Background Information for Final Emissions Factors Development for Flares and Certain Refinery Operations and Final Determination for No Changes to VOC Emissions Factors for Tanks and Wastewater Treatment Systems

Summary of Public Comments and Responses

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Summary of Public Comments and Responses

Contract No. EP-D-11-084
Work Assignment No. 3-06

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, North Carolina 27711

April 2015

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Chapter 1

SUMMARY

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. Per the terms of the consent decree, on August 19, 2014, EPA proposed a new VOC emissions factor for flares and determined that revisions to the VOC emissions factors for tanks and wastewater treatment systems were not necessary. At the same time, EPA also proposed to revise the nitrogen oxides (NOx) and carbon monoxide (CO) emissions factors for flares and proposed several new emissions factors not covered under the consent decree. The public comment period for the proposal ran through December 19, 2014. EPA must issue final revisions to the VOC emissions factors for flares, tanks and wastewater treatment systems, or issue a final determination that revision of these emissions factors is not necessary by April 20, 2015.

Comments were received from 58 sources, including petroleum refiners, industry trade associations and consultants, state and local environment and health departments, environmental groups, and other interested parties. Table 1 lists the individuals (hereon referred to as "commenters") that submitted comments on the emissions factor revisions. All of the comments submitted by the commenters and EPA's responses to the comments are summarized in this document. Several commenters supported the comments submitted by others. By convention, rather than identify all of the supporting commenters in each discussion of issues raised by a primary commenter, we identified the supporting commenters only in this chapter. In the remainder of this document, it is to be understood that each reference to the comment number of a primary commenter includes all of the supporting commenters as well. For example, Commenter 44 supported the comments submitted by Commenter 18 (TCEQ). Commenters 24, 29, 55 supported the comments submitted by Commenter 27 (NW&RA and SWANA). Commenters 45, 43, 49 supported the comments submitted by Commenter 38 (GPA). Commenters 30, 38, 43, 44, 49, 50, 53, 54 supported the comments submitted by Commenter 56 (API). Commenter 30, the Louisiana Chemical Association (LCA), incorporated by reference any comments made by its members and members of the Louisiana Mid-Continent Oil and Gas Association (LMOGA), to the extent such comments are not inconsistent with the comments made in LCA's own comment letter. The summary and EPA's responses form part of the basis for any revisions made to the proposed emissions factors, determination of no need for revisions to emissions factors, and related documents.

Table 1. List of Commenters

Commenter ID Number	Commenter and Affiliation
1	Dave Coffin, P.E.
2, 5, 9, 14	Sparsh Khandeshi, Environmental Integrity Project (EIP)
3	Laurel Kearns, Drew University
4, 21	Gary Fischman, Allegheny County Health Department
5	Michael Zeilstra, Kinder Morgan
7	Mohammad
8	Matthew Todd, American Petroleum Institute (API)
10, 11, 13, 56	Cathe Kalisz, P.E., API
12	Gurinder Saini, RTP Environmental
15, 49	Lisa Beal, Interstate Natural Gas Association of America (INGAA)
16	David Chetkowski, P.E., Monroe Energy, LLC
17	Russell Wozniak, The Dow Chemical Company
18	Steve Hagle, P.E., Texas Commission on Environmental Quality [emailed by Danielle Nesvacil]
19	Steve Gossett, Eastman Chemical Company
20	David Friedman, American Fuel & Petrochemical Manufacturers
22	Paul Morris, Air Products and Chemicals, Inc.
[23][a], 27	Sharon Kneiss, Waste & Recycling Technology (NW&RA) and John Skinner, Solid Waste Association of North America (SWANA) [emailed by Anne Germain]
24	Amy Van Kolken Baniser and Kerry Kelly, Waste Management
25	Sue Sung, Ph.D., P.E., and Richard Trzupek, Trinity Consultants [emailed by Georgette Reeves]
26	Stephen Holcomb, NiSource
[28][a], 29	Angela Marconi, P.E., BCEE, Delaware Solid Waste Authority
30	Lee Vail, on behalf of Louisiana Chemical Association (LCA)
31	Khalid Al-Binali, QEP, Aramco
32	Anthony Stratton, Eastmount Environmental Services, LLC
33	Jay Leduc, Sprague Resources GP LLC

Commenter ID Number	Commenter and Affiliation
34	Daniel DeArment, LFG Specialties, LLC, CB&I
35	Gail Tonnesen, EPA Region 8
36	Momentum Energy Group [emailed by Anthony Guiliani, of Vorys, Sater, Seymour and Pease LLP]
37	Pamela Faggert, Dominion Environmental Services [emailed by Alice Prior]
38	Mark Sutton, Gas Processors Association (GPA) [emailed by Erin Bartlett]
39	Vicente Martinez, Dakota Gasification Company
40	Lucinda Legel, Flint Hills Resources
41	Steven Dietrich, P.E., Wyoming Department of Environmental Quality [emailed by Josh Nall]
42	Hoby Rash, Montana Department of Environmental Quality [emailed by Elizabeth Ulrich]
43, [46][a], [48][a]	David Spigelmyer, Marcellus Shale Coalition [emailed by Loren Anderson, David Callahan, and Nathan Wheldon]
44	Thure Cannon, Texas Pipeline Association [emailed by Angie Adams]
45	Anthony Giuliani, on behalf of Ohio Oil and Gas Association
47	Andrea Grant, on behalf of Independent Fuel Terminal Operators Association (IFTOA) [emailed by Martin Schaefermeier]
50	Lorraine Gershman, P.E., American Chemistry Council (ACC)
51	Larry Conner, Perennial Energy
52	Nathan Wheldon, P.E., Mark West Energy Partners
53	Charles Bennett, Marathon Petroleum Company [emailed by Jacob Fournier]
54	David Friedman, American Fuel & Petrochemical Manufacturers (AF&PM) [emailed by Andriy Shvab]
55	Niki Westenberg, Republic Services, Inc.
57	Sheraz Gill, San Joaquin Valley Air Pollution Control District [emailed by Errol Villegas]
58	Sparsh Khandeshi, EIP; Adrian Shelley, Air Alliance Houston; Hilton Kelley, Community In-Power and Development Association; and Juan Parras, Texas Environmental Justice Advocacy Services.
59	Raymond Allen, Evergreen Environmental Consulting LLC.

[a] This letter was replaced with a later letter or the letter is a duplicate letter.

Chapter 2

NEW AND REVISED EMISSIONS FACTORS FOR INDUSTRIAL FLARES

2.1 General Flare Comments

Comment: Commenters 36, 37, 44, 50, 54, 56 and 57 stated the proposed flare emissions factors should not be finalized. Commenters 34, 36 and 38 stated EPA should retain the existing factors. Commenters 18, 37, 38, 45 and 52 requested EPA withdraw the proposed revisions. Commenter 43 recommended EPA withdraw the emissions factors until a more comprehensive study is completed. Commenters 36 and 45 stated with small sample size and questionable analytical methods, the proposed revisions are not supported by sound scientific data and should not be adopted. Commenter 49 stated the results are not reliable.

Response: The EPA received numerous comments on the flare emissions factors. Taking into account those comments, we have revised our analysis for the emissions factors. Based on available data, we believe it is appropriate to develop a VOC emissions factor for flares and revise the CO factor for flares. The current AP-42 factor is for total hydrocarbon emissions (THC), as a surrogate for VOC. Because VOC is the pollutant of interest, methane and ethane are not regulated as VOC, and because methane and ethane can be a significant fraction of the THC emissions, the existing THC emissions factor is not as appropriate for inventory purposes as a VOC emissions factor.

We disagree with commenters that the final emissions factors for flares are based on questionable analytical methods. We consider the PFTIR (passive Fourier transform infrared spectrometer) data to be a scientifically sound method for measuring pollutants for which the system was calibrated, namely CO and organic compounds. We have decided not to finalize the proposed NOx emissions factor revisions because the FTIR instrument was not calibrated to quantify NOx emissions (see Attachment A) and the quality of the other available data was uncertain due to lack of availability of raw data and quality assurance techniques or admissions of failed quality assurance objectives. See Section 2.5 of this document for further discussion on flare NOx emissions data. We also consider DIAL (differential absorption lidar) data to be scientifically sound and an acceptable tool for measuring emissions. This data can be useful for emissions factor development when the measurements scans are performed in a way that isolates emissions sources.

We disagree with commenters that the final emissions factors for flares are unreliable. The data set included four flares from test facilities burning propylene, propane, and natural gas, which are common gases found in flares for the refining and chemical industry. The data set also included eight flares from refineries and one flare from a chemical plant, all burning typical flare vent gas. Although the data set appears to be more representative of the refining industry, there is a lot of overlap between the refining and chemical industries; in fact, many refineries are either co-located with or next door to a chemical plant. Flares at refineries often burn vent gases from the chemical plant in addition to vent gases from the refinery. This was the case with some of the refinery flares included in the data set for these emissions factors. As such, we feel that the data set adequately captures the emissions profile of both refinery and chemical plant flares.

Comment: Commenter 54 stated EPA should further evaluate the proposed flare emissions factors. Commenter 50 encouraged EPA to review the entire data set and conduct more rigorous analysis. Commenter 8 stated the flares have broad impacts that affect industry, flare manufacturers, and state and local regulators. Commenter 8 stated some have different situations than the narrow flare data used (primarily steam-assist refinery flares). Commenters 36, 38 and 52 stated the flare data are from one type of flare (steam-assist) and one type of facility in one industry sector (petroleum refineries). Commenter 37 stated that the sample set does not represent the waste gas typically found at a natural gas transmission or storage station. Commenter 44 stated data for flares at petroleum refineries does not necessarily represent conditions at midstream industry, where different kinds of flares and waste stream composition are used. Commenter 45 stated the tests do not include various flare types that are commonly used in various industries. Commenter 18 stated that the proposed flare factors are not representative of all industrial flares because only one flare measured was not a steam-assisted flare; no unassisted flares were analyzed. Commenter 22 stated that the flares studied to propose a new AP-42 emissions factor were focused on the petroleum refinery field and do not reflect broad-based flare applications. Commenter 43 stated the proposal ignores the fact that the emissions factors apply to many different facility types and industry sectors beyond just petroleum refineries. Commenter 44 stated the data for the proposed factors are not necessarily representative of conditions in all types of industries. Commenter 52 stated the emissions data are not representative of other industries and operations, and should not be relied on as the sole basis for revising the emissions factors. Commenters 27 and 44 stated that new AP-42 factors should be based on data that accurately represents conditions in all industry segments to which the emissions factors apply.

Commenters 36, 42 and 43 expressed concern that the emissions factors are based on limited data. Commenters 36, 37 and 41 stated the small sample size does not adequately categorize emissions from various flare types being represented by the emissions factors. Commenter 37 requested a broader number and range of flares be sampled and presented for proposal. Commenter 38 stated the studies used to develop factors should be from diverse flare types and facilities. Commenter 37 stated the factors should be based on a statistically significant number of flares. Commenter 57 believed more time is need by EPA to conduct more research and perform additional testing to support revised emissions factors. Commenter 34 stated EPA should conduct additional testing. Commenter 18 recommended that the EPA perform further research and testing of more varied units to develop more robust and representative emissions factors. Commenter 38 stated EPA should determine new emissions factors using performance test data developed from properly designed studies in multiple industry segments.

Commenter 52 stated the factor quality index (FQI) is purported to be a statistical analysis to determine if data belongs to a population but EPA does not include any quantifiable analysis to determine if a limited data set for a single industry and limited service options are representative of the national flare population. Commenter 18 stated that the emissions factors appear to be based on relatively few tests at a wide range of refineries across the country and concluded that due to the limited data available, and the site-specific nature of the process units at the refineries, that these factors are not likely to be representative. Commenter 52 stated EPA should perform a quantitative analysis of the source population to determine if data sets are representative prior to performing any numerical analysis.

Response: The EPA understands the commenters' concerns. However, we note that the original emissions factors are based on testing of only two flares, one steam-assisted and one air-assisted, burning a single fuel (crude propylene). While AP-42 did not previously assign a source classification code (SCC) to the flare emissions factors in Section 13.5, the WebFIRE database, EPA's online emissions factor repository, lists the SCC for these factors as 30190099, which belongs to Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Other. We believe that this is an appropriate classification considering the type of flares and fuel used in the original factor development.

The new emissions factors for flares includes data from the following sources: (1) the original flare study; (2) additional testing of two flares at a flare vendor using limited fuel inputs (natural gas and propylene or propane), similar to the previous study; (3) testing at a chemical manufacturing plant using actual fuel gas; and (4) testing at eight flares from petroleum refineries using actual fuel gas. Tested flares include both steam-assisted flares and air-assisted flares. Consequently, we consider the data set we used to be more representative of real-world industrial flares at chemical plants and refineries. We note that refineries and chemical plants represent a large majority of industrial flares, and that the majority of these flares use an assist medium. Therefore, even though the data set does not include information on unassisted flares, we believe the dataset is representative of the majority of flares used in the chemical and refining industries. As such, we are assigning SCCs 30190099 and 30600904 (Industrial Processes, Petroleum Industry, Flares, Process Gas) to the new emissions factors. Although we always recommend that any industry use source specific data when it is available, if a source needs to use an emissions factor, we believe that these emissions factors are representative for flares that fall into the assigned SCC categories. For industries with flares that do not fall into these SCC categories, the emissions factor user must determine whether the emissions factor is representative of its flare or whether a more appropriate data source (such as data from a manufacturer) is available.

Additionally, we note that there are some other flare factors in AP-42 and WebFIRE that may be more applicable to a specific industrial source outside of the SCC codes listed for the flares in Section 13.5. For example, Section 2.4 of AP-42 provides information on emissions factors for landfill flares with SCCs of 50100410 and 50300601.

Comment: Commenter 39 is concerned that using aggregated flare test data is a poor representation of the industry. Commenter 39 suggested EPA collect more sample data with a greater range of controlled variables, steam and gas ratios, and gas composition. Commenter 39 suggested EPA evaluate more test data and develop multiple emissions factor categories to account for the diversity of flare types used at industrial facilities, such as for flaring lighter compounds (C1 to C3) with greater than 98 percent destruction efficiency (DE).

Commenters 38 and 49 recommended EPA consider reviewing and potentially conducting studies of the emissions from flares used in different industries, as there are too many factors that contribute to emission rates to assume that all flares emit the same concentration of a pollutant. Commenter 49 stated that one emissions factor does not capture the emissions from flares used in a wide range of industries combusting a wide range of waste gas streams with varying heat content. Commenter 49 stated reviewing only one industry segment (refineries) does not account for operating conditions and emissions in other industries.

Commenter 38 stated EPA should determine separate factors for different flare types (steam-assist, air-assist, pressure-assist, non-assist, enclosed, unenclosed), feed composition, and industrial applications. Commenters 26, 41, 42 stated other subcategories of flares should be considered, including type of flare and type of heat input. Commenter 42 suggested non-assist flares and combined air and steam assist flares be included. For heat input, Commenter 42 stated the data represent flares with low BTU content and flares with high BTU content were not considered. Commenter 52 stated the data set only includes petrochemical refining industry for 4 steam-assist, 1 air-assist, and 0 non-assist flares. Commenter 52 stated the emissions factor is 5 times higher than the 1 air-assist flare, and given that 3 or more data sets are needed to determine outliers, it is not known if this data is representative and the emissions factors should not be applied to air-assist flares. Commenter 52 stated there are no emission data for non-assist flares. Commenter 36 noted no studies of enclosed flares were included. Commenter 22 added that the study did not include any non-assisted flares or non-VOC flares. Commenter 26 pointed out that since the Review states that subcategorization could not be performed because of the lack of data, the EPA seems to recognize the value of subcategorization.

Response: The EPA understands the commenters' concerns. We agree that more data, when it is relevant and of high quality, is always preferred in developing emissions factors. However, as described previously in this section, we consider the data set we used to be representative of most industrial flares used in the refining and chemical plant industries and sufficient for finalizing the emissions factors we assigned to the SCC categories described above. For industries with flares that do not fall into these SCC categories, the emissions factor user must determine whether the emissions factor is representative of its flare or whether a more appropriate data source (such as data from a manufacturer) is available.

While the data set included data for different types of flares and fuels, at this time there is not enough data in each subcategory to perform an appropriate statistical analysis to determine if these types of differences really do affect emission profiles. We note that we did use more than three data points to create the emissions factor, and an outlier analysis was conducted on the combined flare data set as a whole (including the original test data and new test data). None of the data points were determined to be outliers. Although a statistical analysis cannot be performed to determine whether the data should be subcategorized, the data for air-assisted flares and steam-assisted flares is similar, indicating that subcategorization based on assist medium may not be necessary. However, we note that emissions factor review is an ongoing process. If more data becomes available for different industries, different fuels, or different flare types, we may use our emissions factors development procedures to determine if it is appropriate to create different emissions factors for subcategories of flares.

Comment: Commenter 54 pointed out that AP-42 emissions factors are specifically designed to represent average flare operations – not abnormal or worst-case emissions. Commenters 36 and 40 stated the *Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database* (RPDEF) recommends use of emissions from normally operating process or activity.[1] Commenter 36 noted the flare air/steam assist was varied to see the response. Commenter 40 stated data from test runs where a flare was intentionally operated outside of its normal operating mode is not reflective of a "normally-operating" flare, and should not be relied on to establish an emissions factor, regardless of the combustion efficiency measured during any given minute within the test run. Commenters 30, 38 and 54 stated the PFTIR testing was designed to determine combustion efficiency under a variety of non-representative operating conditions, which Commenter 54 states may bias the data. Commenter 40 noted that for each condition under which flares were tested, the steam flow was increased from the point of incipient smoke to a point just before snuffing the flare (incipient snuff). Commenter 38 stated the emissions data are unreliable as the purpose of the study was

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[1] *Recommended Procedures for Development of Emissions Factors and Use of the WebFIRE Database*. U.S. Environmental Protection Agency. EPA Publication No. EPA-453/D-13-001. August 2013.

not to quantify emissions. Commenter 36 noted the studies relied on default assumptive process conditions instead of accurate measured conditions.

Commenter 38 noted that the tests were performed to satisfy specific test requirements of Section 114 and consent orders, and the operating conditions of the flare were modified to include various levels of steam or air assist, did not represent typical flare operation, and resulted in higher emissions as combustion efficiency was lowered. Commenter 38 noted the tests were not performed in a manner appropriate for the data to be broadly applicable for calculating emissions factors.

Response: The EPA does not agree that the flare testing cannot be used to represent emissions during normal operations. While the flare testing was used to determine combustion efficiency, it is not uncommon for flares to operate at any point between the incipient smoking point and snuffed flames due to over-steaming. The BP DIAL study provides a real-world example of a flare being over-steamed during "normal operation." As long as the requirements of the General Provisions in 40 CFR Parts 60 or 63 are met, we believe that the flare is operating under conditions that it would normally be allowed to operate under. Nevertheless, we limited the data runs to those achieving a combustion efficiency of 96.5 percent (indicative of destruction efficiency of 98 percent) as a means to ensure that the emissions factors developed from the data were more representative of "normal operations" because we acknowledge that the combustion efficiencies were degraded during the PFTIR tests. We still believe that a well operated flare should achieve 98% destruction efficiency.

Comment: Commenter 51 suggested imposition of the proposed emissions factor is inappropriate for non-assist flares for anaerobically derived gas from wastewater treatment plants and landfills. Commenters 24 and 27 stated EPA should maintain the current emissions factors for landfill gas and other biogas flares. Commenter 27 is very concerned EPA intends that these new emissions factors be used in permitting MSW landfill candlestick flares. Commenter 55 stated the permitting ramifications for flare emissions factors are not justified since there is no test data to support any changes for open flares using non-assist flares combusting landfill gas. Commenters 27, 34 stated the emissions data is not supportive of non-assist, candlestick flares operating on landfill gas. Commenter 27 noted that a flare manufacturer concluded that recent tests are not applicable to landfill gas or non-assist open flares, and the test reports used for the revised emissions factors were for high pressure air-assist or steam-assist flares, for heavier hydrocarbons, or various types of flare tips not used in landfill sector. Commenters 24 and 27 stated none of the tests involved open, non-assist flares, and none of the tests were for landfill gas. Commenters 27, 34 and 51 stated they were not aware of any studies performed on open (candlestick) flares for wastewater treatment or landfill industries that would suggest different values be used (i.e., EPA AP-42 and EPA 40 CFR 60.18).

Commenter 27 noted that although Section 13.5 of AP-42 is generally used by the petroleum industry, it is not limited to that industry, and it is important that it accurately reflects emissions of all types of flares used in other industrial sectors. Commenter 27 stated many existing permits have limits tied to the AP-42 Section 13.5 emissions factors and major manufacturers of landfill gas candlestick flares have recommended use of 1991 Section 13.5 emissions factors as the most appropriate and well-supported (see 2007 attachment to the comment letter). Commenter 27 stated that because Section 13.5 is widely used in permitting by the landfill sector, it is essential that Section 13.5 retain emissions factors that are appropriate for non-assist candlestick flares used at landfills and reflect their actual emissions. Commenters 24, 34 and 55 stated the revised emissions factors will impact landfill projects and beneficial energy projects. Commenter 27 stated EPA should delete its recommendation in section 13.5 that the revised emissions factors be used for non-assist flares as the proposed factors should be limited to relevant industries that use steam-assist and air-assist flares.

Response: As mentioned previously in this section, we are assigning SCCs 30190099 and 30600904 to the new emissions factors. For industries with flares that do not fall into these SCC categories, the emissions factor user must determine whether the emissions factor is representative of its flare or whether a more appropriate data source (such as data from a manufacturer) is available. Additionally, we note that there are factors for landfill flares in Section 2.4 of AP-42.

Combustion theory suggests that, when considering the combustion zone gas properties, there is no difference between steam-assisted and unassisted flares. As such, as long as the net heating value or lower flammability levels in the flare vent gas for a flare is within the range of the combustion zone properties evaluated for steam assisted flares, the new emissions factors should be equally applicable to other flares.

Comment: Commenter 18 stated that if the EPA were to use the proposed flare factors in its air quality modeling activities or emissions inventory development, pollution contributions from states or regions of large concentrations of industry that use flares could be substantially over-estimated. Commenter 18 explained that such over-estimation could lead to unnecessary regulatory burdens, concluding that the EPA should not use any of the proposed factors for any of its modeling activities, rule development, permitting, emissions inventory development, or any other air quality-related activities.

Response: We disagree with the commenter. As discussed in further detail previously in this section, we believe that the new emissions factor are more representative of the chemical manufacturing and refining industries than the previous factor because they are derived from a more robust data set. We have also noted that for flares that are not in the chemical manufacturing and refining industries, there may be more appropriate sources from which to obtain emissions estimates, and that the end users must carefully consider all available information when making a decision on what source of data is most appropriate for their needs.

Because we are finalizing the CO and VOC emissions factors for flares based on the decision that they are representative of the SCC categories assigned to them, we consider the finalized factors suitable for all uses recommended in AP-42. As noted in the AP-42 introduction, the EPA does not recommend using emissions factors for site-specific permit limits or for emissions standards.

Comment: Commenter 22 stated that this revision will continue the misapplication of both the AP-42 emissions factor and existing New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) to non-volatile organic compounds (non-VOC) vents. Commenter 22 explained that NSPS and MACT were both developed by the EPA to control VOC emissions, and that the AP-42 factors were established based on the assumption that flares are used primarily to control VOC emissions. Commenter 22 said that due to this, the standards and the AP-42 factors do not adequately address flares in non-VOC service, primarily inorganic compound service. Commenter 22 added that those types of flares are commonly found at hydrogen gas production facilities. Commenter 22 requested that the EPA re-evaluate the study as it pertains to non-assisted, non-VOC, hydrogen-rich flares, or to clearly exclude them from applicability of the proposed AP-42 factors.

Response: The EPA notes that a majority of flares are used primarily to control VOC emissions. The emissions data used in the development of the emissions factors do not include any data on non-assisted flares specifically, but include data for steam-assisted flares with the steam turned off, which is expected to be representative of non-assisted flare emissions. The emissions data used in the development of the emissions factors also include data for flares with hydrogen content as high as 60 percent. The data do not include data for strictly non-VOC flares, and as such, we are not able to determine whether or not the final emissions factors are representative for these flares. In AP-42 Section 13.5, we have added clarification that these factors are developed using data from steam- and air-assisted flares burning different types of VOC waste gas. It is the responsibility of the emissions factor user to determine whether or not the factor should be applied to other types of flares.

Comment: Commenter 34 stated that testing of candlestick flares cannot be done. Commenter 34 submitted a graph plotting CO and NOx levels against temperature for enclosed flares, noting that candlestick flares operate at a lower temperature than enclosed flares and must therefore produce lower NOx levels than enclosed flares (see Attachment A to the comment letter).

Response: The EPA notes that there are challenges to testing both candlestick and enclosed flares. While it is not possible to use standard test methods to test a candlestick flare because no stack exists where the emissions occur, there have been tests using extractive sampling techniques, passive FTIR measurements, and DIAL. Enclosed flares also present a challenge for performance testing, as often testing is performed either near the flame or even in the flame. If the testing is not performed an adequate distance downstream of the flame, it is unlikely that the emissions are adequately represented in the sample.

Because candlestick flares can be operated with very large flames and with more available air than enclosed flares, it is not necessarily accurate that flame temperatures of enclosed flares are always higher than those of candlestick flares. However, upon further investigation of the data used to develop the proposed NOx emissions factor, we confirmed that the FTIR instruments were not calibrated for NO or NO_2, so we are not finalizing the proposed revisions to the NOx emissions factor.

<u>Comment</u>: Commenter 56 noted the calculations shown in the spreadsheets are not the same as those shown in the support documents, and EPA does not provide an explanation or validation that the calculations are equivalent. Commenter 56 stated mass emissions can be calculated using a carbon balance technique and this is the process described in the *Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations* (draft EF Development Report); however, the calculations provided in the spreadsheets do not match the equations in the draft EF Development Report.[2]

<u>Response</u>: The EPA disagrees with the commenter. The calculations in the draft report contained the overall, concise calculation in reduced form. In preparing the spreadsheets, we performed the calculations in a step-wise fashion. When preparing the documentation of the calculation, it was evident that certain terms cancelled out, so we provided the overall calculation in reduced form. Thus, we consider that the documentation provided is an accurate summary of the spreadsheet calculation. However, we understand the commenters concern. To help clarify the calculations, the final report has expanded on the calculations to clearly show each step in the calculation process instead of the overall calculation.

<u>Comment</u>: Commenter 52 stated the formula for mass flow of carbon uses 385.5 scf/lb-mole as the molar volume correction factor but the correction factor varies with vent gas stream composition. Commenter 52 stated use of the correction factor in the denominator undervalues the mass flow of carbon in the flare vent gas and emissions per vent gas flared has been exaggerated. Commenter 52 stated the calculation should use appropriate correction factors specific to each vent gas stream.

<u>Response</u>: We disagree with the commenter and maintain that the molar volume correction factor of 385.5 scf/lb-mol, which is based on the ideal gas law, applies equally to all compounds in the vent gas. When we calculate the mass of a particular compound, we multiply by the molecular weight of the compound. So, in that respect, the commenter is correct in that the mass flow of carbon is dependent on the composition of the vent gas, but we adequately

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[2] *Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations*. U.S. Environmental Protection Agency. August 2014.

account for that by using the concentration of each compound, the number of moles of carbon per atom and the molecular weight of carbon to determine the mass flow of carbon.

Comment: Commenter 56 identified several computational errors and spreadsheet referencing errors as technical issues. First, Commenter 56 noted for Marathon Texas City flare CO data, the calculation references CO_2 values instead of CO values. Second, Commenter 56 noted the Marathon Texas City flare VOC factor is miscalculated. Finally, Commenter 56 also stated that the spreadsheets use Exhaust Gas Flow to calculate the emissions factors but the term is not mentioned or shown in the equations in the supporting documentation.

Response: The EPA has reviewed the noted errors and incorporated necessary revisions. Following review of the spreadsheet, we determined that the appropriate CO values were incorrectly referencing CO_2 concentrations in the calculations for the Marathon Texas City flare. This caused an exceedingly high CO emissions factor for this flare, which was subsequently removed as an outlier. We also determined the emissions factor was not calculated correctly for VOC. As a result, the VOC emissions factor was exceedingly low for this flare and it was subsequently removed as an outlier.

With respect to the use of "Exhaust Gas Flow," the EPA notes that the Exhaust Gas Flow is a construct originally used to convert the CO_2 path-length concentration to an apparent exhaust gas flow rate and then use the apparent exhaust gas flow rate and other pollutant pathlength concentrations to a mass flow rate. We later realized that most of the conversion factors in the apparent exhaust gas flow rate calculations cancelled out and one was left with a concentration ratio and molecular weight ratio. In the final spreadsheet we used the calculation methodology consistent with the final documentation report.

2.2 Combustion/Destruction Efficiency

Comment: Commenter 56 stated that recent flare testing and analyses do not suggest a need to revise the existing AP-42 emissions factors at this time. Commenter 56 stated while recent flare testing and analyses have suggested some changes to the operating conditions that define a well operated steam-assist flare, the new flare test data are consistent with the existing emissions factors. Commenter 56 stated existing data and new data both support very high combustion efficiency for steam-assisted and air-assisted flares. Commenter 56 stated however, the new data indicate that the operating envelope for a high destruction efficiency flare requires additional parameters to assess the proper amount of assist gas. Commenter 56 stated while this results in some minor changes to the operating envelope (for steam-assisted flares only) and the parameters used to define it, it does not invalidate the existing emissions factors.

Response: The EPA notes that the original flare data measured total hydrocarbons in lieu of volatile organic compounds. Because VOCs are the regulated pollutant, we feel that it is appropriate to develop a new VOC emissions factor and revise the existing CO emissions factor. As the original AP-42 emissions factor for CO from flares was based on a limit data set, we have determined that the new data set incorporates a wider range of data that will better represent the variability within the categories to which it applies. We also agree that the new flare test data do not invalidate the original emissions factors, and in fact, we continue to include the original test data in the new emissions factor analysis. The new CO emissions factor agrees relatively well with the previous CO emissions factor, indicating that the original test data is still a valuable resource.

Comment: Commenter 56 stated it is inappropriate to revise the basis for combustion efficiency guidance because the conclusion from the proposed Refinery Sector Rulemaking (RSR) that properly operated flares only achieve 98% destruction efficiency is not representative of all flares in all industries. Commenter 56 stated that a 98% flare destruction efficiency is simply the minimum destruction efficiency asserted for refinery flares in the recently proposed RSR. Commenter 56 stated many flares operate with destruction efficiencies exceeding 99%, and all refinery flares will have to average above the 98% minimum to assure compliance with the short averaging time required by the RSR. Commenter 56 stated the AP-42 guidance should not reflect a unilateral reduction of the assumed flare destruction efficiency across all industries.

Response: The EPA notes that AP-42 states that a well operated flare achieves at least 98% destruction efficiency. This is not to say that a well operated flare can only achieve this level of destruction, as it is very possible that a well operated flare can exceed 98% destruction efficiency, as is evidenced by many test runs in the data included in the emissions factor development. We encourage destruction efficiency higher than the minimum of 98% and believe that sources should use a site specific value when it is available and appropriate.

Comment: Commenter 58 stated the existing and proposed flare VOC emissions factors assume flares can achieve 98% destruction efficiency, but studies measuring actual emissions have repeatedly demonstrated that flares frequently do not achieve this level of control. Commenter 58 cited several sources as follows:

- Under the Refinery NESHAP, EPA evaluated process data for 38 steam-assisted flares and found these flares only achieved 93.9 percent destruction efficiency on average.
- Commenter 58 conducted an analysis of PFTIR data collected by EPA for 3 refineries, 2 chemical plants, and 2 flare test facilities. The PFTIR data indicated that flares in compliance with minimum heat values and limits on exit gas velocity pursuant to 40 CFR 60.18 and 40 CFR 63.11(b) only achieved 92 percent destruction efficiency on average.
- Commenter 58 pointed out that EPA research found that facilities have incentive to over steam the flare to prevent visible emissions (VE).
- For specific refineries such as BP Whiting, EPA enforcement calculated that flares release 25 times more pollution than originally reported based on historical operating data.
- At Marathon, the facility determined its historical flare combustion efficiency ranged from 65 to 96%, and emissions were 11 times higher than originally reported across all its refining operations (while EPA enforcement determined emissions were actually 12 times higher).
- DIAL studies at Texas facilities in Houston and Texas City both show flare control efficiency is often lower than thought and actual emissions can be several orders of magnitude higher.
- The NSPS for the oil and gas industry determined that certain flares only achieve 95% destruction efficiency.

Commenter 58 stated EPA must revise the proposed text for AP-42 Section 13.5 since the data show overwhelmingly that flares complying with the regulatory requirements do not achieve 98% destruction efficiency. Commenter 58 notes the proposed Refinery NESHAP rule set minimum heat value in the combustion zone at 270 Btu/scf for general flares and 380 Btu/scf for flares with high hydrogen or olefin content.

Response: AP-42 states that a properly operated flare achieves a destruction efficiency of at least 98% in the plume. This claim is supported by data collected with the original AP-42 factor and other more recent testing. However, it is important to note that the flare must be properly operated to achieve this level of destruction. Oversteaming, for example, is not an example of proper flare operation, and a flare this is oversteamed will not likely achieve 98% destruction efficiency. Our review of the available DIAL studies on flares is included in the final version of the *EPA Review of Available Documents and Rationale in Support of Final Emissions Factors and Negative Determinations for Flares, Tanks, and Wastewater Treatment Systems*.[3]

While we are aware of the fact that people in the oil and gas production sector may use the flare factors at their own discretion, we do not necessarily recommend their use, as many of the flares in the oil and gas sector vary from the types of flares from which we collected data to develop the factors. Additionally, as noted, some flares in the oil and gas sector are not required to achieve the same level of control as the refining and chemical manufacturing sectors, and as such, it is not expected that the emission profiles of those flares would be equivalent to the sources used to develop these emissions factors. We reiterate that we do not recommend the use of emissions factors for site-specific permitting decisions. However, if the end user chooses to use the emissions factors for such purposes, we strongly recommend that the user evaluate whether the factor appropriately represents the source for which it is being used.

In the Refinery NESHAP we proposed that it was necessary to increase the monitoring of certain flare parameters in order to ensure that a flare is properly operated and achieving a destruction efficiency of at least 98%. The comments received on that proposal are currently under consideration.

2.3 Use of Passive FTIR Data

Comment: Commenters 31 and 54 noted that EPA reliance on PFTIR data raises technical and regulatory concerns. Commenter 31 stated PFTIR is new, emerging technology that is still under testing for combustion efficiency, that it has challenges such as the location of the instrument toward the flare, wind speed, etc., and these challenges were mentioned in multiple study reports, e.g., Shell Deer Park and TCEQ. Commenter 37 stated PFTIR has limited dynamic range due to a one-sensor configuration and must operate at lower temperatures

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[3] *EPA Review of Available Documents and Rationale in Support of Final Emissions Factors and Negative Determinations for Flares, Tanks, and Wastewater Treatment Systems* U.S. Environmental Protection Agency. April 2015.

where atmospheric interferences can be significant. Commenter 54 stated that PFTIR does not represent an EPA approved test method for measuring flare emissions and has not been objectively compared against approved testing methodologies to confirm that the readings are accurate, replicable, and sufficiently precise. Commenter 54 stated EPA should take sufficient time to investigate the use of this methodology to determine whether it is appropriately rigorous and reliable to serve as the sole basis for the proposed revised factors.

Commenter 36 expressed concern that the data set was exclusively comprised of PFTIR data. Commenter 36 noted there is nothing to suggest PFTIR improved on DIAL’s remote sensing limitations. Commenter 39 stated PFTIR has many technical shortcomings and noted that EPA's own technical guidance document states that PFTIR can give widely varying results. Commenter 31 stated there is no third party consultant that can act as verifier for the spectral data generated from the PFTIR. Commenter 36 stated PFTIR is not as accurate as testing the gas stream, and EPA should test the gas stream directly. Commenter 39 stated EPA should conduct more testing using a wider variety of testing technologies before relying on any one testing methodology.

Response: We note that the PFTIR data used in the development of the final emissions factors was also used in the Refinery NESHAP Rulemaking and was previously subjected to peer review. While PFTIR is not a standard test method, we note that many emissions factors have been developed using non-standard methods and that there are many non-standard test methods that measure data reliably. This is especially true for source categories that are not suited to standard measurement techniques, e.g. where emissions are not vented to a stack. While we have not promulgated an open-path test method for stack emissions as of this time, we have developed Other Test Method 10 (OTM-10), a testing protocol for optical remote sensing which includes an open path-FTIR method. We have also developed Compendium Method TO-16, Long-Path Open-Path FTIR Monitoring of Atmospheric Gases. This demonstrates that we recognize that open-path FTIR measurement methods are often appropriate and accurate for sources with plumes that are not emitted via a conventional stack.

We also note that the data set used for the proposal of the flare emissions factors did contain mostly PFTIR testing, but it did contain the original extractive emissions test for NOx and CO and a DIAL test for VOC. The data set used for the final factors is made up of tests using all three of these sampling techniques.

Comment: Commenter 37 stated PFTIR is commonly used to measure combustion efficiency. Commenter 31 stated the PFTIR instrument was intended to measure combustion efficiency of hydrocarbons and not NOx. Commenter 38 stated the emissions data are unreliable. Commenter 53 requested EPA reconsider use of PFTIR data. Commenter 49 stated the PFTIR data should be discarded and the flare emissions factors revised.

Response: As stated above, we note that the PFTIR data used in the development of the final emissions factors was also used in the Refinery NESHAP Rulemaking and was previously subjected to peer review. We have also recognized that open-path FTIR measurement methods are often appropriate and accurate for sources with plumes that are not emitted via a conventional stack. We conclude that the VOC and CO emissions data from PFTIR tests are adequate for use in emissions factor development. The NOx emissions data from the PFTIR tests are not being considered in emissions factor development because the instrument was not calibrated for NO and NO_2 prior to the test, making the quality and accuracy of the data questionable.

Comment: Commenters 54 and 56 stated the proposed factors were developed using some technically inappropriate analyses and methodologies and cited several technical issues identified in the development of the proposed factors. Commenter 56 stated these issues should be addressed in the development of any updated CO, VOC or NOx emissions factors for flares.

Response: We have reviewed the noted errors and technical issues which are discussed throughout this chapter and have incorporated any necessary revisions.

Comment: Commenter 56 stated that selected data across all runs and conditions was aggregated together from each flare, and this approach masks important quality characteristics of the data.

Response: The EPA agrees with the commenter and has revised the analysis to consider data on a run-by-run basis. This approach is more consistent with how we normally develop emissions factors using standard test methods.

Comment: Commenters 50, 53, 54 and 56 identified use of PFTIR minute data instead of run average data as a technical issue. Commenters 53 and 56 stated one-minute data points are not representative. Commenter 56 stated that the concentration x pathlength values (ppm-m) for each pollutant are recorded every minute and the data acquisition periods (runs) are approximately 10 to 20 minutes. All minute data points collected during a run are averaged for each pollutant, and these run average values are used to calculate flare combustion efficiency. Commenter 56 stated PFTIR measurements are taken across a small cross-section of the plume and require both spatial and temporal averaging to be representative of flare combustion chemistry and that run average data is necessary for valid analyses. Commenter 56 also noted that for [other] recent flare testing, EPA has required facilities to use a 20-minute averaging period, which serves as a guideline for an appropriate averaging interval. Commenter 54 stated use of minute data contradicts EPA's RPDEF document (see p.4-1 of the RPDEF document). Commenter 52 stated that EPA requires one-hour sample runs for its test methods for compliance. Commenter 52 stated EPA should not use different sampling techniques to develop an emissions factor than what is required to show compliance.

Commenter 40 stated EPA's logic to exclude one-minute periods where a flare is achieving less than 96.5 percent combustion efficiency does not hold. Commenter 40 stated the exclusion of one minute data associated with periods of low flare combustion efficiency is not sufficient to ensure that the data that was relied upon is representative of normal flare performance. Commenter 40 stated FHR AU test run 24 consisted of 31 one-minute data points and only 3 one-minute data points from the test run were used. Commenter 40 stated because the steam flow was elevated throughout the run, even these 3 data points correspond to periods where the flare steam to vent gas ratio was elevated (greater than 3.5). Commenter 40 stated the mere exclusion of data associated with low combustion efficiencies does not change the fact that the flare was operated at elevated steam rates throughout the run and achieved an average run combustion efficiency of just 88 percent, and is not sufficient to ensure the remaining data is representative of normal flare performance.

Response: The EPA agrees with the commenters that it is more appropriate to consider data on a run-by-run basis and has revised the analysis of the data. This approach is more consistent with how we normally develop emissions factors using standard test methods. We have revised the analysis to consider combustion efficiency on a run-by-run basis instead of a minute basis.

We do not believe that there is an issue with using the test runs, despite the fact that they are shorter than most, but not all, compliance tests. Emissions factor development and compliance testing represent two different goals and thus data is used differently in each process. For example, in emissions factor development, we use half of the detection limit when data is below the detection limit. But many air agencies require the use of the full detection limit when data is below the detection limit in order to ensure that detection limits can reliably demonstrate compliance assurance. Emissions factor development is not compliance assurance; it is development of an estimate of an average emissions profile for a source. We expect half of sources to emit at rates higher than what is predicted by the emissions factors.

We also note that while the test runs are shorter than most compliance tests, there are more of them. Therefore, the amount of useable data is actually greater than data from a conventional compliance test made up of three one-hour sampling runs.

Comment: Commenter 40 stated that PFTIR testing measured compounds in concentration x pathlength (ppm-m). Commenters 53 and 56 stated PFTIR does not measure absolute/actual concentration and to calculate mass emissions, the pathlength must be known but because the plume dimensions are constantly changing, the pathlength/plume width is not known. Commenters 37 and 40 stated the pathlength (in meters) of the flare plume must be known, and since the purpose of testing was to determine combustion efficiency and not emissions, the flare path, which varies, was not measured. Commenter 37 stated PFTIR technology assumes a consistent path measurement, which is problematic for a dynamic and variable flare plume.

Response: While the EPA agrees that PFTIR measures in units of concentration-pathlength, we do not believe that it is necessary to know the pathlength in the emissions factors calculations. The calculation approach estimates the mass of the pollutant from the pollutant concentration to CO_2 concentration ratio. Because the CO_2 measurement is also in units of concentration-pathlength and occurred on the same pathlength as the pollutants of interest, pathlength cancels out in the calculation.

Comment: Commenters 50, 54 and 56 identified use of a pollutant ratio model to calculate NOx mass emission rates based on CO_2 data as a technical issue. Commenter 56 stated that because absolute concentrations of pollutants are not directly measured by the PFTIR, pollutant mass emissions are estimated from the pollutant to CO_2 ratio, so accurate CO_2 measurement is critical for converting ppm-m to estimated lb/mmBtu. Commenter 56 stated that a fundamental assumption used for the emissions factor development is that the pollutant emission rate can be predicted as a function of CO_2. Commenters 53 and 56 stated a correlation between the pollutant and CO_2 must be present in the data, and if the data shows no correlation, this approach cannot be used. Commenter 56 stated there must be a physical relationship between the pollutant generated and CO_2. Commenter 53 stated the basic chemistry of NOx formation does not support this assumption, and the assumption becomes problematic when the vent gas stream is high in hydrogen. Commenter 56 noted that in the pollutant ratio calculation it is assumed that NOx emissions are solely a function of CO_2 generation in the flare plume, and while this may be true of CO and VOC, NOx is not a direct product of hydrocarbon combustion but rather is formed through thermal NOx, prompt NOx, and fuel NOx. Commenters 22 and 56 pointed out that because hydrogen combustion generates NOx with no CO_2, the presumption that NOx emissions can be predicted from CO_2 generation is not valid for any flare with hydrogen in the vent gas, at least not with the emissions model EPA proposes here. Commenter 22 referenced a presentation from the American Flame Research Committee (AFRC) 2014 Industrial Combustion Symposium entitled, "A Critique of the Flare Provisions of EPA's Proposed Refinery Sector Rule". Commenter 50 also stated the model does not account for NOx generation from hydrogen combustion. Commenter 50 noted that when applying the NOx/CO_2 model on high hydrogen flares such as FHR AU, the calculated NOx emissions are biased high. Commenter 56 stated that since NOx is a function of both plume CO_2 and vent gas hydrogen concentration, a NOx/CO_2 ratio model is not appropriate nor technically justifiable.

Commenter 56 stated EPA's use of aggregated one-minute data and the censoring of that data in their analysis obscures such relationships if they do exist. Commenter 56 stated such a relationship has been demonstrated in the case of combustion efficiency as shown in the many combustion efficiency graphs found in the flare reports; however, EPA does not demonstrate the presence of a similar relationship between each pollutant and CO_2. Commenter 56 provided two graphs that show data from 2 specific runs where a demonstrated relationship exists; a clear relationship is revealed by looking at the run average data, and the commenter also noted the slope of the correlation line is not the same for these two conditions. Commenter 56 stated this is highly relevant to determination of accurate emission estimation for PFTIR data but is completely ignored in EPA's analysis.

Commenter 56 stated the ratio needed for this analysis is not the ratio of individual one-minute data points, but rather the slope of the regression line; if a regression line cannot be drawn, there is no correlation. Commenter 56 provided a figure that shows NO_2 ppm-m vs. total C ppm-m from FHR AU flare test (the data shows no evidence of correlation between NO_2 and C for aggregated [minute data?] or run basis) and from TCEQ 2010 data (the data shows clear correlation between NOx and total C, and the ratio is determined from the slope of the regression line) (see Figure 6 of the comment letter). Commenter 56 also provided a figure showing NO_2 data vs. CO_2 2k data for FHR AU flare tests and stated that the relation presumed between NO_2 and CO_2 does not exist in the data. Commenter 56 stated, therefore, that one of the two main conditions necessary to convert PFTIR data to mass emissions data is not met for the FHR AU flare.

Commenter 56 stated the data do not show a reliable correlation between NOx emissions and CO_2 in the flare plume for these PFTIR tests; this is caused by the combined effects of the use of uncalibrated NO/NO_2 data, use of minute data rather than run average data, and an emission model that does not take hydrogen into account.

Response: The calculations do not assume that NOx emissions correlate to CO_2 emissions. The use of CO_2 in ppm-m was entirely for the purpose of determining the pathlength of the measurement.

One would expect flares with high hydrogen content to produce more NOx per CO_2 than hydrocarbon flares because of the high adiabatic flame temperature of hydrogen and the lack of carbon in hydrogen. However, the calculation of the NOx mass is not dependent on there being a direct correlation between the pollutants, only that the pathlength is the same.

Nonetheless, due to the lack of calibration of the PFTIR instrument for NOx compounds, we are not using the PFTIR data to develop a revised NOx emissions factor. We have, however, retained this approach for development of the CO and VOC emissions factors, although we have changed the analysis to look at data on a run-by-run basis instead of a minute basis.

<u>Comment</u>: Commenter 56 noted an "adjusted CO_2 value" column in EPA spreadsheets appears to filter data exceeding an EPA-defined error threshold; however, the rationale for this adjustment is unclear and not compatible with the data analyses algorithms developed for the validated PFTIR methods.

<u>Response</u>: The “adjusted CO2 values” were used to identify the most appropriate CO_2 measurement for each minute. This approach was documented in the draft emissions factor development report. In the final emissions factor analysis, we no longer included this approach because we were provided information on the most appropriate CO_2 spectral band to use for each test run (see Attachment B) by Clean Air Engineering, who participated in the PFTIR testing. This information was provided via API.

<u>Comment</u>: Commenters 50, 54 and 56 identified apparent averaging of the carbon dioxide (CO_2) spectral bands rather than choosing the appropriate band based on spectral analysis as a technical issue. Commenter 56 noted CO_2 exhibits spectral characteristics around 2000 cm^{-1} (2k), around 1000 cm^{-1} (1k), and around 765 cm^{-1}. Commenter 56 noted the 1k region has water interference and possibly organics interference, tends to be unreliable particularly for a steam-assisted flare, and is seldom used in data analysis. Commenter 56 noted either the 765 or 2k region is typically used. Commenter 56 stated the 765 cm^{-1} region offers strong signal strength and lack of interference; however, it is at the edge of the detector range, occasionally becomes detection limited, and may not be usable. Commenter 56 stated the 2k region has less intense signal strength than the 765 cm^{-1} region, but does not have significant interferences like the 1k region. Commenter 56 stated a determination of which spectral region is applicable for an individual test run is made on-site by a spectroscopist and there is no automated technique available at this time. Commenter 56 stated EPA's approach to average the 765 cm^{-1} and 2k region data introduces error into the emissions factors (see Figure 3 of Appendix A of the comment letter). Commenter 56 further stated accurate CO_2 measurements are critical for determining reliable emissions factors, and biases in the CO_2 measurement affect all 3 factors (VOC, NOx, and CO).

Commenter 56 stated the INEOS test [used in analysis for CO, NOx, and VOC] predated detector advancements that afforded the IR spectral data choices of the current configuration, so it was one of the few instances where 1k CO_2 data was used for the analysis. Commenter 56 stated that because of the unilateral application of an average of 765 cm^{-1} and 2k data, the analysis completely dismisses the 1k data for this test set. Commenter 56 stated the spreadsheets in the supporting documentation do not list 1k CO_2 data from INEOS, so in the case of the INEOS factor, the proper data was not used for the analysis, as part of an average or otherwise.

Response: The EPA developed a standard approach for analyzing the CO_2 data prior to proposal. The 1k data was removed from the test data because we were aware of the interference issues. However, as mentioned above, we have received additional data indicating the correct CO_2 spectral band for each test run and have incorporated this into our final analysis.

Comment: Commenters 50, 54 and 56 identified use of unweighted, rather than hydrocarbon weighted, combustion efficiency as a technical issue. Commenter 56 stated it is unclear why the unweighted CE value was used. Commenter 56 stated the weighted combustion efficiency accounts for the number of carbon atoms in each molecule of the compounds detected in the flare plume, and the unweighted value does not have any analytical value, is never used for any calculation, and is not representative of the actual combustion efficiency of the flare. Commenter 56 stated EPA's use of unweighted values results in emissions factors that are biased high and is not technically supported.

Commenter 56 stated there are additional issues with data filtering that are introduced from use of unweighted combustion efficiency. Commenter 56 noted EPA included all minute data with an unweighted CE > 96.5 percent; however, since unweighted CE is higher than weighted CE, this approach results in low CE data points being included. Commenter 56 provided a figure showing unweighted point combustion efficiency values compared to weighted run averages (see Figure 4 of the comment letter). For example, Commenter 56 noted that for FHR AU A3.0(2) test run, almost every data point in the set was included in the analysis even though the run itself had a weighted CE <96.5 percent. For FHR AU C3.7(1), the minute data point value of 4464 lb/mmBtu is not physical possible and illustrates how inclusion of single data point from unweighted CE is problematic, and because the weighted CE for the minute point and the run average is <96.5 percent, this point would have been excluded if weighted CE were applied.

Response: Based on the comments received, the EPA has revised the analysis to use weighted combustion efficiency when a choice exists between weighted and unweighted combustion efficiency. If only one combustion efficiency is reported in the data file, we assumed that it was the weighted combustion efficiency.

Comment: Commenters 54 and 56 identified misinterpretation of PFTIR zero data values as a technical issue. Commenter 56 stated zero data are unlikely to represent actual emissions values and should not be included. Commenter 56 stated for the MPC DET data, 94 percent of the data used to determine the NOx emissions factor were zero, and for FHR AU, 71 percent were zero. Commenter 56 stated the PFTIR software reports a data point as zero if a QA/QC check is failed (may be a result of not calibrating for NO and NO_2), a poor fit is observed between the sample spectrum and reference spectrum, data are below the detection limit, or if the PFTIR is aimed too close or too far from the flame. Commenter 56 stated the decision whether or not to include a zero is determined by a qualified spectroscopist. Commenter 56 stated for NO and NO_2, the evaluation of zeroes was never performed since the data were never intended to be used, and the decisions for other pollutants [CO, VOC] were made when analyzing the PFTIR data in the flare reports; second-guessing these decisions by assuming all zeroes represent actual data leads to less reliable results.

Response: We are not using the NO and NO_2 data from the PFTIR studies to revise the NO_x emissions factor for flares.

In the final emissions factor analysis for VOC and CO, consistent with the commenter's statement that the onsite spectroscopist determines which zero data points should be included, we used the test run averages as reported in the facility's spreadsheet when the average was already calculated. When averages were not calculated, we averaged all of the minute data over the course of a test run, assuming the decision to keep the zero data points had already been made.

Comment: Commenter 56 provided a recommended approach to analyzing PFTIR data for outliers. Commenter 56 stated that each run is an independent test that should be judged in comparison to all of the other runs; outliers should be identified on a run-by-run basis rather than on a flare-by-flare basis. Commenter 56 stated the following steps should be followed: transform the data; check for normality; perform the outlier test; determine how to handle the outliers; and calculate the emissions factor.

Response: The EPA followed its emissions factor development procedures for considering outliers. These procedures were previously posted for public comment. The procedures look at data on a unit-by-unit basis rather than a run-by-run basis. One of the reasons for this approach is to keep data from one unit from unfairly influencing the data set for the universe of sources, i.e. all of the runs used for emissions factor for a source category should not come from one source.

Comment: Commenter 36 stated with the low Individual Test Rating (ITR) scores, the cited tests would not be acceptable for compliance testing.

Response: As previously explained in this chapter, emissions factor development is not the same as compliance testing. The criteria needed for one is not always equal to the criteria needed for the other. For example, there are procedures for correcting data collected from a run with a failed leak check; an air agency may choose to accept this data for compliance purposes, especially if the data are biased high and the facility is not near its compliance limit. However, this data would be less useful for emissions factor development because data that is biased high would result in an emissions factor that is biased high.

It is important to note that we also are not passing judgment on whether a delegated air agency would accept an individual test for compliance purposes. The ITR scores for the tests in this project consist of only a completeness check based on the EPA's opinion of what makes a test report complete. Air agencies vary considerably on what is required in a test report in order for it to be considered complete. Some agencies require all supporting documentation to be present, while others only require a summary of the test results.

Comment: Commenter 18 stated that the EPA neglected to publish the quality assurance project plan used to obtain pollutant concentrations from the PFTIR measurements used in the development of the proposed factors, which calls the accuracy of the data into question.

Response: The PFTIR tests were conducted under the direction of either the TCEQ or the EPA. Most of the PFTIR data was collected to develop operating limits for consent decree requirements and were therefore subject to significant quality assurance and review. Additionally, the PFTIR data was then compiled and subjected to peer review prior to its use in the Refinery NESHAP proposed rule. Therefore, we consider the data to be reliable and accurate for CO and VOC. Because the PFTIR was not calibrated for NOx species, the quality and accuracy of this data is unknown, rendering the data questionable.

2.4 Use of DIAL Data

Comment: Commenter 54 stated that DIAL does not represent an EPA approved test method for measuring flare emissions; it has [not] been objectively compared against approved testing methodologies to confirm that the readings are accurate, replicable, and sufficiently precise. Commenter 54 stated EPA should take sufficient time to investigate this use of this methodology to determine whether it is appropriately rigorous and reliable to serve as the sole basis for the proposed revised emission factors. Commenter 36 noted the DIAL study cautioned about limited viability of its remote sensing capabilities.

Response: We note that many emissions factors have been developed using non-standard methods and that there are many non-standard test methods that measure data reliably. This is especially true for source categories that are not suited to standard measurement techniques, e.g. where emissions are not vented to a stack. DIAL measurements have been evaluated and compared with other measurement methods, including FTIR, Ultra Violet Differential Optical Absorption Spectroscopy (UV DOAS), and grab sampling methods. While we have not promulgated an open-path test method for stack emissions at this time, we have developed OTM-10, which is a testing protocol for optical remote sensing, which includes DIAL method. This is evidence that we recognize that DIAL measurement methods are often appropriate and accurate for sources that are not emitted via an easily measurable stack.

Comment: Commenter 56 stated that in Section 6 of the Refinery Protocol, the 3rd and 4th sentences in 2nd paragraph indicate that the DIAL technique provides direct measurement but is only a snapshot. Commenter 56 noted that DIAL is very limited in the emissions it can identify, much less quantify, and is difficult to employ even for short term use. Commenter 56 believed these sentences and the related following sentence overstate DIAL's value and they should be deleted.

Response: The EPA disagrees with the commenter. Unless a source is continuously monitored, all emissions testing is a snapshot, making DIAL measurements as relevant as other test methods. DIAL is a valuable technique for determining emissions within a measurement plane. We have recognized its value through issuance of OTM-10. While it can be difficult to isolate emissions attributable to specific sources, especially on a large plant site, with proper technique, it is possible to do so.

2.5 Industrial Flare NOx Emissions Factor

Comment: Commenter 58 stated the revised Flare NOx emissions factor is based on a robust data set and will enable facilities to more accurately report emissions. Commenter 58 stated the Flare NOx emissions factor and the Flare VOC emissions factor have been developed from a significant body of evidence to assure they are representative of actual conditions.

Response: The EPA acknowledges the comment. As discussed in greater detail later in this section, we are not finalizing the proposed revision to the NOx emissions factor because the PFTIR instrument was not calibrated for NOx species. We are finalizing the VOC emissions factor for flares.

Comment: Commenter 58 stated the proposed flare NOx emissions factor is based on accurate, representative data. Commenter 58 stated the revised NOx factor is based on 5 PFTIR studies (3 studies were at actual industrial facilities) plus the existing emissions factor; the PFTIR studies included 85 test runs and 2,075 data points that were reviewed by an expert panel (for developing new monitoring and operating requirements at refineries) that found the underlying test data was reliable. In contrast, Commenter 58 stated the original emissions factor is less reliable and accurate than the new PFTIR data, in that it included 1 study of extractive measurement at 2 pilot scale test flares at a flare test facility, 42 test runs, the fuel was propylene diluted with N_2 which is not representative of industrial flares that combust gas mixtures, and the accuracy of extractive probes is uncertain (expert panel stated it is difficult to place in a representative location).

Commenter 58 stated EPA's continued acceptance of the underlying data used to derive the original emissions factor is unsupported because those tests were not combusting gases that represent gas routed to industrial flares. Commenter 58 stated the revised emissions factor is likely biased low because it includes the original AP-42 data in the average; excluding the original AP-42 data gives a value of 3.4 lb/MMBtu (rather than 2.9).

Response: The EPA acknowledges the comment. While we agree that the data set was robust, as discussed in greater detail later in this section, we are not finalizing the proposed revision to the NOx emissions factor because the PFTIR instrument was not calibrated for NOx species. We also note that even though the flare data was peer reviewed prior to inclusion in the Refinery NESHAP proposed rule, the charge of the peer review panel surrounded questions related to flare combustion efficiency. The NOx emissions data was not part of the peer review.

Comment: Commenters 43, 49, 50, 53, 54 and 56 identified use of uncalibrated nitric oxide (NO) and nitrogen dioxide (NO_2) data as a technical issue. Commenters 18, 30, 49 and 56 stated PFTIR is used to measure combustion efficiency. Commenters 49 and 56 stated there was no intent to gather NO or NO_2 concentration data, and since the NO and NO_2 measurements were not intended for use, the instrument was not calibrated for these pollutants. Commenters 18, 30, 37, 38, 40, 49, 53, 54 and 56 stated the PFTIR instruments used at all of the recent flare tests were not calibrated for NO or NO_2 (or NOx). Commenter 39 stated it is not clear how the NO and NO_2 were calculated using PFTIR technology and whether or not the instrument was properly calibrated to measure these pollutants. Commenter 38 stated the interference tests were not run, response times were not included, and no drift tests were conducted. Commenter 49 stated that in general, EPA does not accept emission testing data from industry that does not meet the calibration protocol, and considers it to be unreliable and unacceptable. Commenter 56 noted this rendered the calculated NOx emission factor as not technically defensible.

Commenter 56 stated NOx values are included in the flare reports only because they are part of the standard PFTIR software reporting format, and it was an unfortunate error that these uncalibrated data were not removed from the test reports. Commenter 56 stated that for proper measurement, the spectral region corresponding to the compound must be identified, and a NIST traceable calibration is performed. Commenter 56 stated that although the PFTIR analytical method used during the tests had a general region for NO and NO_2 defined, it was never fine-tuned to avoid interferences. Commenter 53 stated that water can be a major source of interference, especially for steam-assist flares when the spectral bands are not optimized for a certain compound. Commenter 56 stated that most of the data used for the NOx emissions factor were generated from testing on steam-assist flares that have high water content in the flare plume in additional to other water sources and humidity, and it is likely that much of what is reported as NO or NO_2 is in fact water vapor.

Response: Prior to proposal, we were unaware of the issue with the NOx data on the PFTIR tests. Because the reports spoke to how the instrument was calibrated, we assumed that it was calibrated for all of the pollutants for which data was reported. Based on this comment, we reached out to Clean Air Engineering and IMACC, who performed the PFTIR testing to determine whether the instrument was calibrated for the NOx measurements. We received a signed letter dated April 10, 2015, from Dr. Robert Spellicy of IMACC, the operator of the PFTIR and a leader in PFTIR measurements (see Attachment A). The letter indicates that the instrument was not calibrated for NO and NO_2 during any of the flare testing. Due to the lack of calibration, we agree that the data is questionable and have chosen not to use the data for emissions factor development at this time.

Comment: Commenter 54 noted the flare NOx emissions factor is unnecessary, beyond the scope of the CD, and should not be finalized. Commenter 30 requested that the EPA delay any revision of the AP-42 factor for NOx from flares.

Response: As explained in previous responses, the EPA has determined that the available NOx data are not adequate for emissions factor development at this time. Therefore, we are not finalizing the proposed revisions, and we are retaining the current NOx emissions factor for flares of 0.068 lb/MMBtu in AP-42.

Comment: Commenter 49 stated that one emissions factor does not capture the emissions from flares used in a wide range of industries combusting a wide range of waste gas streams with varying heat content. Commenter 49 stated emissions from flares are the products of combusting the waste stream, and NOx formation results from thermal NOx, fuel NOx, and prompt NOx. Commenter 49 stated that while the emissions factor is assumed to account for each type of NOx formed and to capture emissions from various waste stream compositions, this is not realistic. Commenter 49 noted that thermal NOx depends on combustion temperature, and combustion temperature is based on the heat content and percent of individual components in a stream, or heating value (Btu/scf). Commenter 49 stated the waste stream combusted at a refinery does not have a similar profile to waste streams at natural gas sites; the waste streams have different heating values and different combustion temperatures, and therefore generate different amounts of thermal NOx. Commenter 49 stated the NOx emissions factor does not consider the heating value of the gas being combusted or the variation of waste gas composition with industry type. Commenter 42 stated the proposed NOx emissions factor should only be used for relevant industries and not as a general all-inclusive factor.

Response: As explained in previous responses, the EPA has determined that the available NOx data are not adequate for emissions factor development at this time. Therefore, we are not finalizing the proposed revisions, and we are retaining the current NOx emissions factor for flares of 0.068 lb/MMBtu in AP-42. We agree that all emissions factors should only be used for the industries that they represent unless a user has determined on a case-by-case basis that the factor is representative for its intended use.

Comment: Commenter 41 stated the revised NOx emissions factor is based on limited data. Commenter 19 asserted that the five tests were not representative of NOx concentrations. Commenters 16 and 24 stated that the EPA used inappropriate and limited data to develop the proposed revised AP-42 industrial flare NOx emissions factor. Commenter 52 stated 4 test reports from 5 flares are not adequate to determine an average emissions factor for all flares of varying size, service type, and method of operation.

Commenter 35 stated concern that the test results average of 2.9 lb/hr, is an increase of 42 times the old NOx flare emissions factor, and resulted from only five flare tests with a range of 0.011 to 16 lb/hr. Commenter 52 stated that for determining statistical outliers, the sample size is small for the flare NOx emissions factor. Commenter 37 stated the emissions factor should be based on a statistically significant number of flares. Commenter 42 requested EPA reevaluate the flare NOx emissions factor and expand the data set to ensure the data are scientifically sound, appropriate for intended end use, and appropriately adequate to develop new factors. Commenter 52 stated EPA should delay revising the emissions factor until it has collected data under normal operating conditions from representative industries.

Commenter 52 stated none of the test reports used for the new flare NOx emissions factor were collected for developing new emissions factors and operating conditions are not representative of normal flare performance. Commenter 16 explained that the all of the tests used to develop the emissions factor were not conducted to determine NOx emissions, and instead were conducted to determine the effect of varying operating conditions on the flares' combustion efficiency. Commenter 52 stated none of the test reports relied on for the revised NOx emissions factor included any data on NOx emissions. Commenter 52 stated the fact that the raw NOx emissions data was not the focus of the underlying test report questions the validity of the data and EPA's reliance on it. Commenter 16 added that the data was subject to heavy manipulation by the EPA because of the EPA using data from what it defined as "normal" operating conditions, which only applied to approximately 31% of the data.

Commenter 57 stated the proposed revisions to flare NOx emissions factors are not based upon directly measured NOx emissions from flares, and are based upon remote sensing technology measurements from an instrument not calibrated to measure NOx. Commenter 57 noted the real-world operating conditions of the testing is preferable to the highly controlled and artificial conditions used to develop the original emissions factor; however, no directly measured NOx emission samples were actually taken as a part of the testing for the revised emissions factors, as the tests were conducted with the goal of establishing VOC emission estimates, and not for NOx or other combustion contaminants. Commenter 57 did not believe the testing was designed adequately to determine NOx emissions.

Response: As discussed previously, the EPA has determined that the available NOx data are not adequate for emissions factor development at this time because the PFTIR instrument was not calibrated for NOx species. Therefore, we are not finalizing proposed revisions to the NOx emissions factor.

Comment: Multiple commenters suggested EPA review other available testing data for NOx emissions from flares, including 2010 TCEQ extractive NOx data, 2010 IFC extractive NOx data, and 2013 Dow Chemical Company extractive NOx data (at test facility).

Commenter 17 stated that the EPA should not revise the emissions factor for NOx emissions from flares to 2.9 lbs/MMBtu in Table 13.5-2 without further reviewing existing test data and incorporating new test data. Several commenters noted that other flare testing has been done with the intention to measure NOx emissions. To more accurately establish standard emissions factors for flares, Commenter 57 suggested EPA take advantage of actual emissions tests designed to accurately measure specific pollutants such as NOx conducted on flares in the San Joaquin Valley and other regions. Commenter 50 stated EPA has recent NOx test data for

TCEQ and IFC that show the NOx factor is lower than the current emissions factor, and the commenter was puzzled why EPA chose the flawed data to propose a higher NOx emissions factor. Commenter 53 suggested 2010 TCEQ data and IFC data more accurately represent refinery flare operations and could be used to develop AP-42 factors; the 2010 TCEQ average emissions factor is 0.017 lb NOx/mmBtu.

Commenter 54 stated that not all available data were considered in the emissions factor development. Commenter 54 noted that high quality data was obtained from extractive sampler in the 2010 TCEQ flare emissions study and from the November 2013 Dow Chemical Company testing at the John Zink Company test facility (6 runs for steam-assisted flare for 0.15 lb/mmBtu NOx and six runs for pressure-assisted flare for 0.16 lb/mmBtu NOx).

Commenter 56 stated the TCEQ 2010 test included extractive sampling in addition to PFTIR testing that provided good NOx data during the propane runs, as the extractive instruments were properly calibrated during propane test runs. Commenter 56 stated the NOx emissions were 0.0172 lb/mmBtu at 96.5 percent CE; 0.0229 lb/mmBTU at 98 percent CE, and 0.0362 lb/mmBtu at 99 percent CE. Commenter 56 noted that the emissions factor for 96.5 percent is lower than the current emissions factor, and this suggests a revision downward of the current factor is supported by this higher quality data. Commenter 56 stated IFC 2010 data shows NOx emissions factor ranging from 0.0093 to 0.093 lb/mmBtu. Commenter 56 noted that the valid data from recent flare tests indicate NOx factors should be lower than the current value, not 40 times higher.

Commenter 54 stated EPA failed to use all testing data available to them for this analysis, failed to use higher quality data from the TCEQ and Dow studies, and failed to recognize the sufficient amount of data needed to establish the validity of the new factor. Commenter 54 stated that had EPA included all of the relevant data including the TCEQ and Dow extractive sampler data in its calculation of average flare emissions, even including the statistical outlier FHR data would have had a lesser impact on the resulting emissions factor.

Commenter 18 stated that to develop the proposed emissions factor revisions for flares, the EPA relied primarily on PFTIR spectroscopy measurements of five to nine refinery flares, existing factors in AP-42, and one set of DIAL measurements. Commenter 18 stated that the EPA neglected to analyze more robust sources of data for inclusion in developing revised flare emissions factors, such as extractive sampling measurements from the TCEQ's 2010 flare study, which the commenter notes should be analyzed for NOx emissions factor development.

Commenter 17 included data from 2 tests, one for a steam assist flare tip and one for a pressure assist flare tip, that it sponsored at the John Zink Company test facility in Tulsa, Oklahoma, on November, 2013. The results of the testing were provided to EPA's OAQPS in February 2014, and data tables were provided (see Table 2 and Table 3 of the comment letter).

Commenter 17 concluded from their submitted data that the proposed factor of 2.9 lbs/MMBtu would result in a gross overestimate of NOx emissions from flares.

Commenter 30 stated that the 2010 TCEQ report stated that the NOx data measured during those tests were measured using an analyzer that did not meet data quality specifications and were not included for that reason.

Response: The EPA appreciates the cites to additional available flare testing data. For data that was not provided in the comments, we reached out to commenters to obtain the data, and we have reviewed the additional data. Unfortunately, we have determined that none of the available data is appropriate for use in revising the NOx emissions factor for flares.

The 2010 TCEQ flare study project did describe the use of extractive measurements for NOx and other pollutants. The extractive measurements generally agreed well with the passive FTIR tests in determining flare combustion efficiency (providing further verification of the FTIR results). However, the 2010 TCEQ report specifies that “NOx was also measured during the flare tests, but it is not included because NOx was measured using a commercial chemiluminescence analyzer. This instrument did not meet the data quality objectives over all the ranges of DRE observed.” Although this was stated under the heading of the propylene tests, the report does not specify that the NOx data for the propane tests met the data quality objectives. There is also no information on whether this affected only certain test runs and what objectives the analyzer failed to meet. Because the TCEQ extractive NOx measurements did not meet the data quality objectives and the extent of the data quality issues are unknown, the resulting data are questionable and are not appropriate for use in developing revised NOx emissions factors for flares.

We also reviewed the flare studies conducted by the International Flaring Consortium (IFC), which conducted a series of studies on a small (3 inch diameter) flare tip in a wind tunnel so the entire flare plume could be exhausted through the wind tunnel stack (Gogolek et al, 2010).[4] The results of the IFC studies are reported by Gogolek et al. (2012).[5] We attempted to obtain the raw test data for this study as well as the QA procedures and results to ensure data quality. We were not able to obtain the raw data, so we cannot incorporate these data into a revised NOx emissions factor for flares. However, the current NOx emissions factor for flares in AP-42 falls within the range of values reported from the IFC studies as noted by the commenter. While not fully validated, the extractive NOx data that are available, suggests that the existing NOx emissions factor is reasonably accurate. Therefore, we conclude that it is not necessary at this time to revise the existing AP-42 NOx emissions factor for industrial flares.

We previously reviewed the 2013 Dow flare testing conducted at the John Zink Company test facility as part of a request for an alternative means of emission limitation. The flare in question is a multi-point ground flare. Ground flares are different from a standard “candlestick” flare in both design and operation. Instead of a single flame or flame ring at the top of the flare, multi-point ground flares consists of many rows of individual flares tips located slightly above ground level. These flares use high velocity (up to sonic velocity level) to enhance combustion. Because of the high tip velocities, the ground flare in question cannot comply with the General Provisions of Part 60 or Part 63, which was the reason why Dow submitted the request for an alternative means of emission limitation. We have no data to indicate that ground flare emissions are representative of a candlestick flare’s emissions. Due to the differences in design and operation, we do not consider it appropriate to combine data from a multi-point ground flare with data from a candlestick flare. We may revisit this issue in the future if we obtain more test information on multi-point ground flares.

Finally, we reviewed three test reports for landfill flares located in the San Joaquin Valley Air Pollution Control District (SJVAPCD). This testing included information on NOx, VOC, and CO emissions data using a combination of CARB and EPA reference methods. However, as landfill flares are covered in Section 2.4 of AP-42 and belong to a different SCC than the flares in Section 13.5 of AP-42, we did not consider this data appropriate for developing emissions factors in Section 13.5. We may incorporate this data in future revisions to Section 2.4 of AP-42.

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[4] Gogolek, P., A. Caverly, C. Balderson, J. Pohl, R. Schwartz, J. Zink, and J. Seebold. *Flare Test Facility – Equipment and Calculations.* Prepared for International Flaring Consortium. April 2010.

[5] Gogolek, P., A. Caverly, C. Balderson, R. Schwartz, and J. Seebold, and J. Pohl. *Flare Test Facility – Equipment and Calculations.* Prepared for International Flaring Consortium. January 2012.

Comment: Commenter 52 stated the existing Flare NOx emissions factor has an individual test rating (ITR) of 80, while the new data sets have ITRs ranging from 38 to 52, which indicates inferior data quality. Commenter 52 stated EPA should disregard the new data and retain the current existing emissions factor for NOx, as supported by the OIG Evaluation Report that stresses data quality over data quantity.

Commenter 52 stated the FHR AU test has an ITR of 38, stated there has been no assessment of the validity or representativeness of data (cited missing calibration gas certifications, calibration error tests, drift test, bias tests, and stratification tests), and noted that EPA should not use data for emissions factor development that would not be accepted for showing compliance. Commenter 52 stated FHR AU data should be excluded. Commenter 52 stated EPA should review all other ITR data and exclude other data that is not reliable.

Response: The methods we use to determine the emissions factor and the appropriateness of adding additional test data considers the ITR rating. However, when very few tests are available, increasing the sample size has a significant impact on the confidence interval of the mean. Using our emissions factors development tool, we first rank the data based on the ITR rating. We then sequentially add test data values as long as the addition of the next lowest ranked data improves the overall confidence in the average emissions factor. Therefore, we recognize the need to balance the quality of data and the quantity of data when developing an emissions factor. The methods we used support the inclusion of the PFTIR data for finalizing the CO and VOC emissions factors. As noted previously, the EPA has determined that the NOx data from the PFTIR testing cannot be used for emissions factor development at this time.

We also note that a lower ITR score is not necessarily indicative of poor data quality. A low ITR score in this project is generally indicative of a test report that is less complete. This does not necessarily represent poor data; in fact, it makes the data quality more difficult to judge, although we do believe that with the exception of the NOx data, the data are of sufficient quality for use in factor development. Additionally, the ITR grading sheet was developed with standard stack test methods in mind. The PFTIR method is not a standard stack test method and does not contain many of the components listed in the comment. Therefore, it is harder to achieve a high ITR rating with this method as these fields are left blank in the grading sheet.

Comment: Commenter 19 raised a question over the calculations, stating that the hourly NO and NO_2 emission rates use a column in the spreadsheet titled "NO_2 ppm-m" that the commenter interprets to be a unit of concentration per meter of flare width. Commenter 19 stated that if that interpretation is correct, then the calculations were based on mismatched units of measure and provide meaningless results, because flare width was not determined during the tests.

Commenter 35 stated that EPA calculated the emissions factor using a combined NO and NO_2 MW basis and stated it should have been calculated on an NO_2 MW basis.

Response: The unit of PFTIR measurement is concentration in a pathlength. As previously discussed in this chapter, while the pathlength is unknown, a carbon balance and concentration ratios are used to eliminate the pathlength dependency of the PFTIR concentration measurements.

As previously discussed in this section, we are not finalizing the proposed revisions to the NOx emissions factor for flares.

Comment: Commenter 17 urged the EPA to take into account the fact that the existing AP-42 factor for flares of 0.068 lbs NOx/mmBtu is itself an average of earlier tests, thus the results of each test that were averaged to develop it should be considered as well.

Response: The EPA agrees with the commenter. According to our emissions factor development procedures, when existing factors are used in the data analysis, they should be broken down by each individual source in the factor. In the case of flares, there should have been two numbers for the existing CO and NOx factors, one for the steam-assisted flare and one for the air-assisted flare. We have revised the analysis of the CO emissions factor to incorporate this change.

Comment: Commenter 4 noted they had difficulty in reproducing the EPA's calculations for the Flare NOx emissions factor, and asked for further clarification. Commenter 4 attached two spreadsheets containing the raw data from the FHR test and the commenter's calculations.

Response: In a preliminary response/explanation to the commenter by email, the EPA reviewed the commenter’s calculations and provided input on areas where the commenter’s calculations differed from the EPA’s calculations.

Comment: Commenter 4 asked EPA to provide live Excel spreadsheet calculations of the emissions factors from the test data that would indicate exactly which data were used in the calculation.

Commenter 4 asked EPA what the rationale is for performing the outlier test on the logarithms of the emissions factors rather than the emissions factors themselves.

Commenter 4 asked EPA whether the zero values for NO_2 and NO, where the CO_2 and vent gas flow were not zero, represent actual measurements or missing data.

Response: In a preliminary response/explanation to the commenter by email, the EPA indicated that the draft background documents posted under Section 13.5 contain the compressed data file that we used in the factor calculation. The raw data files that were used for sources that were not outliers are listed as references in the AP-42 section. The references are hyperlinked in order to make the data easily accessible.

We used the log transformed data in the outlier test because that is what the emissions factors procedures dictate. Please see Section 1.0 of Appendix C of the RPDEF document: http://www.epa.gov/ttn/chief/efpac/procedures/procedures81213.pdf.

We included the zeros at proposal as we believed that they represent actual measurements, similar to how other instrumental methods will fall to zero or below zero (because of instrumental drift) at times.

Comment: Commenter 39 stated EPA assumed the aggregated test data is log-normally distributed, but this is an assumption that should not be made without further statistical analysis of individual test data points or the use of a more robust, distribution-free statistical method that does not rely on data parameterization (such as the Kolmogorov-Smirnov Test.)

Commenter 30 stated that in calculating the proposed NOx factor, the EPA apparently assumed that the arithmetic mean was a reasonable and meaningful representation of the collective data, despite the largest number in the set being unreasonably larger than the smallest value—over 1,000 times greater. Commenter 30 stated that EPA apparently evaluated the data for outliers on a lognormal basis, but noted that that methodology assumes that the data is lognormally distributed instead of normally distributed. Commenter 30 explained that the EPA did not present any kind of analysis to support their method, and appeared to merely jump to the conclusion that the data is lognormal. Commenter 30 included a table presenting a simple statistical analysis, showing that the FHR data fails a confidence interval test.

Response: As discussed previously in this section, the EPA has determined that the NOx data from the PFTIR testing cannot be used for emissions factor development at this time.

Comment: Numerous commenters (4, 6, 16, 17, 18, 19, 21, 24, 25, 26, 27, 34, 36, 37, 38, 39, 40, 41, 42, 49, 50, 52, 54, 56, and 57) pointed out issues with the FHR AU flare PFTIR test and stated that the results should not be used in the flare NOx emissions factor. Specific issues included:

- Commenter 40 stated FHR AU testing was conducted under a Section 114 ICR letter.[6] Commenter 40 stated the objective of the FHR AU testing was to better understand the impacts of steam on the overall flare performance in terms of combustion efficiency. Commenter 42 stated the emissions tests for FHR AU were conducted for combustion efficiency, not to determine flare emissions, and were not intended for use in developing emissions factors.
- Commenter 42 stated the operating conditions do not represent normal flare performance but are used to determine conditions that result in poor flare combustion efficiencies.
- Commenter 40 noted that no flare [NOx] emissions data was included in the FHR AU test report. Commenters 26 and 49 recommended that if the FHR AU test is to be used, it should be reweighted and the data adjusted to account for the many discrepancies in it.
- Commenters 37 and 49 stated the FHR AU data over-estimated flare exhaust rate due to low CO_2 concentrations.
- Commenter 37 stated there was a lack of correlation between CO emission and NOx emissions.
- Commenter 37 stated there was a lack of consistent NO and NO_2 emission measurements from the flare plume.
- Commenters 25 and 49 provided a figure showing the extreme variability of the calculated exhaust flow rate and noted that the instances of over-estimated exhaust gas

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[6] Letter from Brooks, P.A., Director, Air Enforcement Division, EPA, to East, J. Environmental Manager, FHR. Section 114 Letter Requiring Emissions Testing, FHR Port Arthur Chemical Complex in Port Author, Texas. November 5, 2010.

flow rates lead to overestimation of NOx emission rates. Typical calculated exhaust gas flow rates are in the range of 1 to 10 mmscfh, exceed 10 mmscfh in 22 instances and exceed 100 mmscfh in 4 instances. A calculated exhaust gas flow of 92 mmscfh results in a NOx emission rate of 3500 lb/mmBtu and a calculated exhaust gas flow rate of 268 mmscfh results in calculated NOx emission rate of 4000 lb/mmBtu, even though measured NOx concentrations and vent gas flow rate are in the normal range.

- Commenters 25 and 49 stated Equation 1 is sensitive to measured carbon concentrations, and when carbon concentrations drop significantly, the reduction in the denominator causes the calculated exhaust gas flow rate to rise proportionally although sudden drops in carbon concentration defy common sense and basic principles of thermodynamics.
- Commenter 42 expressed concern the Flare NOx emissions factor is based on 5 flares with a wide range of emissions. Commenter 42 noted that FHR AU NOx data is 27 times larger than any other data evaluated and is 235 times larger than the existing NOx emissions factor.
- Commenters 17, 25, 37 49, 54 stated the vast difference between the FHR AU data and the rest of the test data set should have triggered questions and additional investigation of the FHR AU data. Commenters 19, 21 and 52 stated EPA should review and validate the raw data for FHR AU data set, using EPA methods for determining outliers, and disregard outliers in the raw data.
- Commenter 38 suggested due to the small data set, further analysis to estimate the uncertainty of its value. Commenters 36 ands, 52 stated that the small sample size allowed for an outlier to change the resulting average by an order of magnitude. Commenter 36 suggested that any changes to NOx and CO emissions factors should incorporate as much usable data as practical to allow statistical credibility. Commenter 52 stated an increased sample size using all the individual data points for the existing NOx emissions factor would allow greater confidence.
- Commenter 26 stated that applying Grubbs' outlier test to the NOx data shows that the Flint Hills Resources data point of 16 lb/MMBtu is an outlier. Commenter 16 stated that applying the Dixon Q outlier test to the natural log of the data points masks the outlier present in the data.

- Commenters 18 and 26 added that the FHR AU value also received the lowest ITR of all the values used to develop the emissions factor.

Response: As discussed previously in this section, the EPA has determined that the NOx data from the PFTIR testing cannot be used for emissions factor development at this time.

Comment: Commenters 25 and 49 provided figures for INEOS data and TCEQ Steam data for NOx, CO and vent gas heating value and compared them with FHR AU data. Commenters 25 and 49 noted that NOx and CO concentrations for INEOS and TCEQ fluctuate as expected: higher concentrations of one generate lower concentrations of the other, and any flare combustion should reasonably be expected to generate detectable concentrations of each, and nonzero measurement of both CO and NOx is the norm. For FHR AU data, Commenters 25 and 49 stated that while CO concentrations have similar variance to the 2 other flares, reported NOx concentrations are zero for 72 percent of the time, suggesting combustion conditions that produce CO are not capable of producing any NOx, but this is inconsistent with other data and defies common sense. Commenters 25 and 49 also noted that no NO_2 concentrations are reported in the FHR AU data set, and NO concentrations vacillate from thousands of ppm to zero and back to thousands.

Response: The EPA has determined that the NOx data from the PFTIR testing cannot be used for emissions factor development at this time.

Comment: Commenter 11 requested that EPA explain the calculation in column BA on the FHR AU worksheet. Commenter 11 stated that they interpret it as an attempt to estimate the volumetric flow rate of the products of combustion and ask the EPA to explain the result up to 14,000 scf of product for every scf of reactant gas.

Response: The EPA stated that the commenter’s assumption was correct. However, the correct units of the calculated exhaust gas flow rate as calculated is scf/hr-meters as it includes a pathlength concentration. As such, this is more of an apparent gas flow rate for calculation purposes and cannot be thought of as the true exhaust gas flow rate. We also note that the wind speed and direction can affect how much of the plume or what portion of the plume is being measured by the PFTIR. If one considered that ambient air dilution with the flare exhaust, one can easily understand how, when very dilute concentrations are measured, that the overall apparent gas flow rate (considering dilution air) is very high.

Comment: Commenter 58 stated that while the NOx emissions for FHR AU flare were significantly higher than for other PFTIR tests, EPA's statistical analysis demonstrates this data point is not an outlier.

Response: The EPA acknowledges the comment.

Comment: Commenter 37 stated the NOx emissions factor may impact emission inventory and compliance demonstrations, and permit limits could appear to be exceeded.

Commenter 42 stated the proposed NOx emissions factor will have impacts on the regulated community and governing agencies.

Commenter 41 expressed concerns that the extreme change in NOx emissions factor impacts emissions inventories, permitting for PSD and NSR, and 1-hour NO_2 NAAQS dispersion modeling.

Commenter 54 stated that higher emissions factor will result in inappropriate impact to RACT and BACT cost-effectiveness decisions.

Commenter 54 stated to the extent that EPA proceeds with finalizing a new flare NOx emission factor, it should first confirm with air quality modeling that use of the new factor does not degrade the model vs. actual performance of AERMOD for NO_2 dispersion modeling and CMAQ or CMAX for ozone modeling.

Commenter 57 stated the flare NOx emissions factor could have significant and detrimental effects on developing accurate attainment plans based on sound science to bring their region into attainment. Commenter 57 stated the proposed flare NOx emissions factor will artificially increase SJVAPCD's NOx emissions inventory to 16 ton/day, affecting their ability to demonstrate attainment of NAAQS, may subject stationary sources to Title V requirements.

Commenters 19, 37 stated that the use of the flare NOx emission factor will cause problems/affect air permits for NOx emissions.

Commenter 17 said that the proposed factor has significant implications for regulated entities who are seeking air permits for new construction projects or revisions to their existing facilities as the proposal is to increase the value by a factor of more than 42 times than it is currently. Commenter 18 stated that use of the proposed NOx factor would potentially affect modeling compliance with the short-term nitrogen dioxide standard and may trigger PSD or non-attainment review for permits, as well as potential Title V permitting obligations.

Response: We have determined that, given the lack of calibration for NOx species in the FTIR instruments used in the flare tests, it is not appropriate at this time to revise the NOx emissions factor.

Additionally we note that AP-42 provides emissions factors for the express purpose of developing national emissions inventories. While we acknowledge in AP-42 that air pollution control agencies may choose to use the emissions factors in permit applications, such as in establishing operating permit fees, we expressly state that: "Use of these factors as source-specific permit limits and/or as emission regulation compliance determinations is not recommended by EPA." (see AP-42 Introduction).

Comment: Multiple commenters were concerned about the magnitude of the proposed revised flare NOx emission factor compared to the original factor. Commenter 49 is concerned with the flare NOx emissions factor because it suggests an increase of 42 times the current factor, is not based on sound science, results in regulatory uncertainty, adversely impacts permitted emissions from numerous facilities, and potentially undermines the basis for existing permitting and compliance scenarios (minor sources becoming major sources). Commenter 49 stated that falsely reporting flare emissions greater than they are leads to over-emphasizing their importance for control strategies and scarce EPA and industry resources are devoted to solve a problem that does not exist.

Commenter 39 expressed concern that the Flare NOx emissions factor is 40 times the existing emissions factor. Commenter 39 stated the change should be carefully evaluated and the science supporting such a change should be of unquestionably high quality.

Commenters 38 and 43 stated the NOx emissions factor would increase by factor of 42 times and could result in NG midstream facilities to be permitted as major sources. On the other hand, Commenter 38 stated refineries are typically major sources for Title V and PSD programs and the change in emissions factor may have little effect on their permitting activities.

Commenter 38 stated that performance testing for flares is not simple or inexpensive, so facilities rely on AP-42 emissions factors. Commenter 38 stated that if facilities choose to conduct performance tests to show lower emissions, they find that the expertise and number of testing companies available to do testing do not exist, the costs for these tests may be prohibitive, and performance testing is not an option for a new or modified flare permitted prior to construction.

Response: Given the lack of calibration for NOx species in the PFTIR instruments used in the flare tests, the EPA has determined that the NOx data from the PFTIR testing cannot be used in the emissions factor development process; therefore, EPA is not finalizing the revised NOx emissions factor for flares at this time.

Comment: Commenter 57 stated the proposed flare NOx emissions factor is suspect, as the value of 2.9 lb/mmBtu of heat input is larger than an equivalent emissions factor for uncontrolled gasoline fueled internal combustion engines or uncontrolled four-cycle rich-burn natural-gas fired internal combustion engines. Commenter 57 stated the combustion temperatures for engines approach 4,500 degrees Fahrenheit and thus thermal NOx emissions are generated, and since flare temperatures are thousands of degrees lower than engine temperatures in more open combustion environments, flares cannot generate the same quantity of thermal NOx emissions.

Commenter 18 stated that the proposed flare NOx emissions factor is higher than the corresponding factor for uncontrolled gasoline-fueled internal combustion engines or uncontrolled four-cycle rich-burn natural-gas fired internal combustion engines. Commenter 18 stated that temperatures in the cylinders of these engines can reach as high as 4,500 degrees Fahrenheit, and are thus in the thermal nitrogen oxides range. Commenter 18 stated that this is an indication that the proposed nitrogen oxides emissions factor for flares is faulty.

Commenter 30 stated that when the first AP-42 was published in 1968, the factor was 0.23 lb/MMBtu for NOx for boilers and heaters, adding that at that point in time, NOx was not yet a concern, so burner technology was primitive with respect to the reduction of NOx. Commenter 30 reasoned that since burner technology has advanced since then, the proposed factor of 2.9 lb/MMBtu defies understanding. Commenter 30 stated that prior to accepting a potentially meaningless factor, the EPA should provide an explanation for the physical phenomenon that would cause such unprecedented results.

Commenter 18 pointed out that several of the other individual test values are higher than the current AP-42 emissions factors for uncontrolled large natural-gas fired boilers.

Commenter 18 stated that the calculation methods for the NOx factor appear to contain errors. Commenter 18 stated that NOx formation is generally driven by either high temperatures, generally in excess of 2,400 degrees Fahrenheit, or fuel-bound nitrogen content. Commenter 18 added that flares typically do not reach temperatures high enough to produce significant quantities of thermal nitrogen oxides.

Response: Given the lack of calibration for NOx species in the PFTIR instruments used in the flare tests, the EPA has determined that the NOx data from the PFTIR testing cannot be used in the emissions factor development process; therefore, EPA is not finalizing the revised NOx emissions factor for flares at this time.

2.6 Industrial Flare VOC Emissions Factor

Comment: Commenter 58 stated the flare VOC emissions factor has been developed from a significant body of evidence to assure it is representative of actual conditions.

Response: The EPA acknowledges the comment.

Comment: Commenter 56 stated that use of a generic VOC emissions factor for flares has limited utility, is inappropriate, and unnecessary. Commenter 56 stated facilities typically calculate VOC emissions based on site-specific knowledge of the streams routed to the flare and the destruction efficiency associated with the flare, and noted that approach results in the most accurate emissions estimates possible. Commenter 56 stated VOC content of streams can vary from 0 percent (hydrogen flaring) to 100 percent (fuel flaring or chemical vapors from loading), and assigning one VOC emissions factor to represent all flares and materials would result in poor characterization of actual emissions.

Commenter 56 stated combustion efficiency achieved is important, as the proposed flare emissions factor has been calculated with combustion efficiencies as low as 96.5 percent, or lower when there are data analysis issues for minute vs. run average, however it is feasible that a flare could achieve 99.5 percent combustion efficiency or higher.

Commenter 18 stated that flare VOC emissions are directly dependent upon the composition of the combusted waste stream, and that due to the varying processes flares abate across a broad range of industries, VOC emissions cannot be adequately represented by a single emissions factor. Commenter 18 added that if a flare that combusts VOC waste gas streams is equipped with steam- or air-assist, the potential for over-steaming or over-aerating exists, which can greatly increase the amount of VOC emissions. Commenter 18 states that due to the added complexities and possible variations of assisted flares, a single emissions factor cannot account for these and cannot be representative of actual VOC emissions.

Response: The EPA agrees that site-specific data should always be used over emissions factors when site-specific data are available. We agree that use of combustion efficiency when known and when the flare is properly operating combined with knowledge of the gas burned in the flare is a valid technique for determining VOC emissions.

However, we disagree with the commenter that the VOC factor is inappropriate and unnecessary. Section 130 of the Clean Air Act requires EPA to review and, if necessary, revise VOC emissions factors every three years. The existing VOC emissions factor for flares relies on total hydrocarbons as a surrogate for VOC. We find it necessary to create an actual VOC emissions factor for flares, given that we have the data to do so. Additionally, as previously stated, the main purpose of AP-42 is to provide emissions factors for national scale emissions inventories. It is unlikely that an inventory developer will always have access to site-specific data in order to estimate VOC emissions using control efficiency and flare gas constituent information. In this cases, it is appropriate to use the emissions factor.

Finally, we agree that over-steaming of flares generally leads to poor combustion efficiency and an increase in VOC emissions. However, we do not believe that such operation of a flare constitutes a well operated flare, which is the premise of the factors located in AP-42 Section 13.5.

Comment: Commenter 31 stated that refineries have different stream compositions going to flares, resulting in a wide range of speciation from one refinery to another. Commenter 31 suggested EPA conduct a comprehensive refinery speciation study for the streams going to flares and continue the development of emissions factors.

Response: We have determined that the number of flares in our data set represent an adequate cross section of the refining and chemical industry. The data set includes test flares as well as flares burning varying vent gases that would normally be burned in the flares. While we believe that the data set is robust, if more data is provided to the EPA, this data may be used in the future to revise the emissions factors, if revisions are necessary.

Comment: Commenter 56 stated the following potentially bias the VOC emissions factor high: use of minute data rather than run average data; averaging of CO_2 spectral bands, and use of unweighted combustion efficiency. Commenter 56 stated that hydrogen content of the stream may increase flame temperature and improve VOC destruction efficiency; however, there is insufficient data from the flare tests to evaluate this.

Response: We have reevaluated the data on a test run average basis with weighted combustion efficiency. Additionally, in the final emissions factor analysis, we no longer included the approach of CO_2 band averaging because we were provided information on the most appropriate CO_2 spectral band to use for each test run (see Attachment B) by Clean Air Engineering, who participated in the PFTIR testing. This information was provided via API.

While we did perform the reanalysis, we note that the data in the proposal did not appear to be biased high, as the final factor has changed very little from the proposed factor.

We acknowledge that we do not have the data to determine whether hydrogen content has an effect on VOC destruction efficiency.

Comment: Commenter 58 stated the emissions factor is based on measured emissions where EPA could confirm 98 percent destruction efficiency, and EPA discarded any PFTIR test data or DIAL scans where the flare did not achieve 98 percent. Commenter 58 recommended EPA provide clear guidance that the flare VOC emissions factor is only representative of flares that achieve 98 percent destruction efficiency and the flare must meet minimum heat value at the flare tip (greater than 270 Btu/scf in typical flares and 380 Btu/scf in flares with high hydrogen and/or olefin content) to be considered properly operating.

Commenter 58 also stated EPA should propose an alternate flare VOC emissions factor that is representative of emissions from flares that are only required to comply with the current regulatory requirements in 40 CFR 60.18 and 40 CFR 63.11(b); this alternate emissions factor would apply to flares that cannot maintain the heat value required to guarantee 98% destruction efficiency or do not have sufficient monitoring to verify the heat value of the flare gas.

Commenter 58 cited the test data that shows flares complying with existing requirements only achieve 93.9% destruction efficiency and PFTIR data that shows flares complying with existing requirements achieve 92% destruction efficiency. Commenter 58 recommended EPA use these 2 data points to propose an alternate flare VOC emissions factor and make it clear that facilities that do not have the monitoring required to guarantee 98% destruction efficiency must use the alternate factor.

Response: In the final flare emissions factor analysis, the EPA developed VOC emissions factors and considered the net heat content of the flare gas stream to ensure all of the flare data we used is compliant with the General Provisions requirements in 40 CFR 60.18 and 40 CFR 63.11(b). When evaluating DIAL test study results, this is the only criteria used to assess the representativeness of the measurement data. However, flare operations were manipulated during the PFTIR tests to determine the point at which combustion efficiency deteriorates. As such, this test data is expected to have more runs in the poor combustion region than actually occurs in practice. While we understand that poor combustion may occur for steam- or air-assisted flares that can be over-assisted, we also consider it inappropriate to use test run data where the normal operations were intentionally altered in order to identify the point at which combustion efficiency deteriorates. Therefore, we are only including test runs from the PFTIR data that achieved a combustion efficiency of 96.5 percent or greater.

Because the PFTIR tests contain more data in the poor combustion region that a flare would see in normal operation if it is well operated, we do not think it is appropriate to base decisions on what constitutes true combustion efficiency in normal operation on this data.

We have previously stated in Section 13.5 that a well operated flare achieves 96.5% combustion efficiency. However, we will make it clear that the emissions factors were developed using data for flares achieving a combustion efficiency of at least 96.5%.

We may continue to evaluate the data further and collect new data as it becomes available to determine whether it is necessary to create subcategories of flare emissions factors based on different operating parameters and combustion efficiencies.

Comment: Commenter 58 stated EPA should propose an alternate flare VOC emissions factor for pit flares used at oil and gas facilities, which the agency has acknowledged only reliably achieve 95% destruction efficiency. Commenter 58 stated that if facilities apply the new/proposed VOC emissions factor based on 98% DE to these flares, emissions would be underestimated by 250%; the proposed factor is biased low and is not useful for estimating emissions from these facilities. Commenter 58 stated an alternate factor would satisfy EPA's information quality act guidelines for objectivity and utility.

Response: We agree that use of the AP-42 Section 13.5 flare emissions factors may not be appropriate for oil and gas pit flares because these flares do not have the same SCC as the emissions factors. Additionally, if the pit flare is only achieving 95% destruction efficiency, it is likely that the VOC factor will underestimate the emissions from the flare. However, the EPA is not currently proposing emissions factors for pit flares at oil and gas facilities as we do not have data on this category of flare. We recommend that sources use site-specific data on combustion efficiency and gas streams in lieu of the VOC emissions factor where such data are available. Manufacturer literature can also provide useful insight into combustion efficiency and/or expected emission rates.

Comment: Commenter 18 stated that the proposed flare VOC emissions factor is higher than the current THC emissions factor in AP-42. Commenters 56 and 58 stated the proposed VOC emissions factor is inconsistent with the existing THC emissions factor, as VOC is considered to be a fraction of THC emissions, and in this instance the VOC emissions factor is higher. Commenter 56 stated that publishing a VOC factor that is higher than the THC factor creates confusion and would not be technically valid if the factors were derived from a common data set.

Commenter 58 stated that because VOCs are a subset of THCs and the VOC factor suggests greater emissions, it is clear that EPA needs to revise the THC factor. Commenter 58 stated the THC emissions factor, which serves as a proxy for VOCs, is based on a much smaller data set and is not derived from flares at working industrial facilities. Commenter 58 noted the new flare VOC emissions factor is developed from several sources based on real-world operating conditions, on flares in actual use at industrial facilities that combust normal process gas, and EPA should use the THC data collected from PFTIR test data to revise the THC factor.

Response: We agree that VOC emissions are a subset of THC emissions. We originally did not propose to update the THC factor because it is not the pollutant of interest; it is a surrogate for VOCs. However, we were hesitant to remove the factor in case there was a need for it. Because we did not propose to remove the THC factor, we are not removing it from Section 13.5 at this time. We may consider doing so in the future in a separate action.

2.7 Industrial Flare CO Emissions Factor

Comment: Commenter 56 stated the following potentially bias the CO emissions factor high: use of minute data rather than run average data; averaging of CO_2 spectral bands, and use of unweighted combustion efficiency.

Response: We have reevaluated the data on a test run average basis with weighted combustion efficiency. Additionally, in the final emissions factor analysis, we no longer included the approach of CO_2 band averaging because we were provided information on the most appropriate CO_2 spectral band to use for each test run (see Attachment B) by Clean Air Engineering, who participated in the PFTIR testing. This information was provided via API.

While we did perform the reanalysis, we note that the data in the proposal did not appear to be biased high, as the final factor has changed very little from the proposed factor.

2.8 Industrial Flare Methane (CH_4) Emissions factor

Comment: Commenter 58 stated EPA should use the data it has to propose a methane emissions factor for industrial flares. Commenter 58 stated methane is a potent global warming agent and industrial flares at refineries and in the oil and gas industry are a significant source of methane; the PFTIR data show the average methane content of refinery flare gas is 12%. Commenter 58 stated a new flare methane emissions factor will enable more accurate reporting and provide regulators with information to account for these emissions in decision-making and developing cost-effective reduction strategies.

Response: The EPA acknowledges the comment. Due to time limitations, the scope of this project was limited to certain sources and certain pollutants. The EPA may use the data to create additional emissions factors in the future.

Comment: Commenter 58 stated EPA should use the methane data from nationwide sampling by GRI collected under the Oil and Gas NSPS and NESHAP rules to propose a flare methane emissions factor for the oil and gas sector. Commenter 58 noted these data show methane content of 82.9% by volume and 65.7% by weight for production and show methane content of 92.8% by volume and 86.2% by weight for transmission.

Response: The EPA acknowledges the comment, but methane emissions factors are outside the scope of this project.

2.9 Revisions to AP-42 Section 13.5

Comment: Commenter 54 noted that the current AP-42 language identifies "typical" steam-to-vent-gas ratios through the industry as ranging from approximately 2:1 to 7:1, but the proposed revision strikes this language, without explanation, and replaces it with generic statements reflecting the same concerns with "oversteaming" that OECA's current flaring enforcement initiative are based on. Commenter 54 stated AP-42 emissions factors are designed to represent long-term averages for all facilities in the source category – not whatever may qualify as EPA's current version of "best practices" or "enhancements," so accordingly, if the "average" steam-to-vent-gas ratio in use throughout the industry remains within the 2:1 to 7:1 range, the revised AP-42 should continue to so state.

Response: We removed this sentence because we have no data to determine a "typical" steam-to-vent-gas ratio. While we do not recommend flare owners or operators use the information in AP-42 to determine an appropriate steam-to-vent gas ratio, we do not want the inclusion of this range to be considered an endorsement of the appropriateness of this range. Therefore, we are finalizing the deletion of this sentence, as proposed.

Comment: Commenter 56 suggested the following corrections to AP-42 Section 13.5:

Section 13.5.1, Fourth Paragraph, Fifth Sentence "Ground flares vary in complexity, and they may consist either of conventional flare burners ~~discharging horizontally~~ with no enclosures or of multiple burners in refractory-lined steel enclosures." [delete "discharge horizontally"]

Section 13.5.1, Sixth Paragraph, Eleventh Sentence "However, if flare waste gas concentrations are near the LFL prior to mixing with air, the air-waste gas mixture can ~~will quickly~~ fall below the flammability region, and ~~poor~~ reduced combustion efficiencies can ~~will~~ occur." [change "will" to "can", delete "quickly" and change "poor" to "reduced"]

Section 13.5.1, Sixth Paragraph, Thirteenth Sentence "Thus, even if there are adequate concentrations of combustibles in the waste gas, if too much steam is added to the waste gas so that the combustibles concentration becomes diluted to near the LFL as the steam-waste gas mixture enters the combustion zone, ~~poor~~ reduced combustion efficiencies will result.” [change “poor” to “reduced” API recommends that it be clarified that LFL and UFL are defined for well, uniformly mixed mixtures of air and fuel. While using LFL correlating variable for combustion efficiency appears to provide an improved correlation relative to steam-to-vent-gas ratio, it should be noted that when assessing the combustibility of hydrocarbon mixtures (with inerts as potential constituents), the LFL applies to uniformly mixed gases. Since the mixing intensity of many flares is not well characterized, using the LFL as a representation of potential vent gas combustibility may not be representative.]

Section 13.5.1, Eighth Paragraph, Third Sentence “Waste gases containing heavy hydrocarbons such as paraffins above methane, olefins, and aromatics, usually ~~burn with smoke~~have a higher tendency to smoke unless the introduction of air into the combustion zone is assisted.” [change “burn with smoke” to “have a higher tendency to smoke unless the introduction of air into the combustion zone is assisted”]

Section 13.5.1, Twelfth Paragraph “~~Many plants have 2 or more flares, in parallel or in series. In the former, 1 flare can be shut down for maintenance while the other serves the system. In systems of flares in series, 1 flare, usually a low-level ground flare, is intended to handle regular gas volumes, and the other, an elevated flare, to handle excess gas flows from emergencies.~~” [API recommends that the entire paragraph be removed as each plant’s flare system varies.]

Section 13.5.2, Second Paragraph, First Sentence “Emissions from flaring may include carbon particles (soot), unburned hydrocarbons, CO, and partially burned and altered hydrocarbons.” [add “may”]

Section 13.5.2, Third Paragraph, Fourth through Seventh Sentences “~~The oxygen supplied as air ranges from 9.6 units of air per unit of methane to 38.3 units of air per unit of pentane, by volume. Air is supplied to the flame as primary air and secondary air. Primary air is mixed with the gas before combustion, whereas secondary air is drawn into the flame. For smokeless combustion, sufficient primary air must be supplied, this varying from about 20 percent of stoichiometric air for a paraffin to about 30 percent for an olefin.~~” [API recommends deletion of these sentences as they only apply to air-assisted flares]

Section 13.5.2, Third Paragraph, Eighth Sentence "If the amount of ~~primary~~ air is insufficient, the gases entering the base of the flame are preheated by the combustion zone, and larger hydrocarbon molecules crack to form hydrogen, unsaturated hydrocarbons, and carbon." [delete "primary"]

Section 13.5.2, Fourth Paragraph, Sixth Sentence "Soot is eliminated by ~~adding steam or air~~using an assisted medium (air, steam, or gas pressure) to induce additional air; hence, most industrial flares are steam-assisted and some are air-assisted." [change "adding steam or air" to "using an assisted medium (air, steam, or gas pressure) to induce additional air"]

Section 13.5.2, Sixth Paragraph, Second Sentence "~~Crude p~~Propylene was used as flare gas during the early EPA tests." [delete "Crude"]

Response: The EPA acknowledges the comment and has made a number of the suggested changes. However, several of the recommended changes we consider to be incorrect or inappropriate. The suggested edits that we are not incorporating and our rationale for not incorporating them are summarized below:

- We are not including suggested language to "qualify" that the LFL applies to uniformly mixed gases and that flare gas may not be well mixed. Analysis of the available data suggests the LFL calculated assuming perfect mixing is strongly correlated with flare combustion efficiency so this qualification is unnecessary.
- Section 13.5.1, Eighth Paragraph, Third Sentence. We are incorporating the phrase "have a higher tendency to smoke", which is consistent with our intended revision; however, we are not including the phrase "unless the introduction of air into the combustion zone is assisted." This additional phrase suggests that these compounds do not have a higher tendency to smoke in assisted flares. We consider that these compounds still have a higher tendency to smoke and may still cause smoke in assisted flares.
- Section 13.5.1, Twelfth Paragraph. We are retaining this paragraph. We are revising the last sentence to read: "In systems of flares in series, 1 flare~~, usually a low-level ground flare,~~ is intended to handle regular gas volumes, and the other~~, an elevated~~ flare~~,~~ **is generally intended** to handle excess gas flows from emergencies." As amended, we consider the discussion to be more general and

broadly applicable, which addresses the commenter’s stated purpose for the suggested deletion.

- Section 13.5.2, Third Paragraph. We are not deleting the fourth through seventh sentences. We did not propose any edits to this paragraph. We find that the information in this section to be important in the understanding of soot (smoke) generation and means by which a flare owner or operator may reduce these emissions.
- Section 13.5.2, Third Paragraph, Eighth Sentence. We are not deleting the word “primary” as suggested. As noted above, we are not deleting the preceding sentences so that the phrase “primary air” is well defined.
- Section 13.5.2, Fourth Paragraph, Sixth Sentence, We did not propose any edits to this paragraph. We have no other discussion of pressure assisted flares and the suggested edit would demand further edits. Pressure assisted flares are not as common in the industry, which is likely why the commenter did not request additional edits to the final half of the sentence. We find that the existing paragraph is accurate and does not need to be revised.
- Section 13.5.2, Sixth Paragraph, Second Sentence. We are not deleting the word “crude” describing the propylene used as fuel. We note that the 1983 report consistently refers to the fuel as “crude propylene.” As noted in the 1983 report and the footnote to Table 13.5-1, the crude propylene was 80 percent propylene and 20 percent propane. Deleting the word crude here would suggest that the fuel was 100 percent propylene rather than a crude propylene/propane mixture.

Chapter 3

NEW AND REVISED EMISSIONS FACTORS FOR SULFUR RECOVERY PLANTS

3.1 Emissions Factors

Comment: Commenter 56 stated EPA should conduct further analyses before adding new emissions factors for Sulfur Recovery Units normalized by sulfur production. Commenter 56 stated EPA should determine if it is appropriate to correlate NOx, CO and THC emissions to the firing of the incinerator or thermal oxidizer versus sulfur production because NOx, CO and THC emissions are closely related to tail gas composition, firing rate in the incinerator, and control technologies (e.g., ULNB or oxidation catalyst for CO). Commenter 56 stated tail gas composition and amount of tail gas produced depend on the SRU configuration, for example, a Claus unit will have 10,000 ppm CO in tail gas, a unit with cobalt molybdenum catalyst (Shell Claus Offgas Treating or Beavon unit) will have a few hundred ppm CO, a SuperClaus followed by a caustic scrubber will not affect CO and the CO going to the thermal oxidizer/incinerator will be higher than other configurations. Commenter 56 stated fuel usage in the incinerator is not always directly related to total sulfur production, so sulfur production would not be an appropriate basis for SRU emissions factors.

Based on a survey of existing SRUs, Commenter 56 provided three figures showing NOx, CO and THC emissions plotted with sulfur production, and noted there is no apparent relationship between NOx, CO or THC and sulfur production for these surveyed SRUs (see Figures 3.3.3-1 through 3.3.1-3 of the comment letter). Commenter 56 recommended EPA not update the AP-42 factors until an improved assessment of the impacts of variations in unit configuration is completed and EPA determines if it would be more appropriate to correlate NOx, CO and THC emissions to the firing of the thermal oxidizer/incinerator versus sulfur production.

Response: We agree with the commenter. We have explored revisions to the proposed SRU emissions factors based on heat rate firing instead of sulfur production rate. We determined that an adequate number of reports contained heat rate firing data collected during the emissions test. The review and analysis of these reports and development of the final SRU emissions factor is further detailed in the *Final Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations.*[7]

In addition to the reanalysis on a heat rate basis, the EPA has also included the SRU emissions factors based on sulfur production rate in the AP-42 section as an alternative to the heat rate based emissions factors. These factors are included as footnotes to the heat rate based emissions factors and are recommended for use when sulfur production rate is unknown. For single SRUs that had actual data for both sulfur production rate and heat rate. We had similarly representative data sets for both sets of factors, and as such we believe both factors are representative of the emissions for these units.

<u>Comment</u>: Commenter 12 noted difficulty in locating the source tests for the SRU NOx emissions.

<u>Response</u>: In a preliminary response to the commenter by email, the EPA explained that the posted spreadsheets were filtered/sorted, that all the test report data reviewed were included in the file, and that all the data could be viewed by unfaltering the spreadsheet.

3.2 Revisions to AP-42 Section 8 and Refinery Protocol

<u>Comment</u>: Because emissions data and test reports are solely from refineries, Commenter 52 stated the emissions factor revisions should be limited to Section 8.13 Sulfur Recovery and Section 5.1 Petroleum Refining emissions factors only and should not be used for revising Section 13.5 Industrial Flares.

<u>Response</u>: We agree that adequate data are available to develop emissions factors for petroleum refining and sulfur recovery units. We disagree with the commenter that the data are not adequate for developing and revising flare emissions factors. As noted in Chapter 2 of this document, the available flare data are adequate for emissions factor development for CO and VOC.

<u>Comment</u>: Commenter 56 indicated Table 8.13-2 of AP-42 has an emissions factor for THC from controlled sulfur recovery plants, but the Refinery Protocol lists the same emissions

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[7] *Final Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations.* U.S. Environmental Protection Agency. April 2015.

factor for VOC in Table 5-7; these classes of compounds should not be used interchangeably. Commenter 56 stated the entry in Table 5-7 of the Refinery Protocol for the VOC emissions factor should be revised to THC, if appropriate.

Response: We agree with the commenter and have revised the Refinery Protocol to provide the emissions factors for THC consistent with Section 8.13 of AP-42. We are also including a footnote in the Refinery Protocol to indicate that THC may be used as a surrogate for VOC emissions.

Comment: Commenter 56 indicated that the first paragraph of Section 5.5.3 of the Refinery Protocol says that SRU CO, NOx and VOC emissions factors come from the ICR Component 4 data, but Section 8.13 of AP-42 lists many test reports, not just the ICR stack tests. Commenter 56 stated EPA must clarify the sources of the SRU CO, VOC, and NOx emissions factors in the Refinery Protocol.

Response: The proposed revisions to Section 8.13 of AP-42 lists 33 references; 24 of these references were used in the creation of the SRU CO, VOC and NOx emissions factors. These 24 references were all collected during the 2011 Refinery Information Collection Request (ICR). Some of the data were collected during testing performed as a result of the ICR (Component 4), and some of the data were existing data that were submitted to the EPA during the ICR (Component 1). The Refinery Protocol has been updated to more broadly state that the data was collected during the 2011 ICR instead of saying that all of the tests were collected under Component 4.

Comment: Commenter 56 suggested the following corrections to AP-42 Section 8.13:

Section 8.13.2, Fourth Paragraph, First Sentence "The furnace normally operates at combustion chamber temperatures ranging from 980 to 1540°C (1800 to 2800°F) with pressures rarely higher than 70 kilopascals (kPa) (10 pounds per square inch ~~absolute~~ gauge)." [change "absolute" to "gauge"]

Section 8.13.2, Fourth Paragraph, Fourth Sentence "Liquid sulfur from the condenser runs through a seal leg or sulfur trap (sulfur traps operate similar to an inverted bucket condensate trap) into a covered pit from which it is pumped to trucks or railcars for shipment to end users. [add “or sulfur trap (sulfur traps operate similar to an inverted bucket condensate trap)”]

Section 8.13.2, Sixth Paragraph, First Sentence “The catalytic reactors operate at lower temperatures, ranging from 200 to 315°C (400 to 600°F). Activated alumina or ~~bauxite~~ titanium dioxide is sometimes used as a catalyst.” [add “Activated” and delete “bauxite”]

Section 8.13.3, First Paragraph, Third Sentence “Claus plants without tailgas ~~cleanup~~treatment, have sulfur recovery efficiencies ranging from 92 to 97 percent; Claus plants with tailgas ~~cleanup~~treatment, have sulfur recovery efficiencies ranging from 99 to 99.9 percent.” [change “cleanup” to “treatment”]

Section 8.13.3, First Paragraph, Fourth Sentence “The efficiency depends upon several factors, including the number of catalytic stages, the concentrations of H_2S and contaminants in the feedstream, stoichiometric balance of gaseous components of the inlet, operating temperature, catalyst maintenance, and the type of tailgas ~~cleanup~~treatment process used.” [change “cleanup” to “treatment”]

Section 8.13.3, First Paragraph, Fifth Sentence “Regardless of whether or not a tailgas ~~cleanup~~treatment process is used to increase recovery efficiency, most sulfur recovery plants use a thermal oxidizer or incinerator to convert H_2S and other sulfur compounds SO_2 prior to atmospheric release.” [change “cleanup” to “treatment”]

Section 8.13.3, Table 8.13-1, for the Mod. Claus 3 Stage w/o Tailgas Cleanup Control (95-96% Removal), Average % Sulfur Recovery “~~95.5~~96.0% with the range being 95-97% Removal” [change “95.5” to “96.0% with the range being 95-97% Removal”]

Section 8.13.3, Table 8.13-1, for the Mod. Claus 3 Stage w/o Tailgas Cleanup Control (95-96% Removal), kg/Mg of Sulfur Produced “~~94~~83” [change “94” to “83”]

Section 8.13.3, Table 8.13-1, for the Mod. Claus 3 Stage w/o Tailgas Cleanup Control (95-96% Removal), lb/ton of Sulfur Produced “~~188~~166” [change “188” to “166”]

Section 8.13.3, Table 8.13-1, Footnote a “The emissions factors were determined assuming all sulfur compounds are converted to SO_2 prior to atmospheric release. These emissions factors are applicable to all Claus sulfur recovery plants whether or not the sulfur recovery plant employs a tailgas ~~cleanup~~treatment system provided the emissions are controlled using a thermal incinerator or thermal oxidizer. These emissions factors are also applicable for

Claus sulfur recovery plants with oxidative tailgas ~~cleanup~~treatment systems that do not use incineration.” [change “cleanup” to “treatment”]

Section 8.13.3, Second Paragraph, First Sentence “A 2-bed catalytic Claus plant typically achieves 92 to 95 percent sulfur recovery efficiency. Recoveries range from 95 to ~~96~~97 percent for a 3-bed catalytic plant ~~and range from 9796 to 98.597 percent for a 4-bed catalytic plant~~.” [change “96” to “97” and delete “and range from ~~97~~96 to ~~98.5~~97 percent for a 4-bed catalytic plant”]. Note that sulfur recovery efficiency is a function of the hydrogen sulfide concentration in the acid gas. Commenter recommended a range from 95 to 97% for a 3-bed Claus plant.

Section 8.13.3, Third Paragraph, First Sentence “Emissions from the Claus process may be reduced by: (1) extending the Claus reaction into a lower temperature liquid phase and thereby increase sulfur recovery efficiencies, (2) adding a scrubbing process to the Claus exhaust stream for the purposes of increasing sulfur recovery efficiencies, ~~or~~ (3) incinerating the sulfur compounds to SO_2 and using conventional flue gas desulfurization (FGD) scrubbing techniques to reduce the SO2 emissions, or (4) providing a SuperClaus unit that involves a special catalyst that converts H_2S to sulfur by direct oxidation.” [delete “ or” and add “or (4) providing a SuperClaus unit that involves a special catalyst that converts H_2S to sulfur by direct oxidation”]

Section 8.13.3, Fifth Paragraph, Fourth Sentence “There are at least ~~3~~4 oxidation scrubbing processes: the Wellman-Lord, Stauffer Aquaclaus, ~~and~~ IFP-2, and Cansolv.” [change “3” to “4”, delete “and”, and add “, and Cansolv”]

Section 8.13.3, Tenth Paragraph, Eighth Sentence “Scrubbing processes that recycle H_2S or SO_2 to~~n~~ the Claus feed become ineffective when there are operational issues with the upstream Claus process.” [change “ton” to “to”]

Section 8.13.4, First Paragraph, Seventh Sentence “All of the data available for NOx, CO, and THC are for units with tailgas ~~clean-up~~treatment units designed to increase the sulfur recovery efficiencies to 99.9 percent; however, the emissions of these pollutants is not expected to be as closely tied to sulfur recovery efficiencies as emissions of SO_2.” [change “clean-up” to “treatment”]

Section 8.13.4, Table 8.13-2, Footnote e “SCC = Source Classification Code. Emissions factors were developed specifically for units with tail gas treatment ~~unis~~units (e.g., SCC 30103204).” [change “unis” to “units”]

Response: We agree with most of the edits suggested and we are incorporating these edits into the final version of AP-42 Section 8.13. However, we disagree that we should alter the range of efficiencies and the average sulfur recovery efficiencies for different 3- and 4-stage Claus units. The commenter provided no data to support the revised values. We note that the values we provided are consistent with the SCC unit descriptions and observed performance levels. Therefore, we are not making the suggested revisions to these efficiencies.

Chapter 4

NEW AND REVISED EMISSIONS FACTORS FOR OTHER REFINERY PROCESSES

4.1 Emissions Factors for Catalytic Reforming Units

4.1.1 THC Emissions Factor

Comment: Commenters 54 and 56 stated EPA has not adequately developed or justified the proposed CRU THC emissions factor, EPA should further evaluate the emissions factor, and the proposed factor should not be finalized. Commenter 56 stated EPA used a data set that is too small to provide representative emissions factors, needs to evaluate test and production data for additional units, should consider potential emission differences due to process configurations, and needs to use robust statistical methods consistent with best practices already established by EPA.

Commenter 56 stated EPA's data is small, and the range and standard deviation are large, implying large uncertainty. Commenter 56 stated the data set could be improved by including additional units and noted there are 4 additional units in the 2011 ICR that could be used if production data were available. Commenter 56 noted EPA appears to have overlooked one 2011 TX3B1220 test report for continuous CRU (Method 25A); however, production data are not available.

Response: We have reevaluated the CRU data set for use in the final emissions factor. The reevaluation resulted in examining the process activity basis, incorporating additional process activity data provided by commenters, including a test report that was inadvertently omitted at proposal, and revising the representativeness characterization from the small population to the large population analysis. We also provided additional detail on the process types and air pollution control devices (APCDs) covered in the available test data on which the final emissions factor was based. The reanalysis is discussed further in the *Final Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations.*

In the final data set, feed rate data are available for 8 units. While we did not have the data to conduct a statistical analysis on the variability between emissions for different unit configurations, we believe that there is enough data representative of the population of sources to provide an average emissions factor across all types of sources. If more data becomes available in the future, we may revisit this issue to determine whether it is appropriate to subcategorize CRUs based upon different configurations.

Comment: Commenters 54 and 56 stated that when reviewing the data sets, EPA needs to properly analyze this data against the technology differences among CRUs to understand THC formation and its destruction or removal during the coke burn step of the CRU reactor regeneration cycle. Commenters 5 and 56 indicated that such technology differences include the CRU's configuration (e.g., semi-regenerative, cyclic, and continuous) as well as pollution control devices (e.g., scrubbers, Chlorosorb) used to control HCl emissions to comply with the emission standards in Refinery MACT UUU (i.e., 40 CFR Part 63, Subpart UUU).

Commenter 56 noted that hydrocarbon emissions occur during catalyst regeneration and not during the reforming process; all of EPA's CRUs are continuous. Commenter 56 stated process conditions affect THC emissions, and these conditions include duration and frequency of purge cycles; HCl emissions control (e.g., scrubber, Chlorosorb); temperatures, pressures, and oxygen concentrations during coke burning; coke properties; and other factors. Commenter 56 cited 1997 test data that suggested a wider range of VOC emissions for semi-regenerative vs. cyclic; the commenter noted the representativeness to current CRUs is unknown, but the data suggests differences in THC emissions for different CRU technology.

Response: There are 8 CRUs with available test data for the final THC emissions factor analysis. All of these units are CRUs with continuous regeneration. The APCDs for the CRUs include 6 scrubbers (3 packed bed, 2 scrubbers, and 1 venturi) and 2 Chlorsorbs. While it is possible that the Chlorsorb may impact the THC emissions, we do not have sufficient data to subcategorize based on APCDs, as there are data available for only 2 units with Chlorsorb. Therefore, a single emissions factor with no subcategorization was developed in the final analysis. We have provided a note in AP-42 Section 5.1 to indicate that the factor was developed using data for CRUs with continuous regeneration. End users should determine whether it is appropriate to apply this emissions factor to other types of CRUs.

Comment: Commenter 56 stated coke burn may be a better activity parameter than reactor feed rate for CRU. Commenter 56 stated hydrocarbon emissions occur during incomplete combustion conditions during coke burn off and emissions depend on coke combustion conditions. Commenter 56 recommended evaluating emissions factors based on coke burn rate in addition to reactor feed rate because coke burn rate is a better indicator of combustion conditions leading to THC emissions and the catalyst coke yield varies independent of reactor feed rate among different CRUs due to many design and operating factors.

Commenter 56 stated coke yields vary with CRU process design, configuration, operating conditions and feeds, etc. Commenter 56 noted that for cyclic and semi-regenerative CRU, the coke burn step occurs while reactor feed is zero, so reactor feed has little direct influence on coke combustion conditions, and CRU reactor feed rate (or cumulative feed between regenerations) is not necessarily a reliable indicator of coke combustion rate or of combustion conditions in the regenerator.

Response: We attempted to explore revisions to the draft emissions factor that included a change from feed rate to coke burn rate per the commenter’s recommendation, but we were unable to find available coke burn data in the test reports. The EPA requested additional coke burn rate data from facilities but found that coke burn rate data are often not recorded during emissions testing, and these data are not readily available. Therefore, no revision to the process activity basis for the CRU THC emissions factor was made, and the final CRU THC emissions factor is based on feed rate data.

Comment: Commenter 56 stated EPA must use robust statistical methods consistent with best practices already established by EPA (e.g., in ProUCL and in EPA’s Data Quality Assessment: Statistical Methods for Practitioners QA-G9S) for evaluating test data and deriving emissions factors. Commenter 56 provided additional standard statistical analysis of EPA's data set, noting that data were not normally distributed (highly skewed), the data set were small and must be evaluated graphically, and exhibit lognormal distribution. Commenter 56 stated that because the data best fit a lognormal distribution, the mean of the log-transformed data also should be used for determining the emissions factor; alternatively, the median of the untransformed data is more representative for this skewed data set.

Response: We used the EPA's recommended procedures for developing emissions factors in this project. The document explains why we chose to use the specified procedures and statistical analyses in emissions factor development. This document was previously subjected to public notice and comment. The procedures ensure that new emissions factors are developed consistently, robustly, and objectively. Because the procedures have already been subjected to public notice and comment, we did not seek comment on them in this project. As such, we are not addressing comments on the emissions factor development procedures as part of this project.

Comment: Commenter 56 stated the data quality rating of "poorly representative" is overly generous. Commenter 56 recommended characterizing the emissions factor as "potentially highly unrepresentative, with high uncertainty" and supplement with advice to use with extreme caution.

Response: During final development of the emissions factor, we revisited and reviewed the representativeness characterization analysis of the emissions factor based on the final data set. This review confirmed that the characterization is based on the total population of CRUs. While the characterization analysis at proposal was based on the "small population" analysis, the emissions factor should be based on the "large population" analysis. In the final analysis, the revised CRU THC emissions factor continues to be characterized as "poorly representative." The characterizations are based on the procedures and categories set forth in the recommended procedures for developing emissions factors.

Comment: Commenter 56 stated the THC emissions factor has been represented as VOC in the Refinery Protocol and should be revised to THC, if appropriate. Commenter 56 noted the test method to measure THC includes methane and ethane, which are not VOCs, and methane and ethane should not be included in VOC emissions factors. Commenter 56 stated EPA has not considered estimating the fraction of VOC (e.g., methane precutter, simultaneous Method 18); where results were available in the data, 85 to 92 percent of THC should be reported as VOC, as propane equivalent (i.e., 8 to 15 percent is non-VOC). To be consistent with the actual measurements, Commenter 56 recommended revising the proposed Refinery Protocol Table 5-6 and related discussion on page 5-19, specifically replacing "VOC" and "volatile organic compounds" with "THC" and "total hydrocarbons," respectively.

Response: We agree with the commenter and have revised the Refinery Protocol to provide the emission factors for THC consistent with the AP-42 factor. We are also including a footnote to indicate that THC may be used as a surrogate for VOC emissions.

4.1.2 CO Emissions Factor

Comment: Commenter 58 stated EPA must use easily accessible process data to propose a CRU CO emissions factor. Commenter 58 noted that 3 out of 3 test reports for CRU CO data did not include production data and stated EPA should collect and use production data and process data for emissions tests (and at least one facility noted that the production data are available upon request). Commenter 58 noted that under the APA the agency has a duty to review and collect data that is easily retrievable using conventional means, and EPA's failure to collect this data substantially impaired the agency's ability to promulgate a new CO emissions factor for CRU.

Response: The Commenter asserts EPA has a statutory duty to "review and collect data that is easily retrievable using conventional means," but the Commenter provides no citation for that assertion (we note the footnote was omitted from the comment) and no further explanation regarding what constitutes "easily retrievable" data and or what qualifies as "conventional means." As explained in previous responses, EPA did use the data we collected through the 2011 Refinery ICR or other means and which we determined qualified as appropriate for emissions factor development, to finalize several emissions factors. In this specific instance, EPA explained that, unfortunately, there were not enough of the CRUs with acceptable CO emissions tests, i.e., tests where enough data were available to determine the quality of the data and the data quality was acceptable, that also included available process data in the test report. It is the EPA's opinion that a complete test report does include process data that is recorded at the time of the request. As such, in the 2011 Refinery ICR, we requested that such data be included in the test reports; therefore, EPA did attempt to collect this data, arguably using the kind of "conventional means" which the Commenter asserts EPA must use for collecting data. However, if the sources do not provide EPA with the data it requests, EPA is not required to bring an enforcement action to obtain this data, *e.g.* EPA does not agree that an enforcement action qualifies as a "conventional means" of obtaining data. EPA may use its enforcement discretion to choose how best to utilize its resources to enforce against those who violate the

CAA, including those sources who fail to provide all of the information requested under an ICR, but is not required to take such action.

4.2 Emissions Factors for Hydrogen Production Units

4.2.1 VOC/THC Emissions Factor

Comment: Commenter 58 stated EPA must use easily accessible process data to propose a H2P THC emissions factor. Commenter 58 noted that 2 out of 4 test reports for H2P THC data did not include production data and stated EPA should collect and use production data and process data for emissions tests. Commenter 58 noted that under the APA the agency has a duty to review and collect data that is easily retrievable using conventional means, and EPA's failure to collect this data substantially impaired the agency's ability to promulgate a new THC emissions factor for H2P.

Response: We attempted to create an emissions factor for VOC (or THC as a surrogate for VOC) and used all available test data in the emissions factor analysis. Unfortunately, there were not enough Hydrogen Production units with acceptable emissions tests that also had available process data. As discussed above, we previously attempted to collect this data in the 2011 Refinery ICR but are not obligated to continue seeking this data.

4.2.2 CO Emissions Factor

Comment: Commenter 58 stated EPA must use easily accessible process data to propose a H2P CO emissions factor. Commenter 58 noted that 2 out of 3 test reports for H2P CO data did not include production data and stated EPA should collect and use production data and process data for emissions tests. Commenter 58 noted that under the APA the agency has a duty to review and collect data that is easily retrievable using conventional means, and EPA's failure to collect this data substantially impaired the agency's ability to promulgate a new CO emissions factor for H2P.

Response: We attempted to create an emissions factor for CO and used all available test data in the emissions factor analysis. Unfortunately, there were not enough Hydrogen Production units with acceptable emissions tests that also had available process data. As discussed above, we previously attempted to collect this data in the 2011 Refinery ICR but are not obligated to continue seeking this data.

4.2.3 NOx Emissions Factor

Comment: Commenter 56 stated the NOx emissions factor for uncontrolled hydrogen plant reformer furnaces is likely of limited value. Commenter 56 stated hydrogen reformer furnaces are large furnaces, many with greater than 100 million MMBTU/hr design firing rate; the majority of hydrogen reformer furnaces they surveyed have ULNB or SCR installed, or both, so the proposed emissions factor would not be applicable to them; and most units have stack test data or CEMS data used for emission inventory purposes.

Response: We acknowledge the comment. As previously stated, we always recommend the use of site-specific data over the use of emissions factors. However, section 130 of the Clean Air Act requires EPA to review, and if necessary, revise NOx emissions factors every three years. No NOx emissions factor currently exists for hydrogen plants; therefore, we find it necessary to create such an emissions factor at this time, given that we have the data to do so. We did not have enough data on controlled hydrogen plants to create a separate NOx emissions factor for these sources, but we recognize that the NOx emissions from controlled units will vary from those emitted by an uncontrolled unit. As such, we specifically designated that the emissions factor is for uncontrolled hydrogen plants. Sources with controlled hydrogen plants may still be able to use this emissions factor if they have information on the control efficiency of the NOx controls installed. The end user would need to decide if such use is appropriate on a case-by-case basis.

Additionally, as previously stated, the main purpose of AP-42 is to provide emissions factors for national scale emissions inventories. Inventory developers do not always have access to site-specific data and the emissions factor may be useful in these cases.

4.3 Hydrogen Cyanide Emissions Factor for Fluid Catalytic Cracking Units

Comment: Commenter 58 stated the new FCCU HCN emissions factor is representative of actual emissions and based on a robust data set. Commenter 58 stated EPA reviewed 22 test reports received from Component 1 and Component 4 of the 2011 ICR, the data used for the emissions factor included 9 test reports for 8 FCCU process units, and this number exceeds the minimum necessary that EPA has relied on in the past to develop emissions factors for other industrial sources. Commenter 58 stated EPA should follow up with facilities that did not provide process data (feed rate and coke burn rate) during the testing, as not providing this data is likely a violation of CAA section 114, this information should be readily available and the APA requires that EPA review readily available data before finalizing the rule.

Response: The EPA acknowledges the comment. As stated in the previous section, we did attempt to collect this data previously, but we are not obligated to continue seeking this data.

Comment: Commenters 54 and 56 stated EPA has not adequately developed or justified the proposed Fluid Catalytic Cracking Unit (FCCU) hydrogen cyanide (HCN) emissions factor. Commenter 54 stated EPA should further evaluate the factor. Commenters 54 and 56 stated the proposed factor should not be finalized. Commenters 54 and 56 stated EPA did not include the impacts of process configurations on HCN formation and emissions. Given the lack of data sufficient to demonstrate statistical significance, the inability to parse the data based on known chemical interactions, and the fact that the FCCU HCN emissions factor is not required by the CD, Commenter 54 stated EPA should defer action on this particular emissions factor to address data gaps and facilitate an informed technical decision.

Commenter 56 stated EPA failed to use the representative process activity rate for emissions factor development, used a data set that is too small to provide representative emissions factors, inappropriately applied statistics, and did not comply with its own procedures outlined in the RPDEF.

Response: We have reevaluated the FCCU data set and developed a revised final emissions factor. The reevaluation resulted in changing the process activity basis to the coke burn rate, incorporating additional process activity data provided by commenters, including a test report for which the process data was inadvertently omitted at proposal, examining multiple comments on the validity of the available test report data, and revising the representativeness characterization from the small population to the large population analysis. We also provided additional detail on the process types and APCDs covered in the available test data on which the final emissions factor was based. We decided to retain the FCCU HCN emissions factor on a feed rate basis as an alternative factor in cases where coke burn rate is not known. We believe that since both factors were developed using a similar data set, both are representative of the emissions of these units. The reanalysis is discussed further in the *Final Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations.*

The final data set consists of 11 FCCUs. We find that this data set is an adequate representation of the FCCU universe and provides enough data for emissions factor development.

Comment: Commenter 54 stated that EPA's justification for the HCN emissions factor of "HCN is a risk driver" is not germane to the technical evaluation regarding adequacy of data to derive a representative emissions factor.

Response: The EPA agrees with the commenter that just because a compound is a risk driver does not mean there is adequate data to derive a factor. We simply included the fact that it is a risk driver to explain why we prioritized the development of this emissions factor over other emissions factors, once we completed developing emissions factors for the pollutants specifically listed in section 130 of the Clean Air Act. The final data set consists of 11 FCCUs. We find that this data set is an adequate representation of the FCCU universe and provides enough data for emissions factor development.

Comment: Commenter 53 provided additional emissions test report data to include in potential reconsideration of the proposed FCCU HCN emissions factor (see Attachment 2 to the comment letter); these data included emissions data summary tables from 3 FCCUs at 3 facilities (IL2A0420, LA3C0610, and MI2A0710).

Response: We were able to obtain the full test reports for 2 of the FCCUs (LA3C0610 and MI2A0710) and included these units in the data set for final analysis; the test report for one FCCU was already included in our data set at proposal (IL2A0420), and the feed rate and coke burn rate for the FCCU submitted by the commenter was attached to the test report.

We were also able to obtain coke burn rate data from another commenter. The test report was already included in our data set at proposal (IN2A0440), and the coke burn rate data was added to the test report.

Comment: Commenter 56 strongly discouraged publication of an HCN emissions factor in lb/bbl feed because feed rate is not a representative indicator of HCN emissions. Commenter

56 recommended EPA use coke burn rate as the appropriate activity rate for HCN as opposed to FCCU feed rate. Commenter 56 cited the following reasons:

1. HCN results from the combustion of coke during catalyst regeneration;
2. Fixed nitrogen in the coke converts to HCN and NH_3 in partial burn units and to NO in full burn units;
3. HCN production is more closely related to coke burn rate;
4. Feed rate alone is not a reliable indicator of coke burn rate, because coke yield varies with feed characteristics; and
5. Feed rate may include recycled slurry or heavy cycle gas oil that have different characteristics than fresh feed. Commenter 56 noted that EPA has not defined total feed rate and should verify that total feed rate was used.

Commenter 56 stated EPA has overlooked a number of reports for units with acceptable HCN measurement results that also provided coke burn rate data in the test reports: CA5A1090, LA3C0560, NJ1A0850, NJA0860, TX3B1250, and VI6A1530. For NJ1A0860, Commenter 56 stated EPA incorrectly rejected one of two sets of test results because production data were not provided in the report; however, the report for the other stack does include coke burn data. Commenter 56 noted they were able to obtain coke burn data for three additional FCCUs with acceptable HCN measurement results. Commenter 56 stated it will continue to work with its member companies and others to expand the FCCU HCN data set for potential emissions factor development.

Response: Based on the comment, we have explored revisions to the draft emissions factor that included a change from feed rate to coke burn rate. The coke burn rate data for several facilities were already part of EPA's proposal data set (LA3C0560, NJ1A0850, NJA0860, TX3B1250 and VI6A1530), and the coke burn rate data that was inadvertently omitted for one facility was added to the data set based on the public comment (i.e., CA5A1090). In the full data set at final analysis, coke burn rate data are available for 11 units where emissions testing was conducted with OTM-029 or a comparable method. The coke burn rate for each of these FCCUs was included in the final emissions factor analysis to develop an HCN emissions factor based on coke burn rate.

If the commenter wishes to continue to expand the available data set by providing test reports with emissions data and concurrent coke burn rate data, we may use this data in the future to determine whether revisions to the emissions factor are appropriate.

We also developed an alternative FCCU HCN emissions factor on a feed rate basis. Because coke burn data are often available to refinery staff but not for other emissions inventory developers, and because feed rate data are often publicly available, an alternative factor based on feed rate was developed. Because feed rate data are more accessible for FCCUs for those outside of refinery facilities, an alternative emissions factor provides additional emissions estimation capabilities for the public. The alternative FCCU HCN emissions factor on a feed rate basis may be used when coke burn data are not available.

Comment: Commenter 56 provided input on the data limitations, indicating that EPA's FCCU HCN data set is very small (8 units, all of which are full burn units) and the range within the data set is very large relative to the arithmetic mean. Commenter 56 noted that 3 tests for 2 of these units should be excluded based on EPA's own test method evaluation methodology, which would further decrease the sample size; this leaves a data set that is too small to justify the proposed revised HCN emissions factor, for example, because of different process configurations affecting HCN emissions. Commenter 56 stated small data sets require different statistical methods than are currently specified in the RPDEF. At a minimum, Commenter 56 stated that assuring a normal distribution exists or transforming the data (e.g., log) to normalize the distribution is necessary to assure accurate emissions factor development.

Response: We have reevaluated the FCCU data set and developed a revised final emissions factor. The reevaluation resulted in changing the process activity basis to the coke burn rate, incorporating additional process activity data provided by commenters, including a test report for which process activity was inadvertently omitted at proposal, examining multiple comments on the validity of the available test report data, and revising the representativeness characterization from the small population to the large population analysis. The final data set consists of 11 FCCUs. We find that this data set is an adequate representation of the FCCU universe and provides enough data for emissions factor development. As noted previously, we retained the FCCU HCN emissions factor on a feed rate basis as an alternative factor for situations where coke burn rate is unknown.

For reasons previously explained in Section 4.1.1 of this document, we are not responding to comments related to our recommended emissions factor development procedures in this project.

Comment: Commenter 56 stated EPA has not adequately considered FCCU process configurations and expected effects on HCN emissions in evaluating valid data combinations. Commenters 54 and 56 stated EPA should revise its analysis of valid HCN data combinations, considering HCN formation, destruction and removal mechanisms and how this would be expected to differ among process configurations (e.g., full and partial burn regenerators, fired CO boilers or heaters, regenerator additives, NOx and acid gas air pollution control technologies, etc.). Commenter 56 stated full burn units favor NOx formation while partial burn units favor formation of HCN and NH_3. Commenter 56 stated regenerator units with CO boilers have lower HCN emissions and less variability in HCN. Commenter 56 stated EPA's data set does not contain any valid test results for units with fired CO boilers in operation. Commenter 56 recommended EPA develop HCN emissions factors for at least the following FCCU configurations: partial burn with CO boiler; full burn with CO boiler; and full burn without CO boiler.

Commenter 56 noted that WGS may partially absorb HCN; however, the amount would be low, and ESPs are not expected to reduce HCN. Commenter 56 stated neither EPA's data set nor theirs contain sufficient data to make any strong conclusion regarding differences in emissions for units with WGS and ESPs.

Response: The FCCU HCN emissions factor is based on 11 units and the majority of these units are complete/full regeneration. These FCCUs included 8 units that are complete regeneration, and 3 units that are complete regeneration followed by a CO boiler. The FCCUs had the following APCD configurations: 3 with ESP and SCR or SNCR; 1 with wet scrubber and SCR; 2 with ESPs; and 5 with wet scrubbers. We reviewed the data and could not find any appropriate means by which to subcategorize emissions by process and control type. While it is possible that different unit configurations will have an effect on HCN emissions, we do not have enough data to determine this. We did not have enough data on partial burn units to attempt a statistical analysis. The student t-test performed to decide whether or not the CO boiler affected the emissions indicated that all data belonged in the same set. Based on our understanding of

HCN control, the different APCDs in the data set are likely to have little impact on HCN emissions. Therefore, a single emissions factor was developed in the final analysis. If we receive more data, in the future we may revisit the issue of whether it is appropriate to create subcategories of FCCUs for emissions factor development.

Comment: Commenter 56 stated the Student's t-test procedure described in RPDEF Appendix E and in the draft EF Development Report, does not provide a robust assessment of valid data combinations for HCN with such a small data set. Commenter 56 stated subgroups should not be established on statistical results alone without some degree of engineering judgment considering process effects, especially with small data sets. Commenter 56 provided analysis results using ProUCL 5.0 and other standard statistical checks for EPA's original data set, for the commenter's suggested Corrected EPA data set, and for the commenter's data set based on coke burn rate activity; the commenter noted differences for CO boiler vs. no CO boiler data, WGS vs. ESP data, and full burn vs. partial burn data.

Response: We used our recommended procedures for developing emissions factors, which were previously publically reviewed, in this project. For the reasons previously noted in Section 4.1.1 of this document, we are not responding to comments on our standard emissions factor development procedures in this project.

Comment: Commenter 56 agreed with most of EPA's findings regarding questionable HCN measurements but provided input for several tests.

Commenter 56 questioned the quality of 2 tests for MS3C0740 that used 0.1N sodium hydroxide absorbing solution and critical quantitative pH checks are not documented in both the 2007 and 2008 tests; in fact, the HCN emissions factor for this unit is the lowest in EPA's data set, which is consistent with a negative (low) bias in the results due to reagent depletion; thus, the quality of the HCN measurement results in both tests is not adequate for use in emissions factor development and should be deleted from EPA's data set.

Commenter 56 questioned the quality of MN2B0720 where:

1. Run 1 was stopped at 33 minutes because the sampling train was plugged due to coagulation in impinger #2, and the test was invalidated;
2. Run 2 was stopped after 48 minutes because impingers #2 and #3 were gelled;

3. A fourth test run was performed; and
4. Critical pH checks are not documented or otherwise mentioned in the report.

Commenter 56 concluded that the quality of the HCN measurement results for this unit is not adequate for use in emissions factor development and should be deleted from EPA's data set.

Commenter 56 questioned the quality of VI6A1530 where:

1. In-field pH tests showed the pH of the final impinger and the combined (total) impinger catch was greater than 12 following the test, while the laboratory custody log shows pH of the combined samples ranged from 10.62 to 10.85;
2. There is no narrative in either the test or laboratory reports; and
3. Commenter 56 noted the HCN results may be biased low (yet are the highest concentration in the data set).

Commenter 56 stated that because the field pH check results conform to OTM-29 specifications, the test results are considered valid for use in emissions factor development at this time, however, the uncertainty in test accuracy justifies a lower test report quality rating, which may justify excluding the data in the future as additional data of higher quality become available.

Commenter 56 questioned EPA's exclusion of NJ1A0850 where the CTM-033 method was modified to use much higher reagent strength, pH checks are documented and pH remained at 12 or above. While EPA concluded incorrectly that the reagent modifications were not made and consequently rejected these data, Commenter 56 concluded that the quality of the HCN measurement results for this unit is acceptable for use in emissions factor development.

Response: We appreciate the thorough input on the data set and have reviewed each recommendation made by the commenters. Our findings are summarized below:

We agree with the commenter that test data for MS3C0740 are based on CTM-033 and deleted these test reports from the final data analysis.

With respect to the MN2B0720 test data, the test report had issues with the laboratory QA/QC and an extended holding time beyond the recommended 30 days. We have decided not to include this test data in the final emissions factor analysis due to the questionable quality of the data.

After reviewing the VI6A1530 test report, we agree with the commenter that this test report be included in the final analysis, and note that an attachment to the test report called "OTM-029 Field QA/QC Checklist" includes a note that the pH in the last impinger was verified to be >12 (see p. 544 of the test report pdf). No change was made to the ITR, as the current score reflects the documentation provided in the test report, and the documentation level has not changed.

With respect to the NJ1A0850 test data, we agree with the commenter that the test report should be included as the testing was based on modified CTM-033 with 6N NaOH solution in the impingers.

While no comments were received on other test reports, the FCCU at NJ1A0820 was deleted from the final emissions factor analysis because the coke burn rate data are not available, and the FCCU at HI5A0380 was added to the final data set because coke burn rate data are available.

Comment: Commenter 56 stated EPA's characterization of the FCCU lb HCN/bbl feed emissions factor quality as "moderately representative" is highly misleading, as feed rate is not a representative indicator of HCN emissions. Commenter 56 noted the range of the underlying data is very large relative to the mean, indicating very low confidence in the reported emissions factor, EPA makes no assessment of the number and configurations of units tested relative to the total population of FCCUs, and therefore the representativeness of the eight units tested to the total population is unknown. Commenter 56 recommended characterizing the emissions factor as "potentially unrepresentative – high uncertainty," with advice to use extreme caution in applying it.

Response: We have reevaluated the characterization of the emissions factor as there was an inadvertent error in the characterization at proposal. In the final analysis, the characterization is based on the total population of FCCUs, not the number of FCCUs used for emissions factor development. While the characterization analysis at proposal was based on the "small population" analysis, the emissions factor would be correctly based on the "large population" analysis. In the final analysis, characterization of the revised FCCU HCN emissions factor was changed to the "large population" category, and because of the increase in the number of FCCUs with available data, characterization remains at "moderately representative." The characterizations are based on the procedures and categories set forth in the recommended procedures for developing emissions factors

4.4 Revisions to AP-42 Section 5.1 and Refinery Protocol

Comment: Commenter 56 stated that FCCU operating factors and potential effects on HCN emissions factors should be discussed in AP-42 Section 5.1 and the Refinery Protocol.

Response: We agree this discussion would be useful. Unfortunately, we do not have enough data to determine specific factors that influence HCN emissions, and as such, a discussion would be merely conjecture. Therefore, we have not included a discussion of this issue in AP-42 or the Refinery Protocol.

Comment: Commenter 56 suggested the following corrections for AP-42 Section 5.1:

Section 5.1.2.6, Fourth Paragraph, Second Sentence "The PSA ~~off-~~tailgas vent contains hydrocarbons and methanol." [change "off-gas" to "tailgas"]

Section 5.1.2.6, Fourth Paragraph, Fourth Sentence "The~~se~~ PSA ~~off-~~tailgas vent and deaerator vent may be directed to the steam methane reforming furnace, which is expected to reduce the hydrocarbon emissions." [change "These" to "The" and change "off-gas" to "tailgas"]

Response: We have made the requested changes.

4.5 Other Comments

Comment: Commenter 58 stated EPA must collect and consider available and reasonably obtainable data to properly review the existing emissions factors for CRUs, FCCUs, SRUs, and Hydrogen units. Commenter 58 stated that collecting missing process data would enable EPA to broaden the data set for new emissions factors it proposed for SRU (NOx, CO, THC), CRU (THC), H2P (NOx), and FCCU (HCN).

Response: As previously discussed in Section 4.1.2 of this document, we believe a complete stack test report includes process data that is recorded at the time of the request. As such, in the 2011 Refinery ICR, we requested that such data be included in the test reports; therefore, we did attempt to collect this data. However, if the sources do not provide EPA with the data as requested, EPA is not required to continue to seek this data.

Chapter 5

REVIEW OF AVAILABLE DOCUMENTS

5.1 DIAL Study Review

Comment: Commenter 58 stated EPA failed to adequately review the available data for wastewater treatment plant (WWTP) and storage tanks and either make a determination that revisions of the VOC emissions factors is not "necessary" or revise the emissions factors. Commenter 58 stated EPA's determination that revision of the VOC emissions factors is not necessary is arbitrary and capricious and that EPA's decision is based on claims that it does not have sufficient data to revise the emissions factors, not that revision is not necessary. Commenter 58 stated that instead of making a determination on the threshold question, "Is revision of the Emission Factor necessary?", EPA evaluated whether there was enough data to revise the emissions factors or evaluated whether the estimated emissions agreed reasonably well with measured emissions. Commenter 58 stated this does not address the threshold question that Section 130 requires EPA to answer. Commenter 58 stated EPA must make a determination as to whether revision of the emissions factors is necessary and revise the emissions factors if the answer to that question is yes.

Commenter 58 stated there is readily available data for EPA to make a determination that revision is necessary and to revise the emissions factors. Commenter 58 stated EPA should propose new emissions factors that better account for VOC pollution from storage tanks and WWTP.

Commenter 58 stated revision of the VOC emissions factor for storage tanks is necessary because the DIAL studies consistently show that the existing factor undercounts emissions. Commenter 58 cited data that demonstrates this fact, including:

- Alberta DIAL study: Extrapolated VOC emissions for storage tanks were projected to be 5,090 tonnes/yr compared to 153 tonnes/yr as reported in the emission inventory.
- BP Texas City DIAL study: The DIAL measurements were more than 2 times higher than estimated emissions at 5 out of 8 tank groups, and only 2 measurements fell within the estimated range of emissions.

- Shell Deer Park DIAL study: DIAL measurements at tank groups were greater than estimated emissions 100 percent of the time, and for 6 out of 9 data points, the measured emissions were 10 times the estimated emissions.

Commenter 58 stated the out of hand dismissal of these data is arbitrary and capricious.

Response: The EPA reviewed the available information, including additional information submitted during the public comment period, and based on all of the available data, we have developed the document entitled *EPA Review of Available Documents and Rationale in Support of Final Emissions Factors and Negative Determinations for Flares, Tanks, and Wastewater Treatment Systems*. This document contains a complete analysis of our review of the available data.

The AP-42 emissions factor correlation equations for both tanks and wastewater treatment systems provide a sophisticated modeling method to estimate emissions, considering a wide variety of unit-specific variables, including the tank size, throughput, content properties, ambient temperatures, and wind speed. When this detailed information is properly used with the AP-42 equations, the emissions estimates derived from the emissions modeling are very similar to the emissions estimates derived from the measurement data included in these studies. This indicates the AP-42 equations are still accurately providing emissions estimates for tanks and wastewater treatment systems.

We recognize that the equations in AP-42 can inaccurately estimate emissions when sources inappropriately use default values or when sources do not enter site-specific inputs into the equations. For example, it is important for sources to develop and use site-specific vapor pressure information for materials like No. 6 fuel oil, which are routinely mixed with more volatile materials. However, we find that misapplication of the equations or use of inaccurate input information does not necessitate a revision of the AP-42 emissions factor equations for tanks and wastewater treatment systems.

We have also investigated differences in short-term tank emissions and annual average tank emissions and found that short-term (hourly) emissions rates can be 5 to 10 times higher than the annual average emissions rate. Thus, comparisons of short-term measured emissions with annual emissions reported in an emissions inventory must consider the variability in the emissions across different temperature, wind speed, and operating characteristics. Thus, we find that when process-specific data are not available for direct modeling comparisons, short-term measurement data within a factor of 5 of the annual average emissions inventory value does not provide justification that the emissions inventory is incorrect or that the emissions factor equations need to be revised.

It is also important to note that the emissions estimation procedures only account for emissions in normal operating scenarios. Emissions from tanks that are improperly operated, defective (e.g. damaged floating roof rim seals and deck fittings), or in disrepair cannot be accurately estimated using these methods. Furthermore, there is no universal method by which to estimate the emissions from these events, since the specific type of event would require detailed analysis. We have included guidance in the *Refinery Protocol* (RTI, 2011) for estimating emissions during malfunctions or upsets, but each such event would require specific engineering calculations to estimate the emissions from these occurrences.

Therefore, we determine that it is not necessary to revise the tank or wastewater treatment system emissions estimation equations in AP-42. The AP-42 emissions estimation equations sufficiently estimate emissions with accurately characterized units, site-specific inputs, and properly operated and maintained equipment.

Comment: Commenter 58 stated EPA can obtain most or all of the data it needs to determine if tanks are defective, what was stored in tanks during time of testing, and if additional upwind sources contributed to the measured emissions. Commenter 58 noted EPA can determine if storage tanks are defective by: reviewing upset emission reports from Texas' Emission Event Database; requesting and reviewing the maintenance logs for these tanks from the date of testing to present from the facilities; and inspecting the tanks in question to determine if they are defective. Commenter 58 noted that if EPA finds the tanks are defective, EPA could conservatively assume that the tanks were also defective at the time of testing.

Commenter 58 stated EPA can determine what was stored in the tanks during testing by doing the following: requesting emission inventory submissions and the underlying data used to report emissions during the time period of the DIAL testing, and requesting storage vessel material handling logs from the time period of the DIAL testing.

Commenter 58 stated EPA can determine if upwind sources contributed to measured emissions by doing the following: requesting information from the authors of the respective studies to determine the range of the DIAL instrument and reviewing emission inventory data from the facility in question and nearby sources to triangulate other potential sources of emissions.

Response: The EPA disagrees with the commenter. Obtaining the detailed information needed to properly apply the AP-42 emissions equations for a specific point in time is not a trivial matter and is not always possible, depending upon the records retained by the facility. For example, it would not be possible to determine today the condition of a tank five years ago unless the facility documented the condition of the tank and retained the documentation. A tank that is defective today was not necessarily defective five years ago, and if it was, we would recommend against the use of AP-42 equations for estimating emissions from the tank. While we agree that Texas' Emission Event Database contains useful information on excess emissions events, we are uncertain whether it contains data on defective tanks. In order for the database to contain such information, a facility would need to note that the tank is defective and estimate emissions from the tank to determine whether excess emissions exist. It is unclear whether facilities are actually estimating excess emissions for defective tanks and including them in Texas' database.

Additionally, application of the tank emission estimation equations requires detailed knowledge of the tank contents, storage conditions, throughput, and levels. Facilities do not generally keep detailed logs of this data. Because inventories are usually developed in yearly increments, it is not uncommon for sources to use a yearly throughput and average tank storage data which provide an adequate annual estimation of emissions, but would possibly under-estimate short-term emissions. To adequately characterize emissions, sampling of the tank contents should be performed routinely, but often operators use process knowledge and default information in lieu of direct sampling, making data on the true tank contents impossible to obtain at time. We have found that most of the discrepancies between the estimated emissions and measured emissions have been associated with improperly characterized tank contents and unusual operating characteristics.

In the *EPA Review of Available Documents and Rationale in Support of Final Emissions Factors and Negative Determinations for Flares, Tanks, and Wastewater Treatment Systems*, we have used available information to determine whether upwind sources contribute to DIAL measurements. This documents discusses our findings on the different DIAL studies.

Comment: Commenter 58 stated that measured storage tank emissions do not agree well with estimated emissions. Commenter 58 stated it is unclear which measurements EPA refers to with their statements, as only 2 out of 9 measurements fell within estimated emissions, and EPA's calculation of the estimated emissions range for Tanks 11, 12, 18, 42, 60, 61, 63, and 65 is unclear, incomplete, and/or incorrect. Commenter 58 noted the following problems with EPA's calculations:

1. Table D-14 appears to be misidentified. Table D-14 states that it models the emissions from Tank 98 and references DIAL scans 11 and 12. Based on the National Physical Laboratory (NPL) report, these scans targeted Tanks 23, 27, 28, and 29.
2. Table D-15 appears to be misidentified. The title states that the table summarizes emissions from Tanks 54, 55, 56, and 98.
3. Because of the misidentified tables, it is unclear how EPA calculated the emissions from tanks 11 and 12.
4. It is not clear if EPA included the estimated emissions from Tank 98 in the range represented for this tank grouping. If the range does include emissions from Tank 98, EPA should provide an explanation supporting this decision. Based on Figure 2.8 and from the NPL report, it appears very unlikely that emissions plume from Tank 98 would cross the path of the DIAL scans 399 to 404.
5. EPA should not have included emissions from Tanks 11, 12 and 18 as sources contributing emissions to the measured emissions. The NPL study performed DIAL scans that isolated these tanks and measured that the emissions from these tanks were negligible, at less than 1 lb per hour. Nevertheless, EPA modeled that the emissions from Tank 18 contributed 2.57 lb per hour and as discussed above, it is unclear what amount Tanks 11 and 12 were calculated to contribute to the modelling.

Response: The commenter is referring specifically to appendix tables in the *Critical Review of DIAL Emission Test Data for BP Petroleum Refinery in Texas City, Texas* (Randall and Coburn, 2010). The commenter is correct that Tables D-14 and D-15 are mislabeled. Table D-14 is a summary of modeled emissions for Tanks 11 and 12 for scans 399+. In addition to the title error, the headers are off by one column. The first column should be "Tank No." and the existing column headers should be shifted one column to the right. Thus, the table is actually missing the data for "Total loss,", but this can be calculated as the sum of the emissions that are presented in the table. Specifically, the total emissions (“loss”) for Tank 11 was 1.075 lb/hr and the total emissions for Tank 12 was 1.079 lb/hr. In addition, the title of Table D-15 should refer to Tanks 43, 60, and 63. We did not estimate emissions from Tank 98 as contributing to these sources.

Finally, we disagree that we should not evaluate the contribution of emissions from Tanks 11, 12, and 18. Emissions factors represent national averages; we expect roughly 50% of sources to be above the estimated emissions and 50% of sources to be below the estimated emissions. Because we are charged with determining whether it is necessary to revise the existing AP-42 emissions factors, we must evaluate both instances where the model under-predicts emissions as well as instances where the model over-predicts emissions to determine if, on average, the emissions factors provide a reasonable estimate of the emissions considering all tanks at the facility. Based on our review, we found that the modeled emissions matched the measured emissions for 10 tanks; the model overestimated emissions by about a factor of three for 4 tanks; and the model underestimated emissions by about a factor of three for 13 tanks.

The three tanks with the largest discrepancy were downwind of the activated sludge system and the measured emissions from the DIAL scans were projected to have emissions contributions from the activated sludge system. For scans where wind direction was such that these tanks were not downwind of the activated sludge unit, the measured emissions matched the model emissions estimates. When we consider the runs when the activated sludge system was not upwind of these tanks, the modeled emissions for 13 tanks matched the measured emissions; the model overestimated emissions for 4 tanks; and the model underestimated emissions for 10 tanks. Direct composition of the tank materials was not determined at the time of the test; therefore, default tank content compositions were used to estimate emissions. This provides significant modeling uncertainty. There are also significant potential measurement uncertainties in the DIAL measurements due to potential upwind emissions sources and wind speed characteristics due to large obstructions (tanks) near the measurement path. Note that if the wind speed in the plume path immediately downwind of a tank is half that measured at an unobstructed location at a 10 meter height, then the DIAL emissions measurement would overstate actual emissions by factor of two. Considering the uncertainties and relative accuracies of both the DIAL and the AP-42 emissions estimation equations, we find that the modeled data compared reasonably well with the measured data, confirming the overall representativeness of the equations.

5.2 Other Storage Tank Comments

Comment: Commenters 33, 47, 54 and 56 agreed with EPA's conclusion that existing data are not adequate to support/do not support revision of the emissions estimating methods for tanks. Commenters 33 and 56 noted that a lack of data and the fundamental limitations noted by EPA led to the appropriate conclusion to not revise the emissions factor. Commenter 33 recommended EPA develop and implement AP-42 changes only if necessary and as required within an appropriate timeframe.

Response: The EPA acknowledges the comment.

Comment: Commenters 32, 33 and 47 cited multiple issues with the temporary total enclosure (TTE) testing approach used for storage tank testing. Commenter 32 stated these observations may warrant additional data evaluation and may warrant additional data collection using other sampling programs. Commenters 33 and 47 stated that the testing approach was based on an experimental testing protocol that provided biased, high VOC emission results. Commenters 32, 33 and 47 stated both terminal operators and their testing firm/consultants raised concerns about the method/correlation between forced ventilation and the recorded emissions. Commenter 33 stated the Sprague emissions data should not be relied on or referenced until further testing is conducted.

Commenter 32 noted that when the Method 204 ID fan speed increased, VOC concentration remained constant, which resulted in an increased estimated VOC emission rate; it was expected that VOC concentration would decrease when fan speed increased because concentration would be diluted with ambient air that entered natural draft openings in the TTE but this did not happen. Commenter 32 noted one could essentially adjust the VOC emission rate by increasing or decreasing the system flow rate. Commenter 32 stated it was difficult to maintain a continuous minimum TTE vacuum of just above -0.007 inches water column (in. w.c.).

Commenter 32 described an additional experiment conducted on the Sprague tank (without TTE system installed) where one of two tank vents was sealed, a pitot tube and manometer were fitted inside the other tank vent, and VOC sample was collected from the center of the vent into a Tedlar bag. Commenter 32 stated the VOC emissions were 41.5 percent of the 30-day average VOC emission rate, and 66.7 percent of the lowest VOC emission rate observed using the experimental TTE testing approach. Commenter 32 stated these results may indicate that use of the variable speed ID fan during the TTE testing artificially increased flow from the tanks above normal tank configuration levels (however commenter 32 also noted that other factors must be considered in evaluating this experiment, including the brevity of the experiment, non-conformance of the vent sampling location to EPA Method 1 criteria, and a high wind condition during the experiment). Commenter 32 noted the use of the TTE sampling system did not represent direct measurement of the tank vents under their normal configuration; tanks breathe both inward and outward depending on ambient conditions, and inward flow was not considered during the sampling program.

Commenter 32 stated that Phase 1 of the testing included sluggish response time for the zero calibration gas, and the testing firm observed oil seeping out of the VOC analyzer despite heated, quartz fiber filters in place to remove oil mists. Commenter 32 stated they theorized that oil mist/droplets entrained in the TTE sampling system was being volatilized at 275°F in the heated filter/sample line and ultimately included in the VOC analysis. Commenter 32 stated that during Phase 2, an unheated coalescing filter was installed to remove oil mist/droplets. Following this change, Commenter 32 stated calibration response to zero and span gas was much faster, and VOC concentration was reduced as compared to Phase 1 data. Commenter 32 noted that Phase 2 data resulted in a 30 percent reduction in VOC emissions from a residual oil tank and a 21 percent reduction in VOC emissions from an asphalt tank, compared to Phase 1. Commenter 32 noted one should consider that a learning curve may have led to generating closer to representative data during the Phase 2 sampling period.

Response: The EPA acknowledges the comment.

Comment: Commenters 33 and 47 stated EPA should provide national guidance on the appropriate method for measuring storage tank emissions to ensure clear and consistent results for use in supporting an Agency determination regarding changes to the AP-42 VOC emissions factor for tanks. Commenter 33 noted this is particularly important for heated tanks. Commenter 33 recommended EPA initiate a national effort to develop a consistent storage tank emissions testing protocol and to conduct additional testing to determine if modifications to the AP-42 equations for tanks are necessary, particularly for No. 6 oil and asphalt storage tanks.

Commenter 33 recommended EPA communicate to all Regions the details on the review and collection of data to determine if changes to AP-42 are necessary and instruct that all VOC emissions reporting requirements for No. 6 oil and asphalt tanks should be delayed until a clear and consistent national emission estimation method is developed.

Response: We will consider the suggestion to develop a national protocol if and when future tank testing is conducted. Additionally, we note that the most important factor in developing emissions estimations for heated tanks is use of a proper vapor pressure of the material stored. In cases where we have noted issues with estimating emissions from No. 6 fuel oil, it is generally because the vapor pressure used in the calculations was much lower than the actual vapor pressure of the material. It is imperative that facilities use site specific data (preferably through fuel sampling) to obtain the best emissions estimations.

Comment: Commenter 47 stated that the "DRAFT EPA Review of Available Documents for Developing Proposed Emissions Factors for Flares, Tanks, and Wastewater Treatment Systems" (Draft Report) concluded that further testing would need to include a number of other elements in order to develop new tank emission methodologies. Commenter 47 stated that this implies that EPA plans to defer to different testing protocols for different geographic regions when measuring compliance with the VOC standard. While Commenter 47 agreed that different conditions affect tank emissions, the commenter expressed concerns with following multiple testing protocols and stated that EPA should develop one uniform protocol.

Response: In the draft report, we were simply pointing out the complexity of the calculations involved in the tank emissions estimations methodology and the number of factors that must be accounted for in development of new factors. We did not mean to imply that each geographic region should follow a different tank testing protocol. We will consider the suggestion to develop a national protocol if and when future tank testing is conducted.

Comment: Commenter 47 stated EPA should refrain from pursuing enforcement actions based on tests conducted using this experimental protocol.

Response: This comment is outside of the scope of this project.

Comment: Commenter 58 stated EPA failed to adequately/fully evaluate the available data on emissions from storage tanks. Commenter 58 stated EPA's review of test data from Global Companies LLC in South Portland Maine and Sprague Operating Resources LLC in Searsport Maine fails to adequately analyze the data to determine if the VOC emissions factors need revision. Commenter 58 stated EPA did not perform an analysis for the Global Companies LLC data, and without a thorough review of this data, EPA cannot claim that its review of the VOC emissions factor for storage tanks meet the requirements of the APA. Commenter 58 stated there is an additional DIAL study for VOC emissions from storage tanks at several refineries in SCAQMD (Carson Area SOF Study 2014). Commenter 58 stated EPA should also review this study and any new data that has become available since the proposed rule. Commenter 58 stated a more recent study using a combination of SOF, Mobil DOAS, MeFTIR, and MW-DOAS found that storage tank VOC emissions are 4 to 8 times higher than those predicted with emissions factors.

Response: We disagree with the commenter. We did review the test data from Global; however, we had limited information on how the emission estimations were calculated. Based on reviewing similar data, we have determined that there is widespread misapplication of default factors, especially for heated storage tanks. As previously noted, this can be very problematic when a heavy fuel is mixed with volatile material and the vapor pressure of the volatile material is not accounted for in the equations. Errors in applying the emissions factors are not a reasonable justification to assert that it is necessary to revise the emissions factors. Our review of the available data suggests that, when properly applied, the AP-42 emissions factors provide reasonably accurate estimates of the emissions from storage tanks.

We did review the Carson and Bay Area Solar Occultation Flux (SOF) studies. However, these studies provide only a total emissions rate from the plant and cannot be used to determine which sources at the plant were responsible for the emissions measured. We also note that comparing annual emissions inventories to measurements made over a short period of time does not necessarily indicate that the emissions inventory is incorrect or that the emissions factors used are inappropriate. There are a number of reasons why short-term emissions can significantly exceed annual average emissions even when the annual emissions estimates are accurate. For example, emissions while actively filling a tank are significantly larger than when the liquid level is constant or declining.

Comment: Commenter 58 stated the current/existing emissions factors are inaccurate, underestimate emissions, and need revision. Commenter 58 noted that remote sensing technologies and airborne measurements and EPA's own studies and review of studies have found that actual storage tank emissions are much higher than estimates. Commenter 58 stated that emissions testing using TTE at Sprague Operating Resources tank terminal in Maine found measured emissions were much higher than expected based on previous year emission inventory estimates.

Response: The EPA disagrees with the commenter. For studies where we were able to obtain sufficient data to model sources, we found that the emissions estimates derived from the emissions estimation modeling were very similar to (within a factor of 2) the emissions estimates derived from the measured data, confirming that the AP-42 emission estimation equations are accurately calculating the emissions for tanks and wastewater treatment systems. We have documented a full review of the available studies in the *EPA Review of Available Documents and Rationale in Support of Final Emissions Factors and Negative Determinations for Flares, Tanks, and Wastewater Treatment Systems.*

While the emissions testing at Sprague Operating Resources did show an underestimation in the facility's emission inventory estimate, we noted that Sprague used the emissions estimation methodologies incorrectly in developing the inventory estimates. Specific issues included:

- Setting the bulk and surface temperatures of the liquid to 0°F, even though No. 6 fuel oil tanks are generally heated to around 130°F and asphalt tanks are generally heated to around 300°F.
- Using too low of a vapor pressure for the No. 6 fuel oil stored in the tank. While AP-42 provides a default vapor pressure for No. 6 fuel oil, this vapor pressure is indicative of a straight residual oil. Most No. 6 fuel oil is mixed with cutter stock, which is much more volatile than residual oil. It is necessary to somehow account for the cutter stock in the vapor pressure of the material. The vapor pressure of the No. 6 fuel oil was determined to be closer to 0.04 psi than 0.00019 psi.

- Using the AP-42 default No. 6 fuel oil vapor pressure as the vapor pressure input for asphalt, although AP-42 does not advocate using No. 6 fuel oil vapor pressure for asphalt, nor does it provide default values for asphalt's vapor pressure. Testing of the asphalt demonstrated that the vapor pressure was closer to 0.58 psi than 0.00019 psi.

Therefore, we conclude that there are issues with the inventory calculations performed by the facility, not with the emissions estimation equations.

5.3 Other Wastewater Treatment Unit Comments

Comment: Commenter 58 stated the existing WWTP VOC emissions factors are inaccurate, underestimates emissions, and need revision. Commenter 58 noted that remote sensing technologies and airborne measurements and EPA's own studies and review of studies have found that actual WWTP emissions are much higher than estimates. Commenter 58 noted the Shell Deer Park study found benzene emissions were 4 to 80 times higher than projected during a temporary malfunction, and emissions were also higher than emission estimates at times when the process was operating normally.

Response: We have documented a full review of the available studies in the *EPA Review of Available Documents and Rationale in Support of Final Emissions Factors and Negative Determinations for Flares, Tanks, and Wastewater Treatment Systems.*

The EPA notes that emissions factors are meant to represent normal operations, not times of malfunctions. Malfunctions are infrequent, unexpected events which cannot be anticipated; therefore, it is not possible to quantify them ahead of time. The EPA has reviewed available measurement study data for refinery wastewater treatment systems. We note that the AP-42 emissions factor correlation equations for wastewater treatment systems provide a sophisticated modeling method to estimate emissions from a wide variety of wastewater treatment units, taking into account unit-specific variables, including the unit size, throughput, wastewater pollutant concentrations, ambient temperatures, and other loss mechanisms (biodegradation and absorption). When this detailed information is properly used with the AP-42 equations to model site-specific emissions, the emissions model (AP-42 equations/WATER9) provides an accurate estimate of actual VOC emissions. However, we recognize that the misapplication of the equations or use of inaccurate input can lead to inaccurate emissions estimates. We have included guidance in the *Refinery Protocol* (RTI, 2011) to highlight key model input parameters and to provide instructions on how to develop site-specific information (e.g., unit-specific biodegradation rates) when applying the AP-42 equations.

We also note that wastewater treatment system emissions are expected to be variable, with dependency on temperature and wind speed. Hourly modeling data suggests that short-term emissions rates may be 5 to 10 times higher than annual emissions. Thus, we find that, when unit-specific data are not available for direct modeling comparisons, short-term measurement data within a factor of 5 of the annual average emissions inventory value likely do not provide justification that the emissions inventory is incorrect or that the emissions factor equations need to be revised.

It is also important to note that the emissions estimation procedures only account for emissions in normal operating scenarios. Emissions from wastewater treatment units that are improperly operated (e.g., unit has an oil film when they should not or if the biological treatment unit receives a shock load) would require special emission modeling to consider the event. Many of the AP-42 emissions factors equations may be able to provide a reasonable emissions estimate during the event (as was seen when one wastewater train was down for repair); however, there is no universal method by which to estimate the emissions from these events since the modeling required would be specific to the type of event that occurred. We have included guidance in the *Refinery Protocol* (RTI, 2011) for estimating emissions during malfunctions or upsets, including spills, but each such event would require specific engineering calculations to estimate the emissions from these occurrences.

Comment: Commenter 58 stated EPA failed to review available source testing they collected on WWTP. As part of the 2011 Refinery ICR, Commenter 58 stated EPA requested 5 facilities to submit testing data for Enhanced Biodegradation Units (EBU) for speciated VOHAP, speciated SVOHAP, aldehydes, sulfide (as sulfur), BOD, and COD. Commenter 58 stated EPA did not appear to review these source test data for WWTP as part of its review, and since the agency already possesses these data, the APA requires EPA to consider the data in its review.

Response: The 2011 Refinery ICR required sampling and analysis of wastewater concentrations at the influent to the EBU, within the EBU near the influent, and at the effluent of the EBU. It also required an evaluation of biodegradation rates for selected compounds. These EBU data were originally reviewed as part of the Refinery Sector Rule, and a summary of the data received from the ICR has been posted on the EPA website; the direct link to the summary is: http://www.epa.gov/ttn/atw/petref/icr4/ww_covermemo.pdf. These data were also reviewed in response to the comment. The ICR sampling and testing did not include any direct evaluation of air emissions from the wastewater treatment system. The only potential revisions to the AP-42 wastewater section based on the ICR data would be the suggested default biodegradation rate constants for selected target pollutants. One study measured higher biodegradation rate constants than provided in AP-42; the other provided rate constants were essentially the same as the default values in AP-42. Therefore, we concluded that no revision to AP-42 was necessary based on the data collected during the ICR. We note that facilities have the right to determine site-specific biodegradation rates for use with the AP-42 emissions estimation equations if they do not believe that the default biodegradation rates provided in AP-42 are representative of their system. We recommend facilities use site-specific biodegradation rates when the AP-42 defaults are not representative of their system.

Comment: Commenters 54 and 56 agreed with EPA's conclusion that existing data are not adequate to support/do not support revision of the emissions estimating methods for wastewater treatment systems. Commenter 56 noted that the fundamental limitations noted by EPA led to the appropriate conclusion to not revise the emissions factors.

Response: The EPA acknowledges the comment.

Chapter 6

REFINERY EMISSION ESTIMATION PROTOCOL REVISIONS

6.1 Extending the Use of the Protocol Beyond the 2011 ICR

Comment: Commenters 8 and 56 stated the Refinery Protocol should remain as an Information Collection Request (ICR) tool and should not be linked to AP-42. Commenters 8 and 56 stated the Refinery Protocol was intended to provide for consistent estimation of refinery emissions as part of an ICR data collection effort, and many of the emissions factors and estimation methods contained therein were not developed using the rigorous methods set out by EPA's Recommended Procedures for the Development of Emissions Factors. Commenters 8, 54 and 56 stated EPA should not expand/repurpose the Refinery Protocol as a broader industry and government agency guidance document.

Commenters 8 and 56 stated it is inappropriate to reference the Refinery Protocol within AP-42. Commenters 8 and 56 stated that both the Refinery Protocol and AP-42 each separately address emissions factors and can result in two different EPA recommendations. Commenter 56 stated if the final AP-42 revisions reference the Refinery Protocol, EPA should make clear that it will simultaneously update both the Protocol and AP-42 factor on the same schedule when there is overlap of emissions factors.

Response: The EPA has previously referenced other emissions estimation tools in AP-42. For example, the Protocol for Equipment Leak Emissions Estimates is linked to AP-42 Chapter 5. We are not requiring the use of the Refinery Protocol, just as we do not require the use of AP-42. It is simply another tool for use in estimating emissions when site-specific test data do not exist or are not available.

We recognize that the methodologies contained in our new emissions factor development procedures were not used throughout the Refinery Protocol, which is one reason the factors in the Refinery Protocol are not contained within AP-42. However, we do recognize that the Refinery Protocol offers estimates of emissions for which AP-42 contains no emissions factors, and as such, we see value in updating it as necessary. We note that the Office of Inspector General (OIG) Review highlighted petroleum refineries as an industry for which available emission factors were considered unacceptable for the decisions being made. The OIG Review highlighted the Texas 2000 Air Quality Study and indicated how improved emissions inventory guidance yielded more accurate emissions inventories. We consider the Refinery Protocol to provide site-specific emissions inventory guidance, similar to that provided in Texas, that is specific to the refinery sector. We consider that the use of the Refinery Protocol will result in more accurate and complete emissions inventories. Therefore, we are finalizing proposed revisions to the Refinery Protocol, with some changes to address specific comments. As noted in the introduction of the Refinery Protocol, it is our intent to update the Refinery Protocol to incorporate revised AP-42 emissions factors, similar to the current set of revisions.

Comment: Commenter 54 stated EPA should not incorporate the overly conservative and invalid assumptions of the ICR Refinery Protocol into emissions factors. Commenter 54 opposed EPA's attempt to legitimize the Refinery Protocol, not only within AP-42 but as a stand-alone reference and guide for determining refinery emissions factors outside the context of the original Refinery ICR. Commenter 54 stated the direct translation from the ICR to the revised AP-42 emissions factors skips a critical step: the evaluation of the underlying ICR data to ensure both that it accurately reflects average industry-wide operations and that it was collected in a sufficiently rigorous manner. In collecting ICR data, Commenter 54 noted EPA specifically instructed the respondents to use the Protocol for making certain assumptions in developing and reporting their emissions data for Component 2 of the ICR. For example, the Refinery Protocol provided an emissions factor developed from limited test data for calculating HCN emissions from FCCUs, regardless of configuration and emission controls; the agency later decided to increase the HCN emissions factor tenfold for residual risk modeling (770 to 8000 lb/MM bbl FCCU feed), and now proposes a revised emissions factor (8000 lb/MM bbl FCCU feed) for the Protocol and AP-42 from only 8 Component 4 tests. Commenter 54 stated the ICR data was not collected using the same rigorous methodologies EPA recommends for developing emissions factors. Commenter 54 stated many of the assumptions underlying the ICR were biased high, and while these assumptions may be justified for the limited purpose of establishing a one-time model for estimating the residual risks, the upward bias built into these assumptions likely results in overestimates of the true emissions.

Response: The EPA disagrees with the commenters that the Refinery Protocol emissions estimation procedures will yield emission estimates that are biased high, particularly given the example cited for HCN. One must understand that the primary purpose of the Refinery Protocol is to provide guidance for inventory developers to assist them in developing complete site-specific emissions inventories. AP-42 explicitly states that the absence of an emissions factor in AP-42 does not imply or suggest that a given pollutant is not emitted from the source or that emissions should not be estimated for these pollutants. In recognition of the fact that AP-42 has very few HAP emissions factors for petroleum refineries, the Refinery Protocol was developed to provide guidance on using best emissions inventory practices (Methodology Ranks) more than providing an alternative set of emissions factors. AP-42 and the Refinery Protocol clearly states that it is always best to use site-specific test data for emissions estimation when it is available. In the absence of AP-42 emissions factors, refinery owners or operators are still required to develop complete emissions inventories, and we believe the Refinery Protocol provides excellent guidance on developing these inventories. Recognizing that the Refinery Protocol did not develop factors based on the recommendations in our emissions factor development procedures, we are not incorporating the factors in the protocol into AP-42. We are simply providing a link to the protocol from AP-42 Chapter 5.

Concerning revisions to HCN emissions, we noticed that very few if any refinery owners or operators reported HCN emissions from their FCCU. Based on a very limited number of source tests, we found that HCN emissions did occur from FCCU, and we previously provided a default HCN emissions factor for FCCU in the Protocol. We also required several facilities to test their FCCU for HCN and other pollutant emissions. Given the new and comparatively extensive measurement data for HCN based on Component 4 of the 2011 Refinery ICR testing and other testing, we proposed revisions of the HCN emissions factor. Further discussion on the HCN emissions factor is found in Section 4.3 of this document and in the *Final Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations.*

Comment: Commenter 54 identified other examples where the Refinery Protocol falls short of substantiating generation of AP-42 emissions factors:

- The standard for emissions from boilers and process heaters is based on a single source test (Hansell and England, 1998). See Protocol, Table 4-3, note b.

- Significant inconsistencies continue to exist between fuels used in a variety of combustion sources. Pages 64-76 highlight emissions factors for various combustion sources using various fuels. Emissions factors for natural gas include trace metals - these metals are not combusted or reacted in the process of using a fuel, and therefore, on a per-unit basis, using the same fuel will emit the same amount of metals regardless of the combustion device employed. The factors EPA provides, however, would indicate that metal emissions vary on a per-unit basis, by a factor of over 3 times in some instances, depending on the equipment used and not the fuel.
- Other emissions factors are based on no "emissions" at all, but rather merely on the detection limits of the test methodology – in other words, where all of the available test data showed "non-detect" for a pollutant, EPA simply assumed that the operation in question emitted at the detection limit. See Protocol, Table 4-3, note a.

While these kinds of shortcuts might be sufficient to support a residual risk determination, they cannot establish the average actual long-term emissions from these operations across the entire refining industry. Furthermore, this methodology is inconsistent with EPA's more typical practice of using half the detection limit for non-detect analytical results, limited to cases where the pollutant would be expected to be present.

Response: As previously stated, we are not incorporating the Refinery Protocol factors into AP-42. We are providing a link to the Refinery Protocol from Chapter 5 of AP-42 because it is a valuable emissions estimation tool for site-specific inventory development and provides information on pollutants not contained within AP-42. We explicitly state in AP-42 that an absence of an emissions factor in AP-42 does not imply or suggest that a given pollutant is not emitted from the source or that emissions should not be estimated for these pollutants. In recognition of the fact that AP-42 has very few HAP emissions factors for petroleum refineries, the Refinery Protocol was developed to provide guidance on using best emissions inventory practices (Methodology Ranks) more than providing an alternative set of emissions factors.

We also note while many of the emissions factors in Table 4-3 of the Refinery Protocol are based on data from Hansell and England, 1998, there are a large number of emissions factors taken directly from AP-42. Nonetheless, we consider the HAP emissions factors developed by Hansell and England, 1998, to be the most complete study of refinery-specific combustion emissions sources available. The study was specifically conducted to address risk assessment requirements for the California Air Resource Board (CARB) and had to be conducted with acceptable rigor to be accepted by CARB. We note that we posted a draft version of the Protocol for public comments and generally received comments that the Hansell and England, 1998, study was the most appropriate and complete study for developing HAP emissions estimates from refinery combustion sources.

6.2 New Methodology for Delayed Coking Units

Comment: Commenter 56 stated EPA should not reference the Refinery Protocol in AP-42 for the estimation of emissions from delayed coking units (DCU). Commenters 54 and 56 believed it is appropriate for EPA to incorporate new emissions estimation methods directly into AP-42 only after completion of the appropriate quality assurance/quality control process outlined by EPA for AP-42 updates.

Response: The EPA is finalizing the proposed revisions to DCU emissions estimation methods with minor revisions. The DCU emissions methodology has been used to support two rulemakings (a South Coast Air Quality Management District rule and proposed amendments to 40 CFR Part 63 Subpart CC). As such, it has been subject to public comment and has been found to be the most appropriate method available for estimating emissions from the DCU.

Comment: Commenter 56 suggested an option for facility-specific or site-specific estimation for DCU emissions should be included. Commenters 54 and 56 stated EPA must allow an option for facilities to use internally developed delayed coking unit emissions models based on site-specific information and engineering calculations as a coker vent emission methodology, as the use of site-specific information is generally more accurate than using an emissions factor.

Response: The EPA has revised the Methodology Ranks for DCU and is providing for the use of site-specific estimates of the emission factors (on a lb/1,000 lb steam basis), when available, as Methodology Rank 3. Facility owners or operators can use engineering estimates of the coker vent emissions, but these emissions would not include emissions from draining or coke cutting. Due to the uncertainties in the latter emissions estimates, we considered that this approach would be Methodology Rank 5. However, we have included provisions when steam vent emissions data are estimated on a lb/cycle basis to use these estimates as part of the decoking operations emissions.

<u>Comment</u>: Commenter 56 stated Methodology Rank 3 (for DCU) oversimplifies the emissions through a dependence only on drum overhead temperature at the time of the vent. Commenter 56 suggested the proposed Methodology Rank 3 approach for emissions from the opening of coke drums and resulting venting to the atmosphere is too conservative and results in an overestimate of emissions.

Commenter 56 stated the values in Table 5-5 of the Refinery Protocol for lbs pollutant/1000 lb steam were developed from test data obtained over the past several years, the raw data has not been reviewed for statistical outliers as recommended by RPDEF, and EPA has not evaluated the data quality.

Commenter 56 stated that facilities that have conducted coker vent testing will have more relevant compound concentration data, which could be used in conjunction with Equation 5-5, and EPA should allow for use of site-specific test data in lieu of the values in Table 5-5.

Commenter 56 provided 3 reasons Proposed Rank 3 Method overestimates the amount vented from the coke drum during venting:

1. It significantly overstates the amount of steam that is generated upon opening the coke drum to the atmosphere, because it makes the following incorrect assumptions:
    a. There is a uniform temperature throughout the entire coke bed and the quench water at the time the vent is started;
    b. the amount of heat evolved is derived from cooling the entire mass of coke and quench water from that initial uniform temperature to 212°F;
    c. 10% of the heat removed from the coke bed and quench water is dissipated through the coke drum and overhead metal and the balance of the heat removed from the coke bed (90%) goes into steam generation; and
    d. 100% of the water in the coke drum at the time of venting is at its bubble point (i.e., all the heat evolved goes toward affecting evaporation and none of it is used in heating the water to the boiling point).
2. It underestimates the mass of coke in the drum and overestimates the porosity of that coke. Commenter 56 noted that an assumption of coke bed density of 42.2 lb/ft^3, versus a

typical density of 52 to 60 lb/ft^3, overstates the void fraction in the coke bed, overestimates the amount of quench water that could be in the bed, and underestimates the mass of coke and thus the potential heat that will be generated by cooling the bed to 212°F. Commenter 56 stated the model assumption that all the void space is filled with water is not supported by available information; if the model void fraction is decreased from 0.5 to 0.35, while maintaining the EPA pure coke density of 84.3 lb/ft3 (a value in line with available data for green coke) to represent a typical coke bed density of around 55 lb/ft^3, Equation 5-3 yields a more accurate representation of the void space and coke mass.

3. It assumes the coke and quench water for the average coke drum is at a much higher temperature than indicated by correlation to the overhead pressure. Commenter 56 stated the assumption that the entire coke bed and quench water are at the overhead temperature of the coke drum is not an accurate reflection, as superheated steam is used to purge safety valves and instruments and impacts the temperature. Commenter 56 stated the overhead temperature and coke bed temperature should be taken at the saturation temperature of steam at the indicated overhead pressure.

Commenter 56 stated their extensive comments (letter dated in the October 28, 2014) on the modeling of coke drum emissions on the proposed Refinery RTR rule should be the basis for revising the Refinery Protocol factors for coke drum emissions. Commenter 56 stated the following adjustments to Methodology Rank 3 are needed:

1. Update the mass of steam calculations to represent the overhead temperature and coke bed temperature using the saturation temperature of steam at the indicated overhead pressure;
2. Update the coke density to provide a more accurate representation of the void space and the coke mass; and
3. Recommend the use of site-specific test data in lieu of values in Table 5-5 where available.

<u>Response</u>: The steam generation model uses much more site specific data than just the overhead temperature. It also relies on the mass of coke and water in the drum, which accounts for different size units and different operational characteristics of those units and represents the best available model for estimating emissions from DCU decoking operations. The EPA has

reviewed the commenters' suggestions for revisions to the model. We agree that site-specific emission factors (lb/1000 lb steam) should be used, when available, rather than the default emissions factors, and we have revised the Refinery Protocol accordingly. We have not revised other model inputs for the following reasons:

1. The final Equation 5-2 assumes that the average bed temperature is the average of 212°F and the overhead temperature. While there may be a small fraction of the bottom of the bed that may be lower than 212°F, we also recognize that there may remain hot spots in the coke bed that are much higher than the wall temperature (where measurements are generally taken), so we consider this approach to provide the best estimate of average bed temperature.
2. We have not provided for the use of pressure-temperature correlation to determine the average bed temperature. The pressure-temperature correlation is only more accurate than the average temperature method provided if the system is closed (and that closed system is allowed to come to equilibrium). Since vapors are continuously being vented from the drum, the overhead drum pressure is lower than the equilibrium pressure of the system. This is easily proven by observing the vessel pressure increase as the system is sealed (closing valves to the blowdown system) prior to venting to the atmosphere. Because the pressure measurement is taken from an actively venting system, we consider using the overhead vent line temperature to estimate the average bed temperature will provide a more accurate estimate of the average coke bed temperature than the pressure-temperature correlation.
3. Heat needed to raise some of the water temperature to the bubble point is generally insignificant. The enthalpy of the phase change is 960 Btu/lb compared to the heat capacity of water, which is 1 Btu/lb/°F. Thus, if every pound of water that turned to steam had to increase in temperature by 20 degrees F, the heat used to increase the temperature of the water would only be 2% of the heat loss from vaporization of that water. We maintain that 10% convective (or other) heat loss is a reasonable assumption.
4. We only recommend the use of a bulk density of coke in the coke drum of 42.2 lbs/ft^3 (which assumes a coke bed porosity of 0.5) to estimate mass of coke when the mass of dry coke produced is not available. Generally, the refinery owner or operator will have mass production quantities over time and these quantities can and should be used to

estimate the mass of coke produced per coke drum cycle. Equation 5-3 of the Protocol was provided as an alternative when the mass of coke produced per cycle are not available.

5. Our estimates of bulk coke drum bed density (or porosity) are based on applying Equation 5-3 to estimate coke production rates. We estimated the coke production quantities using the coke particle density and using either 0.5 or 0.35 for the coke porosity along with Refinery ICR reported values for coke drum vessel dimensions and coke drum outage levels. We then used the reported number of coke drums and cycle times to estimate a typical mass of coke produced per day for the DCU and compared this with coke production capacities reported directly by the ICR respondents. We found that 17 (25 percent) of the DCU had capacity utilizations of greater than 90 percent, with only a few DCU estimated to exceed the reported coke production capacity when using a coke porosity of 0.5. However, using commenters' suggested value of 0.35, 24 DCU (32 percent of all DCU) had coke production rates exceeding 110 percent of their reported capacity. Therefore, we determined that the coke porosity of 0.5 (or bulk density of 42.2 lbs/ft^3) appears to be much more appropriate for calculating the mass of coke in the drum than a porosity value of 0.35 (or bulk density of 55 lb/ft^3).
6. Density data for green coke that has been removed from the coke drum is expected to have less void space than exists within the coke bed and is not appropriate for use in the model. Therefore, we have not revised the default bulk coke bed density value.

Comment: Commenter 56 stated proposed Methodology Rank 4 should be deleted because limited or no test data exists to validate the proposed methodologies used to handle the drum opening and coke cutting operations. Commenter 56 stated Methodology Rank 4 lacks technical justification and Rank 4 is unnecessary; it could be replaced by a modified version of Methodology Rank 3. Commenter 56 stated facilities that have coker steam vent data can use Rank 3 with the option to use their own site-specific test factors in lieu of Table 5-5 factors.

Commenter 56 noted that Methodology Rank 4 could greatly overstate the concentration expected in the bulk water in relation to overhead drum vent, as hydrocarbons have low solubility in water. Commenter 56 noted the emissions from drilling process are negligible (unless there is ongoing chemical reaction, formation of coke, or tail gas and liquid hydrocarbons due to uncompleted reaction when feeding the coke drum), and coke cutting contribution is small. Regarding the requirement to also assess emissions from drained water when facilities conduct steam vent testing and initiate draining within 1 hour or less of starting venting, Commenter 56 noted that EPA did not support the basis for the 1 hour time period requirement with any technical rationale.

Commenter 56 cited several deficiencies for RWET, noting that assumptions do not reflect design of most coking unit drain systems; the equalization tank model with partial aeration to reflect coke pit operation is not real; it is difficult to approximate aerator size required by model inputs; and few sites have the pollutant concentrations required as model inputs.

Response: We have revised the Methodology Ranks for DCUs. Methodology Rank 3 for DCUs is to use the steam generation model and site-specific emissions factors (lbs/1,000 lb steam) developed from site specific emissions tests. Methodology Rank 4 for DCUs is to use the steam generation model and default emissions factors for Rank 4 (in lbs/1,000 lb steam). Methodology Rank 5 for DCUs is to use the default emissions factors for Rank 5 (in lbs/cycle). We continue to suggest that the Rank 5 emissions factors may underestimate emissions from all decoking operations and continue to suggest the use of methods in Sections 7 and 11 of the Refinery Protocol to estimate these emissions. Facilities that have site specific test data should use Methodology Rank 3 rather than estimating the mass emissions from the coker vent based on the source test data and assuming the emissions from draining and coke cutting are negligible.

Comment: Commenter 10 verbally requested information on how Table 5-5 of the Refinery Protocol was developed.

Response: In a preliminary response/explanation to the commenter by email, we provided the spreadsheet used in the development of Table 5-5, as well as an explanation on how the table was developed.

Comment: With respect to delayed coking units, Commenter 13 provided the following notes and questions:

1. The Refinery Protocol states that emissions from draining coker quench water should be estimated using the weir model in RWET and that emissions from cutting water

storage should be estimated using the equalization tanks model in RWET. Verify that emissions from cascading cutting water are not expected (weir model).

2. How did EPA determine that draining emissions were required if draining is initiated sooner than 1 hour after the start of venting?
3. Can EPA confirm that emissions from the coker water storage are NOT required if draining is initiated later than 1 hour after the start of venting?
4. The equalization tanks model in RWET has a required input of number of aerators/power to aerators. There is also a quiescent unit model in RWET but it requires a BOD concentration. Neither of these models seem transferable to coker water storage.
5. Please provide an explanation of the calculation methodology for the weir model including a definition of variables and reference.
6. Is the weir height the distance the water falls from the bottom of the coker vessel to the coker pit? AP-42 specifies that the weir height is the distance from the wastewater overflow to the receiving body of water. RWET doesn't specify.
7. Should the wastewater flow rate include only the flow of quench water or the total of quench water flow plus cutting water flow (related to Question 1)?
8. Does EPA have guidance for what measurement should be used for the length of the weir (e.g., should we use the diameter of the opening in the bottom of the coker?)
9. Does EPA have an expectation regarding how drain water concentration is to be estimated?

Response: We expect that refinery owners or operators will have data needed to use the final Methodology Rank 3 or 4 for DCUs (as described in previous comments) and will not need to model emissions from draining separately. However, the following responses are provided as general guidance. These questions were discussed in further detail during a telephone conference call with the commenter and other industry representatives.

1. We primarily expect emissions from cascading draining water. Depending on the water used for coke cutting, there may be some emissions from the cascading cutting water, but the temperature will be lower.
2. This was based on review of the source test data, but we no longer include a reference to use this approach when test data for the coker vent are available. If test

data from the coker vent are available, site-specific emissions factors should be developed for use in Equation 5-5 of the Refinery Protocol. Consequently, we have deleted reference to a 1 hour interval between venting and draining.

3. Again, we have deleted reference to emissions from a 1 hour interval. Refinery owners or operators should develop as complete an emissions inventory as possible. We do not consider that the DCU emissions methodology for decoking operations consider or include emissions from quench or cutting water storage (other than the coke pit).
4. We recommend that facilities do not alter the default aerator inputs that are preloaded in the spreadsheet (100 hp, 1 aerator, 61 cm (2 ft) impeller diameter, 126 rad/s impeller speed). The equalization tank model can be run with a turbulent surface area of 0 m^2. If there is significant turbulence where the water is entering the coke pit, one can specify this area as the turbulent surface area and use the “default” turbulent mass transfer coefficients for this turbulent area.
5. Appendix B of the Refinery Protocol provides details and references for the various RWET model equations, including the model for weirs.
6. Weir height would be the distance from the bottom of the coker drum drain to the water level in the coker pit.
7. One can model both. We expect that the coke drain water will be much hotter. One must specifically calculate the Henry’s Law constant at the drain water temperature; the temperature input in the Weir model is simply an ideal gas law correction and does not attempt to adjust chemical properties for the pollutants. When properly adjusted for the higher Henry’s Law constant, we expect higher emissions from the coker drain water than the coke cutting water. However, we expect that refinery owners or operators will have data needed to use the final Methodology Rank 3 or 4 for DCUs (as described in previous comments) and will not need to model emissions from draining separately.
8. The width of the weir should be estimated based on the observed width of the draining water along the sloped wall of the coke pit where the drain water flows from the coke drum to the water level in the coke pit.

9. Drain water concentrations can be estimated by analysis of the drain water. Because we do not expect most inventory developers will use this approach, we have not attempted to develop default DCU drain water concentrations.

Comment: Commenter 56 stated Methodology Rank 5 should be deleted. Commenter 56 stated Methodology Rank 5 does not distinguish between units on any basis and is thus not representative of varying emissions profiles for DCU. Commenter 56 stated the Refinery Protocol emissions factors on a pounds per vent cycle basis are based on historical test data obtained over the last several years; however in developing these factors in Table 5-5, no adjustments are made for differences in coker drum size, design, vent pressures or other operational data.

Commenter 56 stated that with recent changes to NSPS subpart Ja and the proposed changes in the Refinery Sector Rule, the operating characteristics for coke drums are subject to changes that will directionally lower emissions. Commenter 56 stated the test data behind the factors for proposed Methodology Rank 5 do not reflect these changes and therefore will not accurately represent emissions.

Commenter 56 stated the raw data used to derive emissions factors included in Methodology Rank 5 (Table 5-5) were not reviewed for statistical outliers as recommended by EPA’s procedures for developing emissions factors.

Response: We agree that Methodology Rank 5 is less accurate than the other methods provided, which is why it is the lowest ranked method. As noted throughout the Refinery Protocol, inventory developers should use the highest ranked methodology for which they have data. However, we are retaining Methodology Rank 5 in the Refinery Protocol as a last resort for developing emissions estimates.

6.3 Other Comments

Comment: Commenter 56 noted that Table 5-4 (FCCU) of the Refinery Protocol includes emissions factors for organic HAPs plus hydrogen chloride, hydrogen cyanide, and mercury. Commenter 56 cited a preliminary analysis by RTI of the ICR stack test data that suggests the factors for hydrogen chloride and mercury should be reduced, but noted only the proposed emissions factor for mercury has been lowered. (*Technical Memorandum for Review of HAP*

Emissions factors for Fluid Catalytic Cracking Units based on Component 4 Source Test Data. RTI International. EPA-HQ-OAR-2010-0682- 0205. "[T]here is essentially an order of magnitude (i.e., factor of 10) difference in the emissions factors for hydrogen chloride [decrease], hydrogen cyanide [increase] and mercury [decrease] between the Protocol defaults and the Component 4 source test results".) Commenter 56 stated EPA should consider revisions of all emissions factors presented in Table 5-4, using all available data and subject to its RPDEF with suggested API improvements.

Response: We acknowledge the comment. As we did not propose to update these other factors in the Refinery Protocol based on the assessment of FCCU data performed as part of the Refinery Sector Rule (*Technical Memorandum for Review of HAP Emissions factors for Fluid Catalytic Cracking Units based on Component 4 Source Test Data*. RTI International. EPA-HQ-OAR-2010-0682- 0205), we do not believe it is appropriate to revise the other factors in Table 5-4 without providing a chance from public comments on these other factors. At this time, we are finalizing the factors we proposed, with revisions made as a response to the comments received. In the future, we may update the rest of the factors in this table.

Comment: Commenter 56 stated the HCN emissions factor of lb/klb coke burned presented in Table 5-4 of the Refinery Protocol is unsupported by explanation of its derivation, and not explained in draft EF Development Report. Commenter 13 questioned whether there is supporting documentation for the FCCU HCN factor expressed as lb/klbs coke burnoff. Commenter 56 believed that using a constant coke yield to convert lb HCN/bbl feed to lb HCN/lb coke burned is misleading and will result in an inaccurate emissions factor. (The commenter noted a constant value of 16 lb coke/bbl feed was used.) Commenter 56 stated coke yield or make is complex and depends on many factors and can vary significantly among different units. Commenter 56 recommended deleting the emissions factors in lb HCN/klb coke burned from Table 5-4 unless they can be derived from actual coke burn data during HCN emissions tests.

Response: The EPA specifically evaluated the FCCU HCN emissions factor both on the basis of feed rate and on the basis of coke burn rate as part of the final emissions factor development process. We are including both of these factors in the final revisions to the Section 5.1 of AP-42 and to Table 5-4 to the Refinery Protocol. The emissions factor on a coke burn basis was derived using actual coke burn rates reported during emissions testing. We note that while these factors were developed separately based on the available process rate data available, the ratio of these factors confirm the 16 lb/bbl feed default factor that was used to provide both sets of factors in the Refinery Protocol. Thus, while we understand that site-specific conditions may vary coke make in the FCCU, our analysis confirms the reasonableness of the emissions factors presented in Table 5-4 on a lb/MMbbl basis.

Comment: Regarding the variable, Keff, in equation 6-1 of the Emission Estimation Protocol, Commenter 2 questioned whether the EPA intends for facilities to use the combustion efficiency or the destruction efficiency to calculate emissions. The commenter added that the proposed revision to the Refinery Protocol and AP-42 emissions factors makes a distinction between the "combustion efficiency" and "destruction efficiency."

Response: The EPA clarified that Keff uses destruction efficiency for hydrocarbons. The EPA clarified that Keff uses combustion efficiency for pollutants like SO_2, but that if equation 6-1 is being applied to SO_2, a mole number factor must be included to account for compounds with two sulfur atoms (e.g., CS_2).

Comment: Commenter 56 stated EPA should incorporate all of API's outstanding recommendations on the previous versions of the Refinery Protocol. Commenter 56 provided these previous comments in an appendix (see Appendix 3 to the comment letter).

Response: The primary purpose of this project is to develop new emissions factors for AP-42. In doing so, we realized that there would be inconsistencies with the Refinery Protocol unless we updated it at the same time. Additionally, we decided it was appropriate to update the Refinery Protocol estimation method for DCU based on the recent Refinery NESHAP proposed rule. Although we acknowledge that this may have caused some confusion, we did not intend to open up the entire Refinery Protocol for comment, as it has already been subjected to notice and comment. We intended only to update the Protocol to incorporate the AP-42 revisions and the DCU methodology, and to only take comment on these specific revisions. As such, we are not responding to comments that are not related to these revisions as we consider other comments on the Refinery Protocol to be outside of the scope of this project.

Chapter 7

OTHER COMMENTS

7.1 Comment Period Schedule and Extension

Comment: Multiple commenters (14, 15, 20) questioned when the last day of submitting comments would be, given that the comment period ended on Sunday, October 19.

Commenter 1 noted that the redline version of the industrial flare section of AP-42 Chapter 13 was inaccessible on the website and requested a 60-day extension to the comment period, or, at a minimum, an extension equal to the number of days it would take the EPA to fix this website error. Commenter 1 justified this request by explaining that the industrial flare section of AP-42 Chapter 13 is used by many other industries beyond the Petroleum Refining and Inorganic Chemical sectors, so an extension is warranted to allow other stakeholders time to review and provide comment.

Response: The EPA originally noted that public comments would be accepted through Monday, October 20, 2014. Through later negotiations with the Plaintiffs, EPA extended the public comment period through October 31, 2014, and then through December 19, 2014.

Comment: Commenter 54 supported the extension of the comment period to December 19, 2014.

Response: We acknowledge the comment.

Comment: Commenter 7 questioned whether the proposal had been updated since it was posted for public comment.

Response: We explained that no changes will be made to the proposal during the comment period, and that after the comment period closes, we will review the comments and determine if revisions are necessary.

Comment: Commenter 8 stated sources should be given time to review stakeholder comments on the proposed Refinery Sector Rule and this information could impact comments on proposed emissions factors. Commenter 8 requested EPA provide a minimum of 180 days, after the Refinery Sector Rule is finalized, for public review and comment on the proposed revisions to AP-42 and the Refinery Protocol (Draft Version 3). Commenter 8 stated a 60-day comment period does not allow the public sufficient time to evaluate emissions factors and their impacts, and provide meaningful comment. Commenter 8 stated all stakeholders need adequate time to assess the proposed revisions.

Response: We acknowledges the comment. Due to a consent decree, we must review, and if necessary, revise the VOC emissions factors for flares, wastewater treatment systems, and tanks by April 20, 2015. We have also chosen to develop and revise other factors at the same time that we performed the required review/revisions. We provided a 120-day comment period for the proposed emissions factors and have determined that the comment period was sufficient, as we received many meaningful comments that we have addressed in this document.

7.2 EPA’s Emissions Factor Development Methodology

Comment: Commenters 52 and 54 stated that EPA considered the existing AP-42 emissions factors for flares as a single test result in calculating the proposed emissions factors and should have instead used the result of each individual test that went into developing the existing emissions factors in calculating the average value. Commenter 36 stated NOx and CO emissions factors are not correctly weighted. Commenters 36 and 54 stated the previous AP-42 emissions factor is itself an average of several individual test results, and Commenter 36 stated it has a much higher ITR. Commenter 54 stated that by combining these results into only one average figure, EPA significantly under-valued the prior emissions tests and incorrectly weighted recent test data. Commenter 42 stated EPA's approach gives equal weight to each of the 5 studies and the existing NOx emissions factor, which results in an emissions factor 43 times the existing emissions factor.

Response: The EPA erroneously included the original emissions factor as one data point. The commenters are correct in that the original factor should have been broken into the individual tests that went into making the original factor. This error has been corrected in the final emissions factor development.

Comment: Commenter 56 stated EPA must acknowledge and address their previous comments on the Emissions Factors Improvement Program Advanced Noticed of Proposed Rulemaking (ANPRM) published on October 14, 2009, and on the RPDEF document dated December 17, 2010, before finalization of AP-42 emissions factors here, as many of the same concerns and issues apply to EPA's current proposed revisions to AP-42.

Response: Although we did not issue a formal response to comments document on either the ANPRM or the draft emissions factor development procedures, we have reviewed and considered all of the comments that we received on both of these actions. We have informally addressed a number of the comments received in the ANPRM throughout the development of our new emissions factor procedures. We have also addressed some of the comments from the ANPRM in the Electronic Reporting and Recordkeeping Requirements Rule for NSPS, proposed on March 20, 2015 (see 80 FR 15100). We addressed comments on the draft emissions factor development procedures when we issued the RPDEF document in 2013. Because the procedures have already been subjected to public notice and comment, we did not seek comment on them in this project. As such, we are not responding to comments on the emissions factor development procedures in this project.

Comment: Commenter 54 stated section 130 requires sufficient public consideration. Commenter 54 recommended that EPA ensure that future evaluations of emissions factors go through notice and comment through the Federal Register and use Federal Register notice and comment procedures to identify all uses of revised emissions factors for regulatory purposes, including all TRI, permitting and permit-related, emissions reporting, and air quality/SIP planning and attainment efforts. Commenter 54 stated a Federal Register notice and comment would be consistent with EPA's RPDEF guidance for large or important emissions factors.

Commenter 54 stated EPA is obligated to formalize the process, and the agency's decision to forego Federal Register notice and comment raises significant legal questions regarding the administrative process and attendant legal obligations. Commenter 54 noted a number of questions, including: what is EPA's legal obligation to review and consider comments; what legal recourse exists in the process should the final action be untenable; what type of "action" does this qualify as (i.e., Rulemaking, Guidance, Other); what is industry's legal obligation to use these factors; and will EPA consider their final publication a "final action" by the agency. Commenter 54 stated EPA should withdraw the proposal until more guidance on the public review process is made available to the regulated community.

Response: Nothing in CAA section 130 provides any specific requirement or obligation regarding the "public participation" EPA must provide for its emission factor development work, nor does section 130 address whether EPA "must formalize the process" when it undertakes this work. Regardless, this document itself is evidence of the robust and extensive opportunity the public had for commenting on this project. During the 120-day public comment period, EPA received comments from 58 sources, including petroleum refiners, industry trade associations and consultants, state and local environment and health departments, and environmental groups (see Table 1). All of these comments are available on EPA's public website. This document summarizes and responds to all of those comments. As explained in this document and other documents posted as part of today's final action, all of the information EPA has received has been considered as part of its analysis and decision-making in its final determinations regarding the emissions factors. EPA will shortly publish a notice in the Federal Register that explains how members of the public may seek judicial review of this final action. As explained elsewhere in this document and in AP-42, sources are under no legal obligation to use these emissions factors. Also, as previously explained, AP-42 identifies the appropriate uses for these emissions factors.

Comment: Commenters 52 and 54 indicated that the 2006 OIG report[8] included the following statement: "EPA officials told us that the majority of emissions factors are developed using 10 points of data or less, which is substantially less than the 30 to 50 data points recommended for the development of a valid statistical analysis." Commenter 54 stated EPA's proposed refinery emissions factors rely on small data sets for the most part. Commenter 54 stated only the SRU CO and NOx meet the breadth of data target discussed by the OIG, and several factors, including flares, rely on less than ten emissions test reports each. Commenter 54 believed that these small data sets results in conclusions that are arbitrary and capricious. Commenter 52 stated EPA should aim to include 30 to 50 data points as recommended by OIG.

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[8] Report No. 2006-P-00017, "EPA Can Improve Emissions Factors Development and Management", Office of Inspector General. p. 26.

Response: In general, we agree that more data is better in the emissions factor development process, but only when the data is relevant and of good quality. While we would like to develop emissions factors that are of the best quality using robust statistical sampling, we realize that is not always feasible. We recognize the OIG has reported on the EPA's lack of emissions factor development; however, we do not feel the OIG's recommendations prevent us from developing emissions factors when we have less than 30 data points. Section 130 of the Clean Air Act is not prescriptive on the requirements for developing emissions factors; instead, section 130 provides the EPA with broad discretion on determining the best methods for developing emissions factors and filling data gaps. While we aim to use large data sets when developing our emissions factors, we feel that it is necessary to develop emissions factors where we can, even if the data set is not as large as we would like for it to be, when we can ensure the data are appropriate for factor development. For the emissions factors developed in this project, and for the reasons discussed in previous chapters of this document, we conclude that the available data provide enough representation of the sources to which the emissions factors are intended to be applied to warrant finalizing these emissions factors.

Comment: Commenter 56 commended the shift towards more objective processes and criteria with the RPDEF, but that the shift to objective processes should not override the need for interpretation and judgment in evaluating data and applying process understanding, especially with very limited data sets such as those used for the proposed petroleum refinery emissions factor updates.

Response: We acknowledge the comment.

Comment: Commenter 56 provided input on issues related to the RPDEF, including the individual test rating (ITR) methodology, the statistical approaches, the handling of outliers, data set normality, handling of non-detect data, and determining valid data combinations.

Response: As previously discussed in this section, we are not responding to comments on our emissions factor development procedures in this action.

Comment: Commenter 56 stated EPA has not fully evaluated data quality when reviewing any of the test reports, in that EPA only completed the source tester section and not the State regulatory agency review section. Commenter 56 stated that prior to proposing new emissions factors, EPA should ensure that the test report reviews are handled in accordance with its own procedures given in the RPDEF. Commenter 56 stated EPA should complete the regulatory agency reviewer section of the ITR criteria to assure that data quality has been reviewed in addition to the completeness of the test report. Commenter 56 recommended that EPA revise the data quality criteria, weighting and scoring method for ITRs such that ITR scores accurately reflect the true quality of the test results.

Response: We only completed the completeness check portion of the ITR scoring. In doing so, we were attempting to automate the procedures, similar to how WebFIRE will automate the procedures. The agency review section is meant for state and local agency reviewers, not for EPA reviewers. Such a review could have been completed and submitted during the comment period, but no such review was.

Comment: Commenter 56 stated that EPA's assumption that all test data values follow lognormal distributions may not always be appropriate statistical practice. Commenter 56 stated this may be reasonable if there are historical data or process knowledge to indicate data may be lognormal. Commenter 52 stated EPA's assumption in determining statistical outliers that all emissions data are lognormally distributed is a faulty assumption that includes data that does not belong to a data set.

Response: In general, environmental data sets follow a lognormal distribution. This is acknowledged in the EPA’s ProUCL. We are retaining the assumption that environmental data will follow a lognormal distribution.

Comment: Commenter 56 provided a figure showing the transformed factor for FHR AU test, that EPA determined was not an outlier, is the only data point that stands out; determining outliers with small data sets is difficult to determine with high degree of confidence.

Response: We acknowledge the comment but continue to use our recommended procedures for emissions factor development, which were previously subject to notice and comment.

Comment: Commenter 56 stated EPA should revise its RPDEF to specify presentation of descriptive statistics along with a recommended emissions factor, such as the number of samples (units) along with mean, median, minimum, maximum, and standard deviation, that would provide the end user with insight into the robustness of an emissions factor and data dispersion, and therefore enable good judgment in its application.

Response: As previously discussed in this section, we are not responding to comments on our standard emissions factor development procedures in this action.

7.3 Scope of Consent Decree

Comment: Commenter 56 stated EPA's decision to expand the scope of updates beyond the actions required under EPA's Consent Decree with Air Alliance Houston et al. (Consent Decree) complicates the public review of proposed emissions factors, as does the overlap of the proposed changes with the ongoing Refinery Sector Rulemaking. Commenter 56 stated EPA should provide sufficient time for considering the comments received in the Refinery NESHAP rulemaking as they impact emission estimates, and allow for incorporation of the impacts of the NESHAP rulemaking on emissions.

Response: It has been our intent to develop new and revised emissions factors using data obtained from recent information collection requests as time and resources allow. We have reviewed the comments on both the proposed Refinery Sector Rulemaking and the proposed emissions factors and coordinated any necessary data revisions between the two projects.

If process unit emissions profiles change as a result of the final Refinery Sector Rulemaking and we are able to obtain enough good quality data that includes both measured emissions and process data, we may use that data to decide if updates are necessary to these emissions factors in the future.

Comment: Commenters 54 and 56 stated EPA should decouple its actions required by the Consent Decree from other potential revisions to AP-42 and the Refinery Protocol. Commenter 56 stated the Consent Decree only requires EPA to evaluate needed revisions to the VOC emissions factors for flares, tanks and wastewater treatment systems, and by including the non-VOC emissions factors and sources not covered by the Consent Decree in the proposed updates, EPA is unnecessarily compressing the review period for those proposed changes and limits

EPA's ability to complete full and robust analyses. Commenter 54 stated decoupling the actions will allow EPA to conduct further analysis and obtain additional data as appropriate for developing factors beyond the scope of the CD. Commenter 54 stated the agency must take the time necessary to evaluate all relevant data and provide for a reasonable review period by all affected parties – not just those few who were involved in the initial lawsuit.

Response: We do not believe that it is necessary to decouple the emissions factors not specifically related to the consent decree. We believe that we have adequate data, and as much as we can gather at this time, to complete an analysis for emissions factors. We also believe that the 120-day comment period for all of the emissions factors was adequate.

Comment: Commenters 54 and 56 recommended EPA delay the emissions factors revisions not required by the Consent Decree. Commenter 50 urged EPA to first finalize the Refinery Sector rulemaking, and then turn attention to AP-42 emissions factors and the Protocol. Commenter 50 stated it is difficult for covered facilities to truly understand the impacts of a proposal when both the emission limits and emissions factors used to calculate the limits are under review and may be subject to change in the same time frame.

Commenter 54 stated EPA should delay the schedule to finalize the emissions factors to match the Refinery NESHAP rule schedule. Commenter 54 stated industry must discuss with the EPA and State agencies the implications of the proposed emissions factors revisions, as more clarity is needed for permitting and related programs such as netting and offsets, emission inventories, air quality planning and SIP development, and compliance and enforcement. Commenter 54 stated the EPA must take time to review all available data and allow the affected public the same. Commenter 54 stated this will also allow industry adequate time to review the underlying data and craft meaningful responses. Commenter 54 noted the magnitude of impacts on end-users warrants sufficient time to consider data quality, and the objectives to review all available data and to use sufficient quantity of data should not be sacrificed to expedite the process. Commenter 54 noted the emissions factors revisions are simultaneous with and may have significant impacts on the RTR proposal.

Commenters 8, 54 and 56 stated EPA should delay finalization of other/any revisions to AP-42 and the Refinery Protocol until one year after the Refinery Sector Rule is promulgated. Commenter 8 stated new flare emissions factors that use the same underlying assumptions as the

Refinery Sector rulemaking prejudices the evaluation of comments on the Refinery Sector rule since the new emissions factors would be finalized prior to finalizing the Refinery Sector rule. Commenter 54 stated EPA should ensure that any effort to review flare emissions factors takes into account the requirements for flare efficiency and operation that EPA has promulgated at the time of completing the review.

Commenter 56 stated EPA should provide sufficient time for considering the comments received in the Refinery NESHAP rulemaking as they impact emission estimates, and allow for incorporation of the impacts of the NESHAP rulemaking on emissions. Commenter 8 stated it is arbitrary and unreasonable to revise emissions factors for refinery processes, and particularly refinery flares, when those emissions factors are known by EPA to reflect operations for which EPA has proposed changes and, as such, will be out-of-date as soon as they are finalized. Commenter 54 stated EPA should re-propose emissions factors after promulgation of the RTR regulations.

Commenter 17 recommended that the EPA should consider waiting to revise the emissions factors for flares until after the refining sector and other industrial sectors make physical or operational changes to flares as a result of future and anticipated rulemaking. With the changes to the Refinery MACT rule that were proposed on June 30, 2014, Commenter 17 stated that the amendments may drive changes to the way flares are operated, and with the expected compliance date to be sometime in 2018, the commenter stated that it is reasonable to expect the refinery sector will be making both physical and operational changes in that timeframe. Commenter 17 added that by delaying, the EPA will have more time to obtain additional NOx measurements and establish a higher quality NOx emissions factor for flares.

Commenter 54 recommended EPA delay applicability and implementation of the emissions factors until at least one year after promulgation of the final RTR regulations.

Response: We have reviewed the comments on both the Refinery sector rulemaking and the emissions factors and coordinated any necessary data revisions between the two projects. We believe that we have adequate data, and as much as we can gather at this time, to complete an analysis for emissions factors. We believe that the 120 days allowed for the comment period is adequate for interested parties to make meaningful comments.

We also note that we cannot delay issuance of the VOC emissions factor for flares due to a Consent Decree deadline and that we are not finalizing the NOx emissions factor at this time due to lack of quality data for emissions factor development.

Finally, emissions factor development is an ongoing process. If process unit emissions profiles change as a result of the final Refinery Sector Rulemaking and we are able to obtain enough good quality data that includes both measured emissions and process data, we may use that data to decide if updates are necessary to these emissions factors in the future.

Comment: Commenter 54 stated industry should have been more involved in the process. Commenter 54 stated EPA should have included them in the discussions establishing the scope and schedule of the CD. Commenter 54 indicated this is another example of EPA negotiating a settlement agreement but excluding direct stakeholders, and the result of this "sue and settle" action represents a maneuver by non-governmental organizations to reallocate the Agency's resources and truncate the regulatory process.

Response: The EPA acknowledges but has no response to these comments.

Comment: Commenter 54 stated Section 130 of the CAA does not obligate EPA to consider refinery emissions factors on a three-year cycle but requires EPA to consider all sources of specified pollutants. Commenter 54 contended that EPA's narrow implementation of the statute is inappropriate and arbitrary, and must be revised to consider the broader universe of emission sources. Commenter 54 stated EPA's efforts should focus on more than the refining sector, and it is unclear why EPA focuses almost entirely on the refining sector when section 130 applies to all source regardless of industry. Commenter 54 stated there is no published plan or schedule by which EPA intends to fulfill its non-discretionary duty to consider its responsibility in the broader sense of the statute, even though the 2006 report of the Office of Inspector General (OIG) recommended that EPA develop and implement a comprehensive strategic plan for the Emissions Factors program including "criteria for prioritizing emissions factors development.[9]

Response: We are not suggesting that section 130 of the Clean Air Act is focused on the refining industry. We agree that our duty to review and revise emissions factors is not limited to

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[9] Report No. 2006-P-00017, "EPA Can Improve Emissions Factors Development and Management", Office of Inspector General, page 26.

refinery sources; however, we note that the OIG report specifically identified petroleum refineries as one of three industries for which emissions factors were considered unacceptable for the decisions being made. Additionally, we had available data from the 2011 Refinery ICR to use in emissions factor development. As such, we consider it appropriate to start our review process with petroleum refineries. We plan to continue reviewing data collected from recent ICRs outside of the refining industry and to develop and revise emissions factors as necessary.

We also note that we did not focus solely on revising emissions factors in Chapter 5, but have also revised emissions factors in Chapters 8 and 13, which are not specific to the refining industry. In response to the OIG report, we did develop and implement a plan for emissions factor development. We discussed our plan in the 2009 ANPRM for Emissions Factors Programs Improvements. Since that time, we have updated our emissions factor development procedures, created the portal for test report submission, updated the Electronic Reporting Tool for stack test reports, and have required stack test report submittal electronically in 25 sector rules. We also have recently proposed a rule that includes electronic submittal of stack test reports that applies to 75 subparts in Part 60 and are nearing completion of programming WebFIRE to automatically run the emissions factor development routines. The new procedures are highly automated, and we anticipate that we will be able to develop emissions factors on a much quicker time scale than we have in the past. The new procedures prioritize development of emissions factors where available data exists and where new data is statistically different from existing data.

7.4 Impact Review, Issue Guidance

Comment: Commenters 54 and 56 stated AP-42 emissions factors are used widely for permit applicability, regulation applicability, determining stationary source classification, permitting new sources, permitting modified existing sources, and basis for permit limits. Commenter 39 stated that while EPA has asserted that facilities rely on AP-42 emissions factors at their own risk, EPA and agencies have traditionally placed greater emphasis on the use of these factors than on other possible data sources. Commenter 22 urged the EPA to consider the secondary impact of revisions to flare regulations, as states often incorporate-by-reference or adopt EPA-developed regulations and emission calculation methodologies.

<u>Response</u>: We acknowledge the comment.

<u>Comment</u>: Commenters 39, 47, 50, 54 and 56 requested the continued use of the existing emissions factor. Commenters 54, 56 noted that Section 130 of the CAA requires periodic revision of EPA emissions factors, but also creates a presumption that previous factors remain valid while EPA is conducting its review. Commenter 56 noted this principle is equally true for the real life application of the standards in permitting and other compliance applications. Commenters 50, 54 and 56 stated EPA should clarify, for determining compliance, that the emissions factor that were current at the time of permit application should continue to be used or the permit limits should be adjusted in proportion to the change in the emissions factor. Commenter 39 stated that provisions should be made for existing facilities to continue using the older emissions factors relied upon in the original facility permitting and modeling activities.

<u>Response</u>: We acknowledge the comment but it is outside of the scope of this project. AP-42 recommends against the use of emissions factors for permitting decisions. It is up to the discretion of the delegated air agency as to whether or not an emissions factor can be used for permitting decisions despite the EPA's recommendation, and if so, how changes in emissions factors impact permitting and compliance decisions.

<u>Comment</u>: Commenter 56 stated EPA must identify and address impacts from any changes to emissions factors. Commenter 42 stated changes to AP-42 emissions factors significantly impact rulemaking, air quality permitting, emission inventories, and compliance monitoring. Commenters 37 and 42 stated that overestimating emissions will result in increased Title V and/or synthetic minor permit applications and potential for sources to be out of compliance. Commenter 37 stated this impact is of particular concern for nonattainment areas in which the difference between minor and major permitting could impact cost and schedule. Commenter 18 explained that such over-estimation could lead to unnecessary regulatory burdens, concluding that the EPA should not use or require the use of any of the proposed factors for any of its modeling activities, rule development, permitting, emissions inventory development, or any other air quality-related activities.

<u>Response</u>: We do not agree that section 130 of the CAA requires an impact analysis as part of our emissions factor development process. Emissions factor development is driven by

data, not by burden and regulatory impact assessments. We believe that the emissions factors are appropriate for the purposes mentioned in AP-42. While we understand emissions factors are at times used for other purposes, the EPA does not require such use, and we again note the caution given when considering such use contained in the introduction to AP-42.

Comment: Commenters 26, 33, 37, 39, 54 and 56 recommended EPA issue guidance on implementing emissions factors. Commenter 56 stated EPA should provide specific guidance for the implementation of updated emissions factors. Commenters 54 and 56 recommended that EPA's AQPD in OAQPS develop guidance to address permitting implications when emissions factors are updated. Commenters 54 and 56 stated the guidance should address permit compliance, renewing NSR construction permits, and/or Title V permits. Commenter 54 stated guidance should also include emission credits and offsets and netting calculations.

Commenters 37 and 39 stated EPA should provide guidance to regulated facilities and agencies on how a change should be implemented into existing permits and emissions reporting. Commenter 37 requested EPA develop guidance for permitting and compliance authorities to address regulatory status of existing sources. Commenter 54 stated guidance should address SIP requirements with respect to revised emissions factors that make sources targets for more stringent regulations for deeper emissions reductions, even though actual emissions are unaffected by emissions factors change.

Commenter 54 recommended EPA issue guidance to States on how to address the implications to air permitting, enforcement, emission inventory, emission fees, and NAAQS planning efforts. Commenter 39 stated EPA should update agencies on how to enforce compliance with the new emissions factors.

Commenter 26 requested that if the emissions factor increases as proposed, then the EPA issue guidance for whether a company would need to revisit permits where a synthetic minor was established based on the existing AP-42 emissions factors.

Commenters 54 and 56 believed that policy and guidance would reflect what Congress intended EPA to follow under Section 130 of the CAA.

Response: We consider this comment outside of the scope of this project. As previously mentioned, we recommend against the use of emissions factors in permitting decisions.

Comment: Commenter 54 stated the revised emissions factors should not result in enforcement actions, permit limit deviations or retroactive fee increases. Commenter 54 stated that OECA has actively pursued enforcement against a variety of sources, alleging that emissions from flares are higher than previously believed and therefore violate a variety of permit terms, SIPS, and regulatory requirements, and OECA may attempt to use the revised emissions factors retroactively in these ongoing and in future enforcement actions. Commenter 54 stated EPA must avoid the appearance that its “regulatory” arm is rushing the current review to provide additional support for the Agency’s “enforcement” arm.

Commenters 54 and 56 stated policy is needed to ensure that a change to emissions factors does not by itself: 1) constitute a basis for a finding of non-compliance with an existing permit, 2) create a situation where a source with emissions previously calculated below a threshold requisite for a permit is now considered to be out of compliance with State or Federal permitting requirements, or 3) make sources liable for retrospective emissions fee increases due to application of a new and improved emissions factor that would result in an increase in past emissions estimates.

Commenter 39 stated that since actual emissions are not changing with the emissions factors change, facilities that have historically relied on AP-42 emissions factors should not be penalized for this change.

Response: We consider this comment to be outside of the scope of this project.

7.5 General Support

Comment: Commenter 3 stated that from their interviews with people living in fenceline communities, the commenter has heard first-hand accounts of what living near an oil refinery means in terms of quality of life and health. The commenter stated that not only do the emissions from oil refineries pose serious environmental justice issues, but they may also have broader environmental impacts that the EPA is charged with protecting. Commenter 3 expressed general support for the EPA's actions.

Response: We acknowledge the comment.

Comment: Commenter 56 supported the development and maintenance of reliable emissions factors that are representative of petroleum industry operations. Commenter 54 supported the development and maintenance of reliable emissions factors that are representative of industry operations.

Response: We acknowledge the comment.

7.6 Miscellaneous

Comment: Commenter 58 stated that because emissions factors underlie so many environmental decisions, it is essential for EPA to ensure that emissions factors are accurate, unbiased, and useable for their intended purpose. Commenter 58 stated that emissions factors are the foundation for air quality decisions that impact public health. Commenter 58 stated that emissions factors are critical for developing control strategies, determining applicability of permitting and control programs, determining the effects of sources and appropriate mitigation strategies, demonstrating compliance with NAAQS, and a number of other applications. Commenter 58 stated that emissions factors are used to set regulatory limits and are used to predict emissions for NSR applicability. Commenter 58 noted that an analysis of Louisiana data from the EIA 2014 Refinery Capacity Report show that 20 percent of reporting instances use EPA emissions factors and 60 percent use emissions models.

Response: We acknowledge the comment.

Comment: Commenter 30 stated that the data the EPA used in developing the proposed factors is not available and/or difficult to locate. Commenter 30 stated that the final reports for the 2010 TCEQ, Marathon, and Flint Hills studies excluded raw data and do not mention nitrogen oxide. Commenter 30 added that a single reference to nitrogen oxide was made in the appendix of the Flint Hills report, and that it considered nitrogen oxide to be interference to the FTIR spectra. Commenter 30 stated that the EPA should clearly identify the location of the data and afford the public more time to evaluate that information. Commenter 30 added that the EPA should draft a written analysis explaining and justifying their calculations and analysis.

Response: We included the data used in developing the proposed factors in the draft versions of AP-42 Sections 5.1, 8.13, and 13.5. The specific references used to create each factor were noted as a footnote to the factor. All references were hyperlinked in order to make the data easily accessible. While the 2010 TCEQ, Marathon, and Flint Hills studies excluded raw data and did not mention nitrogen oxide, this data was provided to the Agency and is included in the reference link in AP-42 Section 13.5. The data were available for the entire public comment period, and as such, we feel it is unnecessary to provide more time for evaluation of the data.

Additionally, we did provide a written explanation for all of the draft emissions factors. This document, *Draft Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations*, was posted at http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html, which is the website dedicated to the EPA's response to the consent decree. The website address was provided in the listserv notice sent out for this action. This document was also included in the draft background document files for each of the affected AP-42 sections. The draft background documents were posted on the AP-42 website in the affected sections.

Comment: Commenter 5 requested a copy of the following memorandum:

Preliminary Analysis of Short-term Variability in Storage Vessel Emissions. Memorandum from Coburn, J. and M. Icenhour, RTI International to B. Shine, U.S. EPA. December 29, 2008.

Commenter 9 requested a copy of the following memorandum:

Implementation of Section 804 of the Clean Air Act Amendments. U.S. Environmental Protection Agency, Office of Air Quality and Planning and Standards. May 14, 1991.

Response: We provided the commenters with the requested documents and attachments.

Comment: Commenters 8, 54 and 56 recommended EPA incorporate New Source Performance Standards Subpart Ja (NSPS Ja) and Refinery Sector rule impacts into the new emissions factors.

Response: We have based the emissions factors on available data. If new rulemaking causes emissions profiles to change and this data is provided to us, we may update these factors in the future.

7.7 Comments Received Past December 19, 2014

Comment: Commenter 59 provided the following comments (see Attachment C):

Commenter 59 noted that in Table 13.5-2, an emissions factor is given in terms of "Volatile organic carbon." Commenter 59 stated they reviewed the background documents and they all report emissions as "Volatile Organic Compounds" or "VOC", and the commenter believed this may be a typo on EPA's part.

Commenter 59 stated the two flare organic compound emissions factors yield significantly different results and DREs. Commenter 59 provided an attached workbook, and noted they applied the two emissions factors based on a flare firing a pure one-component hydrocarbon stream. Commenter 59 noted that the DRE changes based on the emission factor used.

Commenter 59 stated that a 98% combustion efficiency applied to most flare streams shows a much higher emission rate than application of the AP-42 flare THC and VOC emission factors (see spreadsheet attachment to the comment letter). Commenter 59 stated EPA should note that, if VOC emissions are calculated based on a DRE, then it is not necessary to also apply either the THC or VOC emission factor (i.e., including emissions from both methods represents double counting of emissions).

Commenter 59 stated the flare NOx emission factor of 2.9 lb NOx/MMBtu is outrageous and likely not obtainable theoretically. Commenter 59 stated the chemical kinetics of NOx formation increases with temperature. Commenter 59 stated the hottest flame temperature in practice will never exceed the adiabatic flame temperature of the flared compound, and believed that adiabatic flame temperature for almost any hydrocarbon stream will never reach high enough to drive the kinetics of NOx formation enough to yield a result of 2.9 lb NOx/MMBtu.

Commenter 59 stated one major problem with the chosen flare emissions factor is that it incorporates a world-class outlier test result of 16.0 lb NOx/MMBtu (for FHR AU flare). In this case, Commenter 59 believed that this NOx generation rate is theoretically impossible from a NOx formation kinetics perspective, and objected to EPA including this test result given that it defies the laws of chemistry and physics.

Commenter 59 stated EPA should truth-check the NOx emission factors based on NOx formation chemical kinetics evaluated at the adiabatic flame temperature of the flare vent gas stream.

Response: We acknowledge the comments and thank the commenter for his input. However, we note that these comments were received on March 31, 2015, more than three months after the comment period closed, and as such, we are not providing individual responses to these comments. Nothing in these comments changes the actions that we are taking.

Attachment A

Letter Discussing Calibrations Conducted for Flare Emissions Data

From:	Robert Spellicy <rspellicy@imacc-instruments.com>
Sent:	Monday, April 13, 2015 3:17 PM
To:	Garwood, Gerri
Cc:	Scott Evans
Subject:	Letter on Flare NOx data
Attachments:	NOx-data-in-flare-studies.pdf; ATT00001.htm; image003.jpg; ATT00002.htm

Gerri,

Attached is a letter I composed discussing the NO2 data collected as part of Flare testing. The NOx data was not calibrated because it was used for interference correction only and calibration was not necessary. I have outlined this in the letter.

If you have any questions or comments on the letter, give me a call.

Bob

IMACC
800 Paloma, Suite 150
Round Rock, Texas 78665
(512) 341-8189

April 10, 2015

Gerri Garwood
U.S. EPA
109 T.W. Alexander Drive
Durham, NC 27709

Ms. Garwood,

In doing analysis of infrared spectra, it is necessary to account for all spectral features in a region chosen for analysis. Many times, some of these features arise from compounds that are not of particular interest for the task at hand. However, they must be accounted for so they do not bias the analyses of compounds that are of interest. In flare combustion analysis, N_2O and NO overlap with bands of CO and CO_2. As a result, they are included in all flare data analysis to assist with the quantitation of CO andCO_2. But, because these gases are not of interest in computing combustion efficiency, they do not need to be calibrated. All that is required is that appropriate spectra be available that can nullify influences on CO and CO_2.

All of the data generated using the Imacc passive-FTIR software, included compounds like N_2O, NO and occasionally others to treat interferences. Calibrations were never done on these compounds nor were their concentrations intended to be used outside the context outlined here.

I hope this clarifies the issues with the nitrogen compounds appearing in some flare data reports. They are not calibrated results and they should not be assumed to be valid concentrations in and of themselves. If there are any further questions about these issues, please contact me.

Sincerely,

Dr. Robert L. Spellicy
V.P. Imacc, LLC

Attachment B

Recommended CO_2 Spectral Regions for Flare Emissions Data

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

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
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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
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MPC_TXC_MAIN_D_4_1	765
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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
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MPC_TXC_MAIN_E_3_3	765
MPC_TXC_MAIN_E_4_1	765
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MPC_TXC_MAIN_E_5_2	765
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SHELL_DP_EPF_A_4.0_1	765
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SHELL_DP_EPF_A_1_1_60	765
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SHELL_DP_EPF_A_4.5_1_	765
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FHR_AU_A_1.0_2	2K
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FHR_AU_A_3.0_1	2K
FHR_AU_A_3.0_2	2K
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FHR_AU_A_4.0_2	2K
FHR_AU_A_4.0_3	2K
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FHR_AU_B_MIN_1	2K
FHR_AU_B_MIN_2	2K

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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
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FHR_AU_C_MIN_3	2K
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FHR_AU_C_1.0_2	2K
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FHR_AU_C_2.0_2	2K
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FHR_AU_C_3.7_3	2K
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FHR_LOU_A_ 2.0_2	2K
FHR_LOU_A_ 2.0_3	2K
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FHR_LOU_A_ 3.0_2	2K

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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
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FHR_LOU_C_MIN_2	2K
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TCEQ_AIRA_A7_3_2	765
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INEOS_BD_1B	1K
INEOS_BD_2	1K
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INEOS_BD_4	1K
INEOS_BD_5	1K
INEOS_BD_6	1K
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INEOS_BD_8	1K
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

Attachment C

Additional Comment Letter Received Post December 19, 2014

Garwood, Gerri

From:	Raymond Allen <raymond.allen@evergreenenvironmentalconsulting.com>
Sent:	Tuesday, March 31, 2015 11:30 AM
To:	Garwood, Gerri
Subject:	DRAFT Flare Emission Factors - Informal Information Exchange
Attachments:	Evaluation of AP-42 Flare Emission Factors for VOC - R0.xlsx

Gerri:

I want to “informally” share a few observations concerning the DRAFT AP-42 emission factors for flares. This is for EPA’s edification only give the comment deadline has long passed.

1. In Table 13.5-2, an emission factor is given in terms of “Volatile organic carbon.” I reviewed the background documents and they all report emissions as “Volatile Organic Compounds” or “VOC”. I believe this may be a typo on EPA’s part.
2. The two flare organic compound emission factors yield significantly different results and DREs. In the attached workbook, I applied the two emission factors based on a flare firing a pure one-component hydrocarbon stream. You can see how DRE changes based on the emission factor used.
3. A 98% combustion efficiency applied to most flare streams shows a much higher emission rate than application of the AP-42 flare THC and VOC Emission Factors – also see the attached spreadsheet. EPA should note that, if VOC emissions are calculated based on a DRE, then it is not necessary to also apply either the THC or VOC emission factor (i.e., including emissions from both methods represents double counting of emissions)
4. The flare NOx emission factor of 2.9 lb NOx/MMBtu is outrageous and likely not obtainable theoretically. The chemical kinetics of NOx formation increases with temperature. The hottest flame temperature in practice will never exceed the adiabatic flame temperature of the flared compound. I am willing to bet that adiabatic flame temperature for almost any hydrocarbon stream will never reach high enough to drive the kinetics of NOx formation enough to yield a result of 2.9 lb NOx/MMBtu.
5. One major problem with the chosen flare emission factor is that incorporates a world-class outlier test result of 16.0 lb NOx/MMBtu, as shown in the table below. In this case, I am willing to bet the farm that this NOx generation rate is theoretically impossible from a NOx formation kinetics perspective. Shame on EPA for including this test result given that it defies the laws of chemistry and physics. EPA should truth-check the NOx emission factors based on NOx formation chemical kinetics evaluated at the adiabatic flame temperature of the flare vent gas stream.

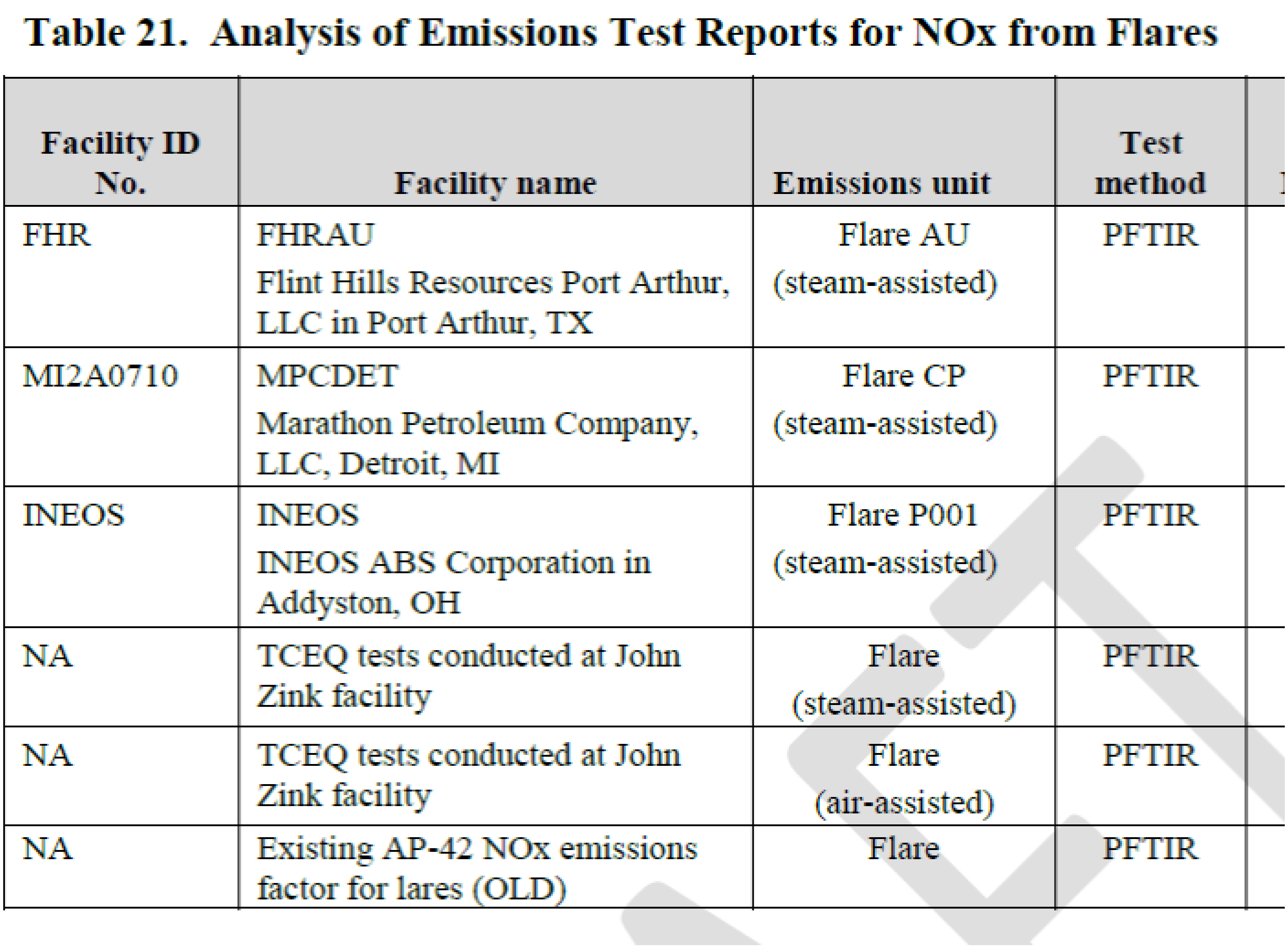

Table 21. Analysis of Emissions Test Reports for NOx from Flares

Facility ID No.	Facility name	Emissions unit	Test method
FHR	FHRAU Flint Hills Resources Port Arthur, LLC in Port Arthur, TX	Flare AU (steam-assisted)	PFTIR
MI2A0710	MPCDET Marathon Petroleum Company, LLC, Detroit, MI	Flare CP (steam-assisted)	PFTIR
INEOS	INEOS INEOS ABS Corporation in Addyston, OH	Flare P001 (steam-assisted)	PFTIR
NA	TCEQ tests conducted at John Zink facility	Flare (steam-assisted)	PFTIR
NA	TCEQ tests conducted at John Zink facility	Flare (air-assisted)	PFTIR
NA	Existing AP-42 NOx emissions factor for lares (OLD)	Flare	PFTIR

I know this is late but I thought EPA should know. Thanks.

Regards,

Raymond R. Allen P.E.
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Cell: 225-590-0491

Evaluation of AP-42 Flare THC and VOC Emission Factors to Assess DREs when Firing 1 MMBtu/hr of a Pure Single-Component Hydrocarbon Stream

Basis: 1 MMBtu/hr-HHV of Pure Compound Flared	Higher Heating Value (Btu/lb)	Quantity Fired = 1 MMBtu/hr (lb/hr)	Pure Compound Mass Emission Rate @ DRE = 98% (lb/hr)	Pure Compound Mass Emission Rate @ DRE = 99% (lb/hr)	AP-42 THC Emission Rate @ 1 MMBtu/hr EF = 0.14 lb/MMBtu (lb/hr)	AP-42 VOC Emission Rate @ 1MMBtu/hr EF = 0.55 lb/MMBtu (lb/hr)	AP-42 THC-Based DRE	AP-42 VOC-Based DRE	Δ DRE = THC DRE - VOC DRE
Methane	23,875	41.88	0.84	0.42	0.14	0.55	99.67%	98.69%	0.98%
Ethane	22,323	44.80	0.90	0.45	0.14	0.55	99.69%	98.77%	0.92%
Ethylene	21,636	46.22	0.92	0.46	0.14	0.55	99.70%	98.81%	0.89%
Acetylene	21,502	46.51	0.93	0.47	0.14	0.55	99.70%	98.82%	0.88%
Propane	21,669	46.15	0.92	0.46	0.14	0.55	99.70%	98.81%	0.89%
Propylene	21,048	47.51	0.95	0.48	0.14	0.55	99.71%	98.84%	0.86%
Butane	21,321	46.90	0.94	0.47	0.14	0.55	99.70%	98.83%	0.87%
n-Butene	20,854	47.95	0.96	0.48	0.14	0.55	99.71%	98.85%	0.86%
Isobutane	21,271	47.01	0.94	0.47	0.14	0.55	99.70%	98.83%	0.87%
Isobutene	20,737	48.22	0.96	0.48	0.14	0.55	99.71%	98.86%	0.85%
n-Pentane	21,095	47.40	0.95	0.47	0.14	0.55	99.70%	98.84%	0.86%
Isopentane	21,047	47.51	0.95	0.48	0.14	0.55	99.71%	98.84%	0.86%
n-Pentene	20,720	48.26	0.97	0.48	0.14	0.55	99.71%	98.86%	0.85%
n-Hexane	20,966	47.70	0.95	0.48	0.14	0.55	99.71%	98.85%	0.86%
Benzene	18,184	54.99	1.10	0.55	0.14	0.55	99.75%	99.00%	0.75%
Toluene	18,501	54.05	1.08	0.54	0.14	0.55	99.74%	98.98%	0.76%
Xylene	18,650	53.62	1.07	0.54	0.14	0.55	99.74%	98.97%	0.76%