DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Minor Permit: AQ0035MSS07 Preliminary Date – March 16, 2022
Revises Construction Permit No. 9923-AC010, Revision 1

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0035MSS07 to the Permittee listed below.

Permittee:	Tesoro Alaska Company, LLC, Kenai Pipeline Company, and Tesoro Logistics Operations, LLC (Tesoro) 19100 Ridgewood Parkway, San Antonio, TX 78259
Stationary Source:	Kenai Refinery, Kenai Pipeline Terminal (KPL), and Nikiski Terminal
Location:	Kenai Refinery: Lat.: 60° 41' 9.603" N; Long.: 151° 22' 12.993" W Kenai Pipeline: Lat.: 60° 41' 10" N; Long.: 151° 23' 15" W Nikiski Terminal: Lat.: 60° 40' 34" N; Long.: 151° 22' 17" W Mile 21 – 22.5, Kenai Spur Highway Kenai, AK 99611
Project:	Revisions to Sulfur BACT Limits and Incorporation of 2016 Consent Decree Requirements
Permit Contact:	Mike Harper, Environmental Supervisor P.O. Box 3369, Kenai, AK 99611 Phone No.: 907-776-3599 email: mdharper@marathonpetroleum.com

This project is classified under 18 AAC 50.508(6) for revising or rescinding the terms and conditions of a Title I permit.

This permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

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James R. Plosay, Manager
Air Permits Program

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List of Abbreviations and Acronyms

AAAQS ..... Alaska Ambient Air Quality Standards
ADEC ..... Alaska Department of Environmental Conservation
AS ..... Alaska Statutes
AAC ..... Alaska Administrative Code
BACT ..... Best Available Control Technology
CAA ..... Clean Air Act
CFR ..... Code of Federal Regulations
CEMS ..... Continuous Emission Monitoring System
CMS ..... Continuous Monitoring System
Department ..... Alaska Department of Environmental Conservation
EF ..... Emission Factor
EIA ..... United States Energy Information Administration
ELDAR ..... Enhanced Leak Detection and Repair
EU ID ..... Emission Unit Identification
EPA or US EPA ..... United States Environmental Protection Agency
FG ..... Fuel Gas
FGRS ..... Flare Gas Recovery System
LPG ..... Liquefied Petroleum Gas
N/A ..... not applicable
NG ..... natural gas
NSR ..... New Source Review
NNSR ..... Nonattainment New Source Review
NSPS ..... Federal New Source Performance Standards [NSPS as contained in 40 C.F.R. 60]
NESHAPs ..... Federal National Emission Standards for Hazardous Air Pollutants [*NESHAPs* as contained in 40 C.F.R. 61 and 63]
PSD ..... Prevention of Significant Deterioration
PTE ..... Potential to Emit
RG ..... Refinery gas
TAR ..... Technical Analysis Report
TBD ..... To be determined
TS ..... Total Sulfur

Units and Measures

bpd ..... barrels per day
gal/hr ..... gallons per hour
gpm ..... gallons per minute
gal/yr ..... gallons per year
hp ..... horsepower
hr/yr ..... hours per year
lb/gal ..... pounds per gallon
KSCFH ..... Kilo standard cubic feet per hour
kW ..... kilowatts
lb/hr ..... pounds per hour
mg/dscm ..... milligram per dry standard cubic meter
MMBtu/hr ..... million British thermal units per hour
MMlb/d ..... million pound per day
SCFD ..... standard cubic foot per day
SCFH ..... standard cubic foot per hour
tpy ..... tons per year
% ..... percent

Pollutants and Chemical Symbols

CO	Carbon Monoxide
H_2S	Hydrogen Sulfide
HAP	hazardous air pollutant
NOx	Oxides of Nitrogen
O_2	Oxygen
PM-10	Particulate Matter with an aerodynamic diameter not exceeding 10 microns
PM-2.5	Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compound

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to operate the EUs listed in Table 1 in accordance with the terms and conditions of this permit and the minor permit application. Except as noted elsewhere in this permit, the information in Table 1 are for identification purposes only. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – EU Inventory for Kenai Refinery[a]

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Fuel Type	Installation or Modification Date
Kenai Refinery - NSPS Subpart J and Ja Boilers, Heaters, and Flare					
2	H-101B	Crude Heater	165.0 MMBtu/hr	FG/NG[d]	1977/1997
3	H-201	Powerformer Preheater	31.8 MMBtu/hr	FG/NG[d]	1975
4	H-202	Powerformer Preheater	51.0 MMBtu/hr	FG/NG[d]	1975
5	H-203	Powerformer Preheater	27.9 MMBtu/hr	FG/NG[d]	1975
6	H-204	Powerformer Reheater	53.8 MMBtu/hr	FG/NG[d]	1980
7	H-205	Powerformer Reheater	48.8 MMBtu/hr	FG/NG[d]	1980
8	H-401	Hydrocracker Recycle Gas Heater	38.9 MMBtu/hr	FG/NG[d]	1981/1989
9	H-402	Hydrocracker Recycle Gas Heater	38.0 MMBtu/hr	FG/NG[d]	1981/1989
10	H-403N	Hydrocracker Fractionator Reboiler	50.0 MMBtu/hr	FG/NG[d]	1997
11	H-404	Hydrocracker Stabilizer Reboiler	64.4 MMBtu/hr	FG/NG[d]	1981/1989
17	H-704	Natural Gas Supply Heater	2.0 MMBtu/hr	FG/NG[d]	1985
18	H-801	Fired Steam Generator	32.0 MMBtu/hr	FG/NG[d]	1980
19	H-802	Hot Glycol Heater	10.8 MMBtu/hr	FG/NG[d]	1980
20	H-1001	Hydrogen Reformer Furnace	152.3 MMBtu/hr	FG/NG[d]	1981
25	H-1105	SCOT Tail Gas Burner	2.0 MMBtu/hr	NG	1985
27	H-1201/1203	PRIP Adsorber Feed Furnace	10.4 MMBtu/hr	FG/NG[d]	1986
28	H-1202	PRIP Recycle H_2 Furnace	11.2 MMBtu/hr	FG/NG[d]	1986
29	H-1701	Vacuum Tower Heater	91.0 MMBtu/hr	FG/NG[d]	1994/2006
115	H-1601	DDU Charge Heater	20.25 MMBtu/hr	FG	05/2007
116	H-1602	Fractionator Tower Reboiler	23.7 MMBtu/hr	FG	05/2007
119	H-1801	Naptha Splitter Reboiler	50.9 MMBtu/hr	NG/FG	10/2010
42	J-801	Refinery Flare	3.0 MMBtu/hr[b] Purge Gas	NG, FG & Process Upset Gas	1981 (installed) 2010 (modified)
Kenai Refinery - NSPS Subpart GGGa/VVa Process Units					
96	None	Crude Unit	72,000 Bpd	N/A	3/1/69; 2010
97	None	Powerformer	14,500 Bpd	N/A	11/73
98	None	LPG Unit	3,000 Bpd	N/A	11/29/73
99	None	Hydrocracker	12, 500 Bpd	N/A	6/79; 10/97

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Fuel Type	Installation or Modification Date
100	None	Hydrogen Unit	12.8 MMSCF/d	N/A	12/23/82
101	None	Sulfur Recovery Unit (SRU)	26 LTPD	N/A	5/2007
102	None	PRIP Unit	4,400 Bpd	N/A	8/29/85
103	None	DIB Unit	6,000 Bpd	N/A	7/3/93
104	None	Vacuum Unit	25,500 Bpd	N/A	3/06
111	None	Tank farm fugitives	N/A	N/A	N/A
112	None	Refinery fugitives	N/A	N/A	N/A
117	None	Distillate Desulfurization (DDU)	10,000 Bpd	N/A	5/07
128	None	Amine Unit	2.35 MMlb/d	N/A	1983
Kenai Refinery - NSPS Subpart GGGa/VVa Compressors					
126	C-810A	FGR Compressor 1	40,000 scf/hr	N/A	2016
127	C-810B	FGR Compressor 2	40,000 scf/hr	N/A	2016
Kenai Pipeline Company (KPL) – NSPS Subpart GGGa/VVa Component Leaks					
10[c]	Equipment Leaks	Component Leaks	N/A	N/A	N/A
Nikiski Terminal – NSPS Subpart GGGa/VVa Component Leaks					
9[e]	Equipment Leaks	Component Leaks	N/A	N/A	N/A

Notes:

[a] Only the EUs with revised operating limits or other requirements due to this permit appear in Table 1. This permit does not authorize the installation of any new units.

[b] Flare ratings are based on purge rates. EU ID 42's rating of 3 MMBtu/hr (75,000 SCFD) comes from the three pilot gas lines (0.2 MMBtu/hr) and the flare vent headers (average of 2.6 MMBtu/hr). Although 75,000 SCFD is the typical purge rate to prevent oxygen infiltration, additional purge up to approximately 200,000 SCFD is sometimes necessary to prevent freezing.

[c] EU ID 10 (equipment leaks) was added to the inventory for KPL to identify the unit as a specific affected emission source for the purpose of incorporating NSPS Subpart GGGa/VVa requirements.

[d] These emission units are permitted to fire liquefied petroleum gas (LPG), but currently only combust natural gas (NG) and refinery gas (RG).

[e] EU ID 9 of Nikiski Terminal consists of equipment leaks from piping systems used to convey liquids into and out of storage tanks, as well as to load products into tank truck loading rack. These piping systems consist of piping, flanges, valves, pumps, and other connectors that are fugitive sources of VOC emissions subject to NSPS Subpart GGGa/VVa requirements.

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

Section 2 Revisions to Previous Permit Actions

2. The Sulfur BACT limits for Refinery Gas in Conditions 43.4.1, 43.5.2, 45, Exhibit B.E (items 1 and 2 pertaining to Refinery Gas), Exhibit C (Process Heaters SO_2 and H_2S), and Exhibit D.4 of Construction Permit No. 9923-AC010 Revision 1 for the Kenai Refinery are rescinded and replaced by Condition 3 of this Minor Permit AQ0035MSS07.

3. **Fuel Gas (FG)[1] H_2S BACT Limit (NG, LPG, and RG Combined).** The Permittee shall limit the sulfur content of the fuel gas burned at the Kenai Refinery to 162 ppmv H_2S or 230 milligram H_2S per dry standard cubic meter (mg H_2S/dscm) determined on a 3-hour rolling average basis.

3.1. To ensure compliance with the BACT limits in Condition 3, comply with Condition 6 (NSPS Subparts J and Ja) and the applicable NSPS Subpart KKKK SO_2 standard and corresponding MR&R requirements, as applied to affected EUs when burning fuel gas, specified in the applicable operating permit issued for the Kenai Refinery under AS 46.14.130(b) and 18 AAC 50.

[1] For the purposes of this condition, *Fuel Gas (FG)* means a combination of refinery gas (RG), natural gas (NG) and liquefied petroleum gas (LPG) burned at the stationary source.

Section 3 Requirements Mandated by Consent Decree

Requirements for the Kenai Refinery, KPL, and Nikiski Terminal

Enhanced Leak Detection and Repair (ELDAR) Program

4. No later than October 1, 2016, all *covered process units* subject to the equipment leak provisions of 40 C.F.R. Part 60, Subpart GGGa or 40 C.F.R. Part 63, Subpart CC at the Kenai Refinery, KPL, and Nikiski Terminal shall be an "affected facility" for purposes of that standard. The requirements of Subpart GGG shall no longer apply prospectively to the covered process units.[2]

5. NSPS Subpart GGGa/VVa Standards and MR&R Requirements. The Permittee shall comply with the applicable requirements of 40 C.F.R. 60.592a in Subpart GGGa by complying with the applicable standards and associated MR&R requirements set out in 40 C.F.R. §§60.482-1a to 60.487a in Subpart VVa:

5.1. These requirements apply to the affected equipment:

a. *in VOC service* (as defined in 40 C.F.R. 60.481a in Subpart VVa)[3] and *in organic HAP service* (as defined in 40 C.F.R. 63.641 in Subpart CC)[4] located in Kenai Refinery's EU IDs 42, 96 – 104, 111, 112, 117, 119, and 126 – 128, as shown in Table 1; and

b. *in VOC service* (as defined in 40 C.F.R. 60.481a in Subpart VVa), located in KPL (EU ID 10) and in Nikiski Terminal (EU ID 9), as shown in Table 1.

5.2. Monitor, record, and report compliance with the NSPS Subpart GGGa/VVa standards required in Condition 5 in accordance with the applicable operating permit issued for the Kenai Refinery, KPL, and Nikiski Terminal under AS 46.14.130(b) and 18 AAC 50.

Requirements for the Kenai Refinery

NSPS Subparts J and Ja Requirements

6. H_2S Monitoring for the Refinery Flare and Fuel Gas System. By July 1, 2015, the Permittee shall:

6.1. Comply with the applicable H_2S limits and corresponding MR&R requirements of 40 C.F.R. 60.100 – 60.109 Subpart J (for EU IDs 2 through 11, 17 through 20, 25, 27 through 29, 101, 115, and 116), 40 C.F.R. 60.100a – 60.109a Subpart Ja (for EU

[2] As of issuance of this permit, all "covered process units" at the Kenai Refinery, KPL, and Nikiski Terminal have become subject to NSPS Subpart GGGa; therefore, they are no longer subject to NSPS Subpart GGG.

[3] As defined in 40 C.F.R. 60.481a (Subpart VVa), *in VOC service* means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. The provisions of §60.485a(d) specify how to determine that a piece of equipment is not in VOC service.

[4] As defined in 40 C.F.R. 63.641 (Subpart CC), i*n organic hazardous air pollutant service* or *in organic HAP service* means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP as determined according to the provisions of §63.180(d) of this part and table 1 of this subpart. The provisions of §63.180(d) also specify how to determine that a piece of equipment is not in organic HAP service.

IDs 42 and 119), and the associated general requirements of NSPS 40 C.F.R. 60.1 through 60.19 Subpart A applicable to the Kenai Refinery Flare (EU ID 42) and Fuel Gas System (EU IDs 2 through 11, 17 through 20, 25, 27 through 29, 101, 115, 116, and 119), as specified in the applicable operating permit issued for the Kenai Refinery under AS 46.14.130(b) and 18 AAC 50;

6.2. Install, calibrate, maintain and operate a high-range H_2S or Total Sulfur (TS) Continuous Monitoring System (CMS)[5] for the Refinery Flare (EU ID 42) and Fuel Gas System (EU IDs 2 through 11, 17 through 20, 25, 27 through 29, 101, 115, 116, and 119) in accordance with the following requirements:

a. The TS CMS monitor *(AI-8716)* for the flare system, EU ID 42, must be capable of satisfying the span value requirements set forth in NSPS Subpart Ja 40 C.F.R. §60.107a(e)(1)(i); and

b. The H_2S CMS monitor (*AI-7408)* for the fuel gas system (EU IDs 2 through 11, 17 through 20, 25, 27 through 29, 101, 115, 116, and 119) must be capable of recording a range up to 3,000 ppm H_2S; and

6.3. Continuously operate the upgraded CMS monitors in accordance with 40 C.F.R. 60.13(e) and the applicable operating permit issued for the Kenai Refinery under AS 46.14.130(b) and 18 AAC 50.

Flaring Requirements

Instrumentation and Monitoring Systems for Flares

7. Evaluating and Upgrading or Replacing, as Necessary, Meters Measuring Sweep Gas and Purge Gas Volumetric Flow Rates. By no later than April 1, 2016, the Permittee shall complete an evaluation of all meters that measure the flow of Sweep Gas and Purge Gas to EU ID 42 *[J-801 flare]* and shall upgrade or replace, as necessary, each such meter in order to ensure an acceptable level of control overflow. Under no circumstances may the Permittee implement any such measure later than April 1, 2017, the due date for installation[6] of flare monitoring system.

8. Installation and Operation of Flare Monitoring Systems. By no later than April 1, 2017, the Permittee shall install, operate, calibrate, and maintain a monitoring system[7] capable of continuously measuring, calculating, and recording the Vent Gas Volumetric

[5] The one-time requirement to upgrade the H_2S or TS CMS has been met (i.e., the installation of a high-range CMS, apart from the low range-CMS required under Subparts J and Ja), demonstrated, and reported in a semi-annual report by the Permittee, hence not included in Condition 6.2.

[6] The Permittee has installed an ultrasonic flow monitor with temperature and pressure correction on EU ID 42 in September 2016, prior to the required installation date of April 1, 2017. To improve flow monitoring and the associated combustion efficiency controls for Assist Air and Supplemental Gas, the refinery installed a new Vent Gas OSI flowmeter in February 2018. The new OSI optical flow meter serves as the refinery's primary Vent Gas flow meter.

[7] The Permittee has installed an ultrasonic flow monitor with temperature and pressure correction on EU ID 42 in September 2016, prior to the required installation date of April 1, 2017. To improve flow monitoring and the associated combustion efficiency controls for Assist Air and Supplemental Gas, the refinery installed a new Vent Gas OSI flowmeter in February 2018. The new OSI optical flow meter serves as the refinery's primary Vent Gas flow meter.

Flow Rate in the EU ID 42 *[J-801 flare]* header or headers that feed the flare as well as any Supplemental Gas used.

8.1. Different flow monitoring methods may be used to measure different gaseous streams that make up the Vent Gas provided that the flow rates of all gas streams that contribute to the Vent Gas are determined. The Permittee shall:

a. Install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of Assist Air used with EU ID 42 *[J-801 flare]*[8]; or

b. Continuously monitor Assist Air flow rates by continuously monitoring fan speed or power and using fan curves.

8.2. The flow rate monitoring systems must be able to correct for the temperature and pressure of the system and output parameters in Standard Conditions.

8.3. Mass flow monitors may be used for determining volumetric flow rate of the Vent Gas. The mass Vent Gas flow rate can be converted to volumetric Vent Gas flow rate at Standard Conditions using Equation 1 (APPENDIX II, *Equation 6*) below:

Equation 1 $$Q_{vol} = \frac{Q_{mass} * 385.3}{MWt}$$

Where

Q_{vol} = Volumetric flow rate, standard cubic feet per second

Q_{mass} = Mass flow rate, pounds per second

MW_t = Molecular weight of the gas at the flow monitoring location, pounds per pound − mole

385.3 = Conversion factor, standard cubic feet per pound − mole

8.4. Mass flow monitors may be used for determining volumetric flow rate of Assist Air. Use Equation 1 to convert mass flow rates to volumetric flow rates of Assist Air. Use a molecular weight of 29 pounds per pound-mole for Assist Air.

8.5. Continuous pressure/temperature monitoring system(s) and appropriate engineering calculations may be used in lieu of a continuous volumetric flow monitoring system provided the molecular weight of the gas is known. For Assist Air, use a molecular weight of 29 pounds per pound mole. For Vent Gas, molecular weight must be determined using compositional analysis as specified in Condition 9.

9. Flare Vent Gas Composition Monitoring. The Permittee shall determine the concentration of individual components in the Vent Gas using either one of the methods described in Conditions 9.1 or 9.2, to assess compliance with the operating limits in Condition 24.1 and, if applicable, Conditions 24.2 and 25. Alternatively, the Permittee may elect to directly monitor the Net Heating Value of the Vent Gas (NHVvg) following the method described in Condition 9.3, and, if desired, may directly measure the hydrogen

[8] EU ID 42 *[J-801 flare]* uses perimeter assist air only; thus, the perimeter assist air volumetric flow is equal to the volumetric flow rate of assist air.

concentration in the Vent Gas following the method described in Condition 9.4 below. The Permittee may elect to use different monitoring methods for different gaseous streams that make up the Vent Gas provided the composition or Net Heating Value of all gas streams that contribute to the Vent Gas are determined. Acceptable Methods are:

9.1. Net Heating Value by Gas Chromatograph. Except as provided in Conditions 9.5 and 9.6 below, the Permittee shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring (i.e., at least once every 15-minutes), calculating, and recording the individual component concentrations present in the Vent Gas.

9.2. Grab Sampling System. Except as provided in Conditions 9.5 and 9.6 below, the Permittee shall install, operate, and maintain a grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours. Subsequent compositional analysis of the samples must be performed according to Method 18 of 40 C.F.R. Part 60, Appendix A-6, ASTM D6420-99 (Reapproved 2010), ASTM D1945-03 (Reapproved 2010), ASTM D1945-14 or ASTM UOP539-12.

9.3. Net Heating Value By Calorimeter. Except as provided in Conditions 9.5 and 9.6 below, the Permittee shall install, operate, calibrate, and maintain a calorimeter capable of continuously measuring, calculating, and recording NHVvg at Standard Conditions. When installed, the Net Heating Value calorimeter shall meet or exceed the applicable specifications and Calibration Standards and Quality Assurance requirements set forth in APPENDIX V.

9.4. Hydrogen Concentration Monitoring. If the Permittee uses a continuous Net Heating Value calorimeter according to Condition 9.3 above, the Permittee may, at its discretion, install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the Vent Gas.

9.5. Monitoring Not Required for Pipeline Quality Natural Gas. Direct compositional monitoring or Vent Gas Net Heating Value calorimeter is not required for purchased ("pipeline quality") natural gas streams. The Net Heating Value of purchased natural gas streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the Net Heating Value of any purchased natural gas stream can be assumed to be 920 BTU/scf.

9.6. The Permittee may also assume a constant molecular weight and composition that have been demonstrated for the Sweep Gas, Purge Gas, or Supplemental Gas that is representative of the molecular weight and composition of natural gas, fuel gas or other appropriate gas supplied at EU ID 42 *[J-801 flare]*.

10. Video Camera. The Permittee shall install and operate a video camera capable of recording, in digital format, whether a flame or Smoke Emissions are present at EU ID 42 *[J-801 flare]* no later than April 1, 2017.[9] It is not a violation of this Condition, however, if the video camera(s) cannot discern the Combustion Zone (as defined in APPENDIX I)

[9] The video camera was installed in March 2017.

and/or any Smoke Emissions (as defined in APPENDIX I) due to weather conditions, such as fog or snow, provided that records are created and retained.

11. Additional Air-Assisted Flare Requirements. The Permittee shall undertake the following measures for EU ID 42 *[J-801 flare]* by no later than October 1, 2017:

11.1. Install a flow meter in order to determine the Vent Gas volumetric flow rate to air-assisted flares. The air flow rate shall be determined from the fan speeds or measured on the Assist Air blowers;[10]

11.2. Continue to operate a variable speed motor on the flares' Assist Air blowers; and

11.3. Install a control system[11] at the Kenai Refinery that will automate the control of the variable speed motor on EU ID 42's *[J-801 flare's]* Assist Air blowers to enable the Permittee to maintain the net heating value dilution parameter (NHVdil) limit in Condition 24.2.

Specifications and QA/QC Requirements

12. The Permittee shall comply with the following instrumentation and monitoring systems specifications and QA/QC requirements:

12.1. The instrumentation and monitoring systems identified in Conditions 7 through 11 shall be able to produce and record data measurements and calculations for each parameter at the following time intervals as applicable to the instrumentation and monitoring system, as shown in Table 2:

Table 2 – Instrumentation and Monitoring Systems Specifications

Instrumentation and Monitoring System	Recording and Averaging Times
Vent Gas flow; Vent Gas average molecular weight; Pilot Gas flow (if installed)	Measure continuously and record 15-minute Block Averages.
Video camera	Record at a rate of no less than 4 frames per minute.
Net heating value by gas chromatograph	Complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute Block Average Period.
Net heating value by calorimeter	Measure continuously and record 15- minute Block Averages.

a. Nothing in this Condition shall prohibit the Permittee from setting up process control logic that uses different averaging times from those in this table provided that the recording and averaging times in this table are available and used for determining compliance.

12.2. **QA/QC Requirements.** For EU ID 42 *[J-801 flare],* the applicable instrumentation and monitoring systems required per Conditions 7 through 12.1 shall meet or exceed the equipment and instrumentation technical specifications and quality assurance/quality control (QA/QC) requirements set forth in APPENDIX V.

[10] Tesoro uses the fan speeds to determine the air flow rate.
[11] The automatic control system was commissioned on September 20, 2017.

12.3. **Operation and Maintenance.** The Permittee shall operate each of the instruments and monitoring systems as required in Conditions 7 through 12.1 on a continuous basis when EU ID 42 *[J-801 flare]* is In Operation and Capable of Receiving Sweep (as defined in APPENDIX I), Supplemental, and/or Waste Gas, except for the following periods:

a. Malfunction of a monitoring system, for a monitoring system needed to meet the requirement(s);

b. Repairs associated with monitoring system malfunctions, for a monitoring system needed to meet the requirement(s); and

c. Required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

13. Exception for Monitoring System Downtime. A failure to comply with the work practices or standards in Conditions 22, 24.1, 24.2, or 27 shall not constitute a violation of such work practice or standard if the noncompliance results from downtime of monitoring systems due to any of the periods specified in Conditions 12.3.a through 12.3.c; provided, however, that this exception shall no longer be applicable if the activities listed in Conditions 12.3.a through 12.3.c exceed 5% of time that EU ID 42 *[J-801 flare]* is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period for any instrument. The calculation of monitoring system downtime shall be made in accordance with 40 C.F.R. 60.13(h)(2) and Paragraph VIII of APPENDIX V.

13.1. If the excepted periods in Conditions 12.3.a through 12.3.c above exceed 5% of the time that the flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period, the Permittee shall be entitled to assert that any period of downtime was justified under the circumstances and/or due to Force Majeure (as defined in APPENDIX I) and should not be counted as part of the 5% period of instrumentation and monitoring system downtime. Nothing in this Condition is intended to prevent the Permittee from claiming a Force Majeure defense to any period of instrumentation and/or monitoring system downtime. Nothing in this Condition supersedes or replaces the monitoring requirements, including operation, maintenance, and quality assurance/quality control requirements, of 40 C.F.R. Part 60, Subpart Ja. All such requirements shall apply in accordance with the terms set forth in 40 C.F.R. Part 60, Subpart Ja.

Flare Gas Recovery System (FGRS)

14. Capacity and Start-Up Dates. By no later than October 1, 2016[12] the Permittee shall complete installation and commence operation of a Flare Gas Recovery System (FGRS) with a minimum operating design capacity of 80 kilo standard cubic feet per hour (KSCFH) for EU ID 42 *[J-801 flare]*. The FGRS will consist of a minimum of two compressors with minimum operating capacities of 40 KSCFH each.

[12] Tesoro has installed the FGRS and began its operation on September 21, 2016. The minimum operating design capacity of the FGRS meets the 80 KSCFH requirement.

15. General Operation Requirements. The Permittee shall operate the FGRS in a manner to minimize waste gas to EU ID 42 *[J-801 flare]* while ensuring safe refinery operations. The Permittee also shall operate the FGRS consistent with good engineering and maintenance practices and in accordance with its design and the manufacturer's specifications.

16. Requirements Related to Compressors Being Available for Operation and/or In Operation. By no later than April 1, 2017, the Permittee shall comply with the following requirements when Potentially Recoverable Gas is being generated:

16.1. For each FGRS at the Kenai Refinery, the Permittee shall have:

a. one compressor Available for Operation and/or In Operation 98% of the time; and

b. two compressors Available for Operation and/or In Operation 95% of the time.

16.2. Period to Be Used for Computing Percentage of Time. For purposes of calculating compliance with the 95% and the 98% of time that a compressor or group of compressors shall be Available for Operation and/or In Operation, as required by Condition 16.1, the period to be used shall be an 8,760-hour Rolling Sum, rolled hourly, using only hours when Potentially Recoverable Gas was generated during all or part of the hour but excluding hours for flows that could not have been prevented through reasonable planning and were in anticipation of or caused by a natural disaster, act of war or terrorism, or external power loss. When no Potentially Recoverable Gas was generated during an entire hour, then that hour shall not be used in computing the 8,760-hour Rolling Sum.

16.3. Periods of maintenance on and subsequent restart of the equipment within the FGRS that is shared by all compressors (for example, the liquid seal, the knock-out drum, valves), such that the entire FGRS shall be shut down in order to undertake the maintenance, may be included in the amount of time that a compressor is Available for Operation; provided however, that these periods shall not exceed 1,344 hours in a five-year Rolling Sum Period, rolled daily. The Permittee shall use best efforts to schedule these maintenance activities during a scheduled turnaround of the flaring process units venting to EU ID 42 *[J-801 flare]*. To the extent it is not practicable to undertake these maintenance activities during a Scheduled Turnaround, the Permittee shall use best efforts to minimize the generation of waste gas during such periods.

Limitations on Flaring:

17. Initial Limits. The Permittee shall comply with the following limits[13] on flaring of waste gas in EU ID 42 *[J-801 flare]*:

[13] The limitations set forth in Condition 17 were calculated using the equations set forth in Conditions 18.1.d(i)(A) and 18.1.d(i)(B); APPENDIX VII sets forth the actual calculation. The crude capacity used in the calculation was taken from the "Total Operable" atmospheric crude oil distillation capacity, in barrels per calendar day, found in Part 5, Code 401, of the Form EIA-820 that the Permittee submitted to the U.S. Energy Information Administration ("EIA") for EIA's report dated June 25, 2014. A copy of that Form is included in APPENDIX VII. The "*Refinery Complexity*" and "*Industry Avg Complexity*" were calculated pursuant to the methodology set forth in APPENDIX VI.

a. 30-day rolling average of 231,354 standard cubic feet per day (SCFD) by May 1, 2017, and

b. 365-day rolling average of 154,236 SCFD by April 1, 2018.

17.1. The rolling average period shall include only the prior 30 days or 365 days, as applicable, when EU ID 42 *[J-801 flare]* was In Operation.

17.2. Each exceedance of the 30-day or 365-day rolling average limits in Conditions 17.a and 17.b shall constitute one day of violation. An exceedance of either or both of the limits shall not prohibit ongoing refinery operations.

18. Requesting an Increase in the Limit. Once per calendar year, the Permittee may submit a request to EPA to increase the limitations on flaring set forth in Condition 17.

18.1. The Permittee may request an increase in the limit(s) and EPA will approve[14] such an increase, only if:

a. The request is based on changes in crude capacity and/or complexity that were not reflected in the U.S. Energy Information Administration (EIA) reports as of June 25, 2014;

b. The changes are or will be permitted by the Department; and

c. The changes in crude capacity and/or complexity result in new limit(s) that are at least 20% higher than the limits set forth in Condition 17.

d. In any such request, the Permittee shall propose

(i) new limit(s) (hereafter referred to as "New Limit(s) Based on Projections") based upon the following equations:

(A) the refinery-wide, 30-day Rolling Average Limit:

Equation 2 Refinery Flaring ≤ 750,000 SCFD * *Refinery Crude Cap*/100,000 bpd * *Refinery Complexity/ Industry Avg Complexity*

(B) the refinery-wide, 365-day Rolling Average Limit:

Equation 3 Refinery Flaring ≤ 500,000 SCFD * *Refinery Crude Cap.*/100,000 bpd * *Refinery Complexity/ Industry Avg Complexity*

18.2. For purposes of the equations in Conditions 18.1.d(i)(A) and 18.1.d(i)(B) above, the following shall apply:

a. The items in italics are variables that will change over time.

b. The Permittee's crude capacity shall be determined as follows:

[14] The EPA shall evaluate any request under Condition 18 on the basis of consistency with Conditions 18.1 and 18.2.

(i) If the modification does not affect the crude capacity, the Atmospheric Crude Oil Distillation Capacity, in barrels per day, that the refinery reported under "Total Operable" capacity on Part 5, Code 401, of the Applicable Form EIA-820; to the extent that the "Parts" or "Codes" on form EIA-820 change in the future, the intent of the Parties is that the "Parts" and "Codes" of future forms that correspond most closely to those found on the Form EIA-820 for its report dated June 25, 2014 will be used; or

(ii) If the modification does affect crude capacity, the projected, new capacity set forth in the air permit application(s) for the modification after July 18, 2016.

c. The Permittee's Complexity shall be calculated in accordance with *Equation 1* of APPENDIX VI.

d. The Permittee shall certify the accuracy of the projected crude capacity and/or flaring process unit capacities used to support the calculations.

e. The Industry Average Complexity shall be calculated in accordance with *Equation 2* of APPENDIX VI.

18.3. Nothing in this condition shall be construed to relieve the Permittee of an obligation to evaluate, under applicable PSD and NNSR requirements, an increase in a refinery-wide limit on flaring.

18.4. The new limit(s) based on projections shall take effect, if ever, beginning on the later of the date that EPA approves the request or a dispute is resolved in the Permittee favor or the date(s) specified in the modification permit(s).

18.5. In the event that the Permittee amend, modify or withdraw the air permit application(s) that is/are the basis for the new limit(s) based on projections requested pursuant to Condition 18 in a manner that affects the limit(s) calculation(s), the Permittee shall, within fifteen (15) Days of amending, modifying, or withdrawing its air permit application(s), revise or withdraw its request under Condition 18.

19. Consequences of a Mistake in Projected Capacities. By no later than ninety (90) days after the startup of the permitted modifications, the Permittee shall determine whether the projected "Refinery Crude Capacity" or the projected capacities for new or modified units that the Permittee relied upon pursuant to Conditions 18.2.b and 18.2.c, respectively, were or are different from the actual capacities that the Permittee have reported or will report to the EIA or the Oil & Gas Journal after the Startup of the permitted modification. If there are differences, the Permittee shall re-calculate the flaring limitation(s) using the actual capacities that the Permittee have reported or will report to the EIA or the Oil & Gas Journal (hereafter referred to as "New Limit(s) Based on Actuals").

19.1. If the new limit(s) based on actuals that the Permittee calculate under Condition 19 is/are greater than the new limit(s) based on projections that the Permittee calculated under Condition 18, then the Permittee shall either:

a. take no further action, the new limits(s) based on projections shall remain in effect; or

b. may elect to submit for EPA approval, a revised, recalculated new limit(s) based on actuals to EPA; after submission to EPA, the Permittee shall secure EPA's approval of the new limit(s) based on actuals before they become effective.

19.2. If the new limit(s) based on actuals that the Permittee calculates under Condition 19.1.b is/are less than the new limit(s) based on projections that the Permittee calculated under Condition 18, then by no later than ninety (90) Days after the startup of the permitted modifications, the Permittee shall:

a. commence complying with the new limit(s) based on actuals calculated under Condition 19.1.b; and

b. submit the revised, recalculated new limit(s) based on actuals to the EPA. After submission to EPA, the Permittee shall consult with EPA about the new limit(s) based on actuals.

20. Meaning and Calculation of "Waste Gas Flow" for Purposes of the Limitation on Flaring. For purposes of the meaning and calculation of "Waste Gas Flow" in the limitations on flaring in Conditions 17 and 18 and any revised limitations on flaring developed, the following shall apply:

20.1. To the extent that the Permittee has instrumentation capable of measuring the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) in the Waste Gas, the contribution of all measured flows of any of these elements/compounds may be excluded from the Waste Gas flow rate calculation.

20.2. Waste Gas flows during all periods (including but not limited to normal operations and periods of Startup, Shutdown, Malfunction, process upsets, relief valve leakages, power losses due to an interruptible power service agreement, and emergencies arising from events within the boundaries of the refinery) shall be included. Waste Gas flows that could not be prevented through reasonable planning and are caused by a natural disaster, act of war or terrorism, or External Power Loss may be excluded from the calculation of flow rate.

Flare (EU ID 42) Emissions Standards, Work Practice, and Monitoring Requirements

21. Combustion Efficiency Requirements. The Permittee shall comply with the following combustion efficiency requirements at EU ID 42 *[J-801 flare]*:

21.1. Operation During Waste Gas Venting. By no later than April 1, 2016, the Permittee shall operate EU ID 42 *[J-801 flare]* at all times when Waste Gas may be vented to it.

21.2. Flare Combustion Efficiency 96.5%. By no later than October 1, 2017, the Permittee shall operate EU ID 42 *[J-801 flare]*, with a minimum of a 96.5% Combustion Efficiency, as calculated in APPENDIX II, *Equation 1*, at all times when Waste Gases are vented to the flare. To demonstrate continuous compliance

with the applicable combustion efficiency requirement, the Permittee shall operate EU ID 42 *[J-801 flare]* within the range of relevant operating parameters set forth in Conditions 24.1 and 24.2.

a. The requirements of Conditions 21.2, 24.1, and 24.2 are not applicable to EU ID 42 *[J-801 flare]* when the only gases being vented to the flare are Pilot Gas and/or Purge Gas. Pilot Gas and Purge Gas will be considered to be the only gases being vented to EU ID 42 *[J-801 flare]* if the following conditions are satisfied for the liquid seal drum that is part of the FGRS associated with the flare:

(i) For the liquid seal drum associated with EU ID 42 *[J-801 flare]*, the pressure difference between the inlet pressure and outlet pressure is less than the liquid seal pressure as set by the static head of liquid between the opening of the dip tube in the drum and the level-setting weir in the drum;

(ii) For the liquid seal drum associated with EU ID 42 *[J-801 flare]*, the liquid level in the drum is at the level of the weir; and

(iii) Downstream of the seal drum associated with EU ID 42 *[J-801 flare]* there is no flow of Supplemental Gas directed to the flare.

b. As an alternative to Condition 21.2.a above, for a flare which does not have a weir, Pilot Gas and Purge Gas will be considered to be the only gases being vented to those flares if the Vent Gas flow meter indicates a flow rate of less than 0.2 feet/second based on a 15-minute Block Average

22. Pilot Flame Presence. By January 30, 2019, the Permittee shall operate EU ID 42 *[J-801 flare]* with a pilot flame present when EU ID 42 *[J-801 flare]* is in operation. The flame presence standard is not met if, during any 15-minute block, there is at least one minute where no pilot flame is present when Vent Gas is routed to EU ID 42 *[J-801 flare].*

22.1. The Permittee shall continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present.

23. No Visible Emissions. By January 30, 2019, the Permittee shall

23.1. specify the smokeless design capacity of EU ID 42 *[J-801 flare]* and operate with no Visible Emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, when the Vent Gas flow rate is less than the smokeless design capacity of EU ID 42 *[J-801 flare]*;

23.2. monitor for Visible Emissions from EU ID 42 *[J-801 flare]*, while the unit is in operation, as follows:

a. conduct an Initial Visible Emissions observation using Method 22 at 40 C.F.R. Part 60, Appendix A-7 for a period of 2 hours;

b. conduct subsequent Visible Emissions observations using either Condition 23.2.b(i) or Condition 23.2.b(ii):

(i) at least once per Day, the Permittee shall conduct Visible Emissions observations using Method 22 at 40 C.F.R. Part 60, Appendix A-7 for a period of 5 minutes;

(A) if, at any time, the Permittee sees Visible Emissions, even if the minimum required daily Visible Emissions monitoring has already been performed, the Permittee shall immediately begin an observation period of 5 minutes using Method 22 at 40 C.F.R. Part 60, Appendix A-7;

(B) if Visible Emissions are observed for more than one continuous minute during any 5-minute observation period, the Permittee shall extend the observation period using Method 22 at 40 C.F.R. Part 60, Appendix A-7 to 2 hours or until 5-minutes of No Visible Emissions are observed; or

(ii) use a video surveillance camera to continuously record (at least one frame every 15 seconds with time and date stamps) images of the flare flame and a reasonable distance above the flare flame at an angle suitable for Visual Emissions observations. The Permittee must provide real-time video surveillance camera output to the control room or other continuously manned location where the camera images may be viewed at any time; and

23.3. record and report any instances where Visible Emissions are observed, in accordance with Conditions 23.2.a and 23.2.b(i), for more than 5 minutes during any 2 consecutive hours, including the date and time of the 2-hour period and an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible.

24. Net Heating Value Standards for EU ID 42 *[J-801 flare]*. By no later than October 1, 2017, for EU ID 42 *[J-801 flare]*, the Permittee shall comply with the following operational limits and monitoring requirements when gases aside from Pilot Gas and/or Purge Gases are routed to the flare:

24.1. Net Heating Value of Combustion Zone Gas (NHVcz). The Permittee shall operate EU ID 42 *[J-801 flare]* to maintain the NHVcz at or above 270 British Thermal Units per standard cubic feet (BTU/scf) determined on a 15-minute Block Average Period basis when gases aside from Pilot Gas and/or Purge Gas are routed to the flare. The Permittee shall determine the NHV_{cz} as specified in Condition 24.1.a or 24.1.b, as applicable, as follows:

a. Direct Calculation Method. Except as specified in Condition 24.1.b, determine the 15-minute Block Average NHVcz based on the 15-minute Block Average Vent Gas and assist gas flow rates using Equation 4 (APPENDIX III, *Equation 3*) below. For periods when there is no Premix Assist Air flow, NHVcz = NHVvg.

Equation 4 $$NHV_{cz} = \frac{(Q_{vg} * NHV_{vg})}{(Q_{vg} + Q_s + Q_{a,premix})}$$

Where:

NHV_{cz} = Net heating value of Combustion Zone Gas, BTU/scf.

NHV_{vg} = Net heating value of Vent Gas for the 15-minute Block Period, BTU/scf.

Q_{vg} = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.

Q_s = Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.

b. Feed Forward Calculation Method. When monitoring gas composition or net heating value in a location representative of the cumulative Vent Gas stream, and when directly monitoring Supplemental Gas flow to EU ID 42 *[J-801 flare]*, the Permittee shall determine the 15-minute Block Average NHVcz using the Equation 5 (APPENDIX III, *Equation 4*) below:

Equation 5 $$NHV_{cz} = \frac{(Q_{vg} - Q_{NG2} + Q_{NG1}) * NHV_{vg} + (Q_{NG2} - Q_{NG1}) * NHV_{NG}}{(Q_{vg} + Q_s + Q_{a,premix})}$$

Where:

NHVcz = Net heating value of Combustion Zone Gas, BTU/scf.

NHV_{vg} = Net heating value of Vent Gas for the 15-minute Block Period, BTU/scf.

Q_{vg} = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.

Q_{NG2} = Cumulative volumetric flow of Supplemental Gas to the flare during the 15-minute Block Period, scf.

Q_{NG1} = Cumulative volumetric flow of Supplemental Gas to the flare during the previous 15-minute Block Period, scf. For the first 15-minute Block Period of an event, use the volumetric flow value for the current 15-minute Block Period, i.e., QNG1=QNG2.

NHV_{NG} = Net heating value of Supplemental Gas to the flare for the 15-minute Block Period determined according to the requirements in Condition 9.5 BTU/scf.

Q_s = Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.

24.2. Net Heating Value Dilution Parameter (NHVdil), Perimeter Assist Air. The Permittee shall operate EU ID 42 *[J-801 flare]* to maintain the NHVdil at or above 22 British Thermal Units per square foot (BTU/ft^2) determined on a 15-minute

Block Average basis when gases aside from Pilot Gas and/or Purge Gas are routed to the flare. The Permittee shall determine the NHV_{dil} only during periods when the Perimeter Assist Air is used and as specified in Condition 24.2.a or 24.2.b, as applicable, as follows:

a. Direct Calculation Method. Except as specified in Condition 24.2.b, determine the 15-minute Block Average NHVdil based on the 15-minute Block Average Vent Gas and Perimeter Assist Air flow rates using Equation 6 (APPENDIX III, *Equation 5*) below. For 15-minute Block Periods when there is no cumulative volumetric flow of Perimeter Assist Air, the 15-minute Block Average NHVdil parameter does not need to be calculated.

Equation 6 $$NHVdil = \frac{(Q_{vg} * Diam * NHV_{vg})}{(Q_{vg} + Q_s + Q_{a.premix} + Q_{a.perimeter})}$$

Where:

NHV_{dil} = Net heating value dilution parameter, BTU/ft2.

NHV_{vg} = Net heating value of Vent Gas determined for the 15 − minute Block Period, BTU/scf.

Q_{vg}: = Cumulative volumetric flow of Vent Gas during the 15 − minute Block Period, scf.

Diam: = Effective diameter of the unobstructed cross sectional area of the flare tip for Vent Gas flow, ft.

Q_s: = Cumulative volumetric flow of Total Steam during the 15 − minute Block Period, scf.

$Q_{a.\,premix}$: = Cumulative volumetric flow of Premix Assist Air during the 15 − minute Block Period, scf.

$Q_{a.\,perimeter}$ = Cumulative volumetric flow of Perimeter Assist Air during the 15 − minute Block Period, scf.

b. Feed-Forward Calculation Method. When monitoring gas composition or net heating value in a location representative of the cumulative Vent Gas stream, and when directly monitoring Supplemental Gas flow additions to EU ID 42 *[J-801 flare]*, the Permittee shall determine the 15-minute Block Average NHVdil using Equation 7 (APPENDIX III, *Equation 6*) below. For 15-minute Block Periods when there is no cumulative volumetric flow of Perimeter Assist Air, the 15-minute Block Average NHV_{dil} parameter does not need to be calculated.

Equation 7 $$NHV_{dil} = \frac{[(Q_{vg} - Q_{NG2} + Q_{NG1}) * NHV_{vg} + (Q_{NG2} - Q_{NG1}) * NHV_{NG}] * Diam}{(Q_{vg} + Q_s + Q_{a.premix} + Q_{a.perimeter})}$$

Where:

NHV_{dil} = Net heating value dilution parameter, BTU/ft2.

NHV_{vg} = Net heating value of Vent Gas determined for the 15 − minute Block Period, BTU/scf.

Q_{vg} = Cumulative volumetric flow of Vent Gas during the 15 − minute Block Period, scf

Q_{NG2} = Cumulative volumetric flow of Supplemental Gas to the flare during the 15 − minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of Supplemental Gas to the

flare during the previous 15 − minute block period, scf.
For the first 15 − minute Block Period of an event, use the period, i. e. , QNG1 = QNG2.

NHV_{NG} = Net heating value of Supplemental Gas to the flare for the 15 − minute Block Period determined according to the requirements in Condition 9.5 , BTU/scf.

Diam = Effective diameter of the unobstructed cross sectional area of the flare tip for Vent Gas flow, ft.

Q_S: = Cumulative volumetric flow of Total Steam during the 15 − minute Block Period, scf.

$Q_{a.\,premix}$: = Cumulative volumetric flow of Premix Assist Air during the 15 − minute Block Period, scf.

$Q_{a.\,perimeter}$ = Cumulative volumetric flow of Perimeter Assist Air during the 15 − minute Block Period, scf.

25. Flare Tip Velocity (Vtip). By January 30, 2019, for EU ID 42 *[J-801 flare]*, provided that the appropriate monitoring systems are in place, whenever the Vent Gas flow rate is less than the smokeless design capacity of the flare, the Permittee shall comply with either of the methods described in Condition 25.1 or Condition 25.2:

25.1. Except as provided in Condition 25.2, the actual Vtip must be less than 60 feet per second. The Permittee shall monitor Vtip using the procedures specified in Condition 25.4 below.

25.2. Vtip must be less than 400 feet per second and also less than the maximum allowed flare tip velocity (Vmax) as calculated according to the following equation (APPENDIX II, *Equation 5*):

Equation 8 $\text{Log}_{10}\, V_{max} = (NHV_{vg} + 1{,}212)/850$

Where:

V_{max}: Maximum allowed flare tip velocity, ft/sec

NHV_{vg}: Net heating value of Vent Gas, BTU/scf, as determined by equations listed in Condition 25.3,

1,212: Constant.

850: Constant.

25.3. The Permittee shall monitor Vtip using the procedures specified in Condition 25.4 below and monitor gas composition and determine NHVvg using the procedures specified in Condition 9 and the following 9 and the following equations (from APPENDIX III, *Equations 1 and 2*):

Equation 9 $NHVvg = \sum_{i=1}^{n}(xi * NHVi)$

Where:

NHV_{vg} = Net heating value of Vent Gas, BTU/scf.

i	=	Individual component in Vent Gas.
n	=	Number of components in Vent Gas.
x_i	=	Concentration of component i in Vent Gas, volume fraction.
NHV_i	=	Net heating value of component i according to Table 1 to APPENDIX III, BTU/scf. If the component is not specified in Table 1 to APPENDIX III, the heats of combustion may be determined using any published values where the net enthalpy per mole of offgas is based on combustion at 25 °C and 1 atmosphere (or constant pressure) with offgas water in the gaseous state, but the standard temperature for determining the volume corresponding to one mole of Vent Gas is 20° C.

Equation 10 $NHVvg = NHVmeasured + 938xH2$

Where:

NHV_{vg}	=	Net heating value of Vent Gas, BTU/scf.
$NHV_{measured}$	=	Net heating value of Vent Gas stream as measured by the continuous net heating value calorimeter, BTU/scf.
X_{H2}	=	Concentration of hydrogen in Vent Gas at the time the sample was input into the net heating value calorimeter, volume fraction.
938	=	Net correction for the measured heating value of hydrogen (1,212 – 274), BTU/scf.

25.4. *Calculation Methods for Cumulative Flow Rates and Determining Compliance with Vtip Operating Limits.* The Permittee shall determine Vtip on a 15-minute Block Average basis according to the following requirements:

a. The unobstructed cross sectional area of the flare tip is the total tip area that Vent Gas can pass through. This area does not include any stability tabs, stability rings, and Upper Steam or air tubes because Vent Gas does not exit through them.

b. The Permittee shall determine the cumulative volumetric flow of Vent Gas for each 15-minute Block Average Period using the data from the continuous flow monitoring system required in Condition 7 according to the following requirements as applicable.

(i) Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute Block Average flow volumes.

(ii) If continuous pressure/temperature monitoring system(s) and engineering calculations are used as allowed under Condition 8.4, the Permittee shall, at a minimum, determine the 15-minute Block Average temperature and pressure from the monitoring system and use those values to perform the engineering calculations to determine the cumulative flow over the 15-minute Block Average period. Alternatively, the Permittee may divide the 15-minute Block Average Period into equal duration subperiods (e.g., three 5-minute periods) and determine the average temperature and pressure for each subperiod, perform engineering calculations to determine the flow for each subperiod, then add the volumetric flows for the subperiods to determine the cumulative.

c. The 15-minute Block Average Vtip shall be calculated using the volumetric flow of Vent Gas for the 15-minute Block Average Period, as in the following equation (from APPENDIX II, *Equation 7*):

Equation 11 $$Vtip = \frac{Qcum}{(Area * 900)}$$

Where:

V_{tip} = Flare Tip Velocity, feet per second.

Q_{cum} = Cumulative volumetric flow over 15-minute Block Average Period, actual cubic feet.

Area = Unobstructed cross sectional area of the flare tip, square feet.

900 = Conversion factor, seconds per 15-minute Block Average

25.5. If the Permittee choose to comply with Condition 25.4.b(ii) above, the Permittee shall also determine the NHVvg using Equation 9 and Equation 10 and calculate Vmax using Equation 8 in order to compare Vtip to Vmax on a 15-minute Block Average basis.

26. Good Air Pollution Control Practices. At all times, including during periods of Startup, Shutdown, and/or Malfunction, the Permittee shall implement good air pollution control practices to minimize emissions from EU ID 42 *[J-801 flare]*; provided however, that the Permittee shall not be in violation of this requirement for any practice that Conditions 7 through 30 requires the Permittee to implement after September 28, 2016 for the period between July 18, 2016 and the implementation date or compliance date (whichever is applicable) for the particular practice.

27. Flare Work Practice Standards. By no later than April 1, 2017, for EU ID 42 *[J-801 flare]*, utilize the instrumentation and controls required to be installed pursuant to Conditions 7 through 12.1. The Permittee shall install and operate on an Automatic Control System[15] that shall automate the control of the Supplemental Gas flow rate to EU ID 42 *[J-801 flare]*.

[15] The automatic control of the supplemental gas system was installed in March 2017.

28. Flare Operation According to Design. By no later than April 1, 2016, for EU ID 42 *[J-801 flare]*, the Permittee shall operate and maintain the flare in accordance with its design, except if, and only to the extent that, operation and maintenance of the flare in conformance with its design, conflicts with compliance with one or more permit conditions. The requirements of this condition shall not apply to the extent necessary to achieve personnel and process safety or prevent equipment damage.

29. Portable Flares. The Permittee shall comply with the following when using Portable Flares as replacement for EU ID 42 *[J-801 flare]*:

29.1. *Distinction Between Planned and Unplanned Outages of Flares.* For purposes of this permit term, a "planned" outage shall mean an outage of EU ID 42 *[J-801 flare]* that is scheduled 30 Days or more in advance of the outage. An "unplanned" outage is an outage of EU ID 42 *[J-801 flare]* that either is scheduled less than 30 Days in advance or is unscheduled.

29.2. *504 Hours or Less.* For any planned or unplanned outage of EU ID 42 *[J-801 flare]* that the Permittee know or reasonably anticipate will result in 504 hours or less of downtime on a 1095-day Rolling Sum Period, rolled daily, the Permittee shall make good faith efforts to ensure that the Portable Flare that replaces EU ID 42 *[J-801 flare]* complies with all of the Permit Conditions that are applicable to EU ID 42 *[J-801 flare]* that the Portable Flare replaces.

29.3. More than 504 Hours:

a. Planned. For any planned outage of a flare that the Permittee know or reasonably can anticipate will last 504 hours or more on a 1095-day Rolling Sum Period, rolled daily, the Permittee shall ensure that the Portable Flare complies with all of the Permit Conditions related to EU ID 42 *[J-801 flare]* that it replaces as of the date that the Portable Flare is In Operation and Capable of Receiving Waste, Supplemental, and/or Sweep Gas.

b. Unplanned. For any unplanned outage of EU ID 42 *[J-801 flare]* that, in advance of the outage, the Permittee cannot reasonably anticipate will last longer than 504 hours, the Permittee shall ensure that the Portable Flare complies with all of the Permit Conditions related to EU ID 42 *[J-801 flare]* that it replaces by no later than 30 Days after the date that the Permittee know or reasonably should have known that the outage will last 504 hours or more.

29.4. *Recordkeeping.* The Permittee shall keep records in accordance with Conditions 30.4.j and 30.5.

Flare Recordkeeping:

30. The Permittee shall comply with the following recordkeeping requirements:

30.1. By no later than October 1, 2017 for EU ID 42 [J-801 flare], the Permittee shall calculate and record, in accordance with the recording and averaging times required in Condition 12.1, as applicable, each of the following parameters:

a. NHVcz (in BTU/scf); and

b. NHV_{vg} (in BTU/scf).

30.2. By no later than October 1, 2017, EU ID 42 *[J-801 flare]*, commencing if and when the downtime of any instrumentation and monitoring system subject to Condition 12.3 above exceeds 5% of the time that the flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period for the flare that is being monitored by the respective instrument, the Permittee shall record

a. the duration of the deviation,

b. an explanation of the cause(s) of the deviation, and

c. a description of the corrective action(s) that the Permittee took.

30.3. At any time that the Permittee deviates from the standards in Conditions 21 through 26 the Permittee shall record

a. the duration of the deviation,

b. an explanation of the cause(s) of the deviation, and

c. a description of the corrective action(s) that the Permittee performed.

30.4. Keep records of the following:

a. Output of the monitoring device used to detect the presence of a pilot flame as required in Condition 22, for a minimum of 2 years.

b. Each 15-minute block during which there was at least one minute that no pilot flame is present when regulated material is routed to a flare, for a minimum of 5 years.

c. Daily Visible Emissions observations or video surveillance images required in Condition 23.2, for a minimum of 3 years.

(i) If Visible Emissions observations are performed using Method 22 at 40 C.F.R. Part 60, Appendix A-7, the record must identify

(A) whether the Visible Emissions observation was performed,

(B) the results of each observation,

(C) total duration of observed Visible Emissions,

(D) whether it was a 5-minute or 2-hour observation, and

(E) if the Permittee performs Visible Emissions observations more than one time during a day, the date and time of day each Visible Emissions observation was performed.

(ii) If video surveillance camera is used pursuant to Condition 10, include all video surveillance images recorded, with time and date stamp and retain the data recorded for six months.

(iii) For each 2-hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours, the record must include the date and time of the 2-hour period and an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible.

d. The 15-minute Block Average cumulative flows for Vent Gas and, if applicable, Perimeter Assist Air, and Premix Assist Air specified to be monitored under Condition 8, along with the date and time interval for the 15-minute Block Average Period.

e. The Vent Gas compositions specified to be monitored under Condition 9.

f. Each 15-minute block average operating parameter calculated following the methods specified in Conditions 24 through 25.4, as applicable.

g. All periods during which operating values are outside of the applicable operating limits specified in Conditions 24.1, 24.2, and 25.

h. All periods during which the Permittee did not perform flare monitoring according to the procedures in Conditions 8 through 10, 12.1, 22, and 23.

i. Records when the flow of Vent Gas exceeds the smokeless capacity of the flare, including start and stop time and dates of the flaring event.

j. Records sufficient to document compliance with the requirements of Condition 29 any time the Permittee uses a Portable Flare.

30.5. *Document Retention.* Except where other time periods are specifically noted, the Permittee shall retain all records created pursuant to Conditions 30.1 through 30.4 for a period of no less than five (5) years or until Termination of Consent Decree Civil No. Civ. SA-16-cv-00722, filed July 18, 2016, whichever is longer, including the raw data values, and shall make any such documents available upon request.

Prohibitions – Emission Credit Generation

31. The Permittee shall neither generate nor use Emissions Reductions associated with any emission reductions resulting from flaring as provided in Conditions 7 through 30 as netting reductions; as emissions offsets; to apply for, obtain, trade, or sell any emission reduction credits; or in determining whether a project would result in a significant net emissions increase in any PSD, major non-attainment, and/or minor NSR permit or permit proceeding.

31.1. Baseline actual emissions during any 24-month period selected by the Permittee shall be adjusted downward to exclude any portion of the baseline emissions that would have been eliminated as a result of the flare requirements in Conditions 7 through 30 had the Permittee been complying with the limits during that 24-month period.

31.2. Any plant-wide applicability limits ("PALs") as, that term is defined in 40 C.F.R. §52.21(b), that apply to emissions reductions specific in this Condition shall be adjusted downward to exclude any portion of the baseline emissions used in establishing such limit(s).

32. If the Waste Gas minimization results in emissions lower than the allowable level under the flaring limitations in Conditions 17 and 18 such reductions are prohibited as emissions reductions and shall be subject to the general prohibition set forth in Condition 31 above.

33. Nothing in Conditions 31 through 32 is intended to prohibit the Permittee from seeking to:

33.1. use or generate Emissions Reductions associated with EU ID 42 *[H-801 flare]* to the extent that the proposed emission reductions represent the difference between emission reductions achieved as provided in Conditions 7 through 30 and more stringent limits that the Permittee may elect to accept for those emissions units in a permitting process, except as provided in Conditions 32 and 33;

33.2. use or generate emission reductions from emissions units that are not specified in Conditions 7 through 30 subject to an emission limitation or control requirement; and

33.3. use Emissions Reductions associated with Conditions 7 through 30 for compliance with any rules or regulations designed to address regional haze or the non-attainment status of any area (excluding PSD and non-attainment NSR rules, but including, for example, RACT rules) that apply to the facility; provided, however, that the Permittee shall not be allowed to trade or sell any Emission Reductions associated with Conditions 7 through 30.

Section 4 Standard Permit Conditions

34. The Permittee must comply with each permit term and condition. Non-compliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

34.1. an enforcement action; or

34.2. permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

35. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

36. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

37. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

38. The permit does not convey any property rights of any sort, nor any exclusive privilege.

39. The Permittee shall allow the Department or an inspector authorized by the Department upon presentation of credentials and at reasonable times with the consent of the owner or operator to

39.1. enter upon the premises where an emissions unit subject to this permit is located or where records required by the permit are kept;

39.2. have access to and copy any records required by this permit;

39.3. inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

39.4. sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

Section 5 Permit Documentation

Date	Document Details
March 27, 2017	Permit Application Received
May 8, 2017	Addendum to the Minor Permit Application requesting addition of EU ID 10 to the Kenai Pipeline Title V Permit No. AQ0033TVP03 to allow the requested NSPS Subpart GGGa/VVa permit term to be attributed specifically to EU ID 10 rather than generically to the facility.
June 16, 2017	Addendum to the Minor Permit Application requesting the removal and/or revision of several existing TVOP conditions that are redundant to conditions requested with the incorporation of the federally enforceable Consent Decree requirements.
December 31, 2021	An updated calculations spreadsheet was received by the Department, along with Tesoro's review comments on the pre-Public Notice draft permits AQ0035MSS07, AQ0035TVP03, AQ0033TVP04, and AQ0036TVP04.