Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations

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Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations

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Office of Air Quality Planning and Standards

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Section 1
Summary

The purpose of this report is to document the review and analysis of test reports and assess the use of test report data for developing emissions factors for flares and certain refinery operations. These emissions factors are finalized as an update to the *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources,* AP-42 (EPA, 1995).

On May 1, 2013, Air Alliance Houston, Community In-Power and Development Association, Inc. (CIDA), Louisiana Bucket Brigade, and Texas Environmental Justice Advocacy Services (TEJAS), (collectively, "Plaintiffs") filed a lawsuit against the U.S. Environmental Protection Agency (EPA) alleging that the EPA had failed to review and, if necessary, revise emissions factors at least once every three years as required in Section 130 of the Clean Air Act (CAA). Air Alliance Houston, *et al.* v. McCarthy, No. 1:13-cv-00621-KBJ (D.D.C.). In the complaint, the Plaintiffs sought to compel the EPA to expeditiously complete a review of the volatile organic compounds (VOC) emissions factors for industrial flares ("flares"), liquid storage tanks ("tanks"), and wastewater collection, treatment and storage systems ("wastewater treatment systems"), and, if necessary, revise these factors. EPA entered into a consent decree with the Plaintiffs to settle the lawsuit. Under the terms of the consent decree, by August 19, 2014, EPA was to review and either propose revisions to the VOC emission factors for flares, tanks and wastewater treatment systems under CAA section 130, or propose a determination under CAA section 130 that revision of these emission factors was not necessary. By April 20, 2015 (originally December 19, 2014), EPA will issue final revisions to the VOC emission factors for flares, tanks and wastewater treatment systems, or issue a final determination that revision of these emission factors for flares is not necessary. EPA will post each proposed revision or determination (or combination thereof), and each final revision or determination (or combination thereof), on its AP-42 website by the dates indicated above.

As part of its efforts to comply with the consent decree, EPA reviewed emissions test data submitted by refineries for the 2011 Petroleum Refinery Information Collection Request (2011 Refinery ICR) and test data collected during the development of parameters for properly designed and operated flares and developed new emissions factors, as shown in Table S-1.

The EPA proposed emissions factors and updates to AP-42 sections 5.1, 8.13, and 13.5 on August 20, 2014 and requested public comments on the emissions factors. The public comment period ended on December 19, 2014. EPA received a total of 59 comment letters and has developed a separate response to comments document (EPA, 2015b).

The EPA is finalizing these emissions factors in AP-42 sections 5.1 Petroleum Refining, 8.13 Sulfur Recovery, and 13.5 Industrial Flares.

Table S-1. Summary of New and Revised Emissions Factors Developed

Emissions Unit and Pollutant	Emissions test data used		Test methods	AP-42 Emissions Factor	Representa-tiveness
	No. of test reports	No. of units [a]			
Catalytic Reforming Unit (CRU), Total Hydrocarbon (THC)	8	8	EPA Method 25A	2.4×10^{-4} lb THC (as propane)/bbl feed	Poorly
Fluid Catalytic Cracking Unit (FCCU), Hydrogen Cyanide (HCN)	11	11	EPA Other Test Method-029; EPA Method 320; modified CTM-033	4.3×10^{-4} lb HCN/lb coke burn	Moderately
	10	10	EPA Other Test Method-029; EPA Method 320; modified CTM-033	7.0×10^{-3} lb HCN/bbl feed	Moderately
Sulfur Recovery Unit (SRU), Carbon Monoxide (CO)	25	24	EPA Method 10; SCAQMD 100.1	0.71 lb CO/mmBtu	Moderately
	23	23	EPA Method 10	1.3 lb CO/ton sulfur	Moderately
Sulfur Recovery Unit, Oxides of Nitrogen (NOx)	25	26	EPA Method 7E	0.10 lb NOx/mmBtu	Moderately
	24	26	EPA Method 7E	0.22 lb NOx/ton sulfur	Moderately
SRU, THC	9	10	EPA Method 25A	1.4 x 10-3 lb THC (as propane)/ mmBtu	Poorly
	7	7	EPA Method 25A	0.040 lb THC (as propane)/ ton sulfur	Poorly
Hydrogen Plant NOx	7	7	EPA Method 7E	0.081 lb NOx/mmBtu	Poorly
Flare CO	7 [b]	10 [b]	Extractive PFTIR [c]	0.31 lb CO/mmBtu	Poorly

Flare Volatile Organic Compounds (VOC)	7	10	Extractive PFTIR; [c] DIAL [d]	0.57 lb VOC/mmBtu	Poorly

[a] Number of units used during emissions factor development process. This number includes outliers.

[b] Includes original flare test report used to create previous emissions factor.

[c] PFTIR is passive Fourier Transform Infrared.

[d] DIAL is Differential infrared absorption LIDAR (light detection and ranging).

Section 2
Background

In April 2011, EPA sent an ICR under CAA section 114 authority to facilities in the Petroleum Refining industry (EPA, 2011) ("2011 Refinery ICR"). The 2011 Refinery ICR consisted of four components, and two of these components requested emissions testing data from refineries. Component 1 of the 2011 Refinery ICR requested all refineries to submit reports for emissions tests that had been conducted since 2005. Component 4 of the 2011 Refinery ICR requested that certain refineries conduct testing for specific pollutants at specific emissions sources in accordance with an EPA-approved protocol and submit the test reports to EPA. Emissions testing reports were collected for catalytic reforming units (CRUs), fluid catalytic cracking units (FCCUs), sulfur recovery units (SRUs), and hydrogen plants, along with several other emissions sources. Testing was conducted for a number of pollutants, including carbon monoxide (CO), hydrogen cyanide (HCN), oxides of nitrogen (NOx), and total hydrocarbons (THC). Emissions testing reports were analyzed for multiple emissions sources and pollutants, as shown in Table 1, for the purpose of updating or developing new emissions factors in AP-42. In general, this project focused on the pollutants required under section 130 of the CAA (CO, NOx, and VOC[1]), and those emissions units and pollutants for which there are no current AP-42 emissions factors (EPA 1995). For hazardous air pollutants (HAPs), we focused on HCN from catalytic cracking units because that emissions unit is often the largest emissions source at the refinery and HCN is a risk driver for the petroleum refinery source category (EPA 2014).

Test data for the operating parameters and emissions from flares at petroleum refineries and chemical plants are available as a result of various enforcement actions related to flare performance issues. The EPA collected additional flare data during development of an analysis of proper flare operating conditions (EPA 2012). We were able to obtain data from a DIAL study in the Houston area in which the emissions from several flares were isolated. We also used the original flare report from which the previous set of flare emissions factors were created. Flare data are available for CO and VOC, as shown in Table 2.

This report documents the review and analysis of the available source test reports from the 2011 Refinery ICR for the emissions sources/pollutants identified in Table 1 and from flare studies for the pollutants identified in Table 2.

The background files for the AP-42 sections being revised contain the information discussed in this document, including the data summary worksheets, the emissions factor creation worksheets, the Individual Test Rating (ITR) score sheets, and test reports that were reviewed but not used in the calculation of the emissions factor. A link to the background files can be found under the section's heading on the AP-42 website (http://www.epa.gov/ttn/chief/ap42/index.html, see sections 5.1 Petroleum Refining, 8.13 Sulfur Recovery, and 13.5 Industrial Flares). The test reports that were used in the development of the

[1] We also focused on THC as a surrogate for VOC.

emissions factors are listed as references in the AP-42 sections being revised. These references can be accessed by clicking the reference's name in the AP-42 section.

Table 1. Emissions Sources and Pollutants with Emissions Test Report Data Reviewed [a]

Emissions source	Pollutant	No. Component 1 emissions test reports	No. Component 4 emissions test reports	Total number of emissions test reports
Catalytic Reforming Units (CRUs)	CO	5	3	8
	THC	13	2	15 [b]
Fluid Catalytic Cracking Units (FCCUs)	HCN	14	7	23 [c]
Sulfur Recovery Units (SRUs)	CO	45	5	50
	NOx	40	1	41
	THC	17	6	23
Hydrogen Plants	CO	5	3	8
	NOx	11	3	14
	THC	13	2	15
Total emissions test reports reviewed				197

[a] This table provides the total number of test reports (and not necessarily the number of emissions units). Each test report may have test data for 1 or more emissions unit(s), and in some instances, an emissions unit may have more than 1 test report.

[b] One test that was part of the 2011 ICR was inadvertently left out of the analysis at proposal and added in for the final analysis.

[c] Two of the tests were conducted after the 2011 ICR. We obtained these data as a result of comments on the proposed emissions factor.

Table 2. Flare Pollutants and Emissions Test Report Data Reviewed [a]

Emissions source	Pollutant	No. emissions test reports
Flares	CO	7 [b]
	VOC	7
Total emissions test reports reviewed		8 [b]

[a] This table provides the total number of test reports (and not necessarily the number of emissions units). Each test report may have test data for 1 or more emissions unit(s).

[b] Includes original flare test used to create the previous emissions factor.

2.1 Overview of Emissions Test Data Review

The facility and emissions information for each test report was compiled in a test data summary worksheet called "Test_Data_Sum_(pollutant)_(emissionssource)". The data fields included in the Test Data Summary file are provided in Appendix A. The Test Data Summary file includes the field "QA Notes" in column DA that summarizes what data are available in the test report and any potential issues with the data. The field "Looked at for EF?" identifies which emissions factor the test report was reviewed for and the field "Used for EF?" identifies whether the test report was included in emissions factor development.

To develop an emissions factor, two basic test data requirements need to be included in the report: (1) pounds per hour (lb/hr) emissions rate, or enough data to calculate the lb/hr emissions rate, and (2) process hourly production or process rate (process activity/hr), e.g., feed rate in barrels per hour (bbl/hr), coke burn rate in lb/hr, or production rate in tons per hour (ton/hr) or standard cubic feet per hour (scf/hr). Each test report was reviewed to confirm whether the critical fields were available, and the calculations in the test report were reviewed for accuracy.

For each emissions test report used in developing the emissions factor (i.e., "Yes" response for field "Use in EF?"), an individual test rating (ITR) score was given to the test report by completing the "Test Quality Rating Tool" tab in the EPA's WebFIRE Template and Test Quality Rating Tool (including instructions) spreadsheet (available on the ERT website at: http://www.epa.gov/ttnchie1/ert/). The "Test Quality Rating Tool" template for the ITR is provided in Appendix B. The ITR is a quantitative measure of the quality of the data contained within a test report. The ITR score may range from 0 to 100 and gives a general indication of the level and quality of documentation available in the test report and the level of conformance with the test method requirements. The "Test Quality Rating Tool" includes a series of questions related to "Supporting Documentation Provided" (columns A and B) and related to "Regulatory Agency Review" (columns G and H). Generally, the "Supporting Documentation Provided" columns are an indication of the completeness of the test report while the Regulatory Agency Review" columns provide an indication of whether the test was conducted according to the requirements of the test method. Columns A and B of the template worksheet were completed in this analysis. Columns G and H, which are specific to State/Local agency reviewers, were not completed.

Because only the "Supporting Documentation Provided" portion of the worksheet was completed, ITR scores for the test reports in the analysis range from approximately 4 to 72. For the "Supporting Documentation Provided" portion, the ITR includes 8 general questions, 8 questions for manual test methods, and 10 questions for instrumental test methods. Examples of the general questions include whether the testing firm described deviations from the test method or provided a statement that deviations were not required; whether a full description of the process and unit tested was provided; and whether an assessment of the validity, representativeness, achievement of data quality objectives and usability of the data was provided. For manual test methods, examples of questions include whether the Method 1 sample point evaluation was included in the test report; whether cyclonic flow checks were included in the report; and whether a complete laboratory report and flow diagram of sample analysis was included. For instrumental test methods, example questions include whether a complete description of the sampling system was provided; whether the response time tests were provided; whether the calibration error tests were included; and whether the drift tests were included. The ITR scores for the test reports reviewed are provided in a spreadsheet called "Webfire-template_(pollutant)_(emissionssource)".

2.2 Overview of Emissions Factor Analysis and Development

The emissions factor development approach followed EPA's *Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database* (EPA, 2013). The emissions factor analysis for each emissions factor is provided in the spreadsheet "EF_Creation__(pollutant)_(emissionssource).xlsm". The recommended procedures in the 2013 guidelines were followed implicitly, including the handling of below detection limit (BDL) test data, assigning an ITR score for those test reports that are used in the emissions factor analysis, recommended statistical procedures for determining whether data sets are part of the same data population, statistical procedures for determining whether any data points are outliers (i.e., outlier checks), and determining whether data for a particular emissions unit should be included in the emissions factor. This last step, determining whether to include data from each unit, involves comparison of the Factor Quality Index (FQI) for different emissions units. The FQI is an indicator of the emissions factor's ability to estimate emissions for the entire national population, and it is related to both the ITR score and the number of units in the data set. Once the statistical procedures are complete, the data set is ranked by ITR score (high to low), and a FQI is developed for each unit in the candidate set. The FQI should decrease with each emissions unit. When the FQI increases, only average test values above the point where the FQI increases are considered in factor development.

EPA's Emissions Factor Creation spreadsheet combines the emissions data from multiple test reports conducted on a single emissions unit, so that each emissions unit is equally weighted with other units. Because the EPA's recommended emissions factor development procedures are based on the premise that more test data values are preferred over fewer test data values, the scope of this project was limited to data sets containing test averages from at least 3 different emissions units. Additionally, there are times when it is necessary to subcategorize the emissions factor data from particular units because the emissions are dissimilar. The recommended emissions factor development procedures include a statistical procedure for determining whether emissions data are from the same data population, to indicate whether emissions data should be subcategorized based on a characteristic of the emissions unit (e.g., type of APCD). This analysis requires 3 or more emissions units from each potential subcategory.

Some of the data from instrumental test methods (e.g. Method 7E, Method 10, etc.) included test run averages reported as a negative value. The 2013 recommended procedures for emissions factor development do not specify how this data should be handled. Because the procedures are silent and it is not possible for emissions rates to be negative, this data has been excluded from emissions factor development in this project.

Section 3
Emissions Factor Development from Test Data Collected Under the 2011 Refinery ICR

EPA has reviewed emissions test data submitted by refineries for the 2011 Refinery ICR. The emissions data review and the emissions factor development for each emissions unit and pollutant are described below.

3.1 Catalytic Reforming Units - CO

The available emissions test data from the 2011 Refinery ICR included multiple test reports for CO from catalytic reforming units (CRU). Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score.

Based on the emissions test report review and analysis, 2 emissions test reports for 2 emissions units had useable data and were included in the development of an emissions factor; these units had reformer charge rate data as the available production data. These useable emissions test reports are provided in Table 3. In addition, another 2 emissions test reports for 2 emissions units had useable data, with coke burn rate data as the available production data. These useable test reports are also provided in Table 3. A complete list of the available test report information is provided in worksheet “Test_Data_Sum_CO_CRU_2015April.xlsm”. For more detail on the analysis and QA conducted, see the field “QA Notes” for each test report. The emissions data (lb CO/hr) in these test reports are based on measurements taken with EPA Method 10 (M10) and EPA M320, and the test reports included production rate data for the CRU in either bbl/hr feed rate or lb/hr coke burn rate.

Certain test reports were excluded from the emissions factor analysis because production rate data are not available.

Overall, 4 test reports have useable data. Two emissions test reports include data on a reformer charge rate basis while the other 2 emissions test reports include data on a coke burn rate basis. These production data bases are not in comparable units, and there is no way to calculate the production rate data on the same basis, so these test reports could not be combined for emissions factor development. Because the scope of this project is limited to data sets containing test averages from at least 3 emissions units and because there are only 2 emissions units with useable test reports in each of the different production rate categories, an emissions factor was not developed for CRU CO.

Table 3. Analysis of Emissions Test Reports for CO from CRUs

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test result	ITR
Production Data as Reformer Charge Rate, bbl/hr						
MS3C0740	Chevron Refinery, Pascagoula, Mississippi	EPN CH-004	Chlorsorb	M10	4.5×10^{-6} lb CO/bbl feed	46
OK2C0990	TPI Refining Company Ardmore Petroleum Refinery Ardmore, Oklahoma	CRU400B	Venturi Scrubber	M10	9.8×10^{-5} lb CO/bbl feed	48
Production Data as Coke Burn Rate, lb/hr						
OK2C0990	TPI Refining Company Ardmore Petroleum Refinery Ardmore, Oklahoma	CRU400B	Venturi Scrubber	M10	2.9×10^{-3} lb CO/lb Coke burn	48
TX3B1170	Exxonmobil Beaumont Refinery, Beaumont, Texas	PTR-4 Reactor Regenerator vent	Caustic Scrubber	M10	2.5×10^{-3} lb CO/lb Coke burn	38

3.2 Catalytic Reforming Units - THC

The available emissions test data from the 2011 Refinery ICR included multiple test reports for THC from CRU units. Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score. An overview of the emissions factor is provided in Table 4.

Based on the emissions test report review and analysis, 8 emissions test reports for 8 emissions units had useable data and were included in the development of the emissions factor. These emissions tests reports are provided in Table 5. A complete list of the available test report information is provided in worksheet “Test_Data_Sum_THC_CRU_2015April.xlsm”. For more detail on the analysis and QA conducted, see the field “QA Notes” for each test report. The ITR scores for these 8 test reports ranged from 23 to 46. The emissions data (lb THC, as propane/hr) in these test reports are based on measurements taken with EPA Method 25A (M25A), and the test reports included production rate data for the CRU in bbl/hr feed rate. In instances where both M25A and EPA Method 18 (M18) were conducted in the same test report, the THC data for M25A alone were extracted from the raw data in the test report appendices, so that the data from all tests was measured on the same basis.

Certain test reports were excluded from the emissions factor analysis for the following reasons: production rate data are not available, the test method was not compatible with THC (i.e, M18 test reports were excluded because M18 measures specific compounds where M25A counts total carbon) or the test method was not clearly identified.

EPA's recommended emissions factor development procedures were followed for the CRU THC data. All 8 emissions units were combined for the emissions factor development. These 8 CRU are continuous regeneration units. The statistical analysis for determining outliers in the data set was conducted, and no data were found to be outliers.

One of the last steps in developing an emissions factor is a comparison of the FQI for different units. The FQI is an indicator of the emissions factor's ability to estimate emissions for the entire national population, and it is related to both the ITR score and the number of units in the data set. Once the statistical procedures are complete, the data set is ranked by ITR score (high to low), and a FQI is developed for each unit in the candidate set. The FQI should decrease with each emissions unit that is added to the emissions factor pool. When the FQI increases, only average test values above the point where the FQI increases should be considered in the factor development. In the development of the emissions factor for THC from CRUs, the FQI evaluation excluded one unit from the data set (this unit has the lowest ITR score).

The emissions factor is based on the emissions test data for 7 units and is characterized as Poorly Representative. The emissions factor analysis for CRU THC is provided in worksheet "EF Creation_THC_CRU_2015April.xlsm".

Table 4. Overview of the Emissions Factor for THC from CRUs

Emissions test data used		Test methods	AP-42 Emissions Factor	Representativeness
No. of test reports	No. of units			
8	8 [a, b]	EPA Method 25A	2.4 x 10^{-4} lb THC (as propane)/bbl feed	Poorly

[a] One CRU was excluded from the data set based on the FQI evaluation.

[b] The final data set for the emissions factor is based on 7 CRUs. All of the CRUs on which the CRU THC emissions factor is based are continuous regeneration units. The control devices in the data set include 5 CRUs with scrubbers and 2 CRUs with Chlorsorb.

Table 5. Analysis of Emissions Test Reports for THC from CRUs

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test result, lb THC, as propane/bbl feed	ITR
IL2A0420	Marathon Ashland Petroleum, in Robinson IL.	16 Platformer	Scrubber	M25A	3.0 x 10^{-5}	46
KY2A0490 [a]	Marathon Ashland Petroleum, in Catlettsburg KY	HPCCR	Packed bed scrubber	M25A	8.8 x 10^{-6}	23

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test result, lb THC, as propane/bbl feed	ITR
KY2A0490	Marathon Ashland Petroleum, in Catlettsburg KY	LPCCR	Packed bed scrubber	M25A	7.1×10^{-6}	41
MS3C0740	Chevron Refinery, in Pascagoula MS	CRU79	Chlorsorb	M25A	1.5×10^{-3}	41
OK2C0990	TPI Refining Company Ardmore Petroleum Refinery Ardmore OK	CRU400B	Venturi Scrubber	M25A	1.4×10^{-5}	37
TX2B1220	Motiva Enterprises, in Port Arthur TX	CRU4	Packed bed scrubber	M25A	1.6×10^{-6}	43
TX3B1250	The Premcor Refining Group, Inc., in Port Arthur TX	CRU1344	Chlorsorb	M25A	9.0×10^{-5}	33
TX3B1310	Valero Refining – Texas, L.P., in Corpus Christi TX	CRU	Scrubber	M25A	1.5×10^{-5}	34

[a] This emissions unit was excluded from the data set based on the FQI evaluation.

3.3 Fluid Catalytic Cracking Units - HCN

The available emissions test data from the 2011 Refinery ICR included multiple test reports for HCN from FCCU units. Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score.

3.3.1 Coke Burn Rate Basis

An overview of the emissions factor using a coke burn rate basis is provided in Table 6.

Based on the emissions test report review and analysis, 11 emissions test reports for 11 emissions units had useable data and were included in the development of the emissions factor. These emissions tests reports are provided in Table 7. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_HCN_FCCU_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The ITR scores for these 11 test reports ranged from 36 to 72. The emissions data (lb HCN/hr) in these test reports are based on measurements taken with EPA Other Test Method-029 (OTM-029), EPA Reference Method 320, and in some instances with EPA Conditional Test Method-033 (CTM-033). Test data using CTM-033 were considered acceptable when the concentration of sodium hydroxide (NaOH) was high (6.0 N NaOH) and the pH was maintained above 12 for the duration of the test. The test reports included production rate data for the FCCU in lb/hr of coke burn rate.

Certain test reports were excluded from the emissions factor analysis for the following reasons: production rate data for coke burn rate were not available or the test method was not compatible with OTM-029 (i.e., CARB Method 426 test reports and some CTM-033 test reports were excluded because the tests did not involve the use of the higher concentration NaOH solution required in OTM-029). Methods that use lower strength caustic solutions are not likely to measure the full HCN emissions.

EPA's recommended emissions factor development procedures were followed for the HCN FCCU data. Complete burn and partial burn regenerators may emit different amounts of HCN, but we are unsure of whether this is true or to what degree the emissions may vary. Because there are 9 complete regeneration and only 2 partial regeneration units, we could not perform the statistical analysis to determine whether these units should be subcategorized based on the type of regenerator. As we are unsure if and to what degree the regenerator type affects the HCN emissions, we decided to group all FCCUs together for emissions factor development. Because 7 FCCUs are controlled with scrubbers and 4 FCCUs are controlled with electrostatic precipitators (ESPs) and it is uncertain what effect each type of control device has on the HCN emissions, a statistical analysis was performed to determine if these data belong to the same population. The statistical analysis showed that all of the data belong to the same data set. Also, while 3 of the FCCUs have CO boilers and 8 of the units do not have CO boilers, the purpose of the CO boiler is to convert CO to CO_2, not to control HCN. However, we performed a statistical analysis for CO Boilers to determine whether these data belong to the same data set, and the statistical analysis showed that all of the data belong to the same data set. Therefore, all 11 FCCUs were combined for the emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no outliers were found. The emissions factor is based on the emissions test data for the 11 units and is characterized as Moderately Representative. The emissions factor analysis for FCCU HCN is provided in worksheet "EF Creation_HCN_FCCU_2015April_(Coke_Burn_Rate).xlsm".

Table 6. Overview of the Emissions Factor for HCN from FCCUs (Coke Burn Rate Basis)

Emissions test data to use				
No. of test reports	**No. of units**	**Test methods**	**AP-42 Emissions Factor**	**Representativeness**
11	11 [a]	EPA OTM-029; EPA Method 320; modified CTM-033	4.3×10^{-4} lb HCN/lb coke burn	Moderately

[a] The final data set for the emissions factor is based on 11 FCCUs. The FCCUs on which the FCCU HCN emissions factor is based include 9 complete regeneration units and 2 partial regeneration units. There are 3 units with CO boilers, and 8 units with none. The control devices in the data set include 7 scrubbers and 4 ESPs.

Table 7. Analysis of Emissions Test Reports for HCN from FCCUs (Coke Burn Rate Basis)

Facility ID No.	Facility name	Emissions unit [a]	APCD	Test method	Average test result, lb HCN/lb coke burn	ITR
CA5A0190	ExxonMobil Torrance Refinery, in Torrance, CA	FCC [a, c]	ESP	EPA OTM-029	1.8×10^{-4}	65
HI5A0380	Chevron Product Company, in Kapolei HI	FCCU [a]	ESP	EPA M320/ M301	4.2×10^{-4}	72
IL2A0420	Marathon Petroleum Company Robinson Refinery, in Robinson, IL	FCCU [b, c]	Scrubber	EPA OTM-029	6.2×10^{-5}	64
IN2A0440	BP Products, in Whiting IN	FCCU500 [a]	ESP	EPA M320	9.5×10^{-6}	57
LA3C0560	Citgo Petroleum Corporation, Lake Charles Manufacturing Complex, Lake Charles, LA	FCCU317 [a]	Scrubber	EPA OTM-029	1.2×10^{-3}	60
LA3C0610	Marathon Petroleum Company, in Garyville LA	Unit 30 [a]	Scrubber	EPA OTM-029	2.8×10^{-4}	45
MI2A0710	Marathon Petroleum Company, Detroit Refinery, in Detroit MI	FCCU [a]	ESP	EPA CTM-033	2.2×10^{-4}	43
NJ1A0850	ConocoPhillips Bayway Refinery, in Linden NJ	U4 FCCU [b, c]	Scrubber	EPA CTM-033	6.3×10^{-5}	36
NJ1A0860	Valero Refining Company, in Paulsboro, NJ	FCCU1 [a]	Scrubber	Modified EPA CTM-033	2.2×10^{-4}	61
TX3B1250	Valero Port Arthur Refinery, in Port Arthur, TX	FCCU1241 [a]	Scrubber	EPA OTM-029	7.7×10^{-4}	65
VI6A1530	Hovensa LLC, in Christiansted, US Virgin Islands	FCCU [a]	Scrubber	EPA OTM-029	1.2×10^{-3}	64

[a] These FCCUs with useable data are complete regeneration units.

[b] These FCCUs with useable data are partial regeneration units.

[c] These FCCUs have CO boilers.

3.3.2 Feed Rate Basis

An overview of the emissions factor using a feed rate basis is provided in Table 8.

Based on the emissions test report review and analysis, 10 emissions test reports for 10 emissions units had useable data and were included in the development of the emissions factor. These emissions tests reports are provided in Table 9. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_HCN_FCCU_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The ITR scores for these 10 test reports ranged from 43 to 65. The emissions data (lb HCN/hr) in these test reports are based on measurements taken with OTM-029, Method 320, and in some instances with CTM-033. Test data using CTM-033 were considered acceptable when the concentration of sodium hydroxide (NaOH) was high (6.0 N NaOH) and the pH was maintained above 12 for the duration of the test. The test reports included production rate data for the FCCU in bbl/hr feed rate.

Certain test reports were excluded from the emissions factor analysis for the following reasons: production rate data were not available or the test method was not compatible with OTM-029 (i.e., CARB Method 426 test reports and some CTM-033 test reports were excluded because the tests did not involve the use of the higher concentration NaOH solution required in OTM-029). Methods that use lower strength caustic solutions are not likely to measure the full HCN emissions.

EPA's recommended emissions factor development procedures were followed for the HCN FCCU data. Complete burn and partial burn regenerators may emit different amounts of HCN, but we are unsure of whether this is true or to what degree the emissions may vary. Because there are 9 complete regeneration units and only 1 partial regeneration unit, we could not perform the statistical analysis to determine whether these units should be subcategorized based on the type of regenerator. As we are unsure if and to what degree the regenerator type affects the HCN emissions, we decided to group all FCCUs together for emissions factor development. Because 7 FCCUs are controlled with scrubbers and 3 FCCUs are controlled with ESPs and it is uncertain what effect each type of control device has on the HCN emissions, a statistical analysis was performed to determine if these data belong to the same population. The statistical analysis showed that all of the data belong to the same data set. Also, while 2 of the FCCUs have CO boilers and 8 of the units do not have CO boilers, the purpose of the CO boiler is to convert CO to CO_2, not to control HCN. There is no data indicating that the CO boiler has a significant impact on the HCN emissions. (Note: The statistical analysis for CO Boilers under the coke burn rate emissions factor showed that all of the data belong to the same data set.) Therefore, all 10 FCCUs were combined for the emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no outliers were found. The emissions factor is based on the emissions test data for the 10 units and is characterized as Moderately Representative. The emissions factor analysis for FCCU HCN is provided in worksheet "EF Creation_HCN_FCCU_2015April_(Feed_Rate).xlsm".

Table 8. Overview of the Emissions Factor for HCN from FCCUs (Feed Rate Basis)

Emissions test data to use				
No. of test reports	No. of units	Test methods	AP-42 Emissions Factor	Representativeness
10	10 [a]	EPA OTM-029; CTM-033	7.0 x 10^{-3} lb HCN/bbl feed	Moderately

[a] The final data set for the emissions factor is based on 10 FCCUs. The FCCUs on which the FCCU HCN emissions factor is based include 9 FCCUs with complete regeneration and 1 FCCU with partial regeneration. The control devices in the data set include 7 FCCU with scrubbers and 3 with ESPs.

Table 9. Analysis of Emissions Test Reports for HCN from FCCUs (Feed Rate Basis)

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test result, lb HCN/bbl feed	ITR
CA5A0190	ExxonMobil Torrance Refinery, in Torrance, CA	FCC [a,c]	ESP	EPA OTM-029	3.1 x 10^{-3}	65
IL2A0420	Marathon Petroleum Company Robinson Refinery, in Robinson, IL	FCCU [b, c]	Scrubber	EPA OTM-029	1.0 x 10^{-3}	64
IN2A0440	BP Products, in Whiting IN	FCCU500 [a]	ESP	EPA M320	1.4 x 10^{-4}	57
LA3C0560	Citgo Petroleum Corporation, Lake Charles Manufacturing Complex, Lake Charles, LA	FCCU317 [a]	Scrubber	EPA OTM-029	1.5 x 10^{-2}	60
LA3C0610	Marathon Petroleum Company, in Garyville LA	Unit 30 [a]	Scrubber	EPA OTM-029	3.8 x 10^{-3}	45
MI2A0710	Marathon Petroleum Company, Detroit Refinery, in Detroit MI	FCCU [a]	ESP	EPA CTM-033	2.9 x 10^{-3}	43
NJ1A0820	Hess Corporation, Port Reading Refinery, in Port Reading, NJ	FCCU-PT1-A [a]	Scrubber	EPA CTM-033	4.7 x 10^{-3}	57
NJ1A0860	Valero Refining Company, in Paulsboro, NJ	FCCU1 [a]	Scrubber	EPA CTM-033	3.8 x 10^{-3}	61

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test result, lb HCN/bbl feed	ITR
TX3B1250	Valero Port Arthur Refinery, in Port Arthur, TX	FCCU1241 [a]	Scrubber	EPA OTM-029	1.4×10^{-2}	65
VI6A1530	Hovensa LLC, in Christiansted, US Virgin Islands	FCCU [a]	Scrubber	EPA OTM-029	2.2×10^{-2}	64

[a] These FCCUs are complete regeneration units.

[b] This FCCU is a partial regeneration unit.

[c] These FCCUs have CO boilers.

3.4 Sulfur Recovery Units - CO

The available emissions test data from the 2011 Refinery ICR included multiple test reports for CO from SRU units. Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score.

3.4.1 Heat Rate Basis

An overview of the emissions factor using a heat rate basis is provided in Table 10.

Based on the emissions test report review and analysis, 25 emissions test reports for 24 emissions units had useable data and were included in the development of the emissions factor. Several test reports provide emissions test data for SRU that share a common stack. When emissions testing is conducted on more than one SRU that share a common stack, the emissions units are counted as one "unit"; the total emissions rate is divided by the total production rate of all SRU venting to the stack when developing the units' average test results.

The emissions test reports used in the factor analysis are provided in Table 11. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_CO_SRU_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The ITR scores for these 25 test reports ranged from 35 to 56. The emissions data (lb CO/hr) in these test reports are based on measurements taken with EPA Method 10 (M10), and the test reports included heat rate data for the SRU in mmBtu/hr.

Certain test reports were excluded from the emissions factor analysis because heat rate data are not available or the concentration data for the test run average in the test report is a negative value.

EPA's recommended emissions factor development procedures were followed for the SRU CO data. The SRUs in the data set include 15 SRU that are Claus units with SCOT tail gas treatment units, 2 SRUs that are Claus units with Beavon tail gas treatment units, 1 SRU that is a Claus unit with Sulften tail gas treatment units, 1 SRU that is a Claus unit with a Resulf tail gas treatment unit, and 5 SRUs that are Claus units. All 24 of the SRUs have either an incinerator or a thermal oxidizer as the control device. Both incinerators and thermal oxidizers work on the same principles of combustion, and these terms are often used interchangeably by field staff. As such, there is no reason to believe that these control devices would have differing levels of CO emissions. Therefore, all of these units were combined for emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no data values were found to outliers.

As previously discussed, one of the last steps in developing an emissions factor is a comparison of the FQI for different units. In the development of the emissions factor for CO from SRUs, the FQI evaluation excluded two units from the data set (these two units have the lowest ITR scores).

The emissions factor is based on the emissions test data for 24 units and is characterized as Moderately Representative. The emissions factor analysis for SRU CO is provided in spreadsheet "EF Creation_CO_SRU_2015April_(Heat_Rate).xlsm".

Table 10. Overview of the Emissions Factor for CO from SRUs (Heat Rate Basis)

Emissions test data to use				
No. of test reports	**No. of units**	**Test methods**	**AP-42 Emissions Factor**	**Representativeness**
25	24 [a, b]	EPA Method 10	0.71 lb CO/mmBtu	Moderately

[a] Two SRUs were excluded from the data set based on the FQI evaluation.

[b] The final data set for the emissions factor is based on 22 SRUs. The SRUs on which the SRU CO emissions factor is based include 13 SRUs with SCOT tail gas treatment units, 2 SRUs with Beavon tail gas treatment units, 1 SRU with Sulften tail gas treatment unit, 1 SRU with Resulf tail gas treatment unit, and 5 SRUs that are Claus units. The control devices in the data set include 22 SRUs with incinerators or thermal oxidizers.

Table 11. Analysis of Emissions Test Reports for CO from SRUs (Heat Rate Basis)

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb CO/mmBtu	ITR
CA5A0120	BP West Coast Products, Carson, California	TGU1 [e]	Incinerator	SCAQMD 100.1	0.37	37
CA5A0120	BP West Coast Products, Carson, California	TGU2 [e]	Incinerator	SCAQMD 100.1	1.4	52

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb CO/mmBtu	ITR
CA5A0190	ExxonMobil Torrance Refinery, Torrance, California	SRU29F4 [e]	Incinerator	SCAQMD 100.1	1.6	46
DE1A0360 (2006) [f]	Valero Delaware City Refinery, The Premcor Refining Group	SRU1 [a]	Thermal oxidizer	M10	0.000836	4
DE1A0360 (2009) [f]	Valero Delaware City Refinery, The Premcor Refining Group	SRU1 [a]	Thermal oxidizer	M10	0.0022	56
DE1A0360 (2006) [f]	Valero Delaware City Refinery, The Premcor Refining Group	SRU2 [a]	Thermal oxidizer	M10	0.0023	4
DE1A0360 (2009) [f]	Valero Delaware City Refinery, The Premcor Refining Group	SRU2 [a]	Thermal oxidizer	M10	0.026	56
LA3C0610	Marathon Petroleum Company LLC, Garyville, Louisiana	SRU220 [b]	Thermal oxidizer	M10	0.048	50
LA3C0610	Marathon Petroleum Company LLC, Garyville, Louisiana	SRU234 [b]	Thermal oxidizer	M10	0.093	50
LA3C0630	Motiva Enterprises, Norco Refinery, Norco, Louisiana	SRU S3 [a]	Incinerator	M10	0.013	48
LA3C0650	Valero Refining - New Orleans, LLC. St. Charles Refinery, Norco, Louisiana	SRU1600 [a]	Thermal oxidizer	M10	0.083	45
LA3C0650	Valero Refining - New Orleans, LLC. St. Charles Refinery, Norco, Louisiana	SRU30 [a]	Thermal oxidizer	M10	0.17	41

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb CO/mmBtu	ITR
OK2C0990	Total Petroleum, Inc. Ardmore Refinery - Ardmore, Oklahoma	SRU1 (500A) [a]	Incinerator	M10	0.023	43
TX3A1230	ConocoPhillips Borger Petroleum Refinery, Borger, Texas	SRU43 [a]	Incinerator	M10	0.047	46
TX3B1110	BP Products North America Inc., Texas City, Texas	SRU [a]	Incinerator	M10	1.3	44
TX3B1131	Citgo Refining and Chemicals Company, Corpus Christi, Texas	West Plant SRU [a]	Incinerator	M10	0.19	52
TX3B1140	Valero Refining - Texas, L.P. East Plant of Bill Greehey Refinery, Corpus Christi, Texas	SRU2 [a]	Incinerator	M10	0.064	49
TX3B1220	Motiva Enterprises, LLC, Port Arthur, Texas	SRU2&3 combined [a]	Incinerator	M10	0.026	48
TX3B1240	ConocoPhillips Company, Sweeny Refinery, Old Ocean, Texas	EPN 28.2	Incinerator	M10	0.0070	48
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU543 [a]	Incinerator	M10	5.6	49
TX3B1250 (2009)	Valero Port Arthur Refinery, Port Arthur, Texas	SRU544 [a]	Incinerator	M10	0.75	49
TX3B1250 (2011)	Valero Port Arthur Refinery, Port Arthur, Texas	SRU544 [a]	Incinerator	M10	0.64	46
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU545 [a]	Incinerator	M10	0.46	49

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb CO/mmBtu	ITR
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU546 [a]	Incinerator	M10	0.22	49
TX3B1310	Valero Refining, Bill Greehey Refinery - West Plant, Corpus Christi, Texas	SRU1&2Sulften [c]	Incinerator	M10	2.8	38
TX3B1320	Valero Refining - Texas, Houston Refinery, Houston Texas	Unit 46 SRU [e]	Incinerator	M10	0.30	48
TX3B1320	Valero Refining - Texas, Houston Refinery, Houston Texas	Unit 39 SRU [e]	Incinerator	M10	0.12	48

[a] These SRUs are Claus units with SCOT tail gas treatment units.

[b] These SRUs are Claus units with Beavon tail gas treatment units.

[c] These SRUs are Claus units Sulften tail gas treatment units.

[d] These SRUs are Claus units with Resulf tail gas treatment units.

[e] These SRUs are Claus units.

[f] This emissions unit was excluded from the data set based on the FQI evaluation.

3.4.2 Sulfur Production Rate Basis

An overview of the emissions factor using a sulfur production basis is provided in Table 12.

Based on the emissions test report review and analysis, 23 emissions test reports for 23 emissions units had useable data and were included in the development of the emissions factor. Several test reports provide emissions test data for SRU that share a common stack. When emissions testing is conducted on more than one SRU that share a common stack, the emissions units are counted as one “unit”; the total emissions rate is divided by the total production rate of all SRU venting to the stack when developing the units’ average test results.

The emissions test reports used in the factor analysis are provided in Table 13. A complete list of the available test report information is provided in worksheet “Test_Data_Sum_CO_SRU_2015April.xlsm”. For more detail on the analysis and QA conducted, see the field “QA Notes” for each test report. The ITR scores for these 23 test reports ranged from 38 to 53. The emissions data (lb CO/hr) in these test reports are based on measurements taken with EPA Method 10 (M10), and the test reports included production rate data for the SRU in ton/hr sulfur production.

Certain test reports were excluded from the emissions factor analysis because production rate data are not available, the concentration data for the test run average in the test report is a negative value, or the SRU did not have controls consistent with the other units (e.g., 2 SRU had no controls).

EPA's recommended emissions factor development procedures were followed for the SRU CO data. The SRUs in the data set include 19 SRU that are Claus units with SCOT tail gas treatment units, 2 SRUs that are Claus units with Beavon tail gas treatment units, 1 SRU that is a Claus unit with Sulften tail gas treatment units, and 1 SRU that is a Claus unit with Resulf tail gas treatment unit. All 23 SRUs have either an incinerator or a thermal oxidizer as the control device. Both incinerators and thermal oxidizers work on the same principles of combustion, and these terms are often used interchangeably by field staff. As such, there is no reason to believe that these control devices would have differing levels of CO emissions. Therefore, all of these units were combined for emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no data were found to be outliers. The emissions factor is based on the emissions test data for 23 units and is characterized as Moderately Representative. The emissions factor analysis for SRU CO is provided in spreadsheet "EF Creation_CO_SRU_2015April_(Sulf_Prod).xlsm".

Table 12. Overview of the Emissions Factor for CO from SRUs (Sulfur Production Rate Basis)

Emissions test data to use		Test methods	AP-42 Emissions Factor	Representativeness
No. of test reports	No. of units			
23	23 [a]	EPA Method 10	1.3 lb CO/ton sulfur	Moderately

[a] The final data set for the emissions factor is based on 23 SRUs. The SRUs on which the SRU CO emissions factor is based include 19 SRUs with SCOT tail gas treatment units, 2 SRUs with Beavon tail gas treatment units, 1 SRU with a Sulften tail gas treatment unit, and 1 SRU with a Resulf tail gas treatment unit. The control devices in the data set include 23 SRUs with incinerators or thermal oxidizers.

Table 13. Analysis of Emissions Test Reports for CO from SRUs (Sulfur Production Rate Basis)

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb CO/ton sulfur	ITR
LA3C0610	Marathon Petroleum Company LLC, Garyville, Louisiana	SRU220 [b]	Thermal oxidizer	M10	0.10	50
LA3C0610	Marathon Petroleum Company LLC, Garyville, Louisiana	SRU234 [b]	Thermal oxidizer	M10	0.21	50

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb CO/ton sulfur	ITR
LA3C0630	Motiva Enterprises, Norco Refinery, Norco, Louisiana	SRU S3 [a]	Incinerator	M10	0.053	48
LA3C0650	Valero Refining - New Orleans, LLC. St. Charles Refinery, Norco, Louisiana	SRU1600 [a]	Thermal oxidizer	M10	0.47	45
LA3C0650	Valero Refining - New Orleans, LLC. St. Charles Refinery, Norco, Louisiana	SRU30 [a]	Thermal oxidizer	M10	0.35	41
MS3C0740	ChevronTexaco Pascagoula Refinery, Pascagoula, Mississippi	SRU2 (F-2745) [a]	Thermal Oxidizer	M10	0.24	47
MS3C0740	ChevronTexaco Pascagoula Refinery, Pascagoula, Mississippi	SRU3 (F-2765) [a]	Thermal Oxidizer	M10	0.20	47
OK2C0990	Total Petroleum, Inc. Ardmore Refinery, Ardmore, Oklahoma	SRU1 (500A) [a]	Incinerator	M10	0.038	43
OK2C0990	Total Petroleum, Inc. Ardmore Refinery - Ardmore, Oklahoma	SRU2 (560A) [a]	Incinerator	M10	0.0061	44
TX3A1190	Delek Refining, LTD. Tyler Refinery, Tyler, Texas	SRU1/SRU2 TGI2 [a]	Incinerator	M10	0.36	38
TX3A1230	ConocoPhillips Borger Petroleum Refinery, Borger, Texas	SRU43 [a]	Incinerator	M10	0.38	46
TX3A1300 [e]	Valero McKee Refinery, Sunray, Texas	EPN V-16 [Unit 830] [a]	Incinerator	M10	8.2	51
TX3A1300 [e]	Valero McKee Refinery, Sunray, Texas	EPN V-16 [Unit 830] [a]	Incinerator	M10	7.1	51
TX3A1300	Valero McKee Refinery, Sunray, Texas	EPN V-5 [Unit 820] [a]	Incinerator	M10	0.065	51

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb CO/ton sulfur	ITR
TX3B1090	Total Petrochemicals USA, Inc., Port Arthur, Texas	SRU1&2 [a]	Thermal Oxidizer	M10	2.0	46
TX3B1110	BP Products North America Inc., Texas City, Texas	SRU [a]	Incinerator	M10	1.7	44
TX3B1140	Valero Refining - Texas, L.P. East Plant of Bill Greehey Refinery, Corpus Christi, Texas	SRU2 [a]	Incinerator	M10	0.061	49
TX3B1220	Motiva Enterprises, LLC, Port Arthur, Texas	SRU2&3 combined [a]	Incinerator	M10	0.032	48
TX3B1240	ConocoPhillips Company, Sweeny Refinery, Old Ocean, Texas	EPN 28.2 [d]	Incinerator	M10	0.057	48
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU543 [a]	Incinerator	M10	7.7	49
TX3B1250 (2009 test)	Valero Port Arthur Refinery, Port Arthur, Texas	SRU544 [a]	Incinerator	M10	1.4	49
TX3B1250 (2011 test)	Valero Port Arthur Refinery, Port Arthur, Texas	SRU544 [a]	Incinerator	M10	5.3	46
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU545 [a]	Incinerator	M10	0.42	49
TX3B1310	Valero Refining, Bill Greehey Refinery - West Plant, Corpus Christi, Texas	SRU1&2Sulften [c]	Incinerator	M10	2.6	38
TX3B1310	Valero Refining, Bill Greehey Refinery - West Plant, Corpus Christi, Texas	SRU3 [a]	Incinerator	M10	1.3	53

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb CO/ton sulfur	ITR

[a] These SRUs are Claus units with SCOT tail gas treatment units.

[b] These SRUs are Claus units with Beavon tail gas treatment units.

[c] These SRUs are Claus units with Sulften tail gas treatment units.

[d] These SRUs are Claus units with Resulf tail gas treatment units.

[e] Data is for same unit from same test report. Separate sets of test runs occurred on multiple days and were reported separately.

3.5 Sulfur Recovery Units - NOx

The available emissions test data from the 2011 Refinery ICR included multiple test reports for NOx from SRU units. Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score.

3.5.1 Heat Rate Basis

An overview of the emissions factor using a heat rate basis is provided in Table 14.

Based on the emissions test report review and analysis, 25 emissions test reports for 26 emissions units had useable data and were included in the development of the emissions factor. Two test reports provide emissions test data for SRU that share a common stack. When emissions testing is conducted on more than one SRU that share a common stack, the emissions units are counted as one "unit"; the total emissions rate is divided by the total production rate of all SRU venting to the stack when developing the units' average test results. The majority of the testing was conducted since 2005, although one test report is from 1996.

The emissions test reports used in the factor analysis are provided in Table 15. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_NOx_SRU_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The ITR scores for these 25 test reports ranged from 30 to 56. The emissions data (lb NOx/hr) in these test reports are based on measurements taken with EPA Method 7E (M7E), and the test reports included heat rate data for the SRU in mmBtu/hr.

Certain test reports were excluded from the emissions factor analysis because heat rate data are not available.

EPA's recommended emissions factor development procedures were followed for the SRU NOx data. The SRUs in the data set include 20 SRU that are Claus units with SCOT tail gas treatment units, 2 SRUs that are Claus units with Beavon tail gas treatment units, 1 SRU that is a Claus unit with Resulf tail gas treatment unit, 1 SRU that is a Claus unit with Sulften tail gas treatment unit, and 2 SRUs that are Claus units. All 26 SRU units have either an incinerator or a thermal oxidizer as the control device. Both incinerators and thermal oxidizers work on the same principles of combustion, and these terms are often used interchangeably by field staff. As such, there is no reason to believe that these control devices would have differing levels of NOx emissions. Therefore, all of these units were combined for emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no data values were found to be outliers. The emissions factor was based on the emissions test data for 26 units and is characterized as Moderately Representative. The emissions factor analysis for SRU NOx is provided in spreadsheet “EF Creation_NOx_SRU_2015April_(Heat_Rate).xlsm”.

Table 14. Overview of the Emissions Factor for NOx from SRUs (Heat Rate Basis)

Emissions test data to use				
No. of test reports	No. of units	Test methods	AP-42 Emissions Factor	Representativeness
25	26 [a]	EPA Method 7E	0.10 lb NOx/mmBtu	Moderately

[a] The final data set for the emissions factor is based on 26 SRUs. The SRUs on which the SRU NOx emissions factor is based include 20 SRUs with SCOT tail gas treatment units, 2 SRUs with Beavon tail gas treatment units, 1 SRU with a Resulf tail gas treatment unit, 1 SRU with a Sulften tail gas treatment unit, and 2 SRUs that are Claus units. The control devices in the data set include 26 SRUs with incinerators or thermal oxidizers.

Table 15. Analysis of Emissions Test Reports for NOx from SRUs (Heat Rate Basis)

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/mmBtu	ITR
DE1A0360 (2006)	Valero Delaware City Refinery, The Premcor Refining Group	28-SRU1 [a]	Thermal Oxidizer	M7E	0.0029	4
DE1A0360 (2009)	Valero Delaware City Refinery, The Premcor Refining Group	28-SRU1 [a]	Thermal Oxidizer	M7E	0.23	56
DE1A0360 (2006)	Valero Delaware City Refinery, The Premcor Refining Group	28-SRU2 [a]	Thermal Oxidizer	M7E	0.030	4
DE1A0360 (2009)	Valero Delaware City Refinery, The Premcor Refining Group	28-SRU2 [a]	Thermal Oxidizer	M7E	0.072	56
LA3C0610	Marathon Petroleum Company LLC, Garyville, Louisiana	SRU220 [b]	Thermal Oxidizer	M7E	0.14	50

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/mmBtu	ITR
LA3C0610	Marathon Petroleum Company LLC, Garyville, Louisiana	SRU234 [b]	Thermal Oxidizer	M7E	0.10	50
LA3C0630	Norco Refinery, Motiva Enterprises, in Norco, Louisiana	SRU S3 [a]	Incinerator	M7E	0.14	48
LA3C0640	Meraux Refinery, Murphy Oil USA, Meraux, Louisiana	SRU2 [a]	Thermal Oxidizer	M7E	0.077	40
LA3C0650[a]	Valero Refining - New Orleans, LLC, St. Charles Refinery, Norco, Louisiana	SRU1600 [a]	Thermal Oxidizer	M7E	0.15	50
LA3C0650	Valero Refining - New Orleans, LLC, St. Charles Refinery, Norco, Louisiana	SRU30 [a]	Thermal Oxidizer	M7E	0.063	46
MT4A0770	CHS, Inc. Laurel Refinery, Laurel, Montana	Zone D SRU [a]	Thermal Oxidizer	M7E	0.029	42
OK2C0990	Total Petroleum, Inc. Ardmore Refinery - Ardmore, Oklahoma	SRU1 (500A) [a]	Incinerator	M7E	0.078	49
TX3A1230	ConocoPhillips Borger Petroleum Refinery, Borger, Hutchinson County, Texas	SRU34 [a]	Incinerator	M7E	0.13	50
TX3A1230	ConocoPhillips Borger Petroleum Refinery, Borger, Hutchinson County, Texas	SRU43 [a]	Incinerator	M7E	0.015	50
TX3B1110	BP Products North America Inc., Texas City, Texas	SRU [a]	Incinerator	M7E	0.16	48
TX3B1131	Laurel Refinery, Laurel, Montana.	West Plant SRU [a]	Incinerator	M7E	0.13	52
TX3B1140	Valero Refining - Texas, L.P. East Plant of Bill Greehey Refinery, Corpus Christi, Texas	SRU1 [a]	Incinerator	M7E	0.12	52

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/mmBtu	ITR
TX3B1140	Valero Refining - Texas, L.P. East Plant of Bill Greehey Refinery, Corpus Christi, Texas	SRU2 [a]	Incinerator	M7E	0.064	52
TX3B1220	Motiva Enterprises, LLC, Port Arthur, Texas	SRU2&3 [a]	Incinerator	M7E	0.11	52
TX3B1220	Motiva Enterprises, LLC, Port Arthur, Texas	SRU4 [a]	Incinerator	M7E	0.18	52
TX3B1240	ConocoPhillips Company, Sweeny Refinery, Old Ocean, Texas	EPN 28.2 [c]	Incinerator	M7E	0.025	45
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU543 [a]	Incinerator	M7E	0.056	56
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU544 [a]	Incinerator	M7E	0.063	52
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU545 [a]	Incinerator	M7E	0.069	52
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU546 [a]	Incinerator	M7E	0.086	49
TX3B1310	Valero Refining, Bill Greehey Refinery - West Plant, Corpus Christi, Texas	SRU1&2Sulften [d]	Incinerator	M7E	0.099	44
TX3B1320	Valero Refining - Texas, Houston Refinery, Houston, Texas	Unit 46 SRU (EPN 46CB6301) [e]	Incinerator	M7E	0.25	48
TX3B1320	Valero Refining - Texas, Houston Refinery, Houston, Texas	Unit 39 SRU (EPN 39CB2001) [e]	Incinerator	M7E	0.11	48

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/mmBtu	ITR

[a] These SRUs are Claus units with SCOT tail gas treatment units.
[b] These SRUs are Claus units with Beavon tail gas treatment units.
[c] These SRUs are Claus units with Resulf tail gas treatment units.
[d] These SRUs are Claus units Sulften tail gas treatment units.
[e] These SRUs are Claus units.

3.5.2 Sulfur Production Rate Basis

An overview of the emissions factor using a sulfur production basis is provided in Table 16.

Based on the emissions test report review and analysis, 24 emissions test reports for 26 emissions units had useable data and were included in the development of the emissions factor. Several test reports provide emissions test data for SRU that share a common stack. When emissions testing is conducted on more than one SRU that share a common stack, the emissions units are counted as one "unit"; the total emissions rate is divided by the total production rate of all SRU venting to the stack when developing the units' average test results. The majority of the testing was conducted since 2005, although one test report is from 1996.

The emissions test reports used in the factor analysis are provided in Table 17. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_NOx_SRU_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The ITR scores for these 24 test reports ranged from 41 to 56. The emissions data (lb NOx/hr) in these test reports are based on measurements taken with EPA Method 7E (M7E), and the test reports included production rate data for the SRU in ton/hr sulfur production.

Certain test reports were excluded from the emissions factor analysis because production rate data are not available.

EPA's recommended emissions factor development procedures were followed for the SRU NOx data. The SRUs in the data set include 22 SRU that are Claus units with SCOT tail gas treatment units, 2 SRUs that are Claus units with Beavon tail gas treatment units,, 1 SRU that is a Claus unit with a Sulften tail gas treatment unit, and 1 SRU that is a Claus unit with a Resulf tail gas treatment unit. All 26 SRUs have either an incinerator or a thermal oxidizer as the control device. Both incinerators and thermal oxidizers work on the same principles of combustion, and these terms are often used interchangeably by field staff. As such, there is no reason to believe that these control devices would have differing levels of NOx emissions. Therefore, all of these units were combined for emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no data were found to be outliers. The emissions factor was based on the emissions test data for 26 units and is characterized as Moderately Representative. The emissions factor analysis for SRU NOx is provided in spreadsheet "EF Creation_NOx_SRU_2015April_(Sulf_Rate).xlsm".

Table 16. Overview of the Emissions Factor for NOx from SRUs (Sulfur Production Rate Basis)

Emissions test data to use		Test methods	AP-42 Emissions Factor	Representativeness
No. of test reports	No. of units			
24	26 [a]	EPA Method 7E	2.2 x 10^{-1} lb NOx/ton sulfur	Moderately

[a] The final data set for the emissions factor is based on 26 SRUs. The SRUs on which the SRU NOx emissions factor is based include 22 SRUs with SCOT tail gas treatment units, 2 SRUs with Beavon tail gas treatment units, 1 SRU with a Sulften tail gas treatment unit, and 1 SRU with a Resulf tail gas treatment unit. The control devices in the data set include 26 SRUs with incinerators or thermal oxidizers.

Table 17. Analysis of Emissions Test Reports for NOx from SRUs (Sulfur Production Rate Basis)

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/ton sulfur	ITR
LA3C0610	Marathon Petroleum Company LLC, Garyville, Louisiana	SRU220 [b]	Thermal Oxidizer	M7E	0.32	50
LA3C0610	Marathon Petroleum Company LLC, Garyville, Louisiana	SRU234 [b]	Thermal Oxidizer	M7E	0.24	50
LA3C0630	Motiva Enterprises, Norco Refinery, Norco, Louisiana.	SRU S3 [a]	Incinerator	M7E	0.54	48
LA3C0650[a]	Valero Refining - New Orleans, LLC, St. Charles Refinery, Norco, Louisiana	SRU1600 [a]	Thermal Oxidizer	M7E	0.87	50
LA3C0650	Valero Refining - New Orleans, LLC, St. Charles Refinery, Norco, Louisiana	SRU30 [a]	Thermal Oxidizer	M7E	0.13	46
MS3C0740	ChevronTexaco Pascagoula Refinery, Pascagoula, Mississippi	SRU2 (F-2745) [a]	Thermal Oxidizer	M7E	0.23	47

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/ton sulfur	ITR
MS3C0740	ChevronTexaco Pascagoula Refinery, Pascagoula, Mississippi	SRU3 (F-2765) [a]	Thermal Oxidizer	M7E	0.13	47
OK2C0990	Total Petroleum, Inc. Ardmore Refinery - Ardmore, Oklahoma	SRU1 (500A) [a]	Incinerator	M7E	0.13	49
OK2C0990	Total Petroleum, Inc. Ardmore Refinery - Ardmore, Oklahoma	SRU2 (560A) [a]	Incinerator	M7E	0.30	48
TX3A1190	Delek Refining, LTD. Tyler Refinery, Tyler, Texas	SRU1/SRU2 TGI2	Incinerator	M7E	0.27	38
TX3A1230	ConocoPhillips Borger Petroleum Refinery, Borger, Hutchinson County, Texas	SRU34 [a]	Incinerator	M7E	0.32	50
TX3A1230	ConocoPhillips Borger Petroleum Refinery, Borger, Hutchinson County, Texas	SRU43 [a]	Incinerator	M7E	0.12	50
TX3A1300	Valero McKee Refinery, Sunray, Texas	EPN V-5 [Unit 820] [a]	Incinerator	M7E	0.27	54
TX3A1300 [e]	Valero McKee Refinery, Sunray, Texas	EPN V-16 [Unit 830] [a]	Incinerator	M7E	0.21	54
TX3A1300 [e]	Valero McKee Refinery, Sunray, Texas	EPN V-16 [Unit 830] [a]	Incinerator	M7E	0.17	54
TX3B1090	Total Petrochemicals USA, Inc., Port Arthur, Texas	SRU1&2 [a]	Incinerator	M7E	0.21	49
TX3B1110	BP Products North America Inc., Texas City, Texas	SRU [a]	Incinerator	M7E	0.21	48
TX3B1140	Valero Refining - Texas, L.P. East Plant of Bill Greehey Refinery, Corpus Christi, Texas	SRU1 [a]	Incinerator	M7E	0.25	52

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/ton sulfur	ITR
TX3B1140	Valero Refining - Texas, L.P. East Plant of Bill Greehey Refinery, Corpus Christi, Texas	SRU2 [a]	Incinerator	M7E	0.062	52
TX3B1220	Motiva Enterprises, LLC, Port Arthur, Texas	SRU2&3 [a]	Incinerator	M7E	0.13	52
TX3B1220	Motiva Enterprises, LLC, Port Arthur, Texas	SRU4 [a]	Incinerator	M7E	0.14	52
TX3B1240	ConocoPhillips Company, Sweeny Refinery, Old Ocean, Texas	EPN 28.2 [c]	Incinerator	M7E	0.20	45
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU543 [a]	Incinerator	M7E	0.085	56
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU544 [a]	Incinerator	M7E	0.12	52
TX3B1250	Valero Port Arthur Refinery, Port Arthur, Texas	SRU545 [a]	Incinerator	M7E	0.086	52
TX3B1310	Valero Refining, Bill Greehey Refinery - West Plant, Corpus Christi, Texas	SRU1&2Sulften [d]	Incinerator	M7E	0.093	44
TX3B1310	Valero Refining, Bill Greehey Refinery - West Plant, Corpus Christi, Texas	SRU3 [a]	Incinerator	M7E	0.22	56

[a] These SRUs are Claus units with SCOT tail gas treatment units.

[b] These SRUs are Claus units with Beavon tail gas treatment units.

[c] This SRU is a Claus unit with a Resulf tail gas treatment unit.

[d] These SRUs are Claus units Sulften tail gas treatment units.

[e] Data is for same unit from same test report. Separate sets of test runs occurred on multiple days and were reported separately.

3.6 Sulfur Recovery Units - THC

The available emissions test data from the 2011 Refinery ICR included multiple test reports for THC from SRU units. Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score.

3.6.1 Heat Rate Basis

An overview of the emissions factor using a heat rate basis is provided in Table 18.

Based on the emissions test report review and analysis, 9 emissions test reports for 10 emissions units had useable data and were included in the development of the emissions factor. The majority of the testing was conducted since 2005, although one test report is from 1996.

The emissions test reports used in the factor analysis are provided in Table 19. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_THC_SRU_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The ITR scores for these 9 test reports ranged from 4 to 44. The emissions data (lb THC [as propane]/hr) in these test reports are based on measurements taken with EPA Method 25A (M25A), and the test reports included heat rate data for the SRU in mmBtu/hr.

Certain test reports were excluded from the emissions factor analysis because heat rate data are not available, the concentration data for the test run average in the test report is a negative or zero value, or the test method was not compatible with THC measurements taken with M25A (i.e., M18 test reports and SCAQMD M25.3 test reports were excluded because these methods measure specific compounds where M25A counts total carbon).

EPA's recommended emissions factor development procedures were followed for the SRU THC data. EPA examined any population differences related to the process types and control devices. There are 8 SRUs that are Claus units with SCOT tail gas treatment units, and there are 2 SRUs that are Claus Units. While we are unsure whether the process type may affect emissions levels, each of the SRUs has combustion controls in place, and as such, the THC emissions from these units are expected to be similar. All ten of the SRU units have either an incinerator or a thermal oxidizer as the control device. Both incinerators and thermal oxidizers work on the same principles of combustion, and these terms are often used interchangeably by field staff. As such, there is no reason to believe that these control devices would have differing levels of THC emissions. Therefore, all of these units were combined for emissions factor development.

The statistical analysis for determining outliers in the data set was conducted, and one data value was found to be an outlier and was removed from the analysis. The emissions test that was an outlier had the highest average test result in the data set. The outlier test conducted on the remaining data set showed no additional outliers.

One of the last steps in developing an emissions factor is a comparison of the FQI for different units. In the development of the emissions factor for THC from SRUs, the FQI evaluation excluded two units from the data set (these two units have the lowest ITR scores), so the emissions factor is based on the emissions test data for 7 units and is characterized as Poorly Representative. The emissions factor analysis for SRU THC is provided in spreadsheet "EF Creation_THC_SRU_2015April_(Heat_Rate).xlsm".

Table 18. Overview of the Emissions Factor for THC from SRUs (Heat Rate Basis)

Emissions test data to use				
No. of test reports	No. of units	Test methods	AP-42 Emissions Factor	Representativeness
9	10 [a, b, c]	EPA Method 25A	1.4×10^{-3} lb THC [as propane]/mmBtu	Poorly

[a] One SRU was shown to be an outlier for the data set and was removed from the emissions factor analysis.

[b] Two SRUs were excluded from the data set based on the FQI evaluation.

[c] The final data set for the emissions factor is based on 7 SRUs. The SRUs on which the SRU THC emissions factor is based include 5 SRUs with SCOT tail gas treatment units and 2 SRUs with Claus units. The control devices in the data set include 7 SRUs with incinerators or thermal oxidizers.

Table 19. Analysis of Emissions Test Reports for THC from SRUs (Heat Rate Basis)

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb THC [as propane]/mmBtu	ITR
DE1A0360 [d]	Valero Delaware City Refinery, in Delaware City DE	28-SRU1 [a]	Thermal Oxidizer	M25A	2.6×10^{-4}	4
DE1A0360 [d]	Valero Delaware City Refinery, in Delaware City DE	28-SRU2 [a]	Thermal Oxidizer	M25A	4.6×10^{-4}	4
LA3C0650	Valero Refining - New Orleans, LLC in St. Charles Refinery in Norco, LA	SRU1600 [a]	Thermal Oxidizer	M25A	1.1×10^{-3}	34
OK2C0990	Total Petroleum, Inc. Ardmore Refinery, in Ardmore, Oklahoma	SRU500A [a]	Incinerator	M25A	1.1×10^{-3}	37
TX3B1110 [c]	BP Products North America Inc. in Texas City, TX	SRU [a]	Incinerator	M25A	1.4×10^{-1}	33
TX3B1220	Motiva Enterprises, LLC in Port Arthur, TX	SRU4 [a]	Incinerator	M25A	1.6×10^{-3}	44

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb THC [as propane]/mmBtu	ITR
TX3B1250	Valero Port Arthur Refinery in Port Arthur, TX	SRU544 [a]	Incinerator	M25A	8.9×10^{-4}	37
TX3B1320	Valero Refining, Houston Refinery, in Houston TX	SRU39 [b]	Incinerator	M25A	7.4×10^{-4}	42
TX3B1320	Valero Refining, Houston Refinery, in Houston TX	SRU46 [b]	Incinerator	M25A	3.0×10^{-3}	44
WA5A1410	Shell Puget Sound Refining Company, in Anacortes WA	SRU4 [a]	Incinerator	M25A	1.1×10^{-3}	41

[a] These SRUs are Claus units with SCOT tail gas treatment units.

[b] These SRUs are Claus units.

[c] These emissions units were shown to be outliers for the data set and were removed from the emissions factor analysis.

[d] This emissions unit was excluded from the data set based on the FQI evaluation.

3.6.2 Sulfur Production Rate basis

An overview of the emissions factor using a sulfur production basis is provided in Table 20.

Based on the emissions test report review and analysis, 7 emissions test reports for 7 emissions units had useable data and were included in the development of the emissions factor. One test report provides emissions test data for SRU that share a common stack. When emissions testing is conducted on more than one SRU that share a common stack, the emissions units are counted as one "unit"; the total emissions rate is divided by the total production rate of all SRU venting to the stack when developing the units' average test results. The majority of the testing was conducted since 2005, although one test report is from 1996.

The emissions test reports used in the factor analysis are provided in Table 21. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_THC_SRU_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The ITR scores for these 7 test reports ranged from 33 to 44. The emissions data (lb THC [as propane]/hr) in these test reports are based on measurements taken with EPA Method 25A (M25A), and the test reports included production rate data for the SRU in ton/hr sulfur production.

Certain test reports were excluded from the emissions factor analysis because production rate data are not available or the concentration data for the test run average in the test report is a negative or zero value.

EPA's recommended emissions factor development procedures were followed for the SRU THC data. All 7 SRU units are Claus units with SCOT tail gas treatment units, and all 7 SRUs have either an incinerator or a thermal oxidizer as the control device. Both incinerators and thermal oxidizers work on the same principles of combustion, and these terms are often used interchangeably by field staff. As such, there is no reason to believe that these control devices would have differing levels of THC emissions. Therefore, all of these units were combined for emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no data were found to be outliers. The emissions factor is based on the emissions test data for 7 units and is characterized as Poorly Representative. The emissions factor analysis for SRU THC is provided in spreadsheet "EF Creation_THC_SRU_2015April_(Sulf_Prod).xlsm".

Table 20. Overview of the Emissions Factor for THC from SRUs (Sulfur Production Rate Basis)

Emissions test data to use				
No. of test reports	**No. of units**	**Test methods**	**AP-42 Emissions Factor**	**Representativeness**
7	7 [a]	EPA Method 25A	4.0×10^{-2} lb THC [as propane]/ton sulfur	Poorly

[a] The final data set for the emissions factor is based on 7 SRUs. The SRUs on which the SRU THC emissions factor is based include 7 SRUs with SCOT tail gas treatment units. The control devices in the data set include 7 SRUs with incinerators or thermal oxidizers.

Table 21. Analysis of Emissions Test Reports for THC from SRUs (Sulfur Production Rate Basis)

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb THC [as propane]/ton sulfur	ITR
LA3C0650	Valero Refining - New Orleans, LLC at St. Charles Refinery in Norco, LA	SRU1600	Thermal Oxidizer	M25A	5.9×10^{-3}	34
OK2C0990	Total Petroleum, Inc. Ardmore Refinery - Ardmore, Oklahoma	SRU500A	Incinerator	M25A	1.9×10^{-3}	37
TX3B1090	Total Petrochemicals USA, Inc. in Port Arthur, TX	SRU1&2	Incinerator	M25A	8.2×10^{-2}	39
TX3B1110	BP Products North America Inc. in Texas City, TX	SRU	Incinerator	M25A	1.8×10^{-1}	33

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb THC [as propane]/ton sulfur	ITR
TX3B1220	Motiva Enterprises, LLC in Port Arthur, TX	SRU4	Incinerator	M25A	1.2×10^{-3}	44
TX3B1250	Valero Port Arthur Refinery in Port Arthur, TX	SRU544	Incinerator	M25A	7.4×10^{-3}	37
WA5A1410	Shell Puget Sound Refining Company, in Anacortes WA	SRU4	Incinerator	M25A	7.4×10^{-5}	41

3.7 Hydrogen Plants - CO

The available emissions test data from the 2011 Refinery ICR included multiple test reports for CO from Hydrogen Plants. Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score.

Based on the emissions test report review and analysis, 3 emissions test reports for 3 emissions units had useable data and were available for inclusion in development of an emissions factor. The emissions units for which emissions data are available include 2 condensate stripper vents (prior to returning water to the site feed water system) and 1 reformer furnace. The production data for these emissions units are not on the same basis. Hydrogen production data in scf/hr is available for 1 of the condensate stripper vents, and production data in the form of Methane Feed Rate in scf/hr are available for the other condensate stripper vent. For the reformer furnace, heat input rate is available as the process activity rate. Because these production data are not in comparable units and there is no way to calculate the production rate data on the same basis, these test reports could not be combined for emissions factor development. These useable emissions test reports are provided in Table 22. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_CO_H2P_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The emissions data (lb CO/hr) in these test reports are based on measurements taken with EPA Method 10 (M10).

Certain test reports were excluded from the emissions factor analysis because production rate data are not available or the concentration data for the test run average in the test report is a negative value.

Because the scope of this project is limited to data sets containing test averages from at least 3 emissions units and there are 2 emissions units with useable test reports for the condensate stripper vent and 1 reformer furnace with useable test data, but none of these units have production rate data on the same basis, an emissions factor was not developed for CO for Hydrogen Plants.

Table 22. Analysis of Emissions Test Reports for CO from H_2 Plants

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results	ITR
Condensate stripper vent						
AR3D0110	Lion Oil Company in El Dorado, AR	Condensate stripper vent (prior to boiler water feed system)	None	M10	0.48 lb CO/MMscf H2 Production	22
NJ1A0850	ConocoPhillips Company Bayway Refinery, ConocoPhillips Company in Linden, NJ	Condensate stripper vent (prior to boiler water feed system)	None	M10	0.0011 lb CO/scf methane process feed	36
Reformer						
CO4A0340	Suncor Energy, Commerce City Refinery, Commerce City, Colorado	Plant 1 Hydrogen Furnace stack	None	M10	0.00077 lb CO/MMBtu	31

3.8 Hydrogen Plants - NOx

The available emissions test data from the 2011 Refinery ICR included multiple test reports for NOx from Hydrogen Plant units. Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score. An overview of the emissions factor is provided in Table 23.

Based on the emissions test report review and analysis, 7 emissions test reports for 7 emissions units had useable data and were included in the development of the emissions factor. The emissions test reports used in the factor analysis are provided in Table 24. A complete list of the available test report information is provided in worksheet "Test_Data_Sum_NOx_H2P_2015April.xlsm". For more detail on the analysis and QA conducted, see the field "QA Notes" for each test report. The ITR scores for these 7 test reports ranged from 23 to 52. The emissions data (lb NOx/hr) in these test reports are based on measurements taken with EPA Method 7E (M7E), and the test reports included activity rate data for the Hydrogen Plant in MMBtu/hr heat input.

Certain test reports were excluded from the emissions factor analysis because heat input data are not available or the emissions unit did not have controls consistent with the other units (e.g., 1 emissions units had ultra-low NOx burners, and 1 emissions unit had selective catalytic reductions controls).

EPA's recommended emissions factor development procedures were followed for the Hydrogen Plant NOx data. None of the 7 units have controls for NOx, and all were combined for emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no data were found to be outliers.

One of the last steps in developing an emissions factor is a comparison of the Factor Quality Index (FQI) for different units. The FQI is an indicator of the emissions factor's ability to estimate emissions for the entire national population, and it is related to both the ITR score and the number of units in the data set. Once the statistical procedures are complete, the data set is ranked by ITR score (high to low), and a FQI is developed for each unit in the candidate set. The FQI should decrease with each emissions unit. When the FQI increases, only average test values above the point where the FQI increases should be considered in the factor development. In the development of the emissions factor for NOx from Hydrogen Plants, the FQI evaluation excluded one unit from the data set, so the emissions factor is based on the emissions test data for 6 units and is characterized as Poorly Representative. The emissions factor analysis for NOx from Hydrogen Plants is provided in spreadsheet "EF Creation_NOx_H2P_2015April.xlsm".

Table 23. Overview of the Emissions Factor for NOx from Hydrogen Plants

Emissions test data to use				
No. of test reports	No. of units	Test methods	AP-42 Emissions Factor	Representativeness
7	7 [a]	EPA Method 7E	8.1×10^{-2} lb NOx/mmBtu	Poorly

[a] One Hydrogen Plant was excluded from the data set based on the FQI evaluation.

[b] The 6 Hydrogen Plants on which the Hydrogen Plant NOx emissions factor is based are all uncontrolled for NOx.

Table 24. Analysis of Emissions Test Reports for NOx from Hydrogen Plants

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/mmBtu	ITR
AL3D0020 (2007 test) [a]	Hunt Refining, Tuscaloosa, Alabama	Reformers A, B, and C	None	M7E	0.016	23
AL3D0020 (2010 test)	Hunt Refining, Tuscaloosa, Alabama	No. 2 Hydrogen Plant Reformer - indirect heaters	None	M7E	0.016	38
IL2A0430	ConocoPhillips Company , Wood River Refinery Hydrogen Plant in Roxana, Illinois	Hydrogen Plant 1	None	M7E	0.041	45
MT4A0790	ExxonMobil Billings Refinery, Billings, Montana	F-551 Hydrogen Plant Process Heater/Furnace	None	M7E	0.17	45

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results, lb NOx/mmBtu	ITR
OH2A0910	BP Husky Refining LLC, Toledo, OH	Hydrogen Furnace	None	M7E	0.090	52
MT4A0800 (2008 test)	Montana Refining Company, Great Falls, Montana	Hydrogen Plant Reformer Heater H1810	None	M7E	0.11	51
CO4A0340	Suncor Energy Inc. Commerce City Refinery, Commerce City, Colorado	H-2101	None	M7E	0.052	31

[a] This facility was excluded from the data set during the emissions factor analysis.

3.9 Hydrogen Plants - THC

The available emissions test data from the 2011 Refinery ICR included multiple test reports for THC from Hydrogen Plant units. Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports included in the emissions factor analysis, given an ITR score.

Based on the emissions test report review and analysis, 3 emissions test reports for 3 emissions units had useable data and were available for inclusion in development of an emissions factor. The emissions units for which emissions data are available include 2 condensate stripper vents (prior to returning water to the site feed water system) and 1 reformer furnace. The production data for these emissions units are not on the same basis. Hydrogen production data in scf/hr is available for 1 of the condensate stripper vents, and production data in the form of Methane Feed Rate in scf/hr are available for the other condensate striper vent. For the reformer furnace, heat input rate is available as the process activity rate. Because these production data are not in comparable units and there is no way to calculate the production rate data on the same basis, these test reports could not be combined for emissions factor development. These useable emissions test reports are provided in Table 25. A complete list of the available test report information is provided in worksheet “Test_Data_Sum_THC_H2Plants_2015April.xlsm”. For more detail on the analysis and QA conducted, see the field “QA Notes” for each test report. The emissions data (lb THC [as propane]/hr) in these test reports are based on measurements taken with EPA Method 25A (M25A).

Certain test reports were excluded from the emissions factor analysis for the following reasons: production rate data were not available or the test method was not compatible with THC measurements taken with M25A (i.e., M18 test reports, SCAQMD M25.3, or BAAQMD Method ST-32 test reports were excluded because these methods measure specific compounds where M25A counts total carbon).

Because the scope of this project is limited to data sets containing test averages from at least 3 emissions units and because there are 2 emissions units with useable test reports for the condensate stripper vent and 1 reformer furnace with useable test data, but none of these units have production rate data on the same basis, an emissions factor was not developed for THC from Hydrogen Plants.

Table 25. Analysis of Emissions Test Reports for THC from Hydrogen Plants

Facility ID No.	Facility name	Emissions unit	APCD	Test method	Average test results	ITR
Condensate stripper vent						
AR3D0110	Lion Oil Company, El Dorado, AR	Condensate stripper vent (prior to boiler water feed system)	None	M25A	1.1 lb THC [as propane]/MMscf H_2 product	13
NJ1A0850	ConocoPhillips Company Bayway Refinery, ConocoPhillips Company, Linden, NJ	Condensate stripper vent (prior to boiler water feed system)	None	M25A	0.0035 lb THC [as propane]/scf methane process feed	36
Reformer						
AL3D0020	Hunt Refining in Tuscaloosa, AL	Reformer	None	M25A	0.00046 lb THC/MMBtu	15

Section 4
Discussion of Revisions to SO_2 Emissions Factors in AP-42 Section 8.13, Sulfur Recovery

In addition to adding new emissions factors for sulfur recovery plants, as described in sections 3.4, 3.5, and 3.6 for CO, NOx, and THC, respectively, revisions were made to the SO_2 emissions factors presented in the 1993 version of Table 8.13-1 in Section 8.13 of AP-42. The previous emissions factors were based on assumed average sulfur recovery efficiencies instead of on a statistical evaluation of measured emissions data. While this approach is technically sound, the previous emissions factors did not appear to be consistent with current sulfur recovery plant performance data because mid-range values were used rather than developing a more statistically-based approach. The 1993 background document for AP-42 section 8.13[2] presents test data for 16 sulfur recovery plants. Nine of the 16 plants had SO_2 emissions of approximately 2 kg/Mg sulfur produced, but the smallest emissions factor in the 1993 version of Table 8.13-1 was 29 kg/Mg. The footnotes to Table 8.13-1 indicated that test data for 2-staged "controlled" units showed 98.3 to 98.8 percent sulfur recovery and that 3-staged "controlled" units showed 95 to 99.9 percent sulfur recovery; using the mid-range value, the 2-staged controlled units have the lowest emissions factor (29 kg/Mg versus 65 kg/Mg). From review of the background document, it is unclear how these ranges were determined unless incineration was considered an SO_2 control (in which case all units tested had "controls"). The data presented in the background document show that the highest average run data for a sulfur recovery plant with a tailgas cleanup unit was 7.8 kg/Mg, so that the lowest "controlled" emissions factor in Table 8.13-1 is roughly 4 times the highest emissions results from a Claus unit with tailgas cleanup. Thus, the "controlled" emissions factors in Table 8.13-1 do not appear to be representative of the Claus sulfur recovery plants with tail gas clean-up.

Due to the issues identified with the previous version of Table 8.13-1, revisions were made to the table to more accurately present emissions factors for different types of sulfur recovery plants based on specific source classification codes (SCCs), which include the expected sulfur recovery efficiencies for those sulfur recovery plants. Revisions were also made for the discussion of tailgas "controls" to more clearly distinguish between tailgas treatment units, which enhance sulfur recovery efficiencies, and incineration, which merely converts reduced sulfur compounds to SO_2.

The revisions to the emissions factors in Table 8.13-1 are still based on a mass balance approach assuming that all sulfur not recovered is emitted as SO_2. The emissions factors in Table 8.13-1 are applicable to sulfur recovery plants that are followed by a thermal oxidizer, incinerator, or other oxidative control system in which hydrogen sulfide or other reduced sulfur compounds in the tailgas can be converted to SO_2 prior to atmospheric release. Revisions were made to the Title of Table 8.13-1 to clarify this applicability. The new title for Table 8.13-1 is

[2] The 1993 background document for sulfur recovery is entitled "Background Report, AP-42 Section 5.18, Sulfur Recovery." With the publication of the Fifth Edition of AP-42, the Chapter and Section number for Sulfur Recovery changed to 8.13.

“SO_2 EMISSION FACTORS FOR CLAUS SULFUR RECOVERY PLANTS WITH OXIDATIVE CONTROL SYSTEMS.”

Additionally, Table 8.13-1 did not previously provide applicable SCCs for the sulfur recovery plants described in the table, and the footnote showing the calculation of the emissions factor was incorrectly presented. Therefore, the new version of Section 8.13 has been updated to specify applicable SCCs and to correct the footnote equations in Table 8.13-1.

Section 5
Emissions Factor Development for Industrial Flares

EPA has reviewed the emissions test data in recent flare studies. Several of these test reports are based on studies that resulted from various enforcement actions related to flare performance issues. The EPA collected additional flare data during development of an analysis of proper flare operating conditions (EPA 2012). We obtained data from a DIAL study in the Houston area in which the emissions from several flares were isolated. We also used the original flare report from which the previous set of flare emissions factors was created. The emissions data review and the emissions factor development for each pollutant are described below.

5.1 Flares - CO

The available emissions test data included multiple test reports for CO from flares. [Additional discussion of these test reports is included in EPA's Review of Available Documents Report (EPA, 2015a).] Each of the available test reports was reviewed, analyzed, and summarized, and given an ITR score. An overview of the emissions factor is provided in Table 26.

Based on the emissions test report review and analysis, 6 emissions test reports for 8 flares had useable data and were included in the development of the emissions factor. The flares tested include 7 steam-assisted flares and one air-assisted flare. The test data are based on the measurement principle of passive Fourier Transform infrared (PFTIR). The emissions data for flares consisted of 1-minute CO concentration-pathlength (ppm-m) data for approximately 10 to 15 test runs for each flare. Each test run was approximately 15 to 20 minutes in duration. Data was reviewed on a run average basis. We used the averages of the data provided by the facility when they were available and calculated the averages from the minute data when the averages were not provided.

The mass emissions of CO were calculated using a carbon balance, where the overall equation is as follows:

$$E_{CO} = C\_inlet \times \frac{[CO]}{[CO_2]} \times CE \times \frac{28}{12}$$

Where:

E_{CO} = emissions rate of carbon monoxide (lbs/hr).

C_inlet= mass flow of carbon in the flare vent gas sent to the flare (lb/hr).

[CO] = PFTIR measured CO concentration (ppm-m).

$[CO_2]$ = PFTIR measured CO_2 concentration (ppm-m).

CE = Measured flare combustion efficiency[3].

28 = molecular weight of carbon monoxide (lb/lb-mole).

12 = molecular weight of carbon (lb/lb-mole).

C_inlet was determined based on the standard flow rate of the vent gas and the carbon constituents of the vent gas. C_inlet was calculated as follows:

$$\text{C\_inlet} = Q_{fg} \times \frac{12}{MVC} \times \sum_{x=1}^{y} \left(MF_x \times CMN_x \right)$$

Where:

C_inlet= mass flow of carbon in the flare vent gas sent to the flare (lb/hr).

Q_{fg} = volumetric flow rate of flare vent gas (standard cubic feet per hour; scf/hr).

12 = molecular weight of carbon (lb/lb-mole).

MVC = molar volume correction factor (scf/lb-mole) = 385.5 scf/lb-mole at 68 ºF and 1 atmosphere pressure.

MF_x = mole fraction of compound "x" in the flare vent gas (mole compound per mole vent gas)[4].

CMN_x = carbon mole number of compound "x" in the flare vent gas (mole carbon atoms per mole compound), e.g., CMN for ethane (C_2H_6) is 2; CMN for propane (C_3H_8) is 3.

12 = molecular weight of carbon (lb/lb-mole).

When performing the calculations, C_inlet was initially used to calculate an apparent pathlength exhaust gas flow rate based on the CO_2 pathlength concentration and combustion efficiency as follow:

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[3] We used the weighted combustion efficiency in the calculations. If the raw data only provided one CE instead of providing both a weighted and unweighted CE, we assumed that the provided CE was the weighted CE. We note that in the calculation of the weighted combustion efficiency, two test reports inadvertently weighted acetylene incorrectly. Acetylene has two carbon atoms, but the calculation indicated that there are three. We analyzed what effect this has on the data, and we determined that this error resulted in a change in the CE of less than a tenth of a percent on average.

[4] Generally the mole percent is provided in the spreadsheets. In the spreadsheet calculation, the mole percent is divided by 100 to get the mole fraction.

$$Q_{exhaust} = C\_inlet \times \frac{MVC}{12} \times \frac{CE \times 10^6}{[CO_2]}$$

Where:

$Q_{exhaust}$ = exhaust gas flow rate in flare exhaust-pathlength (scf/hr-m).

C_inlet = mass flow of carbon in the flare vent gas sent to the flare (lb/hr)[5].

MVC = molar volume correction factor (scf/lb-mole) = 385.5 scf/lb-mole at 68 ºF and 1 atmosphere pressure.

12 = molecular weight of carbon, lb/lb-mol.

CE = measured flare combustion efficiency.

10^6 = parts in one-million parts.

$[CO_2]$ = PFTIR measured CO_2 concentration (ppm-m)[6].

The apparent pathlength exhaust gas flow rate was then used to calculate a mass flow rate of each pollutant. For CO, the mass flow rate is calculated from the pathlength exhaust gas flow rate as follows:

$$E_{CO} = Q_{exhaust} \times \frac{[CO]}{10^6} \times \frac{28}{MVC}$$

Where:

E_{CO} = emissions rate of carbon monoxide (lbs/hr).

$Q_{exhaust}$ = exhaust gas flow rate in flare exhaust-pathlength (scf/hr-m).

[CO] = PFTIR measured CO concentration (ppm-m).

10^6 = parts in one-million parts[7].

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[5] Conservation of Mass dictates that mass can neither be created nor destroyed. As such, the mass flow inlet of carbon is equal to the emission rate of carbon.

[6] In the spreadsheet calculations, the term total carbon (in ppm-m) represents the $[CO_2]$ divided by the CE. Combustion efficiency is the amount of initial carbon that becomes carbon dioxide. The total carbon term back calculates the available carbon in the system in ppm-m. Dividing the total carbon term by one million inserts volumetric concentration into the equation, i.e. standard cubic feet of carbon per standard cubic feet of exhaust gas.

[7] By dividing the PFTIR measurement by one million, we have inserted volumetric concentration into the equation, i.e. standard cubic feet of CO per standard cubic feet of exhaust gas.

28 = molecular weight of carbon monoxide, lb/lb-mol.

MVC = molar volume correction factor (scf/lb-mole) = 385.5 scf/lb-mole at 68 ºF and 1 atmosphere pressure.

Substituting the equation for $Q_{exhaust}$ in the above equations, the 10^6 and MVC conversion factors cancel out, yielding the overall equation. We divided the mass emissions rate by the vent gas heat rate (obtained using information provided by the facility on vent gas flow rate and vent gas net heating value) to arrive at the CO emissions rate in lb/MMBtu.

Because the flare testing was conducted to identify conditions where flare performance deteriorates, there were many test runs conducted at operating conditions that resulted in poor flare combustion efficiencies. These operating conditions are not representative of normal flare performance, and including all of these test runs would skew the data in a way that is unrepresentative of normal operating conditions. Properly operated flares achieve at least 98 percent destruction efficiency in the flare plume. The EPA has set out requirements for flare operation in the General Provisions of 40 CFR Parts 60 and 63[8]. Flares that meet the requirements of the General Provisions are assumed to achieve 98% destruction efficiency. As such, we eliminated any runs where the flare vent gas net heating values were below 300 Btu/scf, and we ensured that the flare tip velocity was below the maximum allowed by the General Provisions. For the PFTIR study data, the run average data were reviewed to determine if the combustion efficiency was less than 96.5 percent (considered to be equivalent to a destruction efficiency of 98 percent) (EPA, 2012). Any data that did not meet this combustion efficiency was excluded from the analysis. Any run with an average reported CO_2 value of 0 was also removed from the data set because the calculation for CO emissions is dependent on knowing the concentration of CO_2. All remaining average run data for a given flare were used to calculate an average emissions value (in CO mass per heat input of vent gas) for the flare.

Some test reports included multiple values for CO_2 measurements. These measurements represent the CO_2 values determined by the PFTIR operator at up to three different wavelengths (765, 1k, and 2k). The preferred wavelength is determined by the spectroscopist at the time of testing. We obtained the preferred CO_2 wavelength for each study (see Appendix C), and the CO_2 pathlength concentration for that wavelength was used in the calculation of the emissions factor. If only one CO_2 band was available in the raw data, we assumed that it was the band identified by the spectroscopist as the appropriate band for that test.

The emissions test reports used in the factor analysis are provided in Table 27. The available data from each test report included in the emissions factor analysis is provided in worksheet "Flare Calculation.xlsx". The ITR scores for these 7 test reports ranged from 38 to

[8] We note that the proposed Refinery NESHAP rulemaking and the EPA Peer Review Study (EPA 2012) have indicated that certain flares need to monitor additional parameters in order to ensure 98% destruction efficiency. However, it is still the EPA's position that a properly operated flare will achieve 98% destruction efficiency. The comments received on this rulemaking are still under consideration. Additionally, this factor applies to flares outside of the refining industry. We have not determined at this time that it is necessary for other sectors to monitor additional operating parameters in order to ensure 98% destruction efficiency. As such, we believe that it is appropriate to base the emissions factor on the requirements of the General Provisions.

52. The emissions data (ppm-m CO) in these test reports are based on measurements taken with passive FTIR, and the activity rate data in the test reports included flare vent gas flow rates and compositions, from which C_inlet (lb C/hr) and the net heat input (MMBtu/hr) to the flare could be calculated.

EPA's recommended emissions factor development procedures include guidelines for the inclusion of previous emissions data when existing emissions factors are revised. The existing data should be included alongside the new data prior to running any statistical tests. The ITR score for the existing data is based on the letter-rating of the data. There was an existing AP-42 emissions factor for CO emissions from flares (see AP-42 section 13.5), and so the emissions factor analysis included the existing CO emissions data. Per the EPA's recommended emissions factor development procedures, since the previous factor was B-rated, an ITR score of 80 was assigned to the existing data. Per the factor development procedures, the existing factor was divided into individual source tests. The existing CO emissions factor was based on data from two different sources, an air-assisted flare and a steam-assisted flare. We calculated the factor for each of these flare using the original data. This calculation is also included in worksheet "Flare Calculation.xlsx". Additionally, to be consistent with the conventions used for the PFTIR data, we limited the data to times when the flares were meeting the requirements of the General Provisions and 96.5 percent combustion efficiency. We note that these tests were also conducted with many runs purposely at deteriorating conditions and including all of these test runs would skew the data in a way that is unrepresentative of normal operating conditions

EPA's recommended emissions factor development procedures were followed for the flare CO data. Potential subcategories were considered for the flare emissions data based on the type of flare. With respect to flare type, because there are 7 steam-assisted flares and only 1 air-assisted flare and the statistical analysis for determining whether the data are part of the same population requires at least 3 emissions units in each category, the statistical analysis for subcategorization could not be performed. However, since the current AP-42 emissions factors are based on emissions from both air-assisted and steam-assisted flares, it is appropriate to combine the emissions from both types of flares for this analysis as well. All 8 units from flare test reports under the current analysis were combined for emissions factor development, along with the existing flare emissions data in AP-42. The statistical analysis for determining outliers in the data set was conducted, and no data were shown to be an outlier. The emissions factor is based on 10 flares and is characterized as Poorly Representative. The spreadsheet "EF Creation_CO_flare_2015April.xlsm" provides the analysis for the emissions factor for CO emissions from flares.

Table 26. Overview of the Emissions Factor for CO from Flares

Emissions test data to use				
No. of test reports	No. of units	Test methods	AP-42 Emissions Factor	Representativeness
7	10 [a]	(Measurement technique is Passive FTIR)	0.31 lb CO/MMBtu	Moderately

[a] The flare CO emissions factor is based on 8 steam-assisted flares and 2 air-assisted flares.

Table 27. Analysis of Emissions Test Reports for CO from Flares

Facility ID No.	Facility name	Emissions unit	Test method	Average test results, lb CO/MMBtu	ITR
FHR	FHRAU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	Flare AU (steam-assisted)	PFTIR	0.12	38
FHR	FHRLOU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	Flare LOU (steam-assisted)	PFTIR	0.13	38
MI2A0710	MPCDET Marathon Petroleum Company, LLC, Detroit, MI	Flare CP (steam-assisted)	PFTIR	0.78	51
TX3B1210	MPCTX Marathon Petroleum Company, LLC, Texas Refining Division in Texas City, TX	Flare Main (steam-assisted)	PFTIR	0.30	51
INEOS	INEOS INEOS ABS Corporation in Addyston, OH	Flare P001 (steam-assisted)	PFTIR	0.55	38
TX3B1260	SHELL Shell Deer Park Refinery in Deer Park, TX	Flare EP (steam-assisted)	PFTIR	0.37	41
NA	TCEQ testing conducted at John Zink facility	Flare (steam-assisted)	PFTIR	0.41	52
NA	TCEQ testing conducted at John Zink facility	Flare (air-assisted)	PFTIR	0.43	52
NA	Existing AP-42 CO emissions factor steam flare	Flare (steam-assisted)	Extractive sampling	0.040	80
NA	Existing AP-42 CO emissions factor air flare	Flare (air-assisted)	Extractive sampling	0.012	80

5.2 Flares – VOC

The available emissions test data included multiple test reports for VOC related data from flares. [Additional discussion of these test reports is included in EPA's Review of Available Documents Report (EPA, 2015a).] Each of the available test reports was reviewed, analyzed, and summarized, and for those test reports that are to be included in the emissions factor analysis, given an ITR score. An overview of the emissions factor is provided in Table 28.

Based on the emissions test report review and analysis, 7 emissions test reports for 10 flares had useable data and were included in the development of the emissions factor. The flares tested include 9 steam-assisted flares and one air-assisted flare. The PFTIR emissions data for flares consisted of 1-minute THC and individual hydrocarbon concentration-pathlength (ppm-m) data for approximately 10 to 15 test runs for each flare. Each test run was approximately 15 to 20 minutes in duration. The DIAL data for flares consisted of multiple scans directly measuring the mass emissions of C3+ hydrocarbons. As the mass emissions of "C3+ hydrocarbons" was directly reported in the DIAL study, only the heat input to the flare had to be calculated. Data on vent gas composition and flow rate were available to perform this calculation.

The overall calculation of the mass emissions of VOC from the PFTIR tests were calculated as follows. Any measurement data for methane and ethane were excluded from the VOC calculation:

$$E_{VOC} = C\_inlet \times \frac{\sum_{x} [HCx] \times MW_{HCx}}{[CO_2] \times 12} \times CE$$

Where:

E_{VOC} = emissions rate of volatile organic compounds (lbs/hr).

C_inlet = mass flow of carbon in the flare vent gas sent to the flare (lb/hr).

[HCx] = PFTIR measured hydrocarbon constituent "x" concentration (other than methane or ethane) (ppm-m).

MW_{HCx} = molecular weight of hydrocarbon constituent "x" (lb/lb-mole).

$[CO_2]$ = PFTIR measured CO_2 concentration (ppm-m).

12 = molecular weight of carbon (lb/lb-mole).

CE = Measured flare combustion efficiency[9].

[9] We used the weighted combustion efficiency in the calculations. If the raw data only provided one CE instead of providing both a weighted and unweighted CE, we assumed that the provided CE was the weighted CE. We note that in the calculation of the weighted combustion efficiency, two test reports inadvertently weighted acetylene incorrectly. Acetylene has two carbon atoms, but the calculation indicated that there are three. We analyzed what

C_inlet was determined based on the standard flow rate of the vent gas and the carbon constituents of the vent gas. C_inlet was calculated as follows:

$$\text{C\_inlet} = Q_{fg} \times \frac{12}{MVC} \times \sum_{x=1}^{y} \left(MF_x \times CMN_x \right)$$

Where:

C_inlet= mass flow of carbon in the flare vent gas sent to the flare (lb/hr).

Q_{fg} = volumetric flow rate of flare vent gas (standard cubic feet per hour; scf/hr).

12 = molecular weight of carbon (lb/lb-mole).

MVC = molar volume correction factor (scf/lb-mole) = 385.5 scf/lb-mole at 68 ºF and 1 atmosphere pressure.

MF_x = mole fraction of compound "x" in the flare vent gas (mole compound per mole vent gas)[10].

CMN_x = carbon mole number of compound "x" in the flare vent gas (mole carbon atoms per mole compound), e.g., CMN for ethane (C_2H_6) is 2; CMN for propane (C_3H_8) is 3.

12 = molecular weight of carbon (lb/lb-mole).

As described in Section 5.1 of this report, the calculation of pollutant mass emissions were calculated by first determining an apparent pathlength exhaust gas flow rate and then the pollutant mass emissions rate. The apparent pathlength exhaust gas flow rate was calculated as follow:

$$Q_{exhaust} = \text{C\_inlet} \times \frac{MVC}{12} \times \frac{CE \times 10^6}{[CO_2]}$$

Where:

$Q_{exhaust}$ = exhaust gas flow rate in flare exhaust-pathlength (scf/hr-m).

C_inlet = mass flow of carbon in the flare vent gas sent to the flare (lb/hr)[11].

effect this has on the data, and we determined that this error resulted in a change in the CE of less than a tenth of a percent on average.

[10] Generally the mole percent is provided in the spreadsheets. In the spreadsheet calculation, the mole percent is divided by 100 to get the mole fraction.

MVC = molar volume correction factor (scf/lb-mole) = 385.5 scf/lb-mole at 68 ºF and 1 atmosphere pressure.

12 = molecular weight of carbon, lb/lb-mol.

CE = measured flare combustion efficiency.

10^6 = parts in one-million parts.

$[CO_2]$ = PFTIR measured CO_2 concentration (ppm-m)[12].

The apparent pathlength exhaust gas flow rate was then used to calculate a mass flow rate of each hydrocarbon pollutant as follows:

$$E_{HCx} = Q_{exhaust} \times \frac{[HCx]}{10^6} \times \frac{MW_{HCx}}{MVC}$$

Where:

E_{HCx} = emissions rate of hydrocarbon "x" (lbs/hr).

$Q_{exhaust}$ = exhaust gas flow rate in flare exhaust-pathlength (scf/hr-m).

[HCx] = PFTIR measured concentration for hydrocarbon "x" (ppm-m).

10^6 = parts in one-million parts[13].

MW_{HCx} = molecular weight of hydrocarbon "x", lb/lb-mol.

MVC = molar volume correction factor (scf/lb-mole) = 385.5 scf/lb-mole at 68 ºF and 1 atmosphere pressure.

The mass emissions of each of the VOC hydrocarbons was then summed to calculate the total VOC emissions. Substituting the equation for $Q_{exhaust}$ in the above equations, the 10^6 and MVC conversion factors cancel out, and the summation yields the overall equation. We divided the mass emissions rate by the vent gas heat rate (obtained using information provided by the

[11] Conservation of Mass dictates that mass can neither be created nor destroyed. As such, the mass flow inlet of carbon is equal to the emission rate of carbon.

[12] In the spreadsheet calculations, the term total carbon (in ppm-m) represents the $[CO_2]$ divided by the CE. Combustion efficiency is the amount of initial carbon that becomes carbon dioxide. The total carbon term back calculates the available carbon in the system in ppm-m. Dividing the total carbon term by one million inserts volumetric concentration into the equation, i.e. standard cubic feet of carbon per standard cubic feet of exhaust gas.

[13] By dividing the PFTIR measurement by one million, we have inserted volumetric concentration into the equation, i.e. standard cubic feet of HC_x per standard cubic feet of exhaust gas.

facility on vent gas flow rate and vent gas net heating value) to arrive at the VOC emissions rate in lb/MMBtu.

Because the flare testing was conducted to identify conditions where flare performance deteriorates, there were many test runs conducted at operating conditions that resulted in poor flare combustion efficiencies. These operating conditions are not representative of normal flare performance, and including all of these test runs would skew the data in a way that is unrepresentative of normal operating conditions. Properly operated flares achieve at least 98 percent destruction efficiency in the flare plume. The EPA has set out requirements for flare operation in the General Provisions of 40 CFR Parts 60 and 63[14]. Flares that meet the requirements of the General Provisions are assumed to achieve 98% destruction efficiency. As such, we eliminated any runs where the flare vent gas net heating values were below 300 Btu/scf, and we ensured that the flare tip velocity was below the maximum allowed by the General Provisions. For the PFTIR study data, the run average data were reviewed to determine if the combustion efficiency was less than 96.5 percent (considered to be equivalent to a destruction efficiency of 98 percent) (EPA, 2012). Any data that did not meet this combustion efficiency was excluded from the analysis. Any run with an average reported CO_2 value of 0 was also removed from the data set because the calculation for CO emissions is dependent on knowing the concentration of CO_2. All remaining average run data for a given flare were used to calculate an average emissions value (in CO mass per heat input of vent gas) for the flare.

Some test reports included multiple values for CO_2 measurements. These measurements represent the CO_2 values determined by the PFTIR operator at up to three different wavelengths (765, 1k, and 2k). The preferred wavelength is determined by the spectroscopist at the time of testing. We obtained the preferred CO_2 wavelength for each study (see Appendix C), and the CO_2 pathlength concentration for that wavelength was used in the calculation of the emissions factor. If only one CO_2 band was available in the raw data, we assumed that it was the band identified by the spectroscopist as the appropriate band for that test.

For the DIAL study included in the emissions factor development, the emissions from three flares are represented. Flare 6 was isolated, but the ULC and temporary flare emissions were contained in the same measurement scans. We treated these two flares as one flare system and divided the total emissions by the combined heat rate of the two flares. Additionally, the DIAL report indicated that on the third day of testing, the flare system did not meet the minimum destruction efficiency of 98%. Based on a review of the data, the ULC flare was achieving a much lower destruction efficiency than the temporary flare. While this was the case on all three days, it was only on the third day that the combined destruction efficiency of the system was

[14] We note that the proposed Refinery NESHAP rulemaking and the EPA Peer Review Study (EPA 2012) have indicated that certain flares need to monitor additional parameters in order to ensure 98% destruction efficiency. However, it is still the EPA's position that a properly operated flare will achieve 98% destruction efficiency. The comments received on this rulemaking are still under consideration. Additionally, this factor applies to flares outside of the refining industry. We have not determined at this time that it is necessary for other sectors to monitor additional operating parameters in order to ensure 98% destruction efficiency. As such, we believe that it is appropriate to base the emissions factor on the requirements of the General Provisions.

below 98%. We believe that this was caused by poor operation of the ULC flare, possibly over-steaming, and as such, we have not included the third day of data in the analysis.

During the DIAL study, process data was recorded once an hour. DIAL scans were not taken on a regular time interval. In order to match up the process data to the DIAL data we used the following convention: if the DIAL scan was recorded in the first twenty minutes of an hour, we used the process data for that hour; if the DIAL scan was recorded in the last twenty minutes of an hour, we used the process data for the next hour; and if the DIAL scan was recorded in the middle twenty minutes of an hour, we averaged the process data for that hour and the next hour.

The TCEQ report contained data for both extractive and PFTIR testing. We were able to locate the data for the extractive testing in the appendices, and we combined this with process data that we had already obtained with the PFTIR results. Because the extractive and PFTIR testing was performed simultaneously, we averaged the results of the tests per flare. This is consistent with how we handle multiple tests for one source in our emissions factor development procedures. Overall, we found that the extractive testing and PFTIR testing agreed fairly well.

The emissions test reports used in the factor analysis are provided in Table 29. The available data from each test report included in the emissions factor analysis is provided in worksheet "Flare Calculation.xlsx". The ITR scores for these 7 test reports ranged from 38 to 52. The emissions data (ppm-m or lb/hr) in these test reports were based on measurements taken with passive FTIR, extractive sampling and DIAL, and the activity rate data in the test reports which included flare vent gas flow rates and compositions, from which C_inlet (lb C/hr) and the net heat input (MMBtu/hr) to the flare could be calculated.

In the existing AP-42 section for Industrial Flares, there is an emissions factor for THC (measured as methane equivalent), but there was no previous emissions factor for VOC. Even though THC is often used as a surrogate for VOC, the measurement methods for the two compounds vary. In this case, the measurements for THC and VOC are not directly comparable. As such, there is no existing emissions factor from AP-42 included in this emissions factor analysis.

EPA's recommended emissions factor development procedures were followed for the flare VOC data. Potential subcategories were considered for the flare emissions data based on the type of flare. With respect to flare type, because there are 9 steam-assisted flares and only 1 air-assisted flare and the statistical analysis for determining whether the data are part of the same population requires at least 3 emissions units in each category, the statistical analysis for subcategorization could not be performed. However, since the current AP-42 emissions factors are based on emissions from both air-assisted and steam-assisted flares, it is appropriate to combine the emissions from both types of flares for this analysis as well. All 10 units from flare test reports under the current analysis were combined for emissions factor development. The statistical analysis for determining outliers in the data set was conducted, and no data were shown to be outliers. The emissions factor is based on the emissions test data for 10 units and is characterized as Poorly Representative. The spreadsheet "EF Creation_VOC_flare_2015April.xlsm." provides the analysis for the emissions factor for VOC emissions from flares.

Table 28. Overview of the Emissions Factor for VOC from Flares

Emissions test data to use		Test methods	Proposed AP-42 Emissions Factor	Representativeness
No. of test reports	No. of units			
7	10 [a]	(Measurement technique is Passive FTIR, extractive sampling and DIAL)	0.57 lb VOC/MMBtu	Poorly

[a] The flare VOC emissions factor is based on 9 steam-assisted flares and 1 air-assisted flare.

Table 29. Analysis of Emissions Test Reports for VOC from Flares

Facility ID No.	Facility name	Emissions unit	Test method	Average test results, lb VOC/MMBtu	ITR
FHR	FHRAU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	Flare AU (steam-assisted)	PFTIR	0.50	38
FHR	FHRLOU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	Flare LOU (steam-assisted)	PFTIR	0.72	38
MI2A0710	MPCDET Marathon Petroleum Company, LLC, Detroit, MI	Flare CP (steam-assisted)	PFTIR	1.60	51
TX3B1210	MPCTX Marathon Petroleum Company, LLC, Texas Refining Division in Texas City, TX	Flare Main (steam-assisted)	PFTIR	0.26	51
INEOS	INEOS INEOS ABS Corporation in Addyston, OH	Flare P001 (steam-assisted)	PFTIR	0.61	38
TX3B1260	SHELL Shell Deer Park Refinery in Deer Park, TX	Flare EP (steam-assisted)	PFTIR	0.34	41
NA	TCEQ testing conducted at John Zink facility	Flare (steam-assisted)	PFTIR, extractive	0.64	52
NA	TCEQ testing conducted at John Zink facility	Flare (air-assisted)	PFTIR, extractive	0.44	52
TX3B1110	BP Texas City, TX	Flare No. 6 (steam-assisted)	DIAL	0.25	40
TX3B1110	BP Texas City, TX	ULC flare and temporary flare (steam-assisted)	DIAL	0.29	40

Section 6
References

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Appendix A

EMISSIONS TEST REPORT DATA FIELDS INCLUDED IN TEST DATA SUMMARY FILES

Appendix A. Data Fields in the Test Data Summary Files

Table column	Field name
A	Test Report filename
B	Facility ID Number
C	Unit ID Number
D	APCD ID(s)
E	Combustion controls used to reduce air pollution (from combustion sources)
F	General Description
G	Code for Process Unit Type
H	Test Report ID
I	Test Date (mm/dd/yyyy)
J	Pollutant Name
K	Pollutant CAS No.
L	Pollutant Class
M	Test Method
N	Run 1 Hourly Production Rate (value)
O	Run 2 Hourly Production Rate (value)
P	Run 3 Hourly Production Rate (value)
Q	Average Hourly Production Rate (value)
R	Hourly Production Rate (units)
S	Production comment
T	Run 1 Hourly Production Rate (value)
U	Run 2 Hourly Production Rate (value)
V	Run 3 Hourly Production Rate (value)
W	Average Hourly Production Rate (value)
X	Hourly Production Rate (units)
Y	Production comment
Z	Run 1 Airflow Rate Outlet (acfm)
AA	Run 1 Airflow Rate Outlet (scfm)
AB	Run 1 Airflow Rate Outlet (dscfm)
AC	Run 1 Gas Moisture Outlet (%)
AD	Run 1 Gas Temp Outlet (F)
AE	Run 1 Gas Pressure Outlet (in. Hg)
AF	Run 1 Gas Oxygen Outlet (%)
AG	Run 1 Gas CO2 Outlet (%)
AH	Run 2 Airflow Rate Outlet (acfm)
AI	Run 2 Airflow Rate Outlet (scfm)
AJ	Run 2 Airflow Rate Outlet (dscfm)
AK	Run 2 Gas Moisture Outlet (%)
AL	Run 2 Gas Temp Outlet (F)
AM	Run 2 Gas Pressure Outlet (in. Hg)
AN	Run 2 Gas Oxygen Outlet (%)

Table column	Field name
AO	Run 2 Gas CO2 Outlet (%)
AP	Run 3 Airflow Rate Outlet (acfm)
AQ	Run 3 Airflow Rate Outlet (scfm)
AR	Run 3 Airflow Rate Outlet (dscfm)
AS	Run 3 Gas Moisture Outlet (%)
AT	Run 3 Gas Temp Outlet (F)
AU	Run 3 Gas Pressure Outlet (in. Hg)
AV	Run 3 Gas Oxygen Outlet (%)
AW	Run 3 Gas CO2 Outlet (%)
AX	Average Airflow Rate Outlet (acfm)
AY	Average Airflow Rate Outlet (scfm)
AZ	Average Airflow Rate Outlet (dscfm)
BA	Average Gas Moisture Outlet (%)
BB	Average Gas Temp Outlet (F)
BC	Average Gas Pressure Outlet (in. Hg)
BD	Average Gas Oxygen Outlet (%)
BE	Average Gas CO2 Outlet (%)
BF	Run 1 Outlet concentration
BG	Run 1 Outlet concentration units
BH	Run 1 Outlet Detect Flag
BI	Run 1 Outlet (lb/hr)
BJ	Run 2 Outlet concentration
BK	Run 2 Outlet concentration units
BL	Run 2 Outlet Detect Flag
BM	Run 2 Outlet (lb/hr)
BN	Run 3 Outlet concentration
BO	Run 3 Outlet concentration units
BP	Run 3 Outlet Detect Flag
BQ	Run 3 Outlet (lb/hr)
BR	Average Outlet concentration
BS	Average Outlet concentration units
BT	Count Outlet Non-Detect Runs
BU	Average Outlet (lb/hr)
BV	Sampling comments
BW	Analytical comments
BX	QA Comments
BY	Other comments
DA	QA Notes
DB	RTI Reviewer initials
DC	Looked at for EF?
DD	Test Rpt Quality for EF use
DE	[PROD RATE 1 basis]

Table column	Field name
DF	[PROD RATE 2 basis]
DG	FINAL [PROD RATE 1 basis] Used in EF?
DH	FINAL [PROD RATE 2 basis] Used in EF?
DI	PROPOSED Used in EF?
DJ	SCC
DK	NEI_POLLUTANT_CODE
DL	PROCESS_DESCRIPTION
DN	CONTROL_CODE1
DO	CONTROL_CODE2
DP	MDL
DQ	FACTOR
DR	UNIT
DS	MEASURE
DT	MATERIAL
DU	ACTION
DV	FLAG
DW	TEST_REPORT_RATING
DX	REF_ID
DY	REFERENCE_TEXT
DZ	No. pages

Appendix B

EPA'S "TEST QUALITY RATING TOOL" TEMPLATE
(ITR TEMPLATE)

August 2013

	A	B	G	H	N
1	Name of Facility where the test was performed				
2	Name of Company performing stationary source test				
3	SCC of tested unit or units				
4	Name of assessor and name of employer.				
5	Name of regulatory assessor and regulatory agency name.	NA			
6					
7	**Emissions Factor Development Quality Indicator Value Rating**		0		
8					
9					
10	**Supporting Documentation Provided**	**Response**	**Regulatory Agency Review**	**Response**	**Justification**
11	**General**				
12	As described in ASTM D7036-12 Standard Practice for Competence of Air Emission Testing Bodies, does the testing firm meet the criteria as an AETB or is the person in charge of the field team a QI for the type of testing conducted? A certificate from an independent organization (e.g., Stack Testing Accreditation Council (STAC), California Air Resources Board (CARB), National Environmental Laboratory Accreditation Program (NELAP)) or self declaration provides documentation of competence as an AETB.		As described in ASTM D7036-12 Standard Practice for Competence of Air Emission Testing Bodies, does the testing firm meet the criteria as an AETB or is the person in charge of the field team a QI for the type of testing conducted? A certificate from an independent organization (e.g., STAC, CARB, NELAP) or self declaration provides documentation of competence as an AETB.		
13			Was a representative of the regulatory agency on site during the test?		
14	Is a description and drawing of test location provided?		Is a description and drawing of test location provided?		
15	Has a description of deviations from published test methods been provided, or is there a statement that deviations were not required to obtain data representative of typical facility operation?		Is there documentation that the source or the test company sought and obtained approval for deviations from the published test method prior to conducting the test or that the tester's assertion that deviations were not required to obtain data representative of operations that are typical for the facility?		
16			Were all test method deviations acceptable?		
17	Is a full description of the process and the unit being tested (including installed controls) provided?		Is a full description of the process and the unit being tested (including installed controls) provided?		
18	Has a detailed discussion of source operating conditions, air pollution control device operations and the representativeness of measurements made during the test been provided?		Has a detailed discussion of source operating conditions, air pollution control device operations and the representativeness of measurements made during the test been provided?		
19	Were the operating parameters for the tested process unit and associated controls described and reported?		Is there documentation that the required process monitors have been calibrated and that the calibration is acceptable?		
20			Was the process capacity documented?		
21			Was the process operating within an appropriate range for the test program objectives?		
22			Were process data concurrent with testing?		
23			Were data included in the report for all parameters for which limits will be set?		
24	Is there an assessment of the validity, representativeness, achievement of DQO's and usability of the data?		Did the report discuss the representativeness of the facility operations, control device operation, and the measurements of the target pollutants, and were any changes from published test methods or process and control device monitoring protocols identified?		
25	Have field notes addressing issues that may influence data quality been provided?		Were all sampling issues handled such that data quality was not adversely affected?		
26	**Manual Test Methods**				
27	**Have the following been included in the report:**				
28	Dry gas meter (DGM) calibrations, pitot tube and nozzle inspections?		Was the DGM pre-test calibration within the criteria specified by the test method?		
29			Was the DGM post-test calibration within the criteria specified by the test method?		
30			Were thermocouple calibrations within method criteria?		
31			Was the pitot tube inspection acceptable?		
32			Were nozzle inspections acceptable?		
33			Were flow meter calibrations acceptable?		
34	Was the Method 1 sample point evaluation included in the report?		Were the appropriate number and location of sampling points used?		
35	Were the cyclonic flow checks included in the report?		Did the cyclonic flow evaluation show the presence of an acceptable average gas flow angle?		
36	Were the raw sampling data and test sheets included in the report?		Were all data required by the method recorded?		
37			Were required leak checks performed and did the checks meet method requirements?		
38			Was the required minimum sample volume collected?		
39			Did probe, filter, and impinger exit temperatures meet method criteria (as applicable)?		

	A	B	G	H	N
40			Did isokinetic sampling rates meet method criteria?		
41			Was the sampling time at each point greater than 2 minutes and the same for each point?		
42	Did the report include a description and flow diagram of the recovery procedures?		Was the recovery process consistent with the method?		
43			Were all required blanks collected in the field?		
44			Where performed, were blank corrections handled per method requirements?		
45			Were sample volumes clearly marked on the jar or measured and recorded?		
46	Was the laboratory certified/accredited to perform these analyses?		Was the laboratory certified/accredited to perform these analyses?		
47	Did the report include a complete laboratory report and flow diagram of sample analysis?		Did the laboratory note the sample volume upon receipt?		
48			If sample loss occurred, was the compensation method used documented and approved for the method?		
49			Were the physical characteristics of the samples (e.g., color, volume, integrity, pH, temperature) recorded and consistent with the method?		
50			Were sample hold times within method requirements?		
51			Does the laboratory report document the analytical procedures and techniques?		
52			Were all laboratory QA requirements documented?		
53			Were analytical standards required by the method documented?		
54			Were required laboratory duplicates within acceptable limits?		
55			Were required spike recoveries within method requirements?		
56			Were method-specified analytical blanks analyzed?		
57			If problems occurred during analysis, is there sufficient documentation to conclude that the problems did not adversely affect the sample results?		
58			Was the analytical detection limit specified in the test report?		
59			Is the reported detection limit adequate for the purposes of the test program?		
60	Were the chain-of-custody forms included in the report?		Do the chain-of-custody forms indicate acceptable management of collected samples between collection and analysis?		
61	**Instrumental Test Methods**				
62	**Have the following been included in the report:**				
63	Did the report include a complete description of the instrumental method sampling system?		Was a complete description of the sampling system provided?		
64	Did the report include calibration gas certifications?		Were calibration standards used prior to the end of the expiration date?		
65			Did calibration standards meet method criteria?		
66	Did report include interference tests?		Did interference checks meet method requirements?		
67	Were the response time tests included in the report?		Was a response time test performed?		
68	Were the calibration error tests included in the report?		Did calibration error tests meet method requirements?		
69	Did the report include drift tests?		Were drift tests performed after each run and did they meet method requirements?		
70	Did the report include system bias tests?		Did system bias checks meet method requirements?		
71	Were the converter efficiency tests included in the report?		Was the NOX converter test acceptable?		
72	Did the report include stratification checks?		Was a stratification assessment performed?		
73	Did the report include the raw data for the instrumental method?		Was the duration of each sample run within method criteria?		
74			Was an appropriate traverse performed during sample collection, or was the probe placed at an appropriate center point (if allowed by the method)?		
75			Were sample times at each point uniform and did they meet the method requirements?		
76			Were sample lines heated sufficiently to prevent potential adverse data quality issues?		
77			Was all data required by the method recorded?		
88					
89					
90					
91				Total	
92			Manual Test	0	
93			Instrumental Test	0	

Appendix C

FLARE EMISSIONS FACTOR DEVELOPMENT -

PREFERRED CO_2 WAVELENGTH

Garwood, Gerri

From:	Cathe Kalisz <kaliszc@api.org>
Sent:	Monday, March 16, 2015 3:30 PM
To:	Garwood, Gerri
Cc:	Scott Evans (sevans@cleanair.com); Gary Mueller
Subject:	PFTIR Testing - CO2 Bands
Attachments:	Copy of Subset of Flare Master Data 150307_CO2 region used.xlsx

Gerri,

Per your request, attached is a file from Clean Air Engineering listing the selected CO2 bands from PFTIR tests.

Cathe

Cathe Kalisz, P.E.
Policy Advisor
Regulatory and Scientific Affairs
American Petroleum Institute
1220 L Street NW
Washington, DC 20005
PH: (202) 682-8318
FAX: (202) 682-8270
kaliszc@api.org

energy API

Run Code	CO2 Used
MPC_DET_CP_A_1_1	2K
MPC_DET_CP_A_1_2	2K
MPC_DET_CP_A_2_1	2K
MPC_DET_CP_A_2_2	2K
MPC_DET_CP_A_3_1	2K
MPC_DET_CP_A_3_2	2K
MPC_DET_CP_A_4_1	2K
MPC_DET_CP_A_4_2	2K
MPC_DET_CP_A_5_1	2K
MPC_DET_CP_A_6_2	2K
MPC_DET_CP_A_7_1	2K
MPC_DET_CP_A_8_1	2K
MPC_DET_CP_A_8_3	2K
MPC_DET_CP_A_9_1	2K
MPC_DET_CP_A_9_3	2K
MPC_DET_CP_B_1_1	2K
MPC_DET_CP_B_2_1	2K
MPC_DET_CP_B_2_2	2K
MPC_DET_CP_B_3_1	2K
MPC_DET_CP_B_3_2	2K
MPC_DET_CP_B_4_1	2K
MPC_DET_CP_B_4_2	2K
MPC_DET_CP_B_6_1	2K
MPC_DET_CP_B_6_2	2K
MPC_DET_CP_B_8_1	2K
MPC_DET_CP_B_8_2	2K
MPC_DET_CP_C_1_1	2K
MPC_DET_CP_C_1_2	2K
MPC_DET_CP_C_2_1	2K
MPC_DET_CP_C_2_2	2K
MPC_DET_CP_C_3_1	2K
MPC_DET_CP_C_3_2	2K
MPC_DET_CP_C_4_1	2K
MPC_DET_CP_C_4_2	2K
MPC_DET_CP_C_5_1	2K
MPC_DET_CP_C_5_2	2K
MPC_DET_CP_D_2_1	2K
MPC_DET_CP_D_3_1	2K
MPC_DET_CP_D_4_1	2K

MPC_DET_CP_D_5_1	2K
MPC_DET_CP_D_6_1	2K
MPC_DET_CP_D_7_1	2K
MPC_DET_CP_D_8_1	2K
MPC_DET_CP_D_9_1	2K
MPC_DET_CP_D_10_1	2K
MPC_DET_CP_E_1_1	2K
MPC_DET_CP_E_2_1	2K
MPC_DET_CP_E_3_1	2K
MPC_DET_CP_E_5_1	2K
MPC_DET_CP_E_6_1	2K
MPC_DET_CP_E_7_1	2K
MPC_DET_CP_LTS_1_1	2K
MPC_DET_CP_LTS_4_1	2K
MPC_DET_CP_LTS_5_1	2K
MPC_DET_CP_LTS_7_1	2K
MPC_DET_CP_LTS_8_1	2K
MPC_TXC_MAIN_A19_1_1	765
MPC_TXC_MAIN_A19_2_1	765
MPC_TXC_MAIN_A19_3_1	765
MPC_TXC_MAIN_A19_4_1	765
MPC_TXC_MAIN_A19_7_1	765
MPC_TXC_MAIN_A11_1_1	765
MPC_TXC_MAIN_A11_2_1	765
MPC_TXC_MAIN_A11_2_2	765
MPC_TXC_MAIN_A11_3_1	765
MPC_TXC_MAIN_A11_3_2	765
MPC_TXC_MAIN_A11_4_1	765
MPC_TXC_MAIN_A11_5_1	765
MPC_TXC_MAIN_A11_6_1	765
MPC_TXC_MAIN_A11_7_1	765
MPC_TXC_MAIN_A11_8_1	765
MPC_TXC_MAIN_A11_9_1	765
MPC_TXC_MAIN_A11_10_1	765
MPC_TXC_MAIN_A11_11_1	765
MPC_TXC_MAIN_A11_11_2	765
MPC_TXC_MAIN_A11_12_1	765
MPC_TXC_MAIN_A11_13_1	765
MPC_TXC_MAIN_A11_14_1	765
MPC_TXC_MAIN_B_1_1	765

MPC_TXC_MAIN_B_1_2	765
MPC_TXC_MAIN_B_2_1	765
MPC_TXC_MAIN_B_2_2	765
MPC_TXC_MAIN_B_3_1	765
MPC_TXC_MAIN_B_3_2	765
MPC_TXC_MAIN_B_4_1	765
MPC_TXC_MAIN_B_4_2	765
MPC_TXC_MAIN_B_4_3	765
MPC_TXC_MAIN_B_5_1	765
MPC_TXC_MAIN_B_5_2	765
MPC_TXC_MAIN_B_6_1	765
MPC_TXC_MAIN_B_6_2	765
MPC_TXC_MAIN_B_7_1	765
MPC_TXC_MAIN_B_7_2	765
MPC_TXC_MAIN_B_8_1	765
MPC_TXC_MAIN_B_8_2	765
MPC_TXC_MAIN_B_9_1	765
MPC_TXC_MAIN_B_9_2	765
MPC_TXC_MAIN_B_10_1	765
MPC_TXC_MAIN_B_10_2	765
MPC_TXC_MAIN_C_1_1	765
MPC_TXC_MAIN_C_1_2	765
MPC_TXC_MAIN_C_2_1	765
MPC_TXC_MAIN_C_2_3	765
MPC_TXC_MAIN_C_3_1	765
MPC_TXC_MAIN_C_3_2	765
MPC_TXC_MAIN_D_1_1	765
MPC_TXC_MAIN_D_1_2	765
MPC_TXC_MAIN_D_1_3	765
MPC_TXC_MAIN_D_2_1	765
MPC_TXC_MAIN_D_2_2	765
MPC_TXC_MAIN_D_2_3	765
MPC_TXC_MAIN_D_3_1	765
MPC_TXC_MAIN_D_3_2	765
MPC_TXC_MAIN_D_3_3	765
MPC_TXC_MAIN_D_4_1	765
MPC_TXC_MAIN_D_4_2	765
MPC_TXC_MAIN_D_4_3	765
MPC_TXC_MAIN_D_5_1	765
MPC_TXC_MAIN_D_6_1	765

MPC_TXC_MAIN_D_7_2	765
MPC_TXC_MAIN_D_8_1	765
MPC_TXC_MAIN_D_10_1	765
MPC_TXC_MAIN_D_10_2	765
MPC_TXC_MAIN_E_1_1	765
MPC_TXC_MAIN_E_1_3	765
MPC_TXC_MAIN_E_2_1	765
MPC_TXC_MAIN_E_2_3	765
MPC_TXC_MAIN_E_3_1	765
MPC_TXC_MAIN_E_3_3	765
MPC_TXC_MAIN_E_4_1	765
MPC_TXC_MAIN_E_4_3	765
MPC_TXC_MAIN_E_5_1	765
MPC_TXC_MAIN_E_5_2	765
SHELL_DP_EPF_A_2.0_1	765
SHELL_DP_EPF_A_3.0_1	765
SHELL_DP_EPF_A_4.0_1	765
SHELL_DP_EPF_A_5.0_1	765
SHELL_DP_EPF_A_5.0_2	765
SHELL_DP_EPF_A_1_1_60	765
SHELL_DP_EPF_A_1_1_55	765
SHELL_DP_EPF_A_1_1_10	765
SHELL_DP_EPF_A_1_1_12	765
SHELL_DP_EPF_B_1_2_10	765
SHELL_DP_EPF_B_51_1	765
SHELL_DP_EPF_B_51_2	765
SHELL_DP_EPF_B_51_3	765
SHELL_DP_EPF_B_61_1	765
SHELL_DP_EPF_B_61_2	765
SHELL_DP_EPF_B_31_1	765
SHELL_DP_EPF_B_31_2	765
SHELL_DP_EPF_B_51_HiF	765
SHELL_DP_EPF_B_51_HiF	765
SHELL_DP_EPF_B_61_2i	765
SHELL_DP_EPF_B_61_2ii	765
SHELL_DP_EPF_B_61_2iii	765
SHELL_DP_EPF_B_61_2iv	765
SHELL_DP_EPF_B_61_3i	765
SHELL_DP_EPF_B_61_3ii	765
SHELL_DP_EPF_B_61_3iii	765

SHELL_DP_EPF_B_61_3iv	765
SHELL_DP_EPF_C_2.5_1	765
SHELL_DP_EPF_C_2.5_2	765
SHELL_DP_EPF_C_3.0_1	765
SHELL_DP_EPF_C_3.0_2	765
SHELL_DP_EPF_C_3.0_3	765
SHELL_DP_EPF_C_4.0_1	765
SHELL_DP_EPF_C_4.0_2	765
SHELL_DP_EPF_C_5.0_1	765
SHELL_DP_EPF_C_6.0_1	765
SHELL_DP_EPF_C_6.0_2	765
SHELL_DP_EPF_C_6.0_3	765
SHELL_DP_EPF_C_6.0_4	765
SHELL_DP_EPF_C_7.0_1	765
SHELL_DP_EPF_C_7.0_2	765
SHELL_DP_EPF_C_8.0_1	765
SHELL_DP_EPF_A_2.0_1_I	765
SHELL_DP_EPF_A_3.0_1_I	765
SHELL_DP_EPF_A_4.0_1_I	765
SHELL_DP_EPF_A_5.0_1_I	765
SHELL_DP_EPF_A_4.0_1_I	765
SHELL_DP_EPF_A_5.0_1_I	765
SHELL_DP_EPF_A_2.0_1_I	765
SHELL_DP_EPF_A_3.0_1_I	765
SHELL_DP_EPF_A_4.0_1_I	765
SHELL_DP_EPF_A_5.0_1_I	765
SHELL_DP_EPF_A_4.5_1_I	765
FHR_AU_A_1.0_1	2K
FHR_AU_A_1.0_2	2K
FHR_AU_A_2.0_1	2K
FHR_AU_A_2.0_2	2K
FHR_AU_A_3.0_1	2K
FHR_AU_A_3.0_2	2K
FHR_AU_A_4.0_1	2K
FHR_AU_A_4.0_2	2K
FHR_AU_A_4.0_3	2K
FHR_AU_A_5.0_1	2K
FHR_AU_A_5.0_2	2K
FHR_AU_B_MIN_1	2K
FHR_AU_B_MIN_2	2K

FHR_AU_B_1.0_1	2K
FHR_AU_B_1.0_2	2K
FHR_AU_B_2.0_2	2K
FHR_AU_B_2.0_3	2K
FHR_AU_B_2.5_1	2K
FHR_AU_B_2.5_2	2K
FHR_AU_B_2.5_3	2K
FHR_AU_B_3.5_1	2K
FHR_AU_C_MIN_1	2K
FHR_AU_C_MIN_2	2K
FHR_AU_C_MIN_3	2K
FHR_AU_C_1.0_1	2K
FHR_AU_C_1.0_2	2K
FHR_AU_C_1.0_3	2K
FHR_AU_C_1.0_4	2K
FHR_AU_C_2.0_1	2K
FHR_AU_C_2.0_2	2K
FHR_AU_C_3.0_1	2K
FHR_AU_C_3.0_2	2K
FHR_AU_C_3.7_1	2K
FHR_AU_C_3.7_3	2K
FHR_AU_D_MIN_1	2K
FHR_AU_D_1.0_1	2K
FHR_AU_D_1.0_2	2K
FHR_AU_D_2.0_1	2K
FHR_AU_D_2.0_2	2K
FHR_AU_D_3.0_1	2K
FHR_AU_D_3.0_2	2K
FHR_AU_D_4.0_1	2K
FHR_AU_D_4.0_2	2K
FHR_AU_D_4.0_3	2K
FHR_AU_D_4.3_1	2K
FHR_LOU_A_MIN_1	2K
FHR_LOU_A_MIN_2	2K
FHR_LOU_A_MIN_3	2K
FHR_LOU_A_ 2.0_1	2K
FHR_LOU_A_ 2.0_2	2K
FHR_LOU_A_ 2.0_3	2K
FHR_LOU_A_ 3.0_1	2K
FHR_LOU_A_ 3.0_2	2K

FHR_LOU_A_ 4.0_1	2K
FHR_LOU_A_ 4.0_2	2K
FHR_LOU_A_ 5.0_1	2K
FHR_LOU_A_ 5.0_2	2K
FHR_LOU_A_ 6.0_1	2K
FHR_LOU_A_ 6.0_2	2K
FHR_LOU_A_8.5_1	2K
FHR_LOU_A_8.5_2	2K
FHR_LOU_B_MIN_1	2K
FHR_LOU_B_MIN_2	2K
FHR_LOU_B_ 1.0_1	2K
FHR_LOU_B_ 1.0_2	2K
FHR_LOU_B_ 2.0_1	2K
FHR_LOU_B_ 2.0_2	2K
FHR_LOU_B_ 3.0_1	2K
FHR_LOU_B_ 3.0_2	2K
FHR_LOU_B_ 4.0_1	2K
FHR_LOU_B_ 4.0_2	2K
FHR_LOU_B_ 5.0_1	2K
FHR_LOU_B_ 5.0_2	2K
FHR_LOU_B_ 5.7_1	2K
FHR_LOU_B_ 5.7_2	2K
FHR_LOU_B_ 6.4_1	2K
FHR_LOU_B_ 6.4_2	2K
FHR_LOU_C_MIN_1	2K
FHR_LOU_C_MIN_2	2K
FHR_LOU_C_ 1.0_1	2K
FHR_LOU_C_ 1.0_2	2K
FHR_LOU_C_ 2.0_1	2K
FHR_LOU_C_ 2.0_2	2K
FHR_LOU_C_ 3.0_1	2K
FHR_LOU_C_ 3.0_2	2K
FHR_LOU_C_ 4.0_1	2K
FHR_LOU_C_ 4.0_2	2K
FHR_LOU_C_ 5.0_1	2K
FHR_LOU_C_ 5.0_2	2K
FHR_LOU_C_ 5.5_1	2K
FHR_LOU_C_ 5.5_2	2K
TCEQ_STMA_S1_5_1	765
TCEQ_STMA_S1_6_1	765

TCEQ_STMA_S1_7_1	765
TCEQ_STMA_S1_8_1	765
TCEQ_STMA_S1_9_1	765
TCEQ_STMA_S2_1_1	765
TCEQ_STMA_S2_1_2	765
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TCEQ_STMA_S4_10_1	765
TCEQ_STMA_S4_11_1	765
TCEQ_STMA_S5_1_1	765
TCEQ_STMA_S5_1_2	765
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TCEQ_STMA_S5_3_3	765
TCEQ_STMA_S5_4_1	765
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TCEQ_STMA_S9_4_1	765
TCEQ_STMA_S9_5_1	765
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TCEQ_AIRA_A2_5_3	765
TCEQ_AIRA_A3_1_1	765
TCEQ_AIRA_A3_1_2	765

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TCEQ_AIRA_A3_2_2	765
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TCEQ_AIRA_A7_3_2	765
TCEQ_AIRA_A7_4_1	765
TCEQ_AIRA_A7_5_1	765
INEOS_BD_1	1K
INEOS_BD_1A	1K
INEOS_BD_1B	1K
INEOS_BD_2	1K
INEOS_BD_3	1K
INEOS_BD_4	1K
INEOS_BD_5	1K
INEOS_BD_6	1K
INEOS_BD_7	1K
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INEOS_BD_9	1K
INEOS_BD_10	1K
INEOS_BD_11	1K
INEOS_BD_12	1K
INEOS_BD_13	1K
INEOS_BD_14	1K
INEOS_BD_15	1K
INEOS_BD_16	1K
INEOS_BD_17	1K
INEOS_BD_17A	1K
INEOS_BD_18	1K