ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Amendments to: State Air Quality Control Plan

Vol. III: Appendices Section II.D.

Clean Air Act Section 110 Infrastructure Certification Documentation Adopted

August 10, 2018

Bill Walker, Governor

Larry Hartig, Commissioner

Amendments to State Air Quality Control Plan Volume III:
Clean Air Act §110 Infrastructure Certification Documentation Appendix to Volume II Section II.D.: State Air Quality Control Program, is amended to update Table 1 and add new table, Table 6.

Table 1

Alaska's State Air Quality Control Plan CAA §110 Infrastructure Certifications

Table 6

Alaska's Compliance with CAA §110 Infrastructure Requirements for the 2015 8-hour ozone NAAQS

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Acronyms, Abbreviations, and Symbols

AAC	Alaska Administrative Code
AMQA	Air Monitoring & Quality Assurance
CAA	Clean Air Act
CBJ	City & Borough of Juneau
CFR	Code of Federal Regulations
DAQ	Division of Air Quality
DEC	Department of Environmental Conservation
EPA	Environmental Protection Agency
FNSB	Fairbanks North Star Borough
FR	Federal Register
MOA	Municipality of Anchorage
MSB	Matanuska-Susitna Borough
MOU	Memorandum of Understanding
NAAQS	National Ambient Air Quality Standards
NNSR	Nonattainment New Source Review
NOx	Nitrous Oxide
NO_2	Nitrogen Dioxide
NSR	New Source Review
O_3	Ozone
NSR	New Source Review
PM-2.5	Fine Particulate Matter
PSD	Prevention of Significant Deterioration
§	Section
SIL	Significant Impact Level
SIP	State Implementation Plan
SO_2	Sulfur Dioxide

Table 1: Alaska's State Air Quality Control Plan CAA §110 Infrastructure Certifications.

NAAQS Element	NAAQS Federal Register Date	NAAQS Federal Register Number	State of Alaska NAAQS Effective Date of Regulation	State of Alaska CAA §110 SIP Certification Effective Date of Regulation	Table Number	Notes
Ozone 8-hour	7/18/97	62 FR 38856	6/21/98	8/1/12	2	
$PM_{2.5}$ annual & 24-hour	7/18/97	62 FR 38652	6/21/98	8/1/12	2	
$PM_{2.5}$ 24-hour	10/17/06	71 FR 61144	4/1/2010	8/1/12	2	Complete except for 110(a)(2)(G), see table 4
Ozone 8-hour	3/27/08	73 FR 16436	4/1/2010	8/1/12	2	
Lead	11/12/08	73 FR 66964	4/1/2010	8/1/12	2	
SO_2 1-hour	6/22/10	75 FR 35520	9/17/2011	4/17/15	3	
NO_2 1-hour	2/9/10	75 FR 6474	1/4/2013	4/17/15	3	
$PM_{2.5}$ 24-hour	10/17/06	71 FR 61144	4/1/2010	12/17/15	4	110(a)(2)(G) only
$PM_{2.5}$ annual	01/15/13	78 FR 3086	3/2/2016	12/17/15	5	
Ozone 8-hour	10/26/15	80 FR 65292	8/20/2016	[insert effective date of regulation]	6	

Table 6: Alaska's Compliance with CAA §110 Infrastructure Requirements for the 2015 8-hour Ozone NAAQS.

CAA §110 Infrastructure Element	How Infrastructure Requirement is Addressed in Alaska's SIP
§110(a)(2)(A) Emission limits & other control measures	**Alaska Administrative Code (AAC), Title 18 Environmental Conservation, Chapter 50 Air Quality Control** DEC has promulgated regulations to implement and enforce the NAAQS and other emission limitations. These regulations include statewide ambient air quality standards, major and minor permits, transportation conformity and fees, among others which are found in the following articles of AAC Title 18 Environmental Conservation, Chapter 50. Air Quality Control: • Article 1. Ambient Air Quality Standards (18 AAC 50.005 - 18 AAC 50.110); • Article 2. Program Administration (18 AAC 50.200 - 18 AAC 50.250); • Article 3. Major Stationary Source Permits (18 AAC 50.300 - 18 AAC 50.390); • Article 5. Minor Permits (18 AAC 50.502 - 18 AAC 50.560); • Article 7. Conformity (18 AAC 50.700 – 18 AAC 50.750); and • Article 9. General Provisions (18 AAC 50.900 – 18 AAC 50.990). The State of Alaska adopted the 2015 8-hour ozone NAAQS into **18 AAC 50**, Article 1 (state effective 8/20/2016). Alaska's current ambient air quality standards are found in Article 1 at **18 AAC 50.010.**[1] Alaska's air quality designations, classifications and control regions are found in **18 AAC 50.015**. There are no ozone nonattainment areas in Alaska at the present time.
§110(a)(2)(B) Ambient air quality monitoring & data analysis system	DEC's statutory and regulatory authority to conduct ambient air monitoring investigations is found in **AS 46.03.020 (5)**, **AS 46.14.180** and **18 AAC 50.201**. On April 1, 2010, the State of Alaska adopted into Articles 1 and 2 of 18 AAC 50 the following 40 CFR Part 50 reference and interpretation methods for the 2008 8-hour ozone NAAQS:

[1] The Division of Air Quality's current regulations are found in **Title 18 AAC 50 Air Quality Control**, as amended through November 7, 2017: http://dec.alaska.gov/commish/regulations/pdfs/18-aac-50.pdf

§110(a)(2)(B) Ambient air quality monitoring & data analysis system (continued)	• Appendix P: Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone. DEC's revised "*Quality Assurance Project Plan for the State of Alaska Air Monitoring & Quality Assurance Program*"[2] was adopted by reference into the State Air Quality Control Plan under **18 AAC 50.030(4)** on October 29, 2010. This manual includes the appropriate, federally referenced ambient air quality monitoring and analysis procedures for ozone. As described in this plan, validated State & Local Air Monitoring Stations (SLAMS), and Special Purpose Monitoring (SPM) ambient air quality monitoring data are reported to the AMQA's database manager. This person verifies the data, and electronically reports these data to EPA through the Air Quality System (AQS) on a quarterly basis. A comprehensive air quality monitoring plan, intended to meet the requirements of 40 CFR part 58 was submitted by Alaska to the EPA on January 18, 1980 (40 CFR 52.70) and approved by the EPA on April 15, 1981. This air quality monitoring plan has been updated annually, most recently on April 12, 2017[3]. The network includes ozone monitoring as described below. **Ozone Monitoring-O_3:** The March 27, 2008 revision of the national ozone standard required the State of Alaska to establish an O_3 monitoring program by April 1, 2010. The regulation required at least one State and Local Air Monitoring (SLAMS) O_3 site in a core based statistical area (CBSA) with a population greater than 350,000. The Anchorage/Matanuska-Susitna Valley population forms the only combined Metropolitan Statistical Area (MSA) in the State of Alaska which meets the criterion. The Municipality of Anchorage conducted monitoring during the O_3 monitoring season (April- October) from 2010 through 2012. An O_3 monitoring site was also established in Wasilla in May 2011 and moved to Palmer in May 2015. Ozone monitoring is ongoing in Palmer and at the multi-pollutant NCore site in Fairbanks, which began monitoring for O_3 in 2012.

[2] Quality Assurance Project Plan for the State of Alaska Air Monitoring & Quality Assurance Program, February 23, 2010: http://dec.alaska.gov/air/doc/adec-amqa-qapp-23feb10-final.pdf
[3] Alaska Department of Environmental Conservation Annual Air Quality Monitoring Network Plan, April 12, 2017: http://dec.alaska.gov/air/am/2016_Air_Monitoring_Plan.pdf

§110(a)(2)(C) Program to enforce control measures, regulate modification & construction of stationary sources and a permit program	DEC's statutory authority to regulate stationary sources via an air permitting program is established in **AS 46.14 Air Quality Control**, Article 01, General Regulations and Classifications; and Article 02, Emission Control Permit Program. DAQ's Air Permits Program issues air discharge permits for stationary sources according to the following regulations: • Construction permit for new or modified construction projects (**18 AAC 50.302**); • Prevention of significant deterioration (PSD) permit (**18 AAC 50.306**); • Non-attainment area major stationary source permit (**18 AAC 50.311**); and • Minor Permits (**18 AAC 50** Article 5). Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943]. Amendments to Alaska's PSD/NSR program were approved by EPA on August 14, 2007 [72 FR 45378] and February 9, 2011 [76 FR 7116]. A copy of the 2001 regulations and SIP amendment were transmitted to EPA Region 10 on October 17, 2011. Alaska's approved PSD/NSR program implements the 2015 8-hour ozone NAAQS. The EPA most recently approved revisions to the Alaska PSD and minor NSR program on August 28, 2017 (82 FR 40712). Standard and compliance conditions for stationary sources are found in **18 AAC 50.345**. Owner requested limits (ORL) and plant-wide applicability limitations (PALs) are regulated according to **18 AAC 50.508, 18 AAC50.540**, and **18 AAC 50.542**. Minor permit regulations requiring analysis of ambient air quality are found at **18 AAC 50.542(c)**. Regulations governing air pollution prohibitions are found at **18 AAC 50.045, 18 AAC 50.110**, and **18 AAC 50.345(c)**. A violation of these prohibitions or any permit condition can result in civil actions (**AS 46.03.760**), administrative penalties (**AS 46.03.761**), or criminal penalties (**AS.03.790**). Regulations pertaining to compliance orders and enforcement proceedings are found in **18 AAC Chapter 95 Administrative Enforcement**.

§110(a)(2)(D)(ii) **Interstate transport and interstate & international pollution abatement** "… insuring compliance with the applicable requirements of CAA § 126 and 115".	Compliance with CAA §110(a)(2)(D)(ii) requirements is satisfied through the implementation of Alaska's PSD/NSR program originally approved by EPA on February 16, 1995 [60 FR 8943]. Revisions to the PSD program were most recently approved by ~~the~~ EPA on August 28, 2017 (82 FR 40712). Alaska's approved PSD/NSR program implements the 2015 ozone NAAQS. Alaska has no pending obligations under section 115 or 126(b) of the CAA.
§110(a)(2)(E)(i) **Adequate personnel, funding and authority to carry out plan**	DEC has implemented CAA requirements and the State Air Quality Control Plan since its inception in 1972. DEC's statutory and regulatory authorities to implement and enforce the State of Alaska's Air Quality Control Plan are found at **AS 46.14.030** and **18 AAC 50.030**, respectively. The State of Alaska has adequate personnel, funding and the authority to implement the 2015 8-hour ozone NAAQS. The statutory authority for establishing local air pollution control programs is found in **AS 46.14.400**- Local Air Quality Control Programs. Where local control programs are relied upon to meet SIP requirements, DEC insures that the local program has adequate resources and documents this in the appropriate SIP sections.
§110(a)(2)(E)(ii) **Comply with state boards**	Alaska's regulations meeting the intent of CAA §110(a)(2)(E) and CAA §128 "conflict of interest" phrases are found in **Attachment 1**- AAC Title 2- Administration; Chapter 50- Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulations of Lobbying - Article 1- Public Official Financial Disclosure (**2 AAC 50.010- 2 AAC 50.920**) and **Attachment 2**-Title 9- Law; Chapter 52- Executive Branch Code of Ethics (**9 AAC 52.010-9 AAC 52.990**). These existing regulations were adopted into the State Air Quality Control Plan and were included as attachments to the SIP on March 12, 2015. DEC submitted these regulations to meet the intent of CAA §110(a)(2)(E) and CAA §128 and for all future CAA §110 certification amendments to the SIP. There are no state air quality boards in Alaska, however, the DEC Commissioner, as an appointed official and the head of an executive agency, is required to file a financial disclosure statement annually by March 15th of each year with the Alaska Public Offices Commission (APOC). These disclosures are publically available

§110(a)(2)(E)(ii) Comply with state boards (continued)	through APOC's Anchorage office. Alaska's Public Officials Financial Disclosure Forms and Internet links to Alaska's financial disclosure regulations can be found at the APOC website: http://doa.alaska.gov/apoc/home.html .
§110(a)(2)(E)(iii)Oversee local & regional government/agencies	As a matter of policy, DEC encourages the development of strong local air quality control programs. DEC provides technical assistance and regulatory oversight to the MOA, FNSB and other local jurisdictions to ensure that the State Air Quality Control Plan and SIP objectives are satisfactorily carried out. As mentioned, DEC has an MOU with the MOA and FNSB which allows them to operate air quality control programs in their respective jurisdictions. The South Central Clean Air Authority has been established to aid the MOA and the MSB in pursuing joint efforts to control emissions and improve air quality in the air-shed common to the two jurisdictions.
§110(a)(2)(F) Stationary source emissions monitoring and reporting system	DEC's general statutory authority to regulate stationary sources via an air permitting program is established in **AS 46.14 Air Quality Control**, Article 01, General Regulations and Classifications; and Article 02, Emission Control Permit Program. Alaska's statutes regarding stationary source permit reporting requirements, completeness determinations, administrative actions, and stack source monitoring requirements are found at **AS 46.140** through **AS 46.14.180**. DEC's regulatory authority to determine compliance with these statutes is found in **18 AAC 50.200 Information requests**; and **18 AAC 50.201 Ambient air quality investigations**. The State of Alaska has adopted into **18 AAC 50, Articles 1 and 2**, the appropriate 40 CFR Part 50 reference and interpretation methods for ozone NAAQS. Monitoring protocols and test methods for stationary sources that have been adopted by reference in the State Air Quality Control Plan are found at **18 AAC 50.030**. Other

Table 6. 2015 8-hour Ozone NAAQS

§110(a)(2)(F) Stationary source emissions monitoring and reporting system (continued)	documents, procedures and test methods adopted by reference, including the federal reference and interpretation methods for the NAAQS, are found at **18 AAC 50.035**. Federal standards adopted by reference are found at **18 AAC 50.040**. Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943]. Revisions to the PSD program were most recently approved by the EPA on August 28, 2017 (82 FR 40712). Ambient air quality and meteorological data that are collected for PSD purposes by stationary sources are reported to DEC on a quarterly and annual basis.
§110(a)(2)(G) Authority to declare air pollution emergency and notify public	DEC's regulatory authority to act during air episodes is found at 18 AAC 50.245. This authority is promulgated under the following statutes: **AS 46.03.020**; **AS 46.03.820**; **AS 46.14.010**; **AS 46.14.020**, **AS 46.14.030** and **46.14.540**. The three major municipalities in Alaska (MOA, FNSB, and CBJ) also have ordinances, codes, or regulations that enable them to declare emergencies in the case of poor air quality due to forest fires, volcanoes, wood smoke or other air quality problem. DEC personnel remain in close contact with each municipality when an air emergency is declared, assisting with air monitoring and analysis, and implementing safety and control measures, as needed. Alaska's emergency episode rules at 18 AAC 50.245 and 18 AAC 50.246 most recently approved by the EPA on September 10, 2017 (82 FR 40712), are consistent with the requirements of 40 CFR part 51 subpart H (prevention of air pollution emergency episodes, sections 51.150 through 51.153) for purposes of the 2015 ozone NAAQS.
§110(a)(2)(H) Future SIP Revisions	DEC's statutory authority to adopt regulations in order to implement the CAA and the state air quality control program is found in **AS 46.03.020(10) (A)**, and **AS 46.14.010(a)**. DEC's regulatory authority to implement any provision of the CAA is found in **18 AAC 50.010**. DEC strives to establish regulations and update Alaska's SIP in a timely fashion as new NAAQS are promulgated by EPA.

§110(a)(2)(J) § 121 consultation	DEC's statutory authority to consult and cooperate with officials of local governments, state and federal agencies, and non-profit groups is found in **AS 46.030.020 (3), (8)**. Municipalities and local air quality districts seeking approval for a local air quality control program shall enter into a cooperative agreement with DEC according to **AS 46.14.400(d)**. DEC can adopt new CAA regulations only after a public hearing (**AS 46.14.010(a)**). Alaska's PSD program provides opportunity and procedures for public comment and notice to appropriate federal, state and local agencies. Alaska rules that define transportation conformity consultation and regional haze interagency planning provide for a process to consult with local governments and federal land managers.
§110(a)(2)(J) § 127 public notification	Public notice and public hearing regulations for SIP submittals and air quality discharge permits are found at **18 AAC 15.050** and **18 AAC 15.060**. ADEC is a partner in the EPA's AIRNOW and Enviroflash Air Quality Alert programs, which provide air quality information to the public for five major air pollutants regulated by the CAA: ground-level ozone, particulate matter, carbon monoxide, sulfur dioxide, and nitrogen dioxide. Alaska also provides real-time air monitoring information to the public on the ADEC air quality website at *http://dec.alaska.gov/applications/air/envistaweb/*, in addition to air advisory information.
§110(a)(2)(J) PSD & visibility protection	Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943]. The EPA most recently approved updates to the Alaska PSD program on August 28, 2017 (82 FR 40712). Alaska's approved program implements the 2015 8-hour ozone NAAQS. DEC concludes that there are no new visibility protection obligations under CAA §110(a) (2) (J) as a result of the 2015 8-hour ozone NAAQS.

Table 6. 2015 8-hour Ozone NAAQS

§110(a)(2)(K) Air quality modeling/data	Air quality modeling by DEC is conducted under **18 AAC 50.215(b)**, ambient air quality analysis methods. Estimates of ambient concentrations and visibility impairment must be based on applicable air quality models, databases, and other requirements specified in the EPA's Guideline on Air Quality Models adopted by reference in **18 AAC 50.040(f)**. This regulation allows some provisions to exclude concentrations attributable to temporary construction activity for a new or modified source, or to new sources outside the United States.
§110(a)(2)(L) Major stationary source permitting fees	DEC's statutory authority to assess and collect permit fees is established in **AS 46.14.240** and **AS 46.14.250**. The permit fees for permitting major and minor stationary sources are assessed and collected by the Air Permits Program according to **18 AAC 50 Article 4. User Fees (18 AAC 50.400 through 18 AAC 50.430)**. The Air Permits Program is required to evaluate emission fee rates at least every four years, and provide a written evaluation of the findings (**AS 46.14.250(g)**; **18 AAC 50.410**). The Division's most recent emission fee evaluation report was completed in May 2015[4]. The EPA fully approved Alaska's title V program on July 26, 2001 (66 FR 38940). In addition, Alaska regulations at 18 AAC 50.306(d)(2) and 18 AAC 50.311(d)(2) require fees for purposes of major new source permitting as specified in 18 AAC 50.400 through 18 AAC 50.499.
§110(a)(2)(M) Consultation/Participation by affected local entities	DEC has the statutory authority to consult and cooperate with officials and representatives of any organization in the state; and persons, organization, and groups, public and private using, served by, interested in, or concerned with the environment of the state (**AS 46.03.020 (3) (A)(B)**).

[4] Department of Environmental Conservation, Division of Air Quality Final 2014 Fee Study Report, May 21, 2015: http://dec.alaska.gov/air/ap/docs/FeesFY14.FeeStudyNarrativeReport.5-21-15.pdf

DEPARTMENT OF

ENVIRONMENTAL CONSERVATION

Amendments to:

State Air Quality Control Plan, Volume II, Section III.L
"Interstate Transport of Pollution"

August 10, 2018

Bill Walker, Governor

Larry Hartig, Commissioner

Amendments to State Air Quality Control Plan, Volume II: Section III.L. Interstate Transport of Air Pollutants is amended to update Table 1 and add new table, Table 5.

Table 1
Alaska's State Air Quality Control Plan CAA §110 Interstate Transport Regulation Certifications

Table 5
Alaska's Compliance with CAA §110 Interstate Transport Requirements for the 2015 8-hour Ozone NAAQS

Acronyms, Abbreviations, and Symbols

AAC	Alaska Administrative Code
AMQA	Air Monitoring & Quality Assurance
CAA	Clean Air Act
CBJ	City & Borough of Juneau
CFR	Code of Federal Regulations
DAQ	Division of Air Quality
DEC	Department of Environmental Conservation
EPA	Environmental Protection Agency
FNSB	Fairbanks North Star Borough
FR	Federal Register
MOA	Municipality of Anchorage
MSB	Matanuska-Susitna Borough
MOU	Memorandum of Understanding
NAAQS	National Ambient Air Quality Standards
NEI	National Emission Inventory
NNSR	Nonattainment New Source Review
NOx	Nitrous Oxide
NO_2	Nitrogen Dioxide
NSR	New Source Review
O_3	Ozone
NSR	New Source Review
PM-2.5	Fine Particulate Matter
PSD	Prevention of Significant Deterioration
§	Section
SIL	Significant Impact Level
SIP	State Implementation Plan
SO_2	Sulfur Dioxide

L. PROVISIONS PROHIBITING REGIONAL TRANSPORT OF AIR POLLUTANTS

The 1990 CAA Amendments, Sections 110(a)(2)(D)(i) (I)&(II), require Alaska's SIP to "contain adequate provisions prohibiting ...any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—

I. Contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard;

Or

II. Interfere with measures required to be included in the applicable implementation plan for any other State... to prevent significant deterioration of air quality or to protect visibility.

DEC demonstrates compliance with NAAQS interstate transport infrastructure requirements by submitting a new and separate table for each promulgated NAAQS as shown in Table 1. This table provides a chronological history of DEC's CAA §110 interstate transport SIP submittals.

Table 1: Alaska's State Air Quality Control Plan CAA §110 Interstate Transport Regulation Certifications.

NAAQS Element	NAAQS Federal Register Date and Number	State of Alaska NAAQS Effective Date of Regulation	State of Alaska Interstate Transport Regulation Certification Effective Date	Table Number	Note
2006 $PM_{2.5}$ Annual & 24-hour	10/17/2006 71 FR 61144	04/01/2010	08/01/2012	N/A	See: Volume II, Section III.D.VI
2008 O_3 Primary & Secondary	03/27/2008 73 FR 16436	04/01/2010	08/01/2012	N/A	See: Volume II, Section III.D.VI
2008 Lead Primary & Secondary	11/12/2008 73 FR 66964	04/01/2010	08/01/2012	N/A	See: Volume II, Section III.H.4
2010 SO_2 Primary 1-hour	06/22/2010 75 FR 35520	09/17/2011	04/17/2015	2	
2010 NO_2 Primary 1-hour	02/09/2010 75 FR 6474	01/04/2013	04/17/2015	3	
2012 $PM_{2.5}$ Primary Annual	01/15/2013 78 FR 3086	03/02/2016	12/17/2015	4	
2015 O_3 Primary & Secondary	**10/26/2015 80 FR 65292**	**08/20/2016**	**[insert effective date of regulation]**	5	

Table 5. Interstate Transport: 2015 Primary & Secondary 8-hour O_3 NAAQS

CAA §110 Interstate Transport Requirement	How Requirement is Addressed in Alaska's SIP
2015 O_3 NAAQS **110(a)(2)(D)(i)(I) Contributions to nonattainment or maintenance of NAAQS in other states**	Alaska does not contribute to nonattainment or interfere with maintenance of the 2015 Primary and Secondary O_3 NAAQS in any other state. This statement is based on the following: EPA has not classified any area of Alaska as not attaining the 2008 O_3 NAAQS, all areas have been identified as "unclassifiable/attainment" (77 FR 30088, May 21, 2012); Alaska is not subject to the "Cross-State Air Pollution Rule" (CSAPR), (76 FR 48208, August 8, 2011) and is not subject to the CSAPR Update (81 FR 74514, October 26, 2016); Ozone has been measured at Fairbanks NCore site and in the Mat-Su Valley at the Wasilla and Palmer sites from 2011 to 2015[1]. All sites are well below the 2015 ozone standard of 0.070 ppm. The highest monitored 8-hour ozone concentration was 0.057 ppm on May 11, 2014 at the NCore site. General trends are consistent among years and sites with the monthly average of the maximum hourly ozone concentrations per day highest in April and May and lowest in December and January.[2] Alaska's anthropogenic ozone precursor emissions are very low compared to national levels. The most recent national emissions inventory data (2014) reports Alaska aggregate emissions are approximately 1% percent of national nitrogen oxide emissions and less than 0.5% of national volatile organic compound emissions. Alaska is geographically isolated from the contiguous 48 states, making significant pollutant transport to other states unlikely. Approximately 600 miles of mountainous terrain in Canada's Province of British Columbia separate the southeastern border of Alaska from the nearest state, Washington. The highest emissions of regulated air pollutants occur even further away from the contiguous 48 states in the Municipality of Anchorage (1,435 miles from Seattle, WA) and the Fairbanks North Star Borough

[1] Alaska Department of Environmental Conservation Annual Air Quality Monitoring Network Plan, Nov. 2015: http://dec.alaska.gov/air/am/2015_Air_Monitoring_plan.pdf
[2] Alaska Department of Environmental Conservation 2015 Ambient Air Quality Network Assessment, Nov. 2016: http://dec.alaska.gov/air/am/Alaska_2015_5-year_Network_Assessment.pdf

Table 5. Interstate Transport: 2015 Primary & Secondary 8-hour O_3 NAAQS

110(a)(2)(D)(i)(I) Contributions to nonattainment or maintenance of NAAQS in other states (continued)	(2,244 miles from Seattle, WA). The nearest 2008 ozone NAAQS nonattainment areas are located even further away in California and Colorado; and Weather patterns make long range transport of air pollutants from Alaska to the 48 contiguous states very unlikely. Regional, predominant low pressure, wind patterns emanate from the western Gulf of Alaska and travel inland towards the east, circulating in a counterclockwise direction.
2015 O_3 NAAQS **110(a)(2)(D)(i)(II) Prevention of significant deterioration of air quality and protection of visibility in other states**	Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943]. Amendments to Alaska's PSD/NSR program were more recently approved by EPA on February 9, 2011 [76 FR 7116] and January 7, 2015 [80 FR 832]. A copy of these regulations and SIP amendment were transmitted to EPA Region 10 on October 17, 2011. On February 14, 2013, EPA approved Alaska's Regional Haze Plan submitted on April 4, 2011, as meeting the requirements set forth in sections 169A and 169B of the CAA and in 40 CFR 51.308 regarding Regional Haze [78 FR 10546].

13.5 Industrial Flares

13.5.1 General

Flaring is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, of waste gases from industrial operations. Natural gas, propane, ethylene, propylene, butadiene and butane constitute over 95 percent of the waste gases flared. In combustion, gaseous hydrocarbons react with atmospheric oxygen to form carbon dioxide (CO_2) and water. In some waste gases, carbon monoxide (CO) is the major combustible component. Presented below, as an example, is the combustion reaction of propane.

$$C_3H_8 + 5\ O_2 \rightarrow 3\ CO_2 + 4\ H_2O$$

During a combustion reaction, several intermediate products are formed, and eventually, most are converted to CO_2 and water. Some quantities of stable intermediate products such as carbon monoxide, hydrogen, and hydrocarbons will escape as emissions.

Flares are used extensively to dispose of (1) purged and wasted products from refineries, (2) unrecoverable gases emerging with oil from oil wells, (3) vented gases from blast furnaces, (4) unused gases from coke ovens, and (5) gaseous wastes from chemical industries. Gases flared from refineries, petroleum production, chemical industries, and to some extent, from coke ovens, are composed largely of low molecular weight hydrocarbons with high heating value. Blast furnace flare gases are largely of inert species and CO, with low heating value. Flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants, and ammonia fertilizer plants.

There are two types of flares, elevated and ground flares. Elevated flares, the more common type, have larger capacities than ground flares. In elevated flares, a waste gas stream is fed through a stack anywhere from 10 to over 100 meters tall and is combusted at the tip of the stack. The flame is exposed to atmospheric disturbances such as wind and precipitation. In ground flares, combustion takes place at ground level and is almost always unassisted. Ground flares vary in complexity, and they may consist either of conventional flare burners with no enclosures or of multiple burners in refractory-lined steel enclosures. Ground flares may also be known as shielded flares.[a] Ground flares should not be mistaken for thermal oxidizers or incinerators. Ground flares operate under the same principals as elevated flares and combustion is achieved through the natural draft of combustion air. Thermal oxidizers and incinerators have combustion air blowers and can be tuned to control combustion chamber temperature, thereby allowing for more effective combustion control.

The typical flare system consists of (1) a gas collection header and piping for collecting gases from processing units, (2) a knockout drum (disentrainment drum) to remove and store condensables and entrained liquids, (3) a proprietary seal, water seal, or purge gas supply to prevent flash-back, (4) a single- or multiple-burner unit and a flare stack, (5) gas pilots and an ignitor to ignite the mixture of waste gas and air, and, if required, (6) a provision for external momentum force (steam injection or forced air) for

[a] For the purposes of 40 CFR part 60 subparts OOOO and OOOOa and 40 CFR part 63 subparts HH and HHH, these units are not considered flares. The definition of flare in these subparts specifically exclude these units. In these subparts, a flare is defined as a thermal oxidation system using an open flame (without enclosure). Under these subparts, these units are considered combustion devices that must be field-tested. Alternatively, a unit tested by a manufacturer may be installed.

smokeless flaring. Natural gas, fuel gas, inert gas, or nitrogen can be used as purge gas. Figure 13.5-1 is a diagram of a typical steam-assisted elevated smokeless flare system.

Combustion requires three ingredients: fuel, an oxidizing agent (typically oxygen in air), and heat (or ignition source). Flares typically operate with pilot flames to provide the ignition source, and they use ambient air as the oxidizing agent. The waste gases to be flared typically provide the fuel necessary for combustion. Combustible gases generally have an upper and lower flammability limit. The upper flammability limit (UFL) is the highest concentration of a gas in air that is capable of burning. Above this flammability limit, the fuel is too rich to burn. The lower flammability limit (LFL) is the lowest concentration of the gas in air that is capable of burning. Below the LFL, the fuel is too lean to burn. Between the upper and lower flammability limits, combustion can occur. Flare waste gases with concentrations above the UFL will become more dilute as the waste gas mixes with ambient air above the flare tip. As this dilution occurs, the air-waste gas mixture will pass through the flammability region, and combustion will occur. However, if flare waste gas concentrations are near the LFL prior to mixing with air, the air-waste gas mixture can fall below the flammability region, and reduced combustion efficiencies can occur. If steam is added to the flare waste gas at or prior to the flare tip (i.e., prior to the "combustion zone" where the mixing with air occurs), the steam will act to dilute the waste gas. 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, reduced combustion efficiencies will result. Consequently, critical considerations of flare combustion include the net heating value and the combustibles concentration in the flare gas and in the combustion zone (e.g., accounting for the amount of dilution by steam or other assist gas that occurs to the waste gas prior to the combustion zone).

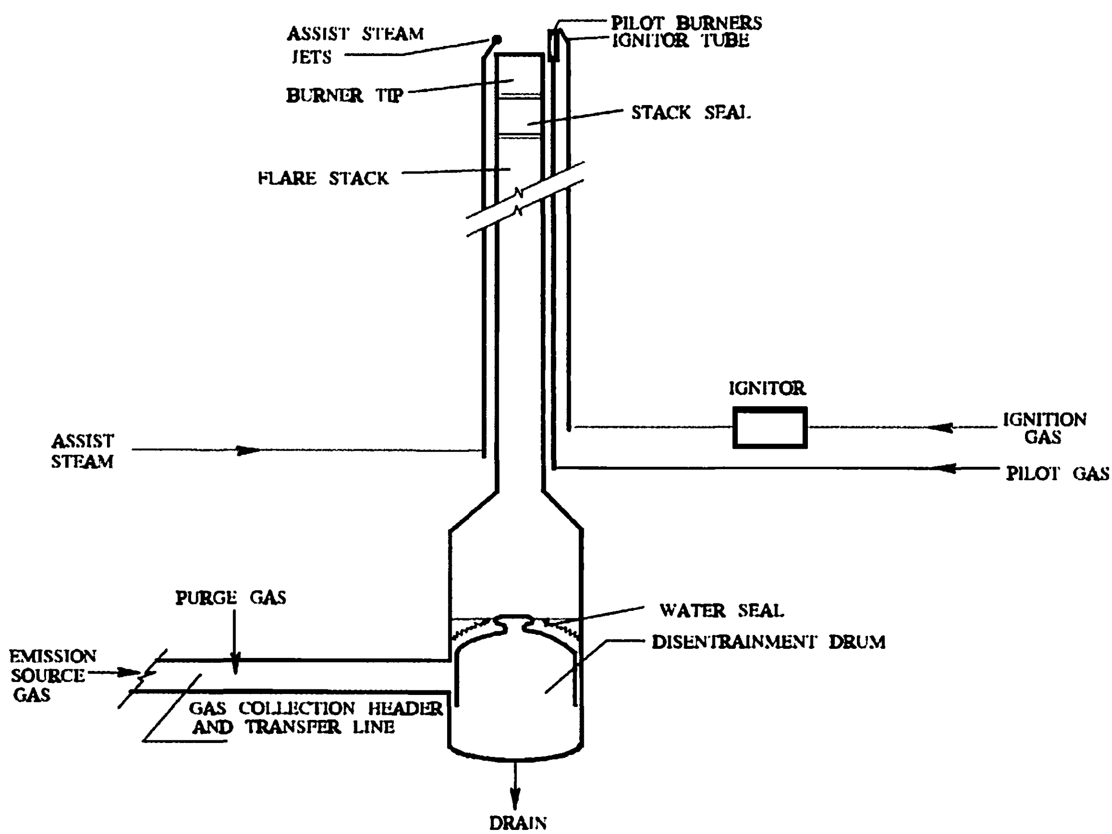

Figure 13.5-1. Diagram of a typical steam-assisted smokeless elevated flare.

Combustion efficiency is the percentage of hydrocarbon in the flare vent gas that is completely converted to CO_2 and water vapor. Destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound (such as CO_2, CO or other hydrocarbon intermediate). The destruction efficiency of a flare will always be greater than the combustion efficiency of a flare. It is generally estimated that a combustion efficiency of 96.5 percent is equivalent to a destruction efficiency of 98 percent.[10]

Smoking may result from combustion, depending upon waste gas components and the quantity and distribution of combustion air. Waste gases containing methane, hydrogen, CO, and ammonia usually burn without smoke. Waste gases containing heavy hydrocarbons such as paraffins above methane, olefins, and aromatics, have a higher tendency to smoke. An external momentum force, such as steam injection or blowing air, is used for efficient air/waste gas mixing and turbulence, which promotes smokeless flaring of heavy hydrocarbon waste gas. Other external forces may be used for this purpose, including water spray, high velocity vortex action, or natural gas. External momentum force is rarely required in ground flares.

Steam injection is accomplished either by nozzles on an external ring around the top of the flare tip or by a single nozzle located concentrically within the tip. At installations where waste gas flow varies, both are used. The internal nozzle provides steam at low waste gas flow rates, and the external jets are used with large waste gas flow rates. Several other special-purpose flare tips are commercially available, one of which is for injecting both steam and air.

Flares are generally designed to handle large quantities of waste gases that may be intermittently generated during plant emergencies, although they may also be used routinely to dispose of low-volume continuous or intermittent emissions from various sources at the plant. Flare gas volumes can vary from a few cubic meters per hour during regular operations up to several thousand cubic meters per hour during major upsets. Flow rates at a refinery could be 45 to 90 kilograms per hour (kg/hr) (100 - 200 pounds per hour [lb/hr]) during regular operation but could reach a full plant emergency rate of 700 megagrams per hour (Mg/hr) (750 tons/hr). Normal process blowdowns may release 450 to 900 kg/hr (1000 - 2000 lb/hr), and unit maintenance or minor failures may release 25 to 35 Mg/hr (27 - 39 tons/hr). Thus, the required flare turndown ratio can be over 15,000 to 1.

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 is intended to handle regular gas volumes and the other flare is generally intended to handle excess gas flows from emergencies.

13.5.2 Emissions

Noise, heat, and visible flame and/or smoke are the most apparent undesirable effects of flare operation. Flares are usually located away from populated areas or are sufficiently isolated, thus minimizing their effects on populations. Because the flame in a ground flare is generally not visible, and they reduce noise and thermal radiation to the surrounding area, these flares are common in populated areas. Emissions from flaring may include carbon particles (soot), unburned hydrocarbons, CO, and partially burned and altered hydrocarbons. Also emitted are nitrogen oxides (NO_x) and, if sulfur-containing material such as hydrogen sulfide or mercaptans is flared, sulfur dioxide (SO_2). The quantities of hydrocarbon emissions generated relate to the degree of combustion. The degree of combustion depends largely on the rate and extent of fuel-air mixing and on the flame temperatures achieved and maintained. Properly operated flares achieve at least 98 percent destruction efficiency in the flare plume, meaning that hydrocarbon emissions amount to less than 2 percent of the hydrocarbons in the gas stream.

The tendency of a fuel to smoke or make soot is influenced by fuel characteristics and by the amount and distribution of oxygen in the combustion zone. For complete combustion, at least the stoichiometric amount of oxygen must be provided in the combustion zone. The theoretical amount of oxygen required increases with the molecular weight of the gas burned. 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. 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. The carbon particles may escape further combustion and cool down to form soot or smoke. Olefins and other unsaturated hydrocarbons may polymerize to form larger molecules which crack, in turn forming more carbon.

The fuel characteristics influencing soot formation include the carbon-to-hydrogen (C-to-H) ratio and the molecular structure of the gases to be burned. All hydrocarbons above methane, i. e., those with a C-to-H ratio of greater than 0.33, tend to soot. Branched chain paraffins smoke more readily than corresponding normal isomers. The more highly branched the paraffin, the greater the tendency to smoke. Unsaturated hydrocarbons tend more toward soot formation than do saturated ones. Soot is eliminated by adding steam or air; hence, most industrial flares are steam-assisted and some are air-assisted. Flare gas composition is a critical factor in determining the amount of steam necessary.

Since elevated flares do not lend themselves to conventional emission testing techniques, until recently only a few attempts have been made to characterize elevated flare emissions. Early EPA tests using propylene as flare gas indicated that efficiencies of 98 percent can be achieved when burning an offgas with at least 11,200 kJ/m^3 (300 Btu/ft^3).[1] However, recent studies on flare performance using passive Fourier Transform Infrared (pFTIR) spectroscopy have been performed on a number of different flares.[4-8] The studies cover a number of flares at refineries, chemical plants and flare test facilities with varying waste gas compositions. The pFTIR studies support the conclusion that the combustion zone properties of the steam-waste gas mixture are predictive of proper flare combustion.[10] There have also been recent studies on sources, including flares, using differential infrared absorption LIDAR [light detection and ranging] (DIAL). To date, many of these studies do not provide the data necessary to isolate the emissions from a particular flare. But enough data existed in one study that the emissions measured by DIAL could be attributed to the flare.[9] For flares operated at petroleum refineries, EPA has determined that the net heating value of the gas in the combustion zone of the flare should be greater than or equal to 270 Btu/ft^3 to obtain a destruction efficiency of at least 98%.[b]

Table 13.5-1 presents flare emissions factors from the EPA tests[1]; Table 13.5-2 presents flare emissions factors from pFTIR and DIAL studies.[4-9] Crude propylene was used as flare gas during the early EPA tests. Methane was a major fraction of hydrocarbons in the flare emissions, and acetylene was the dominant intermediate hydrocarbon species. Many other reports on flares indicate that acetylene is always formed as a stable intermediate product. The acetylene formed in the combustion reactions may react further with hydrocarbon radicals to form polyacetylenes followed by polycyclic hydrocarbons.[2] Typical refinery waste gas feeds were used as flare gas during the pFTIR and DIAL studies.

In flaring waste gases containing no nitrogen compounds, NO is formed either by the fixation of atmospheric nitrogen (N) with oxygen (O) or by the reaction between the hydrocarbon radicals present in

[b] See Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards Final Rule, December 1, 2015 (80 FR 75183). Net heating value of the combustion zone is determined on a 15-minute average, and refinery owners and operators may use a corrected heat content for hydrogen when determining the combustion zone heat value.

the combustion products and atmospheric nitrogen, by way of the intermediate stages, HCN, CN, and OCN.[2] Sulfur compounds contained in a flare gas stream are converted to SO_2 when burned. The amount of SO_2 emitted depends directly on the quantity of sulfur in the flared gases.

With the promulgation of the New Source Performance Standards for Crude Oil and Natural Gas Production, Transmission, and Distribution, EPA developed a manufacturer testing program for combustion control devices. These units are generally equivalent to enclosed ground flares, although they are explicitly excluded from the definition of flare in those subpart (see footnote a to this section). The manufacturer testing program requires performance testing be conducted using pure propylene under four different test conditions. Emissions data from these manufacturer tests have been used to develop emissions factors for enclosed ground flares. Because the factors are representative of enclosed ground flares burning propylene, the factors are included in Table 13.5-1, which are the flare factors developed from the EPA testing of elevated flares using crude propylene. Two factors are representative of enclosed ground flares operating at a low percent load, and two factors are representative of enclosed ground flares operating at a normal to high percent load.[c]

Additionally, the Oil and Gas sector rules, as well as some state programs, are requiring more testing for these types of units in the field. As a result, emissions data are available from enclosed ground flares burning field gas. Table 13.5-3 presents two enclosed ground flare emissions factors for total hydrocarbons (THC) applicable to natural gas production.

Table 13.5-4 presents the description of the source classification codes (SCCs) to which the emissions factors in Tables 13.5-1 through 13.5-3 are applicable.

[c] Because it is possible to test enclosed ground flares, the EPA recommends testing sources and using site-specific data in lieu of emissions factors whenever possible.

Table 13.5-1 (English Units). THC, NOx AND SOOT EMISSIONS FACTORS FOR FLARE OPERATIONS FOR CERTAIN CHEMICAL MANUFACTURING PROCESSES[a]

Pollutant	SCC[e]	Emissions Factor Value	Emissions Factor Units	Grade or Representativeness
THC, elevated flares[c]	30190099; 30119701; 30119705; 30119709; 30119741	0.14[b,f]	lb/10^6 Btu	B
THC, enclosed ground flares[g,h] Low Percent Load[i]		8.37[j] or 3.88e-3[f]	lb/10^6 scf gas burned lb/10^6 Btu heat input	Moderately
THC, enclosed ground flares[g,h] Normal to High Percent Load[i]		2.56[j] or 1.20e-3[f]	lb/10^6 scf gas burned lb/10^6 Btu heat input	Moderately
Nitrogen oxides, elevated flares[d]		0.068[b,k]	lb/10^6 Btu	B
Soot, elevated flares[d]		0 – 274[b]	μg/L	B

[a] All of the emissions factors in this table represent the emissions exiting the flare. Since the flare is not the originating source of the THC emissions, but rather the device controlling these pollutants routed from a process at the facility, the emissions factors are representative of controlled emissions rates for THC. These values are not representative of the uncontrolled THC routed to the flare from the associated process, and as such, they may not be appropriate for estimating the uncontrolled THC emissions or potential to emit from the associated process.
[b] Reference 1. Based on tests using crude propylene containing 80% propylene and 20% propane.
[c] Measured as methane equivalent. The THC emissions factor may not be appropriate for reporting volatile organic compounds (VOC) emissions when a VOC emissions factor exists.
[d] Soot in concentration values: nonsmoking flares, 0 micrograms per liter (μg/L); lightly smoking flares, 40 μg/L; average smoking flares, 177 μg/L; and heavily smoking flares, 274 μg/L.
[e] See Table 13.5-4 for a description of these SCCs.
[f] Factor developed using the lower (net) heating value of the vent gas.
[g] THC measured as propane by US EPA Method 25A.
[h] These factors apply to well operated ground flares achieving at least 98% destruction efficiency and operating in compliance with the current General Provisions requirements of 40 CFR Part 60, i.e. >200 btu/scf net heating value in the vent gas and less than the specified maximum exit velocity. The emissions factor data set had an average destruction efficiency of 99.99%. Based on tests using pure propylene fuel. References 12 through 33 and 39 through 45.
[i] The dataset for these tests were broken into four different test conditions: ramping back and forth between 0 and 30% of load; ramping back and forth between 30% and 70% of load; ramping back and forth between 70% and 100% of load; and a fixed rate maximum load condition. Analyses determined that only the first condition was statistically different. Low percent load is represented by a unit operating at approximately less than 30% of maximum load.
[j] Heat input is an appropriate basis for combustion emissions factor. However, based on available data, heat input data is not always known, but gas flowrate is generally available. Therefore, the emissions factor is presented in two different forms.
[k] Factor developed using the higher (gross) heating value of the vent gas.

Table 13.5-2 (English Units). VOC and CO EMISSIONS FACTORS FOR ELEVATED FLARE OPERATIONS FOR CERTAIN REFINERY AND CHEMICAL MANUFACTURING PROCESSES[a,b]

<table>
<tr><th>Pollutant</th><th>SCC[e]</th><th>Emissions Factor (lb/10^6 Btu)[f]</th><th>Representativeness</th></tr>
<tr><td>Volatile organic compounds[c]</td><td rowspan="2">30190099; 30600904; 30119701; 30119705; 30119709; 30119741; 30119799; 30130115; 30600201; 30600401; 30600508; 30600903; 30600999; 30601701; 30601801; 30688801; 40600240</td><td>0.66</td><td>Poorly</td></tr>
<tr><td>Carbon monoxide[d]</td><td>0.31</td><td>Poorly</td></tr>
</table>

[a] The emissions factors in this table represent the emissions exiting the flare. Since the flare is not the originating source of the VOC emissions, but rather the device controlling these pollutants routed from a process at the facility, the emissions factor is representative of controlled emissions rates for VOC. This values is not representative of the uncontrolled VOC routed to the flare from the associated process, and as such, it may not be appropriate for estimating the uncontrolled VOC emissions or potential to emit from the associated process.

[b] These factors apply to well operated flares achieving at least 98% destruction efficiency and operating in compliance with the current General Provisions requirements of 40 CFR Part 60, i.e. >300 btu/scf net heating value in the vent gas and less than the specified maximum flare tip velocity. The VOC emissions factor data set had an average destruction efficiency of 98.9%, and the CO emissions factor data set had an average destruction efficiency of 99.1% (based on test reports where destruction efficiency was provided). These factors are based on steam-assisted and air-assisted flares burning a variety of vent gases.

[c] References 4 through 9 and 11.

[d] References 1, 4 through 8, and 11.

[e] See Table 13.5-4 for a description of these SCCs.

[f] Factor developed using the lower (net) heating value of the vent gas.

Table 13.5-3 (English Units). THC EMISSIONS FACTOR FOR ENCLOSED GROUND FLARES AT NATURAL GAS PRODUCTION SITES[a]

Pollutant	SCC[e]	Emissions Factor[f]	Representativeness
THC[b,c,d]	31000205 31000212 31000227	332 lb/10^6 scf gas burned or 0.335 lb/10^6 Btu heat input[g]	Poorly

[a] The emissions factor in this table represents the emissions exiting the flare. Since the flare is not the originating source of the THC emissions, but rather the device controlling these pollutants routed from a process at the facility, the emissions factor is representative of controlled emissions rates for THC. This value is not representative of the uncontrolled THC routed to the flare from the associated process, and as such, it may not be appropriate for estimating the uncontrolled THC emissions or potential to emit from the associated process.

[b] THC measured as propane by US EPA Method 25A.

[c] These factors apply to well operated flares achieving at least 95% destruction efficiency, as required by the Oil and Gas sector rules in 40 CFR parts 60 and 63. Although the Oil and Gas sector rules in parts 60 and 63 do not require ground flares to operate in compliance with the current General Provisions requirements of 40 CFR Part 60 or 63, i.e. >200 btu/scf net heating value in the vent gas and less than the specified maximum exit velocity, the reference flares do meet these requirements. The emissions factor data set had an average destruction efficiency of 99.33% for the gas volume basis and an average destruction efficiency of 99.23% for the heat input basis. Based on tests using natural gas production field gas, e.g. tank vents, dehydrator vents. References 32 through 38.

[d] For enclosed ground flares with the SCCs specified in this table, the EPA recommends the use of this THC emissions factor instead of the VOC emissions factor in WebFIRE, as background documentation for this new emissions factor is available and the factor is based on field data from similar units.

[e] See Table 13.5-4 for a description of these SCCs. For the purposes of 40 CFR part 60 subparts OOOO and OOOOa and 40 CFR part 63 subparts HH and HHH, these units are not considered flares. The definition of flare in these subparts specifically exclude these units. In these subparts, a flare is defined as a thermal oxidation system using an open flame (without enclosure).

[f] Heat input is an appropriate basis for combustion emissions factor. However, based on available data, heat input data is not always known, but gas flowrate is generally available. Additionally, based on the available reports, there was a more robust dataset to develop an emissions factor on a gas volume basis. Therefore, the emissions factor is presented in two different forms.

[g] Factor developed using the lower (net) heating value of the vent gas.

Table 13.5-4. SCC Descriptions

SCC	Level 1 Description	Level 2 Description	Level 3 Description	Level 4 Description
30600903	Industrial Processes	Petroleum Industry	Flares	Natural Gas
30600904	Industrial Processes	Petroleum Industry	Flares	Process Gas
30190099	Industrial Processes	Chemical Manufacturing	Fuel Fired Equipment	User Specified
30600999	Industrial Processes	Petroleum Industry	Flares	Not Classified
30600201	Industrial Processes	Petroleum Industry	Catalytic Cracking Units	Fluid Catalytic Cracking Unit
30130115	Industrial Processes	Chemical Manufacturing	Chlorobenzene	Atmospheric Distillation Vents
30688801	Industrial Processes	Petroleum Industry	Fugitive Emissions	User Specified
30600401	Industrial Processes	Petroleum Industry	Blowdown Systems	Blowdown System with Vapor Recovery System with Flaring
30601801	Industrial Processes	Petroleum Industry	Hydrogen Generation Unit	General
30601701	Industrial Processes	Petroleum Industry	Catalytic Hydrotreating Unit	General
30600508	Industrial Processes	Petroleum Industry	Wastewater Treatment	Oil/Water Separator
40600240	Petroleum and Solvent Evaporation	Transportation and Marketing of Petroleum Products	Marine Vessels	Gasoline: Barge Loading - Average Tank Condition
30119701	Industrial Processes	Chemical Manufacturing	Butylene, Ethylene, Propylene, Olefin Production	Ethylene: General
30119741	Industrial Processes	Chemical Manufacturing	Butylene, Ethylene, Propylene, Olefin Production	Ethylene: Flue Gas Vent
30119705	Industrial Processes	Chemical Manufacturing	Butylene, Ethylene, Propylene, Olefin Production	Propylene: General
30119709	Industrial Processes	Chemical Manufacturing	Butylene, Ethylene, Propylene, Olefin Production	Propylene: Fugitive Emissions
30119799	Industrial Processes	Chemical Manufacturing	Butylene, Ethylene, Propylene, Olefin Production	Other Not Classified
31000205	Industrial Processes	Oil and Gas Production	Natural Gas Production	Flares
31000212	Industrial Processes	Oil and Gas Production	Natural Gas Production	Condensate Storage Tank
31000227	Industrial Processes	Oil and Gas Production	Natural Gas Production	Glycol Dehydrator Reboiler Still Stack

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January 30, 2017

Subject: Inclusion of Emissions from Worker Housing Units in Air Quality Permits

Dear :

This letter addresses how worker housing owned or operated by a stationary source is to be addressed in air quality permits. The Alaska Department of Environmental Conservation (ADEC) has not consistently included emissions from fuel-burning emission units (EUs) that directly support worker housing units at or near a stationary source when assessing a permit applicability determination. ADEC's inconsistency has led to different monitoring, record-keeping, and reporting requirements between various Permittees for their worker housing EUs.

To correct this inconsistency, ADEC intends to treat worker housing consistent with this letter in all future permit decisions. We encourage all Permittees that provide worker housing to carefully review the information provided in this letter to see if they need to take additional steps to maintain or revise their permitting strategies.

Worker housing may be a support activity

Support activities are part of the stationary source for permitting purposes. According to the Region 10 office of the U.S. Environmental Protection Agency, worker housing owned or operated by a stationary source constitutes a support activity for that stationary source if 50 percent or more of the services provided by the housing units are used to support the stationary source. When worker housing constitutes a support activity, its emissions must be included in the potential-to-emit calculations for the permitted source. These calculations may affect the classification of the source in a new source review permit application or affect a permit avoidance strategy.

ADEC believes that most worker housing provided by Alaskan Permittees constitute support activities for their stationary source. ADEC will treat all worker housing as support activities unless the Permittee demonstrates to ADEC's satisfaction that their worker housing is not a support activity (see below). All Permittees that provide housing for their employees should assess whether the housing emissions have been properly included in their past permit applications and permitting strategies. Permittees who find that worker housing emissions were not correctly included in their prior permit actions should contact ADEC for guidance on how to correct the error.

For stationary sources with an Owner Requested Limit (ORL) to avoid a permit classification, the Permittee should assess how worker housing emissions would affect the avoidance strategy of the ORL. Permittees may need to apply to revise their ORL to ensure their limit actually avoids the permit classification.

If you think worker housing is not a support activity

Permittees who believe their worker housing is not a support activity should demonstrate this in their next permit application, along with any resulting changes to their permit. The demonstration must show that less than 50 percent of the beds being provided are dedicated to workers and contractors. To make this demonstration, the Permittee would need to describe:

- where the housing is located in relation to the stationary source;
- who they allow to lodge at their housing;
- the maximum number of beds allocated to employees/contractors;
- the total bed count;
- the resulting ratio of employee/contractor beds to total beds; and
- how the Permittee advertises the availability of lodging, if at all.

Applicants for new stationary sources would need to provide this same type of information in their application to show that their worker housing is not a support activity.

Emissions from insignificant emission units still count toward permit applicability

ADEC recognizes that some worker housing EUs may qualify as "insignificant EUs" under the Title V permit program. However, all emissions at the stationary source, including emissions from insignificant EUs, need to be included when determining a stationary source's permit classification or developing a permit classification avoidance strategy.

Contact us for further information

If you have any questions as to how the information provided in this letter may affect your stationary source, please contact the Anchorage air permit supervisor (Patrick Dunn), or the Juneau air permit supervisor (Jim Plosay). Mr. Dunn may be contacted at: (907) 269-7582, or patrick.dunn@alaska.gov. Mr. Plosay may be contacted at (907) 465-5561, or jim.plosay@alaska.gov.

Sincerely,

John F. Kuterbach

John F. Kuterbach, Manager
Air Permits Program

cc: Jim Plosay, ADEC/APP/Juneau
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