1
ICE, Natural Gas	3	VOC	Formaldehyde	4.71E+00	lbs/MMcf	1
ICE, Natural Gas	3	VOC	Propylene	5.38E+00	lbs/MMcf	1
ICE, Natural Gas	3	VOC	Toluene	2.39E-01	lbs/MMcf	1
ICE, Natural Gas	3	VOC	Xylene (Total)	6.46E-01	lbs/MMcf	1
ICE, Natural Gas	4	SVOC	Ethylbenzene	3.23E-02	lbs/MMcf	3
ICE, Natural Gas	4	VOC	Benzene	2.95E-01	lbs/MMcf	1
ICE, Natural Gas	4	VOC	Formaldehyde	5.15E+00	lbs/MMcf	1
ICE, Natural Gas	4	VOC	Toluene	1.89E-01	lbs/MMcf	1
ICE, Natural Gas	4	VOC	Xylene (Total)	6.45E-02	lbs/MMcf	3
SG, Crude oil	1	Halogens	HCl	2.09E-04	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Arsenic	2.85E-03	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Beryllium	3.19E-04	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Cadmium	5.45E-04	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Chromium (Hex)	3.36E-04	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Chromium (Total)	2.16E-03	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Copper	1.84E-03	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Lead	4.90E-04	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Manganese	5.73E-03	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Mercury	5.17E-03	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Nickel	4.01E-01	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Phosphorus	6.78E-02	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Selenium	3.09E-03	lbs/1000 gallons	2
SG, Crude oil	1	Metals	Zinc	2.60E-01	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Acenaphthene	9.22E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Acenaphthylene	1.79E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Anthracene	2.51E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Benzo(a)anthracene	1.49E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Benzo(a)pyrene	1.25E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Benzo(b)fluoranthene	1.60E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Benzo(b+k)fluoranthene	1.25E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Benzo(g,h,i)perylene	1.25E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Benzo(k)fluoranthene	1.07E-06	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Chrysene	3.45E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Dibenz(a,h)anthracene	1.25E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Fluoranthene	5.23E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Fluorene	4.59E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Indeno(1,2,3-cd)pyrene	1.25E-05	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Naphthalene	1.62E-03	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Phenanthrene	1.62E-04	lbs/1000 gallons	2
SG, Crude oil	1	PAH	Pyrene	7.22E-05	lbs/1000 gallons	2
SG, Crude oil	1	SVOC	Benzaldehyde	3.25E-03	lbs/1000 gallons	3
SG, Crude oil	1	VOC	Acetaldehyde	2.67E-03	lbs/1000 gallons	1
SG, Crude oil	1	VOC	Benzene	9.90E-04	lbs/1000 gallons	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
SG, Crude oil	1	VOC	Formaldehyde	1.64E-03	lbs/1000 gallons	2
SG, Crude oil	1	VOC	Propylene	9.35E-04	lbs/1000 gallons	3
SG, Crude oil	1	VOC	Toluene	3.56E-03	lbs/1000 gallons	1
SG, Crude oil	1	VOC	Xylene (Total)	2.15E-04	lbs/1000 gallons	3
SG, Natural Gas	1	VOC	Acetaldehyde	1.56E-02	lbs/MMcf	1
SG, Natural Gas	1	VOC	Benzene	1.92E-03	lbs/MMcf	3
SG, Natural Gas	1	VOC	Formaldehyde	2.95E-02	lbs/MMcf	1
SG, Natural Gas	1	VOC	Propylene	5.45E-02	lbs/MMcf	3
SG, Natural Gas	1	VOC	Toluene	5.95E-03	lbs/MMcf	3
SG, Natural Gas	1	VOC	Xylene (Total)	1.37E-02	lbs/MMcf	3
SG, Natural/CVR Gas	1	PAH	Acenaphthene	1.04E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Acenaphthylene	2.70E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Anthracene	2.09E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Benzo(a)anthracene	1.22E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Benzo(a)pyrene	6.86E-07	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Benzo(b)fluoranthene	2.00E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Benzo(g,h,i)perylene	9.80E-07	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Benzo(k)fluoranthene	8.21E-07	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Chrysene	1.55E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Dibenz(a,h)anthracene	1.98E-07	lbs/MMcf	3
SG, Natural/CVR Gas	1	PAH	Fluoranthene	3.66E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Fluorene	5.63E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Indeno(1,2,3-cd)pyrene	1.17E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Naphthalene	2.89E-04	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Phenanthrene	1.64E-05	lbs/MMcf	1
SG, Natural/CVR Gas	1	PAH	Pyrene	6.00E-06	lbs/MMcf	1
SG, Natural/CVR Gas	1	SVOC	Ethylbenzene	9.22E-03	lbs/MMcf	1
SG, Natural/CVR Gas	1	VOC	Acetaldehyde	1.12E-02	lbs/MMcf	1
SG, Natural/CVR Gas	1	VOC	Benzene	1.18E-03	lbs/MMcf	3
SG, Natural/CVR Gas	1	VOC	Formaldehyde	1.58E-02	lbs/MMcf	1
SG, Natural/CVR Gas	1	VOC	Hydrogen Sulfide	1.48E-01	lbs/MMcf	1
SG, Natural/CVR Gas	1	VOC	Propylene	1.83E-01	lbs/MMcf	1
SG, Natural/CVR Gas	1	VOC	Toluene	1.37E-02	lbs/MMcf	1
SG, Natural/CVR Gas	1	VOC	Xylene (Total)	1.85E-02	lbs/MMcf	1
Turbine, Distillate	2	Dioxin/Furan	Dioxin:4D Total	3.74E-09	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Dioxin:5D Total	7.15E-09	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Dioxin:6D Total	9.00E-09	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Dioxin:7D Total	1.68E-08	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Dioxin:8D	1.07E-07	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Furan:4F Total	3.34E-08	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Furan:5F Total	4.67E-08	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Furan:6F Total	2.41E-08	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Furan:7F Total	1.67E-08	lbs/1000 gallons	1
Turbine, Distillate	2	Dioxin/Furan	Furan:8F	8.61E-09	lbs/1000 gallons	1
Turbine, Distillate	2	Halogens	HCl	8.61E-02	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Arsenic	2.72E-04	lbs/1000 gallons	2

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Turbine, Distillate	2	Metals	Beryllium	1.37E-04	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Cadmium	3.56E-04	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Chromium (Hex)	1.64E-05	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Chromium (Total)	5.60E-04	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Copper	1.48E-03	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Lead	7.18E-04	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Manganese	1.43E-02	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Mercury	5.14E-06	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Nickel	1.42E-01	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Selenium	9.13E-06	lbs/1000 gallons	2
Turbine, Distillate	2	Metals	Zinc	1.42E-01	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Acenaphthene	5.53E-05	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Acenaphthylene	2.22E-05	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Anthracene	4.92E-05	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Benzo(a)anthracene	9.47E-06	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Benzo(a)pyrene	2.89E-05	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Benzo(b)fluoranthene	3.73E-05	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Benzo(b+k)fluoranthene	3.65E-06	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Benzo(g,h,i)perylene	3.65E-06	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Benzo(k)fluoranthene	9.99E-06	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Chrysene	9.99E-06	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Dibenz(a,h)anthracene	3.65E-06	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Fluoranthene	2.68E-05	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Fluorene	3.48E-05	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Indeno(1,2,3-cd)pyrene	3.65E-06	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Naphthalene	5.34E-04	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Phenanthrene	1.62E-04	lbs/1000 gallons	2
Turbine, Distillate	2	PAH	Pyrene	3.78E-05	lbs/1000 gallons	2
Turbine, Distillate	2	VOC	Benzene	1.13E-02	lbs/1000 gallons	1
Turbine, Distillate	2	VOC	Formaldehyde	1.56E-01	lbs/1000 gallons	2
Turbine, Natural Gas	1	VOC	Benzene	9.09E-02	lbs/MMcf	1
Turbine, Natural Gas	1	VOC	Formaldehyde	4.04E+00	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Acenaphthene	1.90E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Acenaphthylene	1.47E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Anthracene	3.38E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Benzo(a)anthracene	2.26E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Benzo(a)pyrene	1.39E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Benzo(b)fluoranthene	1.13E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Benzo(e)pyrene	2.18E-07	lbs/MMcf	3
Turbine, Natural Gas	2	PAH	Benzo(g,h,i)perylene	1.37E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Benzo(k)fluoranthene	1.10E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Chrysene	2.52E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Dibenz(a,h)anthracene	6.30E-07	lbs/MMcf	3
Turbine, Natural Gas	2	PAH	Fluoranthene	4.32E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Fluorene	5.80E-05	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Indeno(1,2,3-cd)pyrene	2.35E-05	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Turbine, Natural Gas	2	PAH	Naphthalene	1.66E-03	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Phenanthrene	3.13E-04	lbs/MMcf	1
Turbine, Natural Gas	2	PAH	Pyrene	2.77E-05	lbs/MMcf	1
Turbine, Natural Gas	2	SVOC	2-Chloronaphthalene	8.70E-08	lbs/MMcf	3
Turbine, Natural Gas	2	SVOC	2-Methylnaphthalene	5.29E-06	lbs/MMcf	1
Turbine, Natural Gas	2	SVOC	Ethylbenzene	1.79E-02	lbs/MMcf	1
Turbine, Natural Gas	2	SVOC	Perylene	2.76E-07	lbs/MMcf	3
Turbine, Natural Gas	2	VOC	1,3-Butadiene	6.20E-05	lbs/MMcf	3
Turbine, Natural Gas	2	VOC	Acetaldehyde	1.37E-01	lbs/MMcf	1
Turbine, Natural Gas	2	VOC	Benzene	1.33E-02	lbs/MMcf	1
Turbine, Natural Gas	2	VOC	Formaldehyde	9.17E-01	lbs/MMcf	1
Turbine, Natural Gas	2	VOC	Hexane	2.59E-01	lbs/MMcf	1
Turbine, Natural Gas	2	VOC	Propylene	7.71E-01	lbs/MMcf	1
Turbine, Natural Gas	2	VOC	Propylene oxide	1.99E-02	lbs/MMcf	3
Turbine, Natural Gas	2	VOC	Toluene	7.10E-02	lbs/MMcf	1
Turbine, Natural Gas	2	VOC	Xylene (m,p)	4.89E-02	lbs/MMcf	1
Turbine, Natural Gas	2	VOC	Xylene (o)	2.40E-02	lbs/MMcf	1
Turbine, Natural Gas	2	VOC	Xylene (Total)	2.61E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Antimony	3.26E-05	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	Metals	Arsenic	3.26E-05	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	Metals	Barium	8.73E-04	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Beryllium	1.31E-05	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	Metals	Cadmium	1.28E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Chromium (Hex)	1.53E-05	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	Metals	Chromium (Total)	3.59E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Cobalt	1.55E-04	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Copper	5.87E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Lead	1.66E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Manganese	5.09E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Mercury	3.09E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Nickel	4.57E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Phosphorus	1.93E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Selenium	1.63E-04	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	Metals	Silver	1.37E-04	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	Metals	Thallium	1.63E-05	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	Metals	Zinc	1.57E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Acenaphthene	9.00E-06	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Acenaphthylene	4.75E-06	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Anthracene	1.39E-05	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Benzo(a)anthracene	6.24E-06	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Benzo(a)pyrene	4.68E-07	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	PAH	Benzo(b)fluoranthene	9.88E-06	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Benzo(e)pyrene	4.68E-07	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	PAH	Benzo(g,h,i)perylene	7.79E-06	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Benzo(k)fluoranthene	4.68E-07	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	PAH	Chrysene	3.94E-05	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Turbine, Natural/Ref. Gas	1	PAH	Dibenz(a,h)anthracene	4.68E-07	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	PAH	Fluoranthene	3.84E-05	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Fluorene	6.73E-05	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Indeno(1,2,3-cd)pyrene	4.68E-07	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	PAH	Naphthalene	1.37E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Phenanthrene	2.55E-04	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	PAH	Pyrene	4.82E-05	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	SVOC	2-Methylnaphthalene	6.35E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	SVOC	Ethylbenzene	1.82E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	SVOC	Perylene	4.68E-07	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	SVOC	Phenol	3.74E-07	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	VOC	Acetaldehyde	8.84E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	VOC	Ammonia	1.07E+01	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	VOC	Benzene	8.37E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	VOC	Formaldehyde	1.22E-01	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	VOC	Hydrogen Sulfide	7.95E-02	lbs/MMcf	3
Turbine, Natural/Ref. Gas	1	VOC	Toluene	6.54E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	VOC	Xylene (m,p)	5.96E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	VOC	Xylene (o)	1.68E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas	1	VOC	Xylene (Total)	2.06E-01	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Acenaphthene	6.56E-06	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	PAH	Acenaphthylene	4.21E-06	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	PAH	Anthracene	4.94E-05	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	PAH	Benzo(a)anthracene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Benzo(a)pyrene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Benzo(b)fluoranthene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Benzo(e)pyrene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Benzo(g,h,i)perylene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Benzo(k)fluoranthene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Chrysene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Dibenz(a,h)anthracene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Fluoranthene	1.79E-05	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	PAH	Fluorene	1.89E-05	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	PAH	Indeno(1,2,3-cd)pyrene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Naphthalene	5.95E-04	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	PAH	Phenanthrene	1.69E-04	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	PAH	Pyrene	4.73E-05	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	SVOC	2-Methylnaphthalene	5.60E-05	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	SVOC	Ethylbenzene	8.79E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	SVOC	Perylene	1.87E-06	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	VOC	Acetaldehyde	3.00E-01	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	VOC	Benzene	4.05E-03	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	VOC	Formaldehyde	7.80E-03	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	VOC	Toluene	1.97E-02	lbs/MMcf	1
Turbine, Natural/Ref. Gas/Butane	1	VOC	Xylene (m,p)	4.30E-03	lbs/MMcf	3
Turbine, Natural/Ref. Gas/Butane	1	VOC	Xylene (o)	4.94E-03	lbs/MMcf	1

Major Group	Sub Group	Category	Substance	Emission Factor	Unit	Source
Turbine, Natural/Ref./LP Gas	1	Metals	Arsenic	3.26E-05	lbs/MMcf	3
Turbine, Natural/Ref./LP Gas	1	Metals	Beryllium	1.31E-05	lbs/MMcf	3
Turbine, Natural/Ref./LP Gas	1	Metals	Cadmium	7.41E-03	lbs/MMcf	1
Turbine, Natural/Ref./LP Gas	1	Metals	Copper	4.08E-02	lbs/MMcf	1
Turbine, Natural/Ref./LP Gas	1	Metals	Lead	3.22E-02	lbs/MMcf	3
Turbine, Natural/Ref./LP Gas	1	Metals	Manganese	1.75E-01	lbs/MMcf	1
Turbine, Natural/Ref./LP Gas	1	Metals	Nickel	2.78E-01	lbs/MMcf	1
Turbine, Natural/Ref./LP Gas	1	Metals	Selenium	1.63E-04	lbs/MMcf	3
Turbine, Natural/Ref./LP Gas	1	Metals	Zinc	4.12E-01	lbs/MMcf	1
Turbine, Natural/Ref./LP Gas	1	SVOC	Phenol	5.80E-02	lbs/MMcf	1
Turbine, Ref. Gas	1	Metals	Arsenic	3.26E-05	lbs/MMcf	3
Turbine, Ref. Gas	1	Metals	Beryllium	1.31E-05	lbs/MMcf	3
Turbine, Ref. Gas	1	Metals	Cadmium	7.41E-03	lbs/MMcf	1
Turbine, Ref. Gas	1	Metals	Chromium (Hex)	1.53E-05	lbs/MMcf	3
Turbine, Ref. Gas	1	Metals	Chromium (Total)	1.84E-02	lbs/MMcf	1
Turbine, Ref. Gas	1	Metals	Copper	5.78E-02	lbs/MMcf	1
Turbine, Ref. Gas	1	Metals	Lead	3.99E-02	lbs/MMcf	1
Turbine, Ref. Gas	1	Metals	Manganese	1.80E-01	lbs/MMcf	1
Turbine, Ref. Gas	1	Metals	Mercury	2.15E-02	lbs/MMcf	1
Turbine, Ref. Gas	1	Metals	Nickel	2.33E-01	lbs/MMcf	1
Turbine, Ref. Gas	1	Metals	Selenium	1.63E-04	lbs/MMcf	3
Turbine, Ref. Gas	1	Metals	Zinc	6.99E+00	lbs/MMcf	1
Turbine, Ref. Gas	1	SVOC	Phenol	9.41E-03	lbs/MMcf	1
Turbine, Ref. Gas	1	VOC	Acetaldehyde	2.18E-02	lbs/MMcf	1
Turbine, Ref. Gas	1	VOC	Benzene	7.20E-02	lbs/MMcf	3
Turbine, Ref. Gas	1	VOC	Formaldehyde	8.41E-01	lbs/MMcf	1
Turbine, Ref. Gas	1	VOC	Hydrogen Sulfide	7.90E-02	lbs/MMcf	3
Turbine, Ref. Gas	1	VOC	Toluene	1.09E+00	lbs/MMcf	1
Turbine, Ref. Gas	1	VOC	Xylene (Total)	3.14E+00	lbs/MMcf	1

Source of Emission Factor:
1. Mean Emission Factor, CATEF
2. Maximum Emission Factor, CATEF (Hot Spots Inventory Guidelines, Appendix D Source and Pollutant)
3. Half of Minimum Emission Factor (Detect Ratio = 0.00), CATEF
4. Refinery MACT 2 source testing more recent (see EPA's Protocol)
5. Mean Emission Factor from Subcategory 1 (Excess air not shown to influence halogens), CATEF
6. Half of Minimum Emission Factor of both subcategories CATEF (Detect Ratio = 0.00), CATEF
7. Mean Emission Factor from Subcategory 1 (Excess air not shown to influence metals), CATEF
8. Half of Minimum Emission Factor from Subcategory 1 (Detect Ratio = 0.00) (Excess air not shown to influence metals), CATEF

Table A-2: Descriptions of Sub-Groups Listed in Table A-1

Major Group	Sub Group	Sub Group Description
Asphalt Prod., Blowing	1	Natural Gas/Flux, Fume Incinerator
Asphalt Prod., Diesel	1	Rotary Dryer Conventional Plant, Abatement (Cyclone, Fabric Filter)
Asphalt Prod., Diesel	2	Drum Dryer: Hot Asphalt Plants, Abatement (Fabric Filter)
Asphalt Prod., Diesel	3	Drum Dryer: Hot Asphalt Plants, Abatement (Wet Scrubber)
Asphalt Prod., Natural Gas	1	Rotary Dryer Conventional Plant, Abatement (Cyclone/Fabric Filter or Wet Scrubber)
Asphalt Prod., Oil	1	Rotary Dryer Conventional Plant with Cyclone/Baghouse or Cyclone/Wet Scrubber
Asphalt Prod., Truck Load	1	Truck Load Out
Boiler, Coal/Natural Gas	1	No Abatement
Boiler, Coke/Coal	1	Lime Injection/Ammonia Injection/Baghouse
Boiler, Distillate	1	Industrial/Commercial/Institutional, No Abatement
Boiler, Fuel oil	2	Industrial (All Capacities, No. 6 Fuel, Residual Fuel), No Abatement
Boiler, Ref. Gas	1	Excess Air > 100%
Boiler, Ref. Gas	2	Excess Air < 100%
Catalytic Reformer	1	No Abatement
Catalytic Reformer	2	Abatement (Activated Carbon)
Coke Calcining	1	Abatement (Fabric Filter)
FCCU, Refinery gas	1	Abatement (ESP, CO Boiler)
Heater, Natural Gas	1	Process Heater, No Abatement
Heater, Natural/Ref. Gas	1	Process Heater, No Abatement
Heater, Oil	1	Process Heater (Crude Oil-Fired), No Abatement
Heater, Ref. Gas	1	Excess Air < 100%
Heater, Ref. Gas	2	Excess Air > 100%
ICE, Diesel (Prime)	1	Industrial, O_2 < 13%, No Abatement
ICE, Diesel (Prime)	4	Industrial, O_2 >13%, No Abatement
ICE, Diesel (Emergency or Standby)	1	Industrial, No Abatement, O_2 < 13%
ICE, Diesel (Emergency or Standby)	4	Industrial, No Abatement, O_2 > 13%
ICE, Natural Gas	1	Industrial, 4 Stroke, Lean, < 650 HP, No Abatement
ICE, Natural Gas	2	Industrial, 4 Stroke, Rich, < 650 HP, No Abatement
ICE, Natural Gas	3	Industrial, 4 Stroke, Lean, > 650 HP, No Abatement
ICE, Natural Gas	4	Industrial, 2 Stroke, Lean, > 650 HP, No Abatement
SG, Crude oil	1	Process Heater/Steam Generator, No Abatement or Abatement (SO_2 Scrubber)
SG, Natural Gas	1	Process Heater/Steam Generator, No Abatement
SG, Natural/CVR Gas	1	Process Heater/Steam Generator (Natural Gas-Fired or CVR-Gas Fired), No Abatement
Turbine, Distillate	2	Industrial, No Abatement
Turbine, Natural Gas	1	Electric Generation or Industrial, No Abatement
Turbine, Natural Gas	2	Industrial, No Abatement or Abatement (Ammonia Injection/SCR or CO Oxidation Catalyst)
Turbine, Natural/Ref. Gas	1	Industrial (Natural Gas/Process-Gas Fired), Abatement (SCR/Ammonia Injection/CO Oxidation Catalyst)
Turbine, Natural/Ref. Gas/Butane	1	Abatement (SCR, CO Oxidation Catalyst)
Turbine, Natural/Ref./LP Gas	1	Abatement (SCR, CO Oxidation Catalyst)
Turbine, Ref. Gas	1	Abatement (CO Oxidation Catalyst)

Table A-3: Default Emission Factors for Equipment Leaks

Component Type	Stream Service	Emission Factor (kg/hour/component)	Source
Valves	Gas	2.68E-02	(1)
	Light Liquid	1.09E-02	(1)
	Heavy Liquid	7.08E-05	(2)
Pumps (other than those with steam quench seal)	Light Liquid	1.14E-01	(1)
	Heavy Liquid	2.42E-03	(2)
Pumps (with steam quench seal)	Light Liquid	1.14E-01	(1)
	Heavy Liquid	2.10E-02	(1)
Compressor Seals	Gas	6.36E-01	(1)
Agitator Seals	All	1.14E-01	(1)
Sampling Connections	All	1.50E-02	(1)
Other	Heavy Liquid	1.67E-04	(2)
Connectors	Gas or Light Liquid	2.50E-04	(1)
	Heavy Liquid	4.54E-05	(2)
Flanges	Gas or Light Liquid	2.50E-04	(1)
	Heavy Liquid	1.17E-04	(2)
Open-Ended Lines	Gas or Light Liquid	2.30E-03	(1)
	Heavy Liquid	5.33E-05	(2)
Pressure Relief Devices	Gas	1.60E-01	(1)
	Heavy Liquid	4.70E-04	(2)

Source:

1. CAPCOA 1999 *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* – Table IV-1a
2. Derived from Regulation 8, Rule 18 maximum emission limits inserted into correlation equations listed in CAPCOA 1999 *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* – Table IV-3a. These factors will be updated to reflect average emission factors developed through the Air District Heavy Liquid Study, once finalized.

APPENDIX B

Emission Calculation Templates

Table B-1: Summary of Emission Estimation Templates

Section	Section Title	Rank	Measurement Method	Template
3.1	Fugitive Emission Leaks	1	Direct measurement	TBD
		2	Correlation equations	TBD
		3 & 4	Average emission factors	TBD
3.2	Storage Tanks	1	Direct measurement	TBD
		2	Tank-specific modeling	TBD
3.3	Stationary Combustion	1	Direct measurement (flow rate and gas composition)	TBD
		2	Direct measurement (F factors)	TBD
		3A	Fuel analysis/mass balance	TBD
		3B	Source-specific stack testing	TBD
		4	Default emission factors	TBD
3.4	Process Vents	1	Continuous gas composition analyzer (flow meter)	TBD
		2	Continuous gas composition analyzer (F-factor)	TBD
		3	Grab samples	TBD
		4	Source tests	TBD
		5	Default emission factors	TBD
3.5	Flares	1	Continuous flow rate monitoring Continuous composition monitoring	TBD
		2	Continuous flow rate monitoring Occasional sampling	TBD
		3	Continuous flow rate & heating value monitoring	TBD
		4	Engineering calculations	TBD
		5	Energy consumption-based emission factors	TBD
		6	Default emission factors	TBD
3.6	Wastewater	1	Direct measurement	TBD
		2	Predictive modeling with site-specific factors & biodegradation rates	TBD
		3A	Engineering estimates (wastewater plant load)	TBD
		3B	Engineering estimates (crude throughput)	TBD
3.7	Cooling Towers	1	Direct water measurement (continuous)	TBD
		2	Direct water measurement (periodic)	TBD
		3	Default emission factors	TBD
3.8	Loading Operations	1A	Continuous gas composition analyzer and continuous vent gas flow measurement	TBD
		1B	Continuous gas THC analyzer with periodic sampling speciation and continuous vent gas flow measurement	TBD
		2	Site specific emission factors (EPA Method 18)	TBD
		3	Default emission factors (NMOC source tests)	TBD
		4	Default emission factors (measured loading rates)	TBD
3.9	Fugitive Dust	1	Calculated emission factor (measured silt loading)	TBD
		2	Calculated emission factor (default silt loading)	TBD
3.10	Startup and Shutdown	1A	Engineering estimate (ideal gas law)	TBD
		1B	Engineer estimate (residual liquids vaporizing)	TBD
		1C	Engineering estimate (ideal gas law, liquid "heel")	TBD
3.11	Malfunctions/ Upsets	1	Direct measurement	TBD
		2	Engineering calculations (control device)	TBD
			Engineering calculations (vessel over pressurization)	TBD
			Engineering calculations (liquid spill)	TBD
3.12	Miscellaneous Sources			
3.12.1	Non-Retail Gasoline Dispensing Facility	1	Default emission factors	TBD

Section	Section Title	Rank	Measurement Method	Template
3.12.2	Architectural or Equipment Painting	1	Material balance	TBD
3.12.3	Abrasive Blasting	1	Default emission factors	TBD
3.12.4	Solvent Degreaser	1	Material balance	TBD
3.12.5	Soil Remediation	1	Material balance	TBD
3.12.6	Air Stripping	1	Material balance	TBD

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APPENDIX C

Quality Assurance Program

(Example Outline)

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1.0 Quality Assurance Policy Statement

1.1. Purpose of the Program
1.2. Scope

2.0 Summary

a. Organization Chart
b. Emission Inventory Tasks and Responsibilities
c. Information Flow
d. Summary of Control Techniques and Relation to Information Flow
e. Audit Procedures

3.0 Technical

3.1 Task Planning

3.1.1 Training and Staff Qualification
3.1.2 Schedule and Frequency of Updates
3.1.3 Quality Assurance Coordinator – Duties and Responsibilities
3.1.4 Data Sources

3.2 Data Collection

3.2.1 Forms and Procedures
3.2.2 Data Review
3.2.3 Quality Assurance Controls

3.3 Technical Procedures

3.3.1 Emission Factors
3.3.2 Instrumentation
3.3.3 Data Flow
3.3.4 Review Procedures

3.4 Data Recording and Reporting

3.4.1 Recording and Coding Forms
3.4.2 Rules for Data Coding
3.4.3 Data Editing Procedures

4.0 System Audits

4.1 Audit Responsibility and Schedule
4.2 Procedures

4.2.1 Elements
4.2.2 Schedule
4.2.3 Audit Report

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APPENDIX D

Emission Inventory Report

(Approved Format)

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