Pursuant to the Air Pollution Control Rules of the State of North Dakota (North Dakota Administrative Code Article 33.1-15, Chapter 33.1-15-14 and Chapter 33.1-15-25), the North Dakota Department of Environmental Quality hereby issues a Permit to Construct for the following source:

1. **General Information:**

   A. **Permit to Construct Number:** PTC17015

   B. **Source:**

      1) **Name:** Tesoro Refining & Marketing Company, LLC
      2) **Location:** Mandan, ND, Morton County
      3) **Source Type:** Petroleum Refinery
      4) **Equipment at Facility Subject to Consent Decree:**
         a) Fluidized Catalytic Cracking Unit (FCCU): EU 1A-2, EP 1A
         b) Equipment in Volatile Organic Compound Service
         c) Flare System: EU 1B, EU 2B, and EU 3B

   C. **Owner/Operator:**

      1) **Name:** Marathon Petroleum Corporation
      2) **Address:** 539 South Main Street, Findlay, OH 45840

2. **Permit Conditions:**

   The Permit to Construct incorporates requirements imposed on the Tesoro Refining & Marketing Company, LLC (Mandan Refinery) resulting from the United States v. Tesoro Refining & Marketing Company, LLC, No. 15:16-cv-00722 ("Consent Decree"). The source shall be operated in accordance with the terms of this Permit to Construct and the Title V Permit to Operate. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Environmental Quality (NDDEQ) and to the conditions specified below:
A. Permit to Construct No. PTC11014: Upon the issuance date of this permit, the hydrogen fluoride (HF) emission limits for the Alkylation Unit B-2 Furnace (EU 2A-2) listed in PTC11014 Condition II.D. are rescinded.

B. Special Conditions:

1) FCCU Testing and Operational Requirements:
   a) The owner/operator shall conduct annual Particulate Matter (PM) stack testing using three test runs of at least one hour in length as set forth in 40 C.F.R. § 63.1571(b)(2) to demonstrate compliance with 40 C.F.R. § 63.1564.
   b) The owner/operator shall operate the scrubber and the wet electrostatic precipitator at the Mandan Refinery according to manufacturer’s specifications and good engineering practices. The operations and maintenance plan shall be reviewed once every Title V permit term to facilitate operations consistent with manufactures specifications and good engineering practices.

2) NSPS & Covered Process Units Applicability. All Covered Process Units as defined by 40 CFR Part 60 Subpart GGGa shall be an “affected facility” and considered Covered Equipment for purposes of that standard. If Subpart GGGa applies to a process unit then the requirements of Subpart GGG no longer apply prospectively to that unit.
   a) For all Covered Equipment, the owner/operator shall comply with the monitoring frequency for valves as required by 40 C.F.R. § 60.482-7a, except as provided in 40 C.F.R. § 60.482-1a, and for pumps as required by 40 C.F.R. § 60.482-2a.

3) Flaring Events Control Requirements:
   a) 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 owner/operator shall complete an evaluation of all meters that measure the flow of Sweep Gas and Purge Gas to the Alky (EU 2B), GHT (EU 3B) and Combo (EU 1B), flares (herein referred to as “Flare System”) and shall upgrade or replace, as necessary, each such meter in order to ensure an acceptable level of control over flow. Under no circumstances may the owner/operator implement any such measure later than April 1, 2017.
   b) Installation and Operation of Flare Monitoring Systems. By no later than April 1, 2017, the owner/operator shall have completed the installation and commenced the operation of the instrumentation, controls and monitoring systems. The owner/operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the Vent Gas volumetric flow rate in the Alky, GHT and Combo flare headers or headers that feed the flares as well as any Supplemental Gas used. 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 owner/operator shall install, operate, calibrate, and maintain
a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of Assist Steam used with each Alky, GHT and Combo flares.

1] The flow rate monitoring systems must be able to correct for the temperature and pressure of the system and output parameters in standard conditions.

2] 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 the below equation:

\[ Q_{vol} = \frac{Q_{mass} \times 385.3}{MW_t} \]

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

3] Mass flow monitors may be used for determining volumetric flow rate of Assist Steam using the equation in Condition 2.B.3(b)2] to convert mass flow rates to volumetric flow rates of Assist Steam. Use a molecular weight of 18 pounds per pound-mole for Assist Steam.

4] 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 Steam, use a molecular weight of 18 pounds per pound-mole. For Vent Gas, molecular weight must be determined using compositional analysis as specified in Condition 2.B.3(c). c)

Vent Gas Composition Monitoring. The owner/operator shall determine the concentration of individual components in the Vent Gas using either Condition 2.B.3(c)1] or 2.B.3(c)2] provided below, to assess compliance with the operating limits in Condition 2.B.5(d) below and, if applicable, Conditions 2.B.5(a)4].

Alternatively, the owner/operator may elect to directly monitor the Net Heating Value of the Vent Gas following Condition 2.B.3(c)3] below, and, if desired, may directly measure the hydrogen concentration in the Vent Gas following the Condition 2.B.3(c)4] below. The owner/operator may elect to use a different monitoring method 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:

1] Net Heating Value by Gas Chromatograph. Except as provided in Conditions 5] and 6] below, the owner/operator 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.

2] **Grab Sampling System.** Except as provided in Conditions 5] and 6] below, the owner/operator 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.

3] **Net Heating Value By Calorimeter.** Except as provided in Conditions 5] and 6] below, the owner/operator shall install, operate, calibrate, and maintain a calorimeter capable of continuously measuring, calculating, and recording NHV$_{vg}$ 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 Flare Appendix V.

4] **Hydrogen Concentration Monitoring.** If the owner/operator uses a continuous net heating value calorimeter according to Method c above, that owner/operator 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.

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.

6] The owner/operator 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 Alky, GHT and Combo flares.

d) **Video Camera.** A video camera shall record, in digital format, whether a flame or Smoke Emissions are present at the Alky, GHT and Combo flares no later than April 1, 2017. It is not a violation of this Condition, however if the video camera(s) cannot discern the Combustion Zone (as defined in Flare Appendix I) and/or any Smoke Emissions (as defined in Flare Appendix I) due to weather conditions, such as fog or snow, provided that records are created and retained.

e) **Instrumentation and Monitoring Systems: Specifications.** For the Alky, GHT and Combo flares the applicable instrumentation and monitoring systems required per
Conditions 2.B.3(a), 2.B.3(b), 2.B.3(c), 2.B.3(d), and 2.B.3(f) shall meet or exceed the equipment and instrumentation technical specifications and quality assurance/quality control requirements set forth in Flare Appendix V.

f) The instrumentation and monitoring systems identified in Conditions 2.B.3(a), 2.B.3(b), 2.B.3(c), and 2.B.3(d) 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:

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

Nothing in this Condition shall prohibit the owner/operator 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.

g) **Instrumentation and Monitoring Systems: Operation and Maintenance.** The owner/operator shall operate each of the instruments and monitoring systems required in Conditions 2.B.3(a), 2.B.3(b), 2.B.3(c), 2.B.3(d), 2.B.3(e), and 2.B.3(f) on a continuous basis when the associated flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas, except for the following periods:

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

2] Repairs associated with monitoring system malfunctions, for a monitoring system needed to meet the requirement(s);

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

4] **Quality Assurance/Quality Control Activities:** Provided however, that in no event shall the excepted periods 1], 2], and 3] defined above for any instrument
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 calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VIII of Flare Appendix V. If the excepted periods 1], 2], and 3] 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 owner/operator shall be entitled to assert that the period of instrumentation and monitoring system downtime was justified under the circumstances and/or due to a Force Majeure (as defined in Flare 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 owner/operator 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.

4) Flare Gas Recovery System and Limitations on Flaring:
   a) Flare Gas Recovery Systems: Capacity and Start-Up Dates. By no later than July 1, 2016 the owner/operator shall complete installation and commence operation of a Flare Gas Recovery System (FGRS) with a minimum operating design capacity of 60 kscfh for the GHT and Combo flares. The FGRS will consist of a minimum of two compressors each with minimum operating capacities of 30 kscfh.
      1] General. The owner/operator shall operate each FGRS in a manner to minimize Waste Gas to the GHT and Combo flares while ensuring safe refinery operations. The owner/operator also shall operate each FGRS consistent with good engineering and maintenance practices and in accordance with its design and the manufacturer’s specifications.
      2] Requirements related to compressors being Available for Operation and/or In Operation. By no later than April 1, 2017, the owner/operator shall comply with the following requirements when potentially Recoverable Gas is being generated:
         a] The owner/operator shall have one FGRS compressor Available for Operation and/or In Operation 98% of the time and two compressors Available for Operation and/or In Operation 95% of the time.
         b] 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 this Condition, the period to be used shall be an
8760-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 8760-hour rolling sum.

c) 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 owner/operator shall use best efforts to schedule these maintenance activities during a scheduled turnaround of the flaring process units venting to the flare. To the extent it is not practicable to undertake these maintenance activities during a scheduled turnaround, the owner/operator shall use best efforts to minimize the generation of Waste Gas during such periods.

c) Initial Limitations on Flaring:

1] The owner/operator shall comply with the 30-day rolling average of 313,139 scfd and a 365-day rolling average of 208,759 scfd by May 1, 2017 and April 1, 2018 respectively for the Alky, GHT and Combo flares combined.

The rolling average period shall include only the prior 30 days or 365 days, as applicable, when the Alky, GHT and Combo flares were In Operation. Each exceedance of the 30-day rolling average limit or each exceedance of the 365-day rolling average limit shall constitute one day of violation. An exceedance of either or both of the limits shall not prohibit ongoing refinery operations.

2] The limitations set forth in Condition 2.B.4(c)1] above were calculated using the equations set forth in Conditions 2.B.4(d)1][a] and 2.B.4(d)1][b] and Flare 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 owner/operator 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 Flare Appendix VII. The “Refinery Complexity” and “Industry Avg Complexity” were calculated pursuant to the methodology set forth in Flare Appendix VI.

d) Requesting an Increase in the Limitations on Flaring:

1] Once per calendar year, the owner/operator may submit a request to EPA to
increase the limitations on flaring set forth in Condition 2.B.4(c)1]. The owner/operator may request an increase in the limit(s) and EPA will approve such an increase, only if: (i) the request is based on changes in crude capacity and/or complexity that were not reflected in the EIA reports as of June 25, 2014; (ii) the changes are or will be permitted by the NDDEQ; and (iii) 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 2.B.4(c)1]. In any such request, the owner/operator shall propose (a) new limit(s) (hereafter referred to as “New Limit(s) Based on Projections”) based upon the following equations:

a] For the owner/operator, the refinery-wide, 30-day Rolling Average limit:

\[
\text{Refinery Flaring} \leq 750,000 \text{ scfd} \times \frac{\text{Refinery Crude Cap.}}{100,000 \text{ bpd}} \times \frac{\text{Refinery Complexity}}{\text{Industry Avg Complexity}}
\]

b] For the owner/operator, the refinery-wide, 365-day Rolling Average limit:

\[
\text{Refinery Flaring} \leq 500,000 \text{ scfd} \times \frac{\text{Refinery Crude Cap.}}{100,000 \text{ bpd}} \times \frac{\text{Refinery Complexity}}{\text{Industry Avg Complexity}}
\]

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

2] For purposes of equations a] and b] above, the following shall apply:

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

b) The owner/operator’s Crude Capacity shall be determined as follows:

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 owner/operator’s Complexity shall be calculated in accordance with Equation 1 of Flare Appendix VI. The owner/operator shall certify the accuracy of the projected Crude Capacity and/or flaring process unit capacities used to support the calculations.

d] The Industry Average Complexity shall be calculated in accordance with
3] **EPA Response to Request.** EPA shall evaluate any request under this Condition on the basis of consistency with Conditions 2.B.4(d)1 and 2.B.4(d)2 above.

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 owner/operator favor or the date(s) specified in the modification permit(s).

5] In the event that the owner/operator 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 2.B.4(d)1 in a manner that affects the limit(s) calculation(s), the owner/operator shall, within fifteen (15) days of amending, modifying, or withdrawing its air permit application(s), revise or withdraw its request under Condition 2.B.4(d)1.

6] **Consequences of a Mistake in Projected Capacities.**

   a] By no later than ninety (90) days after the startup of the permitted modifications, the owner/operator shall determine whether the projected “Refinery Crude Capacity” or the projected capacities for new or modified units that the owner/operator relied upon pursuant to Conditions 2.B.4(d)2[b] and 2.B.4(d)2[c] above, respectively, were or are different from the actual capacities that the owner/operator 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 owner/operator shall re-calculate the flaring limitation(s) using the actual capacities that the owner/operator have reported or will report to the EIA or the Oil & Gas Journal (hereafter referred to as “New Limit(s) Based on Actuals”).

   b] If the new limit(s) based on actuals that the owner/operator calculate under 2.B.4(d)6[a] above is/are greater than the new limit(s) based on projections that the owner/operator calculated under Condition 2.B.4(d)1 above, then no further action shall be required. If the owner/operator elects to take no action, then the new limits(s) based on projections shall remain in effect. The owner/operator, however, may elect to submit for EPA approval, a revised, recalculated new limit(s) based on actuals to EPA. After submission to EPA, the owner/operator shall secure EPA’s approval of the new limit(s) based on actuals before they become effective.

   c] If the new limit(s) based on actuals that the owner/operator calculates under Condition 2.B.4(d)6[a] above is/are less than the new limit(s) based on projections that the owner/operator calculated under Condition 2.B.4(d)1 above, then by no later than ninety (90) days after the startup of the permitted modifications, the owner/operator shall:

   i. Commence complying with the new limit(s) based on actuals; and

   ii. Submit the revised, recalculated new limit(s) based on actuals to EPA.
After submission to EPA, the owner/operator shall consult with EPA about the new limit(s) based on actuals.

e) 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 2.B.4)(c) and 2.B.4)(d) above and any revised limitations on flaring developed, the following shall apply:

1] To the extent that the owner/operator have 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.

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.

5) Flare Combustion Efficiency Requirements:

a) Flare(s) Emission Standards and Work Practice. The owner/operator shall comply with the following combustion efficiency requirements at the Alky, Combo and GHT flares:

1] Operation During Waste Gas Venting. By no later than April 1, 2016, the owner/operator shall operate each flare at all times when Waste Gas may be vented to it.

2] No Visible Emissions.

a] By January 30, 2019, the owner/operator shall specify the smokeless design capacity of each 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 the flare. The owner/operator shall monitor for Visible Emissions from the flare as specified in Condition 2.B.5)(a)2][b] below.

b] By January 30, 2019, the owner/operator shall monitor Visible Emissions when the flare is In Operation. An initial Visible Emissions demonstration must be conducted using an observation period of 2 hours using Method 22 at 40 C.F.R. Part 60, Appendix A-7. Subsequent Visible Emissions observations must be conducted using either Condition 2.B.5)(a)2][b][i] and 2.B.5)(a)2][b][ii] below. The owner/operator must record and report any instances where Visible Emissions are observed 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.

i. At least once per day, the owner/operator shall conduct Visible Emissions observations using an observation period of 5 minutes using Method 22 at 40 C.F.R. Part 60, Appendix A-7. If at any time the owner/operator sees Visible Emissions, even if the minimum required daily Visible Emissions monitoring has already been performed, the owner/operator shall immediately begin an observation period of 5 minutes using Method 22 at 40 C.F.R. Part 60, Appendix A-7. If Visible Emissions are observed for more than one continuous minute during any 5-minute observation period, the observation period using Method 22 at 40 C.F.R. Part 60, Appendix A-7 must be extended to 2 hours or until 5-minutes of no Visible Emissions are observed.

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 owner/operator 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.

   a] Pilot Flame Presence. By January 30, 2019, the owner/operator shall operate the Alky, GHT and Combo flares with a pilot flame present when the flare is In Operation. Each 15-minute block during which there is at least one minute where no pilot flame is present when Vent Gas is routed to the flare, the flame presence standard is not met. The owner/operator shall monitor for the presence of a pilot flame as specified in Condition 2.B.5)a]3]b] below.

b] Pilot Flame Monitoring. By January 30, 2019, the owner/operator 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.

   a] For the Alky, GHT and Combo flares, the owner/operator shall comply with either Condition 2.B.5)a]4]a]i or 2.B.5)a]4]a]ii below, provided the appropriate monitoring systems are in place, whenever the Vent Gas flow rate is less than the smokeless design capacity of the flare.

i. Except as provided in Condition 2.B.5)a]4]a]ii below, the actual flare tip velocity (Vtip) must be less than 60 feet per second. The owner/operator
shall monitor Vtip using the procedures specified in Condition 2.B.5(a)4](b) below.

ii. Vtip must be less than 400 feet per second and also less than the maximum allowed flare tip velocity (Vmax) as calculated according Flare Appendix II, Equation 5. The owner/operator shall monitor Vtip using the procedures specified in Condition 2.B.5(a)4](b) below and monitor gas composition and determine NHVvg using the procedures specified in Condition 2.B.3(c) and Flare Appendix III, Equations 1 and 2.

b] Calculation Methods for Cumulative Flow Rates and Determining Compliance with Vtip Operating Limits. The owner/operator shall determine Vtip on a 15-minute block average basis according to the following requirements:

i. 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.

ii. The owner/operator 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 2.B.3(b) according to the following requirements as applicable.

- 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.
- If continuous pressure/temperature monitoring system(s) and engineering calculations are used as allowed under Condition 2.B.3(b)4], the owner/operator 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 owner/operator 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.

iii. 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 Flare Appendix II, Equation 7.

iv. If the owner/operator chooses to comply with method 2.B.5(a)4](b)ii
above, the owner/operator shall also determine the NHV\textsubscript{vg} using Flare Appendix III Equations 1 and 2 and calculate V\text{max} using Flare Appendix II Equation 5 in order to compare V\text{tip} to V\text{max} on a 15-minute block average basis.

5) **Monitoring According to Applicable Provisions.** The owner/operator shall comply with all applicable Subparts of 40 C.F.R. Parts 60, 61, or 63, that state how the Alky, GHT and Combo flares shall be monitored.

6) **Good Air Pollution Control Practices.** At all times, including during periods of startup, shutdown, and/or malfunction, the owner/operator shall implement good air pollution control practices to minimize emissions from the Alky, GHT and Combo flares; provided however, that the owner/operator shall not be in violation of this requirement for any practice that Condition 2.B.3) requires the owner/operator 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.

b) **Flare Work Practice Standards.** By no later than April 1, 2017, for the Alky, GHT and Combo flares, utilize the instrumentation and controls required to be installed pursuant to Conditions 2.B.3)a), 2.B.3)b), 2.B.3)c), 2.B.3)d), and 2.B.3)f). The owner/operator shall install and operate on each flare an automatic control system that shall automate the control of the Supplemental Gas flow rate to the respective flares.

c) **Flare Operation According to Design.** By no later than April 1, 2016, for the Alky, GHT and Combo flares, the owner/operator shall operate and maintain each flare in accordance with its design, except if, and only to the extent that, operation and maintenance of the flares 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.

d) **Net Heating Value Standards for each Flare.**

1) By no later than October 1, 2017, for the Alky, GHT and Combo flares, the owner/operator shall operate each respective flare to maintain the Net Heating Value of Combustion Zone Gas (NHV\textsubscript{cz}) at or above 270 BTU/scf determined on a 15-minute block average period basis. The owner/operator shall monitor and calculate NHV\textsubscript{cz} as specified in Conditions 2.B.5)d)2[a] and 2.B.5)d)2[b] below.

2) **Calculation Methods for Determining Combustion Zone Net Heating Value.** The owner/operator shall determine the Net Heating Value of the Combustion Zone Gas (NHV\textsubscript{cz}) as specified in Conditions 2.B.5)d)2[a] and 2.B.5)d)2[b] below:

a) For the Direct Calculation Method, determine the 15-minute block average
NHVcz based on the 15-minute block average Vent Gas and assist gas flow rates using the equation below (Flare Appendix III, Equation 3):

\[
NHVcz = \frac{(Q_{vg} - NHV_{vg})}{(Q_{vg} + Qs + Qa,\text{premix})}
\]

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.
- \(Qs\): Cumulative volumetric flow of Total Steam during the 15 – minute block period, scf.
- \(Qa,\text{premix}\): Cumulative volumetric flow of Premix Assist Air during the 15 – minute Block Period, scf.

For periods when there is not Assist Steam flow, \(NHVcz = NHV_{vg}\).

b) When using the Feed Forward Calculation Method, determine the 15-minute block average \(NHVcz\) utilizing the equation below (Flare Appendix III, Equation 4):

\[
NHVcz = \frac{(Q_{vg} - Q_{NG2} + Q_{NG1}) \cdot NHV_{vg} + (Q_{NG2} - Q_{NG1}) \cdot NHV_{NG}}{(Q_{vg} + Qs + Qa,\text{premix})}
\]

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., \(Q_{NG1} = Q_{NG2}\).
- \(NHV_{NG}\): Net Heating Value of Supplemental Gas to the flare for the 15 – minute block period determined according to the requirements in Condition D, e, BTU/scf.
- \(Qs\): Cumulative volumetric flow of Total Steam during the 15 – minute Block Period, scf.
- \(Qa,\text{premix}\): Cumulative volumetric flow of Premix Assist Air during the 15 – minute Block Period, scf.

e) Flare Combustion Efficiency of 96.5%. By no later than October 1, 2017, the owner/operator shall operate the Alky, GHT and Combo flares, with a minimum
of a 96.5% Combustion Efficiency, as calculated in Flare Appendix II, Equation 1, at all times when Waste Gases are vented to each respective flare. To demonstrate continuous compliance with the applicable combustion efficiency requirement, the owner/operator shall operate each of the respective flares within the range of relevant operating parameters set forth in Condition 2.B.5)(d).

f) The requirements of Conditions 2.B.5)(d) and 2.B.5)(e) are not applicable to any of the Alky, GHT and Combo flares when the only gases being vented to the respective flares are Pilot Gas and/or Purge Gas. Pilot gas and Purge Gas are considered to be the only gases being vented to those flares if the following conditions are satisfied for the liquid seal drum that is part of the FGRS associated with the respective flare(s):

1] For the liquid seal drum associated with respective flare(s), 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;

2] For the liquid seal drum associated with the respective flare(s), the liquid level in the drum is at the level of the weir; and

3] Downstream of the seal drum associated with the respective flare(s) there is no flow of Supplemental Gas directed to the flare(s).

As an alternative to Condition 2.B.5)(f) 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.

g) Flare(s) Recordkeeping: The owner/operator shall comply with the following recordkeeping requirements:

1] By no later than October 1, 2017 for the Alky, GHT and Combo flares, the owner/operator shall calculate and record, in accordance with the recording and averaging times required in Condition 2.B.3)(f), each of the following parameters:

a] NHVcz (in BTU/scf);

b] S/VG (in lbs steam/lbs Vent Gas), Total Steam Mass Flow Rate (in lb/hr), Vent Gas mass rates (in scfm and lb/hour) for Alky, GHT and Combo flares, until October 1, 2017.

c] NHVvg (in BTU/scf).

2] By no later than October 1, 2017, the Alky, GHT and Combo flares, commencing if and when the downtime of any instrumentation and monitoring system subject to Condition 2.B.3)(g) 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 owner/operator shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that the owner/operator took.

3] At any time that the owner/operator deviates from the standards in Conditions 2.B.5)a), 2.B.5)d), or 2.B.5)e), the owner/operator shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that the owner/operator performed.

4] Output of the monitoring device used to detect the presence of a pilot flame as required in Condition 2.B.5)a)3].


a] If Visible Emissions observations are performed using Method 22 at 40 C.F.R. Part 60, Appendix A-7, the record must identify whether the Visible Emissions observation was performed, the results of each observation, total duration of observed Visible Emissions, and whether it was a 5-minute or 2-hour observation. If the owner/operator performs Visible Emissions observations more than one time during a day, the record must also identify the date and time of day each Visible Emissions observation was performed.

b] If video surveillance camera is used, the record must include all video surveillance images recorded, with time and date stamp.

c] 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.

6] The 15-minute block average cumulative flows for Vent Gas and, if applicable, Total Steam specified to be monitored under Condition 2.B.3)b), along with the date and time interval for the 15-minute block average period.

7] The Vent Gas compositions specified to be monitored under Condition 2.B.3)c).

8] Each 15-minute block average operating parameter calculated following the methods specified in Condition 2.B.5)a)4]b] and Flare Appendix III, as applicable.

9] All periods during which operating values are outside of the applicable operating limits specified in Conditions 2.B.5)a)4] and 2.B.5)d)1].

10] All periods during which the owner/operator did not perform flare monitoring according to the procedures in Conditions 2.B.3)b), 2.B.3)c), 2.B.3)d), 2.B.3)f), 2.B.5)a)2], and 2.B.5)a)3].
11] Records of when the flow of Vent Gas exceeds the smokeless capacity of the flare, including start and stop time and dates of the flaring event.

12] **Recordkeeping: Document Retention.** Except with respect to the data produced by video cameras required pursuant to Condition 2.B.3(d), the owner/operator shall retain all records created pursuant to this Condition, including the raw data values, and shall make any such documents available upon request. The owner/operator shall retain the data recorded by the video cameras required pursuant to Condition 2.B.3(d) for six months.

h) **Portable Flares.**

1] **Applicability.** The provisions of this Condition shall apply to Portable Flares.

2] **Distinction Between Planned and Unplanned Outages of Flares.** For purposes of this permit term, a “planned” outage shall mean an outage of the Alky, GHT and Combo flares that is scheduled 30 days or more in advance of the outage. An “unplanned” outage is an outage of the Alky, GHT and Combo flares that either is scheduled less than 30 days in advance or is unscheduled.

3] **Less than 504 Hours.** For any planned or unplanned outage of the Alky, GHT and Combo flares that the owner/operator know or reasonably anticipate will result in 504 hours or less of downtime on a 1095-day rolling sum period, rolled daily, the owner/operator shall make good faith efforts to ensure that the Portable Flare that replaces the Alky, GHT and Combo flares complies with all of the Permit Conditions that are applicable to Alky, GHT and Combo flares that the Portable Flare replaces.

4] **Greater than 504 Hours.**

   a] **Planned.** For any planned outage of a flare that the owner/operator know or reasonably can anticipate will last 504 hours or more on a 1095-day rolling sum period, rolled daily, the owner/operator shall ensure that the Portable Flare complies with all of the Permit Conditions related to the Alky, GHT and Combo flares 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 the Alky, GHT and Combo flares that, in advance of the outage, the owner/operator cannot reasonably anticipate will last longer than 504 hours, the owner/operator shall ensure that the Portable Flare complies with all of the Permit Conditions related to the Alky, GHT and Combo flares that it replaces by no later than 30 days after the date that the owner/operator know or reasonably should have known that the outage will last 504 hours or more.

5] **Recordkeeping.** The owner/operator shall keep records sufficient to document compliance with the requirements of this Condition any time it uses a Portable Flare.
6) NSPS Subparts A and Ja Flare Applicability and Exception for Monitoring System Downtime:

a) NSPS Subparts A and Ja. The Alky, GHT and Combo flares shall be an “affected facility” within the meaning of Subparts A and Ja of 40 C.F.R. Part 60, and shall comply with all of the requirements of Subparts A and Ja.

b) A failure to comply with the work practices or standards in Conditions 2.B.5)a), 2.B.5)b), and 2.B.5)d) shall not constitute a violation of such work practice or standard if the noncompliance results from downtime of monitoring systems due to the following:

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

2] Repairs associated with monitoring system malfunctions, for a monitoring system needed to meet the requirement(s);

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

4] Quality Assurance/Quality Control activities on a monitoring system needed to meet the requirement.

Provided, however, that this exception shall no longer be applicable if the activities listed in 1] through 4] above exceed 5% of time that the 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 Flare Appendix V.

7) Flare System Reporting Requirements:

a) Monitoring System Downtime and Emissions Exceedances. The owner/operator shall provide a summary of the following, for each Covered Flare (hours shall be rounded to the nearest tenth) in their semi-annual reports submitted pursuant to Condition 2.B.9)a):

1] The total number of hours of downtime of each monitoring instrument/equipment required pursuant to Conditions 2.B.3)b) through 2.B.3)d), 2.B.3)f) and 2.B.3)g) above, expressed as both an absolute number and a percentage of time each flare that the instrument/equipment monitors is available for operation;

2] If the total number of hours of downtime of any monitoring instrument/equipment required pursuant to Conditions 2.B.3)b) through 2.B.3)d), 2.B.3)f) and 2.B.3)g) 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 an identification of the periods of downtime by date, time, cause (including Malfunction or maintenance), and, if the cause is asserted to be a Malfunction, the corrective action taken;

3] Inapplicability of Emissions Standards. The total number of hours expressed as both an absolute number of hours and a percentage of time each flare was In Operation in which the requirements of Conditions 2.B.5)d) and 2.B.5)e) above were not applicable because the only gas or gases being vented was/were Pilot Gas and/or Purge Gas; for purposes of Conditions 2.B.7)a)4] and 2.B.7)a)5] below, all remaining hours shall be termed “Hours of Applicability”;

4] Exceedances of Standards. During the Hours of Applicability, the total number of hours of exceedances of each of the standards in Condition 2.B.5)d) above, expressed as both an absolute number of hours and a percentage of time each flare was In Operation; provided however, that if the exceedance of these standards was less than 5% of the time that the Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period, the report shall so note;

a] Records of the output of the monitoring device used to detect the presence of a pilot flame as required in Condition 2.B.5)a)3] for each 15-minute block.

b] Visible Emission records of 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 for each period of 2 consecutive hours during which Visible Emissions exceed a total of 5 minutes.

c] The 15-minute Block Average Periods for which the applicable operating limits specified in Conditions 2.B.5)a)4], 2.B.5)d) are not met. Indicate the date and time for the period, the Net Heating Value and/or Flare Tip Velocity operating parameter(s) determined following the methods in Flare Appendix II and III as applicable.


a] For any Waste Gas flows that are excluded from the calculation of flow rate because they are asserted to be based on one or more of the excludible events identified in Condition 2.B.4)e) above, the information required in Condition 2.B.4)e) above;

b] An identification of each day in which the limitations on flaring set forth in Condition 2.B.4)c) (or Condition 2.B.4)d), if applicable) above were exceeded;

c] The cause of the exceedance;

d] If the cause is asserted to be a malfunction, description of the malfunction
and any corrective actions taken;

e) A quantification of the total flow and a calculation of the percent over the standard in Condition 2.B.4)c) (or Condition 2.B.4)d), if applicable) above.

b) Emissions Data. In the semi-annual report that is required to be submitted by Condition 2.B.9)a) below by September 1st of each year, for each flare the owner/operator shall provide, for the prior calendar year, the amount of emissions of the following compounds (in tons per year): VOCs, SO₂, H₂S, CO₂, methane, and ethane.

8) Emission Credit Generation:

a) Prohibition. The owner/operator shall neither generate nor use emissions reductions associated with: any emission reductions as a result of flaring as provided in Conditions 2.B.3) through 2.B.6) for the Alky, GHT and Combo flares that occurred May 1, 2017: 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. Baseline actual emissions during any 24-month period selected by the owner/operator 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 2.B.3) through 2.B.6) had the owner/operator been complying with the limits during that 24-month period. 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).

b) Additional Prohibition. If the Waste Gas minimization results in emissions lower than the allowable level under the flaring limitations in Conditions 2.B.4)c) and 2.B.4)d) such reductions are prohibited as emissions reductions and shall be subject to the general prohibition set forth in Condition 2.B.8)a) above.

c) Outside the Scope of Prohibition. Nothing in Conditions 2.B.8)a), 2.B.8)b), and 2.B.8)c) is intended to prohibit the owner/operator from seeking to:

1] Use or generate emission reductions emissions reductions associated with Alky, GHT and Combo flares to the extent that the proposed emission reductions represent the difference between limits established in Conditions 2.B.3) through 2.B.6) and more stringent limits that the owner/operator may elect to accept for those emissions units in a permitting process, except as provided in Condition 2.B.1)b);

2] Use or generate emission reductions from emissions units that are not specified in Conditions 2.B.3) through 2.B.6) subject to an emission limitation or control requirement; and

3] Use emissions reductions associated with Conditions 2.B.3) through 2.B.6) 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 owner/operator shall not be allowed to trade or sell any emission reductions associated with Conditions 2.B.3) through 2.B.6).

9) General Reporting, Recordkeeping, and Certification:

a) The owner/operator shall submit to EPA and the NDDEQ a semiannual report which the owner/operator is responsible for compliance with this permit on each March 1st and September 1st until termination. Semi-annual reports shall cover the time period from January 1st through June 30th of each year (submitted by September 1st of each of the following years) and the period of July 1st through December 31st of each year (submitted by March 1st of each of the following years). Each report shall contain for the period covered by the report:

1] A summary of the emissions data that is specifically required by the reporting requirements of this permit;

2] A description of any problems anticipated with respect to meeting the requirements of this;

3] A description of the implementation activity for the Environmental Mitigation Projects set forth in Consent Decree Section IX (Environmental Mitigation Projects);

4] A summary of the owner/operator’s actions implemented and expenditures (cumulative and in the current reporting period) made to implement the Environmental Mitigation Projects required pursuant to Consent Decree Section IX (Environmental Mitigation Projects);

5] Any additional matters that the owner/operator believes should be brought to the attention of EPA and NDDEQ; and

6] Any additional items required by any other Condition of this permit to be submitted with a semi-annual report.

b) Within sixty (60) days following the completion of each Environmental Mitigation Project required under Section IX (Environmental Mitigation Projects) of the Consent Decree (including any applicable periods of demonstration or testing), The owner/operator shall submit to the United States and the NDDEQ a report that documents:

1] The date that the Mitigation Project was completed;

2] The results achieved by implementing the Mitigation Project, including the emission reductions or other environmental benefits expected to be realized;

3] The methodology and any calculations used in the derivation of such expected
benefits, reductions, or mitigation;

4] The project dollars expended by the owner/operator in implementing the Mitigation Project; and

5] Certification by an authorized representative that the Mitigation Project has been completed in full satisfaction of the requirements of the Consent Decree and Appendix D.

c) **Emissions Data.** In the semi-annual report required by Condition 2.B.9(a) above to be submitted by September 1st of each year, the owner/operator shall provide the following emissions data for compliance with this permit, for the prior calendar year:

1] VOCs, SO\(_2\), H\(_2\)S, CO\(_2\), methane, and ethane emissions in tons per year from each flare.

2] For the estimates or calculations in the above Condition, provide the basis for the emissions estimate or calculation (i.e., stack tests, CEMS, emission factor, etc.).

To the extent that the required emissions summary data are available in other reports generated by the owner/operator, such other reports can be attached, or the appropriate information can be extracted from such other reports and attached to the report to satisfy the requirement.

d) **Certification.** Each semi-annual report shall be certified by either the person responsible for environmental management and compliance, or by a person responsible for overseeing implementation of this permit. The certification shall state:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

e) Except where other time periods are specifically noted, the owner/operator shall retain all records required to be maintained in accordance with this permit for a period of no less than five (5) years or until termination, whichever is longer, unless applicable regulations require the record to be maintained longer, in which case the owner/operator shall comply with those regulations. The owner/operator shall provide such records to EPA or NDDEQ upon request.
C. **Definitions:** Except as expressly set forth elsewhere in this permit, such as the Flare Appendices, the terms used in this permit shall have the meaning given to those terms in this Condition, or, if not defined in this permit, as defined in the Clean Air Act and the regulations promulgated thereunder. The following terms used in this permit shall be defined, solely for purposes of this permit and the reports and documents submitted pursuant thereto, as follows:

“**Compressor**” shall mean with respect to a FGRS, a mechanical device designed and installed to recover gas from a Flare header. Types of FGRS compressors include reciprocating compressors, centrifugal compressors, liquid ring compressors, and liquid jet ejectors.

“**Downtime**” or “**CEMS Downtime**” or “**CMS Downtime**” shall mean the period of time during operation of the emission unit being monitored in which any of the required CEMS/CMS data are either not recorded or are invalid for any reason (e.g., monitor malfunctions, data system failures, preventive maintenance, unknown causes, etc.), but shall not include downtime associated with routine CEMS/CMS zero and span checks and Quality Assurance (“QA”) and Quality Control (“QC”) (collectively “QA/QC”) activities required by this Consent Decree. CEMS/CMS data that meet the requirements of 40 C.F.R. § 60.13 shall be considered valid for purposes of determining Downtime.

“**Environmental Mitigation Project**” or “**Project**” shall mean the projects identified in Section IX (Environmental Mitigation Projects) and Appendix D of the Consent Decree.

“**EPA**” or “**U.S. EPA**” shall mean the United States Environmental Protection Agency and any successor departments or agencies of the United States.

“**Flare**” shall mean a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases. Applicable the Combo, Alky, and GHT flares at the Mandan Refinery.

“**Fuel Gas**” shall have the meaning set out in 40 C.F.R. § 60.101a.

“**Fuel Gas System**” means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species.

“**Hours of Applicability**” shall have the meaning set forth in Condition 2.B.7(a)3].
“LDAR” shall mean Leak Detection and Repair.

“Method 21” shall mean the test method found at 40 C.F.R. Part 60, Appendix A-7, Method 21.

“Owner/operator” shall mean the Mandan Refinery owner or operator.

“Termination” shall be the date on which the Court orders that the Consent Decree (or a part thereof) or permit condition terminates pursuant to Section XXI of the Consent Decree.

FOR THE NORTH DAKOTA DEPARTMENT OF ENVIRONMENTAL QUALITY

Date:______________ By: __________________________
James L. Semerad
Director
Division of Air Quality

Attachment 1: Flare Appendices
Flare Appendix I: Definitions
Flare Appendix II: General Flare Equations
Flare Appendix III: Heating Value Requirements
Flare Appendix IV: Compounds Analyzed
Flare Appendix V: Monitor Equipment Specifications
Flare Appendix VI: Refinery Complexity Calculation
Flare Appendix VII: Summary Information for Mandan Refinery

Consent Decree information on EPA website:
The link below is for information purposes and the conditions are not an enforceable portion of this Permit to Construct unless specifically listed in the permit:
https://www.epa.gov/enforcement/tesoro-and-par-clean-air-act-settlement
### ATTACHMENT: FLARE APPENDICES

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FLARE APPENDIX I

The following terms used in this Permit, when capitalized, shall be defined, solely for purposes of this Permit and the reports and documents submitted pursuant thereto, as follows:

“Assist Air” shall mean all air that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. Assist Air includes Premix Assist Air and Perimeter Assist Air. Assist Air does not include the surrounding ambient air.

“Assist Steam” shall mean all steam that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. Assist Steam includes, but is not necessarily limited to, Center Steam, Lower Steam, and Upper Steam.

“Automatic Control System” shall mean a system that utilizes programming logic to automate the operation of the instrumentation and systems required in Condition 5)b)2.B.5)b) of this Permit so as to produce the operational results required in Condition 2.B.3)f) of this Permit.

“Available for Operation” shall mean, with respect to a compressor within a FGRS, that the compressor is capable of commencing the recovery of Potentially Recoverable Gas as soon as practicable but not more than one hour after the need for a compressor to operate arises; the period of time, not to exceed one hour, allowed by this definition for the Startup of a compressor shall be included in the amount of time that a compressor is Available for Operation.

“Block Average” means the arithmetic mean of a measured or calculated parameter during a Block Average Period.

“Block Average Period” or “Block Period” means the uninterrupted period of time during which the Block Average must be calculated.

“Block Sum” means the sum total of the measured or calculated standard, exception, or triggering event during a Block Sum Period. Most often, the term “block sum” is not explicitly used; rather, the concept is implicit in the description.

“Block Sum Period” means the uninterrupted period of time during which the Block Sum must be calculated. Most often, the term “Block Sum Period” (and indeed the term “sum period”) is not explicitly used; rather, the concept is implicit in the description.

“Capable of Receiving Sweep, Supplemental, and/or Waste Gas” shall mean, for a flare, that the flow of Sweep, Supplemental, and/or Waste Gas is/are not prevented from being directed to the flare by means of closed valves and/or blinds.
“Center Steam” shall mean the portion of Assist Steam introduced into the stack of a flare to reduce burnback.

“Combustion Efficiency” or “CE” shall mean a Flare’s efficiency in converting the organic carbon compounds found in Vent Gas to carbon dioxide. Combustion Efficiency shall be calculated as set forth in Equation 1 in Appendix II of this Permit.

“Combustion Zone Gas” shall mean all gases and vapors found just after a flare tip. This gas includes all Vent Gas, Total Steam, and Premix Assist Air.

“Combustion Zone” shall mean the area of the flare flame where the Combustion Zone Gas combines for combustion.

“Day” or “Days” shall mean a calendar day or days. “Working Day” shall mean a day other than a Saturday, Sunday, or Legal holiday, as that term is defined by Federal Rule of Civil Procedure 6(a)(6). In computing any period of time under this Consent Decree, where the last day would fall on a Saturday, Sunday, or Legal holiday, the period shall run until the close of business on the next Working Day.

“External Power Loss” shall mean a loss in the supply of electrical power to the Mandan Refinery that is caused by events occurring outside the boundaries of the refinery, excluding power losses due to an interruptible power service agreement.

“Flare Gas Recovery System” or “FGRS” shall mean a system of one or more compressors, piping, and associated water seal, rupture disk, or similar device used to divert Potentially Recoverable Gas from a flare and direct Potentially Recoverable Gas to a Fuel Gas System, to a combustion device other than the flare, or to a product, co-product, by product, or raw material recovery system or other system that avoids combustion of the gases.

“Force Majeure” shall mean any event arising from causes beyond the control of the owner/operator, of any entity controlled by the owner/operator, or of the owner/operator’s contractors, that delays or prevents the performance of any obligation under this Permit despite the owner/operator’s best efforts to fulfill the obligation. The requirement that the owner/operator exercise “best efforts to fulfill the obligation” includes using best efforts to anticipate any potential force majeure event and best efforts to address the effects of any such event (a) as it is occurring and (b) after it has occurred to prevent or minimize any resulting delay to the greatest extent possible. “Force Majeure” does not include the owner/operator’s financial inability to perform any obligation. The failure of a Permitting Authority to issue a necessary construction or operating permit in a timely fashion is a force majeure event where the owner/operator submitted a timely and complete permit application and the failure of the Permitting Authority to issue the relevant permit is beyond the control of the owner/operator.

“In Operation” shall mean any and all times that any gas (e.g. Waste Gas, Vent Gas, Purge Gas, pilot Gas) is or may be vented to a flare. A flare that is In Operation is Capable of Receiving Sweep, Supplemental, and/or Waste Gas unless all Sweep, Supplemental, and/or Waste Gas flow is prevented by means of closed valves, and/or blinds.
“Lower Steam” shall mean the portion of Assist Steam piped to an exterior annular ring near the lower part of a flare tip, which then flows through tubes to the flare tip, and ultimately exits the tubes at the flare tip.

“Malfunction” shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

“Net Heating Value” or “NHV” shall mean Lower Heating Value.

“Perimeter Assist Air” means the portion of Assist Air introduced at the perimeter of the flare tip or above the flare tip. Perimeter Assist Air includes air intentionally entrained in Lower and Upper Steam. Perimeter Assist Air includes all Assist Air except Premix Assist Air.

“Pilot Gas” shall mean gas introduced into a Flare tip that provides a flame to ignite the Vent Gas.

“Portable Flare” shall mean a flare that is not permanently installed that receives Waste Gas that has been redirected to it from a flare.

“Potentially Recoverable Gas” shall mean the Sweep Gas, Supplemental Gas introduced prior to a flare’s water seal, and/or Waste Gas directed to a flare’s FGRS or group of flares’ FGRS. Purge Gas and Supplemental Gas introduced between a flare’s water seal and a flare’s tip is not Potentially Recoverable Gas. Hydrogen venting from the steam methane reformer (hydrogen plant) is not Potentially Recoverable Gas. Recycled hydrogen that bypasses the FGRS to reestablish hydrogen balance in the event that hydrogen demand declines or stops rapidly is also not Potentially Recoverable Gas. Excess Fuel Gas and excess gases generated during Shutdown, in turnaround, and during Startup, caused by a gas imbalance that cannot be consumed by fuel gas consumers in the refinery, because there is not sufficient demand for the gas, is not Potentially Recoverable Gas. Nitrogen purges of Flaring Process Units that are being Shutdown, in turnaround and during Startup, or the nitrogen purging of operating flaring process units during a partial refinery turnaround scenario, that cause the NHV of the fuel gas at the exit of the mix drum to fall below 740 BTU/scf, shall not be considered Potentially Recoverable Gas, and may be routed around the FGRS. The gas stream from the spent air vent from the Tesoro Mandan Refinery’s Merox Unit regenerator vessel shall not be considered Potentially Recoverable Gas.

“Premix Assist Air” means the portion of Assist Air that is introduced to the Vent Gas, whether injected or induced, prior to the flare tip. Premix Assist Air also includes any air intentionally entrained in Center Steam.

“Purge Gas” shall mean the minimum amount of gas introduced between a flare header’s water seal and the flare tip necessary to prevent freezing and oxygen infiltration (backflow) into the flare. For a flare with no water seal, the function of Purge Gas is performed by Sweep Gas and, therefore, by definition, such a flare has no Purge Gas.
“Rolling Average” or “y rolling average, rolled n” requires: (i) the calculation of a Block Average during each Block Average Period of n length of time; and (ii) the calculation of the arithmetic mean of the Block Average values for the total number of Block Averages that equals y length of time.

“Rolling Average Period” means the total length of time for which the arithmetic mean of the Block Averages must be calculated.

“Rolling Sum” or “y rolling sum, rolled n” requires: (i) the calculation of a Block Sum during each Block Sum Period of n length of time; and (ii) the adding together of the Block Sum values for the total number of Block Sums that equals y length of time.

“Rolling Sum Period” means the total length of time for which the Block Sums must be added together.

“Scheduled Turnaround” shall mean the Shutdown of any emission unit or process unit that is scheduled at least six months in advance of the Shutdown, and the purpose of such Shutdown is to: (i) perform general equipment cleaning and repairs due to normal equipment wear and tear; (ii) perform required equipment tests and internal inspections; (iii) install any unit or equipment modifications/additions, or make provisions for a future modification or addition; and/or (iv) perform normal end of run catalyst changeouts or refurbishments.

“Shutdown” shall mean the cessation of operation of equipment for any purpose.

“Smoke Emissions” shall have the definition set forth in Section 3.5 of Method 22 of 40 C.F.R. Part 60, Appendix A.

“Standard Conditions” shall mean a temperature of 68 degrees Fahrenheit and a pressure of 1 atmosphere. Unless otherwise expressly set forth in this Permit or a Flare Appendix, Standard Conditions shall apply.

“Startup” shall mean the setting into operation of equipment for any purpose.

“Supplemental Gas” shall mean all gas introduced to the flare in order to improve the combustible characteristics of Combustion Zone Gas.

“Sweep Gas” shall mean, for a flare with a Flare Gas Recovery System, the minimum amount of gas necessary to maintain a constant flow of gas through the flare header in order to prevent oxygen buildup, corrosion or freezing in the flare tip or header; Sweep Gas in these flares is introduced prior to and recovered by the Flare Gas Recovery System. Sweep Gas may be added to certain FGRS bypass lines that contain gas that is not Potentially Recoverable Gas. For a flare without a flare Gas Recovery System, Sweep Gas means the minimum amount of gas necessary to maintain a constant flow of gas through the flare header in order to prevent oxygen buildup, corrosion or freezing in the flare header or tip and to prevent oxygen infiltration (backflow) into the flare tip.

“Total Steam” shall mean the total of all steam that is supplied to a flare and includes, but is not limited to, Lower Steam, Center Steam and Upper Steam.
“Total Steam Mass Flow Rate” or “ṁₚₜₜ” shall mean the mass flow rate of Total Steam supplied to a Flare. Total Steam Mass Flow Rate shall be calculated as set forth in Equation 3 in Appendix II of this Permit.

“Upper Steam,” sometimes called ring steam, shall mean the portion of Assist Steam introduced via nozzles located on the exterior perimeter of the upper end of the flare tip.

“Vent Gas” shall mean all gas found just prior to the flare tip. This gas includes all Waste Gas and that portion of Sweep Gas that is not recovered, Purge Gas and Supplemental Gas, but does not include pilot Gas, Total Steam, or Assist Air.

“Vent Gas Volumetric Flow Rate” or “Qvg-rate” shall mean the volumetric flow rate of Vent Gas directed to a Covered Flare in wet scfm.

“Vent Gas Volumetric Flow Rate” or “Qvg” shall mean the cumulative volumetric flow rate of Vent Gas during the 15-minute Block Average Period in standard cubic feet.

“Visible Emissions” shall mean five minutes or more of Smoke Emissions during any two consecutive hours.

“Waste Gas” shall mean the mixture of all gases from facility operations at a Covered Refinery that is directed to a flare for the purpose of disposing of the gas. Waste Gas does not include gas introduced to a flare exclusively to make it operate safely and as intended; therefore, Waste Gas does not include pilot gas, Total Steam, Assist Air, or the minimum amount of Sweep Gas and Purge Gas that is necessary to perform the functions of Sweep Gas and Purge Gas. Waste Gas also does not include gas introduced to a flare to comply with regulatory requirements; therefore, Waste Gas does not include Supplemental Gas. Depending upon the instrumentation that measures Waste Gas, certain compounds (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, and/or water (steam)) that are directed to a flare for the purpose of disposing of these compounds may be excluded from calculations relating to Waste Gas flow.
**FLARE APPENDIX II**

**GENERAL EQUATIONS**

*Equation 1: “Combustion Efficiency” or “CE” (percent):*

\[
CE = \left( \frac{[CO_2]}{[CO_2] + [CO] + [OC]} \right) \times 100
\]

where:

- \([CO_2]\) = Concentration in volume percent or ppm-meters of carbon dioxide in the combusted gas immediately above the Combustion Zone
- \([CO]\) = Concentration in volume percent or ppm-meters of carbon monoxide in the combusted gas immediately above the Combustion Zone
- \([OC]\) = Concentration in volume percent or ppm-meters of the sum of all organic carbon compounds in the combusted gas immediately above the Combustion Zone, counting each carbon molecule separately where the concentration of each individual compound is multiplied by the number of carbon atoms it contains before summing (e.g., 0.1 volume percent ethane shall count as 0.2 percent OC because ethane has two carbon atoms)

For purposes of using the CE equation, the unit of measurement for CO₂, CO, and OC must be the same; that is, if “volume percent” is used for one compound, it must be used for all compounds. “Volume percent” cannot be used for one or more compounds and “ppm-meters” for the remainder.

*Equation 2: [Reserved].*

*Equation 3: “Total Steam Mass Flow Rate” or “ṁs”*

\[
ṁs = Qs\text{-rate} \times \left( \frac{18}{385.3} \right)
\]

where:

- \(Qs\text{-rate}\) = Total Steam Volumetric Flow Rate
- 385.3 = Conversion factor, standard cubic feet per pound-mole
**Equation 4:** “Vent Gas Mass Flow Rate” or “Qmass-rate”:

\[ Q_{\text{mass-rate}} = Q_{vg} \times \left( \frac{MW_{vg}}{385.3} \right) \]

where:
- \( Q_{vg-rate} \) = Vent Gas Volumetric Flow Rate
- \( MW_{vg} \) = Molecular Weight, in pounds per pound-mole, of the Vent Gas, as measured by the Vent Gas Average Molecular Weight Monitoring System or Analyzer
- 385.3 = Conversion factor, standard cubic feet per pound-mole

**Equation 5:** “Maximum Tip Velocity” or “Vmax”:

\[ \log_{10}(V_{\text{max}}) = \frac{(NHV_{vg} + 1.212)}{850} \]

where:
- \( V_{\text{max}} \) = Maximum allowed Flare Tip Velocity, ft/sec
- \( NHV_{vg} \) = Net heating value of Vent Gas, as determined by Equation 1 or Equation 2 in Appendix III, BTU/scf.
- 1.212 = Constant.
- 850 = Constant.

**Equation 6:** Mass Flow to Volumetric Flow Rate or “Qvol”:

\[ Q_{\text{vol}} = \frac{(Q_{\text{mass}} \times 385.3)}{MW_{t}} \]

where:
- \( Q_{vol} \) = Volumetric flow rate, standard cubic feet per second
- \( Q_{\text{mass}} \) = Mass flow rate, pounds per second
- 385.3 = Conversion factor, standard cubic feet per pound-mole
- \( MW_{t} \) = Molecular weight of the gas at the flow monitoring location, pounds per pound-mole
Equation 7: “15-Minute Block Average Tip Velocity” or “Vtip”:

\[
V_{\text{tip}} = \frac{Q_{\text{cum}}}{(\text{Area} + 900)}
\]

where:

\(V_{\text{tip}}\) = Flare Tip Velocity, feet per second.

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

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

900 = Conversation factor, seconds per 15-minute Block Average.
FLARE APPENDIX III

**Determine the Net Heating Value of the Vent Gas (NHV\textsubscript{vg})**

If compositional analysis data are collected as provided in Condition 2.B.3)c), the owner/operator shall determine the NHV\textsubscript{vg} of a specific sample using the following equation.

**Equation 1**

\[
\text{NHV}_{vg} = \sum_{i=1}^{n} (x_i \times \text{NHV}_i)
\]

- **NHV\textsubscript{vg}** = Net heating value of Vent Gas, BTU/scf.
- **i** = Individual component in Vent Gas.
- **n** = Number of components in Vent Gas.
- **x\textsubscript{i}** = Concentration of component \textit{i} in Vent Gas, volume fraction.
- **\text{NHV}_i** = Net heating value of component \textit{i} according to Table 1 of this appendix, BTU/scf. If the component is not specified in Table 1 of this appendix, 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.

**Direct Net Heating Value by Calorimeter Data without Hydrogen Analyzer**

If direct net heating value by calorimeter monitoring data are collected as provided in Condition 2.B.3)c) but a hydrogen concentration monitor is not used, the owner/operator shall use the direct output of the monitoring system(s) (in BTU/scf) to determine NHV\textsubscript{vg} for the sample.

**Direct Net Heating Value by Calorimeter Data with Hydrogen Analyzer**

If direct net heating value by calorimeter monitoring data are collected as provided in Condition 2.B.3)c) and hydrogen concentration monitoring data are collected as provided in Condition 2.B.3)c)4], the owner/operator shall use the following equation to determine NHV\textsubscript{vg} for each sample measured via the net heating value calorimeter.
\textit{Equation 2}

\[ \text{NHV}_{vg} = \text{NHV}_{measured} + 938 \times \text{H}_2 \]

where:

\begin{align*}
\text{NHV}_{vg} & = \text{Net heating value of Vent Gas, BTU/scf.} \\
\text{NHV}_{measured} & = \text{Net heating value of Vent Gas stream as measured by the continuous net heating value calorimeter, BTU/scf.} \\
x_{H2} & = \text{Concentration of hydrogen in Vent Gas at the time the sample was input into the net heating value calorimeter, volume fraction.} \\
938 & = \text{Net correction for the measured heating value of hydrogen (1,212 – 274), BTU/scf.}
\end{align*}

\textbf{Required Time Period for 15-Minute Block Averages}

Use set 15-minute time periods starting at 12 midnight to 12:15 AM, 12:15 AM to 12:30 AM and so on concluding at 11:45 PM to midnight when calculating 15-minute Block Averages.

\textbf{Monitoring Elections}

When a continuous monitoring system is used as provided in Conditions 2.B.3)(c)1] or 3] and, if applicable, Condition 2.B.3)(c)4], the owner/operator may elect to determine the 15-minute Block Average \(\text{NHV}_{vg}\) using either the feed-forward or direct calculation methods below. The owner/operator may choose to comply using the feed-forward calculation method for some flares at the petroleum refinery and comply using the direct calculation method for other flares. However, for each flare, the owner/operator must elect one calculations method that will apply at all times, and use that method for all continuously monitored flare vent streams associated with that flare. If the owner/operator intend to change the calculation method that applies to the flare, the owner/operator must notify the EPA and NDDEQ 30 Days in advance of such a change.

\textit{Feed-Forward Calculation Method}

When calculating \(\text{NHV}_{vg}\) for a specific 15-minute block:

Use the results from the first sample collected during an event, (for periodic Vent Gas flow events) for the first 15-minute block associated with that event. If the results from the first sample collected during an event (for periodic Vent Gas flow events) are not available until after the second 15-minute Block Period starts, use the results from the first sample collected during an event for the second 15-minute Block Period associated with that event. For all other cases, use the results that are available from the most recent sample prior to the 15-minute Block Period for that 15-minute Block Period for all Vent Gas streams. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at
12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute Block Period from 12:45 a.m. to 1:00 a.m.

**Direct Calculation Method**

When calculating NHV\n\nvg for a specific 15-minute Block Period:

If the results from the first sample collected during an event (for periodic Vent Gas flow events) are not available until after the second 15-minute Block Period starts, use the results from the first sample collected during an event for the first 15-minute Block Period associated with that event. For all other cases, use the arithmetic average of all NHV\n\nvg measurement data results that become available during a 15-minute block to calculate the 15-minute Block Average for that period. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute Block Period from 12:30 to 12:45 a.m.

**Grab Sample Option**

When grab samples are used to determine Vent Gas composition:

Use the analytical results from the first grab sample collected for an event for all 15-minute Block Periods from the start of the event through the 15-minute block prior to the 15-minute block in which a subsequent grab sample is collected. Use the results from subsequent grab sampling events for all 15 minute Block Periods starting with the 15-minute Block Period in which the sample was collected and ending with the 15-minute Block Period prior to the 15-minute Block Period in which the next grab sample is collected. For the purpose of this requirement, use the time the sample was collected rather than the time the analytical results become available.

**Measurement of Separate Gas Streams**

If the owner/operator monitors separate gas streams that combine to comprise the total Vent Gas flow, the 15-minute Block Average net heating value shall be determined separately for each measurement location according to the methods above and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute Block Average net heating value of the cumulative Vent Gas.
Calculation Methods for Determining Combustion Zone Net Heating Value (NHVcz)

Direct Calculation Method

Except as specified in Condition 2.B.5)d)2[b] for the feed-forward calculation method, determine the 15-minute Block Average NHVCZ based on the 15-minute Block Average Vent Gas and assist gas flow rates using Equation 3. For periods when there is neither Assist Steam flow nor Premix Assist Air flow, NHVcz = NHVvg.

Equation 3

$$NHV_{cz} = \frac{(Q_{vg} \times NHV_{vg})}{(Q_{vg} + Q_{s} + Q_{a, premix})}$$

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.
Feed-Forward Calculation Method

Flares that use the feed-forward calculation methodology below and that monitor gas composition or net heating value in a location representative of the cumulative Vent Gas stream and that directly monitor Supplemental Gas flow additions to the flare must determine the 15-minute Block Average NHVcz using Equation 4.

**Equation 4**

\[
NHVcz = \frac{(Qvg - QNG2 + QNG1) \times NHVvg + (QNG2 - QNG1) \times NHVNG}{(Qvg + Qs + Qa, premix)}
\]

where:

- \(NHVcz\) = Net heating value of Combustion Zone Gas, BTU/scf.
- \(NHVvg\) = Net heating value of Vent Gas for the 15-minute Block Period, BTU/scf.
- \(Qvg\) = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.
- \(QNG2\) = Cumulative volumetric flow of Supplemental Gas to the flare during the 15-minute Block Period, scf.
- \(QNG1\) = 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., \(QNG1=QNG2\).
- \(NHVNG\) = Net heating value of Supplemental Gas to the flare for the 15-minute Block Period determined according to the requirements in Condition 2.B.3)c)3, BTU/scf.
- \(Qs\) = Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.
- \(Qa, premix\) = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.
**Calculation Methods for Determining the Net Heating Value Dilution Parameter (NHVdil)**

The owner/operator shall determine the net heating value dilution parameter (NHVdil) as specified below for flares using either the feed-forward calculation method or the direct calculation method, as applicable.

**Calculation Methods for Determining the Net Heating Value Dilution Parameter (NHVdil)**

*Direct Calculation Method*

For flares using the direct calculation method, determine the 15-minute Block Average NHVdil based on the 15-minute Block Average Vent Gas and Perimeter Assist Air flow rates using Equation 5 only during periods when the Perimeter Assist Air is used. 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 5*

\[
NHVdil = \frac{(Q_{vg} \times \text{Diam} \times NHV_{vg})}{(Q_{vg} + Q_s + Q_{a, \text{premix}} + Q_{a, \text{perimeter}})}
\]

where:

- **NHVdil** = 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. Use the area as determined in Condition Error! Reference source not found. and determine the diameter as Diam = 2 \times \sqrt{\frac{\text{Area}}{\pi}}.
- **Q_s** = Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.
- **Q_{a, \text{premix}}** = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.
- **Q_{a, \text{perimeter}}** = Cumulative volumetric flow of Perimeter Assist Air during the 15-minute Block Period, scf.
Feed-Forward Calculation Method

Flares that use the feed-forward calculation methodology and that monitor gas composition or net heating value in a location representative of the cumulative Vent Gas stream and that directly monitor Supplemental Gas flow additions to the flare must determine the 15-minute Block Average NHVdil using the following equation only during periods when the Perimeter Assist Air is used. 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**

\[
\text{NHVdil} = \frac{[(Q_{vg} - Q_{NG2} + Q_{NG1}) \cdot \text{NHVvg} + (Q_{NG2} - Q_{NG1}) \cdot \text{NHVNG}] \cdot \text{Diam}}{(Q_{vg} + Q_{s} + Q_{a.\text{premix}} + Q_{a.\text{perimeter}})}
\]

where:

- **NHVdil** = Net heating value dilution parameter, BTU/ft².
- **NHVvg** = Net heating value of Vent Gas determined for the 15-minute Block Period, BTU/scf.
- **Qvg** = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.
- **QNG2** = Cumulative volumetric flow of Supplemental Gas to the flare during the 15-minute Block Period, scf.
- **QNG1** = 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.
- **NHVNG** = Net heating value of Supplemental Gas to the flare for the 15-minute Block Period determined according to the requirements in Condition 2.B.3)c)3], BTU/scf.
- **Diam** = Effective diameter of the unobstructed cross sectional area of the flare tip for Vent Gas flow, ft. Use the area as determined in Condition Error! Reference source not found. and determine the diameter as \(\text{Diam} = 2 \times (\text{Area}/\pi)^{0.5}\)
- **Qs** = Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.
- **Qa.\text{premix}** = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.
- **Qa.\text{perimeter}** = Cumulative volumetric flow of Perimeter Assist Air during the 15-minute Block Period, scf.
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<th>CMNi (mole per mole)</th>
<th>NHVi (British thermal units per standard cubic)</th>
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<td>5.0</td>
</tr>
<tr>
<td>Methyl-</td>
<td>C3H4</td>
<td>40.06</td>
<td>3</td>
<td>2,088</td>
<td>1.7</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>N2</td>
<td>28.01</td>
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<td>0</td>
<td>∞</td>
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<tr>
<td>Oxygen</td>
<td>O2</td>
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<tr>
<td>Pentane+ (C5+)</td>
<td>C5H12</td>
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<td>42.08</td>
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<td>Water</td>
<td>H2O</td>
<td>18.02</td>
<td>0</td>
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\(^{a}\)The theoretical net heating value for hydrogen is 274 BTU/scf, but for the purposes of the flare requirement in this Permit, a net heating value of 1,212 BTU/scf shall be used.

The sources for values in this table are Appendix to Subpart CC of Part 63 Table 12.
FLARE APPENDIX IV

LIST OF COMPOUNDS A GAS CHROMATOGRAPH MUST BE CAPABLE OF SPECIATING *

Unless an alternative monitoring option is selected from Condition 2.B.3)c), the gas chromatograph must be capable of speciating the Vent Gas into the following except as noted as optional below:

1. Hydrogen
2. Carbon monoxide (optional)
3. Methane
4. Ethane
5. Ethene (aka: ethylene)
6. Propane
7. Propene (aka: propylene)
8. 2-Methylpropane (aka: iso-butane)
9. Butane (aka: n-butane)
10. Butenes and 1,3 butadiene (these constituents will be measured on the same column and the reported result will be one value: the sum of the constituents. A net heating value of 2,690 btu/scf will be assumed.)
11. N-pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.
12. Acetylene (optional)
13. Propadiene (optional)
14. Hydrogen sulfide (optional)

*Outputs from the gas composition analyzer shall be on a mole percent or volume percent basis, except hydrogen sulfide may be on a parts per million basis.
FLARE APPENDIX V

EQUIPMENT AND INSTRUMENTATION TECHNICAL SPECIFICATIONS AND QUALITY ASSURANCE/QUALITY CONTROL REQUIREMENTS

These technical specifications are the minimally acceptable standards. Standards better than or beyond these are acceptable.

I. VENT GAS FLOW METER

1. Velocity Range: 0.1–250 ft/sec
2. Repeatability:
   - ± 10% of reading over the velocity range 0.1 to 1.0 ft/s
   - ± 1% of reading over the velocity range >1.0 to 250 ft/s
3. Design Accuracy: ± 5% initially to 40%, 60%, and 90% of monitor full scale as certified by the manufacturer
4. Operational Accuracy: ± 20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second). ± 5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second).
5. Installation: Applicable AGA, ANSI, API, or equivalent standard
6. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F
7. QA/QC: Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer’s specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the meter has a redundant flow sensor. Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

II. VENT GAS AVERAGE MOLECULAR WEIGHT ANALYZER (may be part of the Vent Gas Flow Meter)

Molecular Weight Range and Accuracy: 2 to 120 gr/grmol, ± 2%
III. STEAM FLOW METERS

For the new steam flow meters that must be installed by the date in Condition 2.B.3)b):

1. Repeatability: ± 5% of reading over the range of the instrument

2. Accuracy: ± 5 percent over the normal range of flow measured or 1.9 liters per minute (0.5 gallons per minute), whichever is greater, for liquid flow. ± 5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow. ± 5 percent over the normal range measured for mass flow.

   a. Installation: Applicable AGA, ANSI, API, or equivalent standard

   b. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F

   c. QA/QC: Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer’s specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor. Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

IV. VENT GAS FLOW METERS: PRESSURE AND TEMPERATURE SENSORS

1. Temperature monitor accuracy: ± 1 percent over the normal range of temperature measured, expressed in degrees Celsius C, or 2.8 degrees C, whichever is greater.

2. Temperature monitor QA/QC: Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer’s specified maximum rated temperature or install a new temperature sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor. Record the results of each calibration check and inspection.

3. Locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.

4. Pressure monitor accuracy: ± 5 percent over the normal range or 0.12 kilopascals (0.5 inches of water column), whichever is greater.
5. Pressure monitor QA/QC: Review pressure sensor readings at least once a week for straight line (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated. Using an instrument recommended by the sensor’s manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following a period of more than 24 hours throughout which the pressure exceeded the manufacturer’s specified maximum rates pressure or install a new pressure sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor. Record the results of each calibration check and inspection.

6. Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.

V. **NET HEATING VALUE BY GAS CHROMATOGRAPH**

A. **General**

1. Accuracy: As specified in Performance Specification 9 of 40 C.F.R. Part 60, Appendix B.

2. 8-Hour Repeatability:

   ± 0.5% of full scale for ranges between 2-100% of full scale;
   ± 1% of full scale for ranges between 0.05-2% of full scale;
   ± 2% of full scale for ranges between 50-500 ppm;
   ± 3% of full scale for ranges between 5-50 ppm;
   ± 5% of full scale for ranges between 0.5-5 ppm.

3. The minimum sampling frequency shall be one sample every 15 minutes.

4. The gas chromatograph shall be capable of speciating all gas constituents listed in Flare Appendix IV, except those listed as optional or if an alternative monitoring option is selected within Condition 2.B.3)c).

5. The sampling line temperature must be maintained at a minimum temperature of 60°C (rather than 120°C).

6. Where technically feasible, the sampling location should be at least two equivalent duct diameters downstream from the nearest control device, point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate occurs. The location should not be close to air in-leakages. Where technically feasible, the location should also be at least 0.5 diameters upstream from the exhaust or control device.
B. **Calibration Standards: Net Heating Value and Analyte Measurements**

For the net heating value and analyte measurements, the gas chromatograph shall be operated and maintained in accordance with Performance Specification 9 ("PS9") of Appendix B of 40 C.F.R. Part 60 except:

1. Follow the procedure in Performance Specification 9 of 40 C.F.R. Part 60, Appendix B, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly).

2. Unless an alternative monitoring option is selected from Condition 2.B.3)c), the analytes to be used are except as noted as optional below:
   a. Hydrogen
   b. Carbon monoxide (optional)
   c. Methane
   d. Ethane
   e. Ethene (aka: ethylene)
   f. Propane
   g. Propene (aka: propylene)
   h. 2-Methylpropane (aka: iso-butane)
   i. Butane (aka: n-butane)
   j. Butenes and 1,3 butadiene (these constituents will be measured on the same column and the reported result will be one value: the sum of the constituents.
   k. N-pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.
   l. Acetylene (optional)
   m. Propadiene (optional)
   n. Hydrogen sulfide (optional)

1. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the owner/operator must calibrate the instrument on all of the gases.

VI. **NET HEATING VALUE BY CALORIMETER**

A. **General**

1. Accuracy: ± 2% of span.
2. Repeatability: ± 1% of reading over full scale.
3. The minimum sampling frequency shall be one sample every 15 minutes.
4. Where feasible, select a sampling location at least two equivalent diameters downstream from and 0.5 equivalent diameters upstream from the nearest
disturbance. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration or emission rate occurs.

B. **Calibration Standards and Quality Assurance**

The net heating value calorimeter shall be operated and maintained in accordance with the following:

1. Calibration requirements should follow manufacturer’s recommendations at a minimum.

2. Temperature Control. Heat and/or cool the sampling system as necessary to ensure proper year-round operation.

VII. **HYDROGEN ANALYZER**

A. **General**

1. Accuracy: ± 2 percent over the concentration measured or 0.1 volume percent whichever is greater.

2. The minimum sampling frequency shall be one sample every 15 minutes.

3. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration occurs.

B. **Calibration Standards and Quality Assurance**

Calibration requirements should follow manufacturer’s recommendations minimum.

VIII. **CALCULATION OF INSTRUMENT DOWNTIME**

A. **Gas Chromatograph**

1. For purposes of calculating the 5% of instrument downtime allowed in any six month period pursuant to Condition 2.B.3g) of the Permit, the time used for gas chromatograph calibration and validation activities required by Subsection V.B. of this Flare Appendix may be excluded.

2. Any hour that meets the requirements as set forth below shall not be counted toward instrument downtime. Specifically:

   a. For a full operating hour (any clock hour where the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas)), if there are at least four valid data points to calculate
the hourly average (that is, one data point in each of the 15-minute sector of the hour), then there is no period of instrument downtime;

b. For a partial operating hour (any clock hour where the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas)), if there is at least one valid data point in each 15-minute sector of the hour in which the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) to calculate the hourly average, then there is no period of instrument downtime; and

c. For any operating hour in which required maintenance or quality assurance activities on the instruments or monitoring systems associated with the flare are performed:

i. If the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) in two or more 15-minute quadrants of the hour and if there are at least two valid data points separated by at least 15 minutes to calculate the hourly average, then there is no period of instrument downtime; or

ii. If the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) in only one 15-minute quadrant of the hour and if there is at least one valid data point to calculate the hourly average, then there is no period of instrument downtime.

B. Net Heating Value Calorimeter

1. For purposes of calculating the 5% of instrument downtime allowed in any six month period pursuant to Conditions 2.B.3)g) and Error! Reference source not found. of the Permit, the time used for NHV calorimeter calibration and validation activities required by Subsection V.B.1 of this Flare Appendix may be excluded.

2. Any hour that meets the requirements of 40 C.F.R. § 60.13(h)(2) shall not be counted toward instrument downtime. Specifically:

(i) For a full operating hour (any clock hour where the flare is Available for Operation for 60 minutes), if there are at least four valid data points to calculate the hourly average (that is, one data point in each of the 15-minute quadrants of the hour), then there is no period of instrument downtime;

(ii) For a partial operating hour (any clock hour where the flare is Available for Operation for less than 60 minutes), if there is at least one valid data point in each 15-minute quadrant of the hour in
which the flare is Available for Operation to calculate the hourly average, then there is no period of instrument downtime; and

(iii) For any operating hour in which required maintenance or quality assurance activities on the instruments or monitoring systems associated with the flare are performed:

(A) If the flare is Available for Operation in two or more quadrants of the hour and if there are at least two valid data points separated by at least 15 minutes to calculate the hourly average, then there is no period of instrument downtime; or

(B) If the flare is Available for Operation in only one quadrant of the hour and if there is at least one valid data point to calculate the hourly average, then there is no period of instrument downtime.
DETERMINING REFINERY-SPECIFIC AND INDUSTRY-AVERAGE COMPLEXITY THROUGH USE OF THE NELSON COMPLEXITY INDEX

DEFINITIONS:

"Applicable EIA Annual Refinery Publication" shall mean the Annual EIA Refinery Publication that was the most recent one posted on EIA's website prior to a refinery's request for an increase in flaring caps.

"Applicable Form EIA-820" shall mean the Form EIA-820 that forms the source for the requesting refinery's capacity information that is summarized and compiled in the Applicable Annual EIA Refinery Publication.

For example, if a refinery requests an increase in flaring caps in March of 2015, the "Applicable Form EIA-820," is the Form EIA-820 that the refinery submitted prior to February 15, 2014, for its capacities as of January 1, 2014, (and not the Form EIA-820 that the Refinery submitted prior to February 15, 2015, for its capacities as of January 1, 2015). This is because the Applicable EIA Annual Refinery Publication is the one published in June of 2014 (i.e., the last one published prior to March of 2015).

"Applicable O&GJ Refining Survey" shall mean the survey that is published in December of the year prior to the year of the Applicable EIA Annual Refinery Publication.

For example, if the Applicable EIA Annual Refinery Publication is the one published in June of 2014, then the Applicable O&GJ Refining Survey is the one published in December of 2013 for capacities as of January 1, 2014.

"EIA" shall mean the United States Energy Information Agency.

"EIA Annual Publication of the Number and Capacity of Petroleum Refineries" or "EIA Annual Refinery Publication" shall mean the information posted on EIA's website on approximately June 21 of each year that compiles and summarizes the data submitted on the Form EIA-820s that each refinery submits prior to February 15 of that year. The most recent EIA Annual Refinery Publication is found at http://www.eia.gov/petroleum/refinerycapacity.

"Form EIA-820" shall mean the annual requirement that each refinery is required to submit to the EIA prior to February 15 of each year. The "Report Year" of a Form EIA-820 refers to the capacities that exist as of January 1 of the "Report Year." A copy of a typical Form EIA-820 is Attachment 1 to this Appendix.

"Oil & Gas Journal Worldwide Refining Survey" or "O&GJ Refining Survey" shall mean the survey that the Oil & Gas Journal publishes in December of each year that lists refining capacities as of January 1 of the following year. A copy of the national refining capacities listed in the December 2014 O&GJ Refining Survey for January 1, 2015 is Attachment 2 to this Appendix.
**REFINERY COMPLEXITY:** The complexity of the refinery is to be calculated using the following formula:

\[ \text{Complexity} = \sum_{i=1}^{n} \frac{\text{NCI}_i \times \text{CAP}_i}{\text{CAP}_{\text{DIST}}} \]

Where:

- \( \text{NCI}_i \) = The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for Flaring Process Unit \( i \).

The throughput capacity for the Refinery's process unit \( i \) in barrels per calendar day, which shall be determined as follows:

- \( \text{CAP}_i \) = (a) for a process unit that is not new or modified and for which the Applicable EIA Annual Refinery Publication lists total US throughput for that process, the capacity, in barrels per calendar day, that the refinery reported for process \( i \) on Part 6 or Part 7 of the Applicable Form EIA-820. If the refinery did not report the capacity of process \( i \) in "barrels per calendar day," but instead reported it in "barrels per stream day," then "barrels per stream day" will be converted to "barrels per calendar day" by multiplying "barrels per stream day" by the following factors: 0.95 for a vacuum distillation unit and 0.9 for all other units; or

  (b) for a process unit that is not new or modified, if and only if the Applicable EIA Annual Refinery Publication does not list total US throughput capacity for that process unit, then the refinery's capacity for that process unit, in barrels per calendar day, listed in the Applicable O&GJ Refining Survey.

  (c) for a process unit that is new or modified, where the new or modified capacity was not reported on the Applicable Form EIA-820, the projected new or modified unit capacity that is set forth in the air permit application(s) for the post-Lodging modification.

The refinery's Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, which shall be determined as follows:

- \( \text{CAP}_{\text{DIST}} \) = (a) if the post-Lodging modification does not affect the crude capacity, the Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, that

  (b) if the post-Lodging modification does affect crude capacity, the projected, new capacity set forth in the air permit application(s) for the post-Lodging modification.

---

1 The references to particular "Parts" or "Codes" of Form EIA-820 are to the Parts and Codes as they exist for the Form EIA-820 that was used for Report Year 2014, included in this Appendix. To that extent that the "Parts" or "Codes" on Form EIA-820 are changed 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 Report Year 2014 will be used.
INDUSTRY AVERAGE COMPLEXITY: The Industry Average Complexity is to be calculated using the following formula:

**Equation 2**

\[
\text{Industry Average Complexity} = \frac{\sum_{i=1}^{n} (NC_i \times ICAP_i)}{ICAP_{DIST}}
\]

Where:

- \( NC_i \) = The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for process unit \( i \)

Total US throughput capacity, in barrels per calendar day, for process unit \( i \) which shall be determined as follows:

- \( ICAP_i \) = (a) From the Applicable EIA Annual Refinery Publication, the total US capacity of process unit \( i \) in barrels per calendar day. For the total US capacity of those process units that the EIA lists only in "barrels per stream day" and not in "barrels per calendar day," the "barrels per stream day" shall be converted to "barrels per calendar day" by multiplying "barrels per stream day" by the following factors: 0.95 for a vacuum distillation unit and 0.9 for all other units.\(^2\)

(b) If and only if the Applicable EIA Annual Refinery Publication does not list a total US throughput capacity for a process unit that the refinery operates, then the total US throughput capacity for that process unit listed in the Applicable O&GJ Refining Survey.

- \( ICAP_{DIST} \) = From the Applicable EIA Annual Refinery Publication, the total "Operable" US Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day.\(^3\)

---

\(^2\) For example, for catalytic reforming, the total US capacity as of January 1, 2015, is 3,392,641 barrels per calendar day. See EIA Annual Refinery Publication at page 46. Note that the capacity for catalytic reforming on page 1 of Attachment 1 should not be used because that is listed in "barrels per stream day," not bpcd. For vacuum distillation, the total US capacity for 2015 is 8,979,485 barrels per stream day. See id. at page 46. This figure would be converted to 8,530,051 barrels per calendar day (8,979,485 x .95).

\(^3\) Total Operable US Atmospheric Crude Oil Distillation Capacity (total \( ICAP_{DIST} \)) of a January 1, 2015, is 17,967,088 barrels per calendar day. See id. at page 42.
### Table 1: 2011 Nelson Complexity Index Coefficients

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<th>Refining Process</th>
<th>NCI Coefficients</th>
</tr>
</thead>
<tbody>
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<td>Distillation Capacity</td>
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<tr>
<td>Vacuum Distillation</td>
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<tr>
<td>Coking</td>
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<td>Catalytic Cracking</td>
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<td>Catalytic Reforming</td>
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</tr>
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<td>Polymerization</td>
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<tr>
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<tr>
<td>Oxygenates</td>
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</tr>
<tr>
<td>Sulfur Extraction</td>
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</table>
### TYPICAL FORM EIA-820

**FORM EIA-820**  
ANNUAL REFINERY REPORT  
REPORT YEAR 2014

This report is mandatory under the Federal Energy Administration Act of 1974 (Public Law 93-275). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning the confidentiality of information in the instructions. Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly makes to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.

<table>
<thead>
<tr>
<th>PART 1: RESPONDENT IDENTIFICATION DATA</th>
<th>PART 2: SUBMISSION/RESUBMISSION INFORMATION</th>
</tr>
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<tbody>
<tr>
<td><strong>EIA ID NUMBER:</strong> 0316008101</td>
<td>If this is a resubmission, enter an &quot;X&quot; in the box: [ ]</td>
</tr>
</tbody>
</table>

If any Respondent Identification Data has changed since the last report, enter an "X" in the box: [ ]

| **Company Name:** Tesoro Refining & Marketing Company LLC |
| **Doing Business As:** |
| **Site Name:** Anacortes |
| **Terminal Control Number (TCN):** T-91-WA-4428 |
| **Physical Address (e.g., Street Address, Building Number, Floor, Suite):** 10200 W. March Point Rd. |
| **City:** Anacortes **State:** WA **Zip:** 98221 |
| **Mailing Address of Contact (e.g., PO Box, RR):** If the physical and mailing addresses are the same, only complete the physical address. 19100 Ridgewood Parkway |
| **City:** San Antonio **State:** TX **Zip:** 78259 |
| **Contact Name:** Laurie Isaac |
| **Phone No.:** (210) 626-4224 **Ext.:**  
| **Fax No.:** (210) 745-4431 |
| **Email address:** Laurie.A.Isaac@tsocorp.com |

**A completed form must be received by February 16th of the designated report year.**

Forms may be submitted using one of the following methods:

- Email: OOG.SURVEYS@eia.gov
- Fax: (202) 586-1076
- Secure File Transfer: https://sso.non.eia.doe.gov/upload/noiceecq.jsp

**Questions? Call:** 202-586-6281

Comments: Explain any unusual or substantially different aspects of your current year's operations that affect the data reported. For example, note new processing units, major modifications or retirement of processing units, sale of refinery, etc. (To separate one comment from another, press ALT+ENTER)
O&GJ REFINING SURVEY JANUARY 1, 2015

2014 Worldwide Refining Survey

Leena Koottungal
Survey Editor/News Writer

All figures in barrels per calendar day (b/cd)

LEGEND
Numbers identify processes in table

**Coking**
1. Fluid coking
2. Delayed coking
3. Other

**Thermal process**
1. Thermal cracking
2. Vitrification

**Catalytic cracking**
1. Fluid
2. Other

**Catalytic reforming**
1. Semi-regenerative
2. Cyclic
3. Continuous regen.
4. Other

**Catalytic hydrocracking**
1. Distillate upgrading
2. Residual upgrading
3. Lube oil manufacturing
4. Other
5. Conventional (high pressure) hydrocracking (<100 barg or 1,450 psig)
6. Mild to moderate hydrocracking (<100 barg or 1,450 psig)

**Alkylation**
1. Sulfinic acid
2. Hydrotreated acid

**Isomerization**
1. C4 feed
2. C5 feed
3. C6 and C7 feed

**Polymerization/Dimerization**
1. Polymerization
2. Dimerization

**Dehydrogenation**
1. MTBE
2. ETBE
3. TAME
4. Other

**Aromatics**
1. BTX
2. Hydrodixylalkylation
3. Cyclohexane
4. Cumene

**Hydrogen**
Hydrogen volumes presented here represent either generation or upgrading to 90+% purity.

**Catalytic reforming**
1. Semi-regenerative reforming is characterized by shutdown of the reforming unit at specified intervals, or at the operator's convenience, for in situ catalyst regeneration.
2. Cyclic regeneration reforming is characterized by continuous or continual regeneration of catalyst in situ in any one of several reactors that can be isolated from and returned to the reforming operation. This is accomplished without changing feed rate or octane.
3. Continuous regeneration reforming is characterized by the continuous addition of this regenerated catalyst to the reactor.
4. Other includes non-regenerative reforming (catalyst is replaced by fresh catalyst) and moving-bed catalyst systems.

**REFINERY REMOVALS**

<table>
<thead>
<tr>
<th>Name</th>
<th>Location</th>
<th>Country</th>
<th>Crude b/cd</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Caltex Australia Ltd</td>
<td>Kuala</td>
<td>Australia</td>
<td>125,000</td>
<td>Converting to fuel import terminal</td>
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NOTES
A Previously Listed as Tencor
B Previously Listed as Sun Oil Co.
C Previously Listed as US Oil & Refining Co.
D Idle
E Previously Listed as North Atlantic Refining Ltd.
F New
G Previously Listed as Western Tier Energy LLC
H Previously Listed as EOG Refining Northernbredea North
I Previously Listed as Shal Refining Manhattan Pte. Ltd.

Capacity definitions:
Capacity expressed in barrels per calendar day (b/cd) is the maximum number of barrels of input that can be processed during a 24-hour period, after making allowances for the following: (a) Types and grades of inputs to be processed, (b) Types and grades of products to be manufactured, (c) Environmental constraints associated with refinery operations, (d) Scheduled downtime such as mechanical problems, repairs, and slowdown. Capacity expressed in barrels per stream day (b/cd) is the amount a unit can process when running at full capacity under optimal feedstock and product slate conditions. An asterisk (*) beside a refinery location indicates that the number has been converted from b/cd to b/cd using the conversion factor 0.93 for crude and vacuum distillation units and 0.9 for all downstream cracking and conversion units.
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<td>3,000</td>
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<td>Yemen Oil Co.—Merito</td>
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<td>—</td>
<td>2,500</td>
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<td><strong>Total</strong></td>
<td></td>
<td>140,000</td>
<td>10,500</td>
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<td>—</td>
<td>—</td>
<td>14,500</td>
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<td>Zimbabwe—Petroleum Refinery Co., Ltd.—Shona Refinery Area, Mbo</td>
<td>23,750</td>
<td>2,280</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>14,300</td>
<td>8,300</td>
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<td>5,527</td>
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<tr>
<td><strong>Total</strong></td>
<td></td>
<td>23,750</td>
<td>2,280</td>
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<td>8,300</td>
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<td>5,527</td>
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</table>
# FLARE APPENDIX VII

<table>
<thead>
<tr>
<th>Refinery</th>
<th>Calculation Basis</th>
<th>Refinery Crude Capacity (b/cd)</th>
<th>Refinery Complexity^2</th>
<th>US Complexity^2</th>
<th>Refinery/US Complexity</th>
<th>30-Day Rolling Average SCFD</th>
<th>365-Day Rolling Average SCFD</th>
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<tr>
<td>Mandan</td>
<td>EIA/O&amp;GJ (b/cd)^1</td>
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<td>6.68</td>
<td>11.19</td>
<td>0.596</td>
<td>313,139</td>
<td>208,759</td>
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Notes:

1) Data in barrels per calendar day (b/cd) are shown on the next page.

2) Nelson Complexity factors are shown on the next page, and are specified in Flare Appendix VI
<table>
<thead>
<tr>
<th>Process</th>
<th>Nelson Complexity Factors</th>
<th>Capacity (b/cd, except H₂ and S)</th>
<th>Source (Note 1)</th>
<th>US Capacity (b/cd, except H₂ and S)</th>
<th>Source (Note 1)</th>
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<tr>
<td>Atmospheric Distillation</td>
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<td>Process</td>
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<td>Capacity (b/cd, except H₂ and S)</td>
<td>Source (Note 1)</td>
<td>US Capacity (b/cd, except H₂ and S)</td>
<td>Source (Note 1)</td>
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<td>Polymerization</td>
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<td>O&amp;GJ (12/5/2013), b/cd</td>
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<td>O&amp;GJ (12/5/2013), b/cd</td>
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<td><strong>Refinery / US Complexity</strong></td>
<td><strong>6.68</strong></td>
<td></td>
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<td><strong>11.19</strong></td>
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</table>

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2014 from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/25/2014 and available at www.eia.gov) were used preferentially, see Typical Form EIA-820 in Appendix VI above, along with the corresponding Tesoro capacities as of 1/1/2014 submitted by Tesoro on Form EIA-820 Annual Refinery Report Parts 5, 6, and 7, Typical Form EIA-820 in Appendix VI above. For processes where US capacities were not included on the US EIA report (i.e. Polymerization and Oxygenates), Oil & Gas Journal Worldwide Refining Survey (published 12/5/2013) calendar day capacities as of 1/1/2014 were used for both the US and Tesoro, see O&GJ Refining Survey in Appendix VI above. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.