TECHNICAL REVIEW DOCUMENT
for
MODIFICATION TO OPERATING PERMIT 96OPAD120

Suncor Energy (U.S.A), Inc. – Commerce City Refinery, Plants 1 and 3 (West)
Source ID 0010003

Prepared by Jacqueline Joyce
December 2016 and January thru May 2017

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SECTION I - Purpose

This document establishes the decisions made regarding the requested modification to the Operating Permit for Suncor Energy’s – Commerce City Refinery Plants 1 and 3. This document provides information describing the type of modification and the changes made to the permit as requested by the source and the changes made due to the Division’s analysis. The following applications to modify the permit are summarized in the table below:

<table>
<thead>
<tr>
<th>Date Received</th>
<th>Modification Type</th>
<th>Modification Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>11/2/2015</td>
<td>Significant Mod</td>
<td>Mod to allow tank degassing activities controlled by a thermal oxidizer. <strong>Replaces 9/29/15 modification.</strong></td>
</tr>
<tr>
<td>12/16/2015</td>
<td>N/A*</td>
<td>No. 3 HDS Rerate Project</td>
</tr>
<tr>
<td>2/17/2016</td>
<td>Minor Mod</td>
<td>Connect the existing East-West Transfer line to the existing rundown line for Tank T80 (revise RVP and emission limits for T34)</td>
</tr>
<tr>
<td>2/26/2016</td>
<td>Administrative Amendment</td>
<td>Replace centrifuge</td>
</tr>
<tr>
<td>5/20/2016</td>
<td>Administrative Amendment</td>
<td>Replace Blower for AIRS pt 634, Zone 4</td>
</tr>
<tr>
<td>5/31/2016</td>
<td>Minor Mod</td>
<td>Revised NSPS Ja monitoring and permitted emissions for AU (P3) flare</td>
</tr>
<tr>
<td>7/11/2016</td>
<td>Minor Mod</td>
<td>Address 3,000 gal underground sump at pipeline receipt station</td>
</tr>
<tr>
<td>9/7/2016</td>
<td>Minor Mod</td>
<td>Install new SVE</td>
</tr>
<tr>
<td>11/8/2016</td>
<td>Significant Mod</td>
<td>Include permit limit for Hydrogen Cyanide (HCN)</td>
</tr>
<tr>
<td>12/20/2016</td>
<td>Administrative Amendment</td>
<td>Revise Responsible Official’s Authorized Representative.</td>
</tr>
<tr>
<td>12/28/2016</td>
<td>Minor Mod</td>
<td>NSPS GGGa Applicability Update</td>
</tr>
<tr>
<td>2/10/2017</td>
<td>Minor Mod</td>
<td>Miscellaneous Process Vent (MPV) Project</td>
</tr>
</tbody>
</table>

*No permit revision is necessary for this modification but since these project involved physical changes or changes to the method of operation, the emissions increase from this project was assessed.

This document is designed for reference during review of the proposed permit by EPA and for future reference by the Division to aid in any additional permit modifications at this facility. The conclusions made in this report are based on the modification applications indicated in the above table, additional information submitted on January 25 and 28, February 11, June 14, November 21 and 29, and December 5, 2016 and January 9, 25, 26 and 30, March 15 and April 18 and 26, 2017, comments on the draft permit and technical review document received on February 28, 2017, e-mail correspondence and telephone conversations with the source. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction
Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

SECTION II - Description of Permit Modification Request/Modification Type

The Operating Permit for the Suncor Plants 1 and 3 was renewed on October 1, 2012 and last revised on February 1, 2016. The expiration date for the permit is October 1, 2017. Each of the modification requests will be addressed separately to identify the modification type and any associated modeling required for that modification.

1. November 2, 2015 Modification (Tank Degassing Thermal Oxidizer)

The purpose of the November 2, 2015 modification is to include the use of a portable thermal oxidizer in the permit to use in tank degassing. The thermal oxidizer is used to control vapors from the degassing of floating roof tanks. The source relies on a contractor to provide the thermal oxidizer and degas the tanks. Currently the source is relying on thermal oxidizers with portable construction permits to perform this task, however, since this is an ongoing activity at the refinery, tank degassing should be addressed in the permit.

Modification Type

Prior to the November 2, 2015 submittal, the source submitted a minor modification application on September 25, 2015. Requested emissions were below 1 ton per year for criteria pollutants, however, uncontrolled VOC emissions were estimated to be over 40 tons per year of VOC.

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications “are not otherwise required by the Division to be processed as a significant modification” (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that “any change that causes a significant increase in emissions” be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.A.7.a). According to Part G of Regulation No. 3 (Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications) the Division considers that a significant increase in emissions is the potential to emit above the major stationary source significant level in Colorado Regulation No. 3, Part D, Section II.A.44. Potential to emit does not include controls, unless the control device is federally enforceable. Since the purpose of this modification is to permit the control device, potential to emit is based on uncontrolled emissions, thus the increase is “significant” and the September 25, 2015 modification application did not qualify as a minor modification.

In addition, Colorado Regulation No. 3, Part C, Section I.A.7.h specifies that every change that “seeks to establish or change a permit term or condition for which there is no corresponding applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject” be processed as a significant permit modification. This essentially means that if a source is taking
limits to avoid requirements such as prevention of significant deterioration (PSD) and/or non-attainment area new source review (NANSR) requirements, the modification cannot be processed as a T5 minor modification. Since uncontrolled emissions are above the significance level for VOC, the thermal oxidizer is limiting emissions below that level and thus avoids NANSR review. Therefore, the September 25, 2015 modification application did not qualify as a minor modification.

In an October 6, 2015 letter to the source, the Division indicated that the modification could not be processed as a minor modification and the source needed to either resubmit it as a significant modification or obtain a construction permit for the thermal oxidizer. The source resubmitted the application as a significant modification on November 2, 2015.

Significant modifications are processed under the same time lines and procedures as new operating permits, including Public Comment and EPA review. Sources cannot institute the proposed modifications addressed in a significant modification application until the revised operating permit has been issued.

Discussion

The initial minor modification application (submitted September 25, 2015) relied on a thermal oxidizer control efficiency of 99.9%. In the Division’s October 6, 2015 letter to the source indicating that the application did not qualify as a minor modification, the Division also noted that we would not allow a control efficiency above 98% to be used without requiring a stack test. The October 6, 2015 letter also indicated that testing had previously been required in a construction permit issued for a thermal oxidizer with a control efficiency of 98%.

The November 2, 2015 application requested a control efficiency of 98%. The application addressed a specific thermal oxidizer unit (i.e. manufacturer’s model number and serial number were provided) and requested emissions were based on a performance test conducted on the thermal oxidizer. The source submitted a similar application for the Plant 2 permit (95OPAD108), addressing the same specific thermal oxidizer. Prior to submittal of the November 2, 2015 application the Division indicated to the source that since they were permitting the same thermal oxidizer in both Title V permits, that only one APEN was required. An APEN was submitted with the Plant 2 application.

Permitting a specific thermal oxidizer would limit the source to using only that unit for tank degassing, thus if the contractor was unable to provide that specific unit or the source went with a different contractor, the permit would either need to be revised or the contractor would need to provide a thermal oxidizer that had a been issued a Colorado portable construction permit. The Division considers that since degassing is a regular activity at the facility, the activity should be addressed in the Title V permit. Therefore, the Division determined that it would be more appropriate to permit the activity and not the specific thermal oxidizer. The tank degassing activities would be based on the same size thermal oxidizer as identified in the application (20 MMBtu/hr). A review of other permit applications for thermal oxidizers used for tank degassing indicates that this represents the high range for size.

In addition, the Division considered that emissions from tank degassing should be
based on actual tank degassing information, rather than a generic performance test based on an unknown source of emissions. Therefore, the Division asked the source to provide revised information on tank degassing emissions, indicated that a performance test would be required on any thermal oxidizer at 98% control efficiency and noted that since tank degassing was being addressed as an activity at each facility, an APEN would be required for each permit.

Suncor submitted revised emission calculations on November 21, 2016. The basis for the emission calculations is a two step process for each floating roof tank. First, EPA TANKs is run to estimate the working losses from the tank for one turnover to represent clingage emissions. Second, to estimate the vapors displaced under the floating roof, calculate working loss emissions from the tank as if it were a fixed roof tank with a height equal to the tank’s legs for one turnover using equations 1-29 and 1-33 in AP-42 Section 7.1 (dated 11/06). Emissions from both steps would be added together to get uncontrolled emissions from degassing a specific tank.

The source’s November 21, 2016 emission estimates are based on the largest tank storing the highest vapor pressure material (gasoline RVP 15), 12 tank degassings per year and a thermal oxidizer control efficiency of 95%. The November 21, 2016 submittal indicates that clingage emissions (step 1) are not routed to the thermal oxidizer. Since these emissions are estimated based on one tank turnover (i.e. emptying tank contents to prepare for degassing), the Division considers that these emissions are reported on the specific APEN for the tank as part of typical tank operations. The same is also true of refilling the tank, after degassing. Thus degassing emissions are only based on step 2 of the calculation process.

VOC emissions from degassing operations from this modification are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Uncontrolled</th>
<th>Requested/Controlled</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clingage (one tank)</td>
<td>10.29 lb</td>
<td>N/A¹</td>
</tr>
<tr>
<td>Degassing (one tank)</td>
<td>16,433 lb</td>
<td>822 lb</td>
</tr>
<tr>
<td>Degassing (12 tanks)</td>
<td>197,196 lb</td>
<td>9,860 lb</td>
</tr>
<tr>
<td>Combustion Emissions</td>
<td>109 lb</td>
<td>109 lb</td>
</tr>
<tr>
<td>(see table below)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Requested Emissions²</td>
<td>197,387 lb (98.7 tons)</td>
<td>9,969 lb (4.98 tons)</td>
</tr>
</tbody>
</table>

¹Emissions from clingage is addressed on the specific APEN for the tank as part of typical tank operations.
²Requested VOC limit is based on degassing 12 tanks and emissions from propane combustion (see table below) at requested level (500 hours per year of operation).

Requested emissions of criteria pollutants and greenhouse gases (GHG) from combustion are based on the design rate of the thermal oxidizer (20 MMBtu/hr) and 500 hours per year of operation as indicated in the tables below:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor¹</th>
<th>Emissions (tons/yr)²</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>At 500 hours per year²</td>
</tr>
<tr>
<td>PM/PM_{10}/PM_{2.5}</td>
<td>0.7 lb/1000 gal</td>
<td>0.04</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.09S lb/1000 gal (0.018 lb/1000 gal)</td>
<td>9.8 x 10⁻⁴</td>
</tr>
<tr>
<td>NOₓ</td>
<td>13 lb/1000 gal</td>
<td>0.71</td>
</tr>
<tr>
<td>VOC</td>
<td>1 lb/1000 gal</td>
<td>0.05</td>
</tr>
<tr>
<td>CO</td>
<td>7.5 lb/1000 gal</td>
<td>0.41</td>
</tr>
</tbody>
</table>

¹From AP-42, Section 1.5 (dated 7/08), Table. 1.5-1. S= sulfur content in gr/100 ft³ and S was assumed to
be 0.2 gr/100 ft³.

2 Emissions are based on a heat content of propane assumed to be 91.5 MMBtu/1000 gal per footnote a, for fuel rate of 218.6 gal/hr of propane.

Since emissions of PM, PM₁₀, PM₂.₅, NOₓ, SO₂ and CO are below the APEN de minimis level at the requested throughput (10,000 MMBtu/yr), limits for those pollutants will not be included in the permit.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor¹</th>
<th>Multiplier²</th>
<th>At 500 hours per year²</th>
<th>At 8760 hours per year</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>62.87 kg/MMBtu</td>
<td>1</td>
<td>693</td>
<td>12,142</td>
</tr>
<tr>
<td>CH₄</td>
<td>3.0 x 10⁻³ kg/MMBtu</td>
<td>25</td>
<td>1</td>
<td>14</td>
</tr>
<tr>
<td>N₂O</td>
<td>6.0x 10⁻⁴ kg/MMBtu</td>
<td>298</td>
<td>2</td>
<td>34</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>696</td>
<td>12,190</td>
</tr>
</tbody>
</table>

¹From 40 CFR Part 98, Tables C-1 and C-2.
²From 40 CFR Part 98, Table A-1.

An APEN was submitted for this permit on January 26, 2017.

The degassing requirements addressed in the permit apply only to degassing of floating roof tanks. The source has indicated that fixed roof tanks can be degassed every 10 to 20 years based on tank conditions but these tanks generally store low vapor pressure materials, so emissions from any degassing activities from these tanks are low. Therefore, degassing of fixed roof tanks is not addressed in the permit.

In addition, in their comments on the draft permit and technical review document, received on February 28, 2017, the source indicated that the thermal oxidizer would only be used to degas tanks containing liquids with a true vapor pressure greater than or equal to 0.75 psia. Tanks with a capacity of 40,000 gallons or greater and stored-liquid maximum true vapor pressure greater than or equal to 0.75 psia is a Group 1 tank under MACT CC. The source submitted information indicating that emissions during degassing of tanks less than 0.75 psia were below 1 ton/yr.

Note that the Title V permit for Plant 2 (95OPAD108) will also include an emission limit for tank degassing at the same requested level as for the Plants 1/3 permit. The limit for the Plants 1/3 permit would apply to Plants 1/3 equipment and the limit for the Plant 2 permit (95OPAD108) would apply to Plant 2 equipment. Requested (permitted) emissions from both permits together (10 tons/yr VOC) are less than the significance levels.

Regulatory Requirements

The thermal oxidizer is subject to the opacity requirements in Colorado Regulation No. 1 (20%/30%).

Tank degassing is not a new activity at the refinery. In the past the source has conducted tank degassing using thermal oxidizers with portable construction permits. Sources are prohibited from disposing of VOC emissions by evaporation or spillage unless RACT is applied as noted in Colorado Regulation No. 7, Section V.A. New or modified sources are subject to RACT requirements as specified in Colorado Regulation No. 3, Part B, Section III.D.2.a and Colorado Regulation No. 7, Section II.C.2. Tank degassing is not a new activity, although it is being newly permitted and RACT must be
applied (vapors cannot be vented without applying RACT), thus the RACT requirements in Regulations No. 3 apply. Use of the thermal oxidizer and the requested VOC emission limit are considered to be RACT.

The thermal oxidizer is considered a fuel gas burning device under 40 CFR Part 60 Subparts J and Ja and as such is subject to an H₂S limit for fuel gas and subsequent monitoring requirements (continuous H₂S monitoring system). An alternative monitoring plan (AMP) was approved by EPA on December 17, 2013 for thermal oxidizers used for tank degassing at petroleum refineries. Although the AMP was issued to the subcontractor who owns the specific thermal oxidizer included in the November 2, 2015 application, EPA indicated in a February 11, 2016 email that the AMP approved for the subcontractor would be valid for the source’s Title V permit. The provisions from the AMP will be included in the permit.

Note that NSPS Ja includes an exemption from the SO₂ requirements in 60.102a(g)(1)(iii), as follows:

The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section.

There was no discussion of the exemption in the preamble to the rule, so it wasn’t clear whether the term “generator” in this exemption referred to equipment that is generating the vapors from degassing or an internal combustion engine combusting tank degassing vapors and generating electricity. At the request of the Division, EPA indicated in a December 5, 2016 email that the exemption would not apply to a thermal oxidizer and that an AMP is required.

2. December 16, 2015 Additional Information Submittal (No. 3 HDS Rerate Project)

The purpose of the December 16, 2015 submittal is to change the method of operation of the No. 3 Hydrodesulfurizer (HDS) to increase the unit’s design throughput. In addition, minor physical changes will be made to ensure the long term stability of the modified process operation. The December 16, 2015 submittal was submitted as a minor modification application.

The Division reviewed the information in the December 16, 2015 submittal, requested additional information and made comments on the calculations and assumptions used in the December 16, 2015 application. Responses to the comments and revised calculations were submitted via email on January 25 and 28, 2016. The following items were important to note in regards to the application:

- Since there is no modified equipment associated with the No. 3 HDS rerate project that is itself a source of emissions and emissions from new components (e.g., flanges, valves, etc.) associated with the project are below the APEN de minimis level, the Division considers that a modification to the Title V permit is not necessary. A description of and emissions estimates associated with this project are being memorialized in the technical review document for the latest revision to the Plants 1 and 3 permit.
- According to the application, based on a 1997 relief valve study, the capacity of the No. 3 HDS prior to the project is 21,396 barrels per day. A recently completed material balance indicated that the feed controller for the No. 3 HDS is reading low by 1,500 barrels per day (with the feed controller correction, the pre-project maximum is 22,896 barrels per day). Note that previous analyses for past projects relied on the “low” feed controller values but according to the source, this would not have affected the applicability analyses for past projects because the unit feed controller was used for both the baseline and future projected throughputs for the No. 3 HDS. The Division would agree with this statement.

- A subsequent relief valve study indicated that the capacity of the No. 3 HDS can be increased by approximately 2,500 barrels per day to reach a “new” capacity of 25,352 barrels per day.

- Although this project results in an increased throughput for the No. 3 HDS, the No. 4 HDS will see a reduction in throughput (feed will be rerouted from the No. 4 HDS to the No. 3 HDS). The 2,500 barrel per day increase to the No. 3 HDS, results in an increase in diesel production of 300 barrels per day.

- Increases from the loading racks include increases from the No. 1 and No. 3 crude unit modification projections (addressed in February 1, 2016 revised Title V permit), as well as the 300 barrels per day of increased diesel production from this modification. The No. 1 and No. 3 crude unit projects are separate projects but fall within the five year period after this particular modification, so are included in projected actual emissions.

- The application notes that for this project there will not be an increase in the utilization of the refinery utility units (e.g. hydrogen plant, boilers, cooling towers, sulfur recovery plants, etc.), nor does it increase the utilization or production of process units upstream of the No. 3 HDS.

- The projected increase in emissions from the project is shown in the table below. Note that although a PSD modification cannot be triggered by greenhouse GHG emissions by itself and the increase in criteria pollutant emissions are below the significance level, GHG emissions were estimated for this project and are shown in the table below.

<table>
<thead>
<tr>
<th>Source</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>PM/PM10/PM2.5</th>
<th>SO2 (^1)</th>
<th>GHG (CO2e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fugitive VOCs from new components</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.03</td>
<td></td>
</tr>
<tr>
<td>No. 3 HDS heaters (H-31 &amp; H-32)(^2)</td>
<td>2.51</td>
<td>1.27</td>
<td>0.11</td>
<td>0.29</td>
<td>4.69</td>
<td>2,570</td>
</tr>
<tr>
<td>Storage Tanks(^2,^3)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.07</td>
<td></td>
</tr>
<tr>
<td>Loading Rack (Truck Rack)(^2)</td>
<td>0.17</td>
<td>0.93</td>
<td>3.02</td>
<td>0.02</td>
<td>0.02</td>
<td>392</td>
</tr>
<tr>
<td>Total</td>
<td>2.68</td>
<td>2.20</td>
<td>3.23</td>
<td>0.31</td>
<td>4.71</td>
<td>2,962</td>
</tr>
<tr>
<td>PSD/NANSR Significance Level (T5 Minor Mod Level)</td>
<td>40</td>
<td>100</td>
<td>40</td>
<td>25/15/10</td>
<td>40</td>
<td>75,000</td>
</tr>
</tbody>
</table>

\(^1\)Baseline \(\text{SO}_2\) emissions were based on the \(\text{H}_2\text{S}\) concentration in fuel gas during the baseline period (6.87 ppm). Projected actual emissions were based on the NSPS \(\text{H}_2\text{S}\) limit of 162 ppmvd (3-hr average).

\(^2\)Not a modified emission unit and no increase in permit limits were requested. Increased emissions are from the...
projected increase in emissions due to increased utilization of equipment.

3Includes T72, T3801 and T774

As discussed above, since emissions from the new components are less than the APEN de minimis level (1 ton/yr of VOC) and there are no changes to the emission or throughput limits for existing equipment associated with this project, no changes to the permit are necessary

3. **February 17, 2016 Modification (East-West Transfer Line, Tank T80)**

The purpose of the February 17, 2016 modification is to install a new section of piping (a “jumper”) from the existing East-West transfer line to the existing rundown line for Tank 80 in the Plant 1 Oil Movements Division (OMD1). The new jumper will be used to route debutanized gasoline from the Plant 2 FCCU to the finished product blending in OMD1. Debutanized gasoline from the Plant 2 FCCU is currently blended in the Plant 2 Oil Movements Division (OMD2). The jumper is needed in the event that the gasoline blending tankage in OMD2 is down for routine maintenance or inspection. This project will also provide flexibility for blending debutanized gasoline from the Plant 2 FCCU in the Plant 1 online blenders, versus batch blending in Plant 2.

**Modification Type**

The source indicated that this modification would qualify as a minor modification. Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications “are not otherwise required by the Division to be processed as a significant modification” (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that “any change that causes a significant increase in emissions” be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.A.7.a). According to Part G of Regulation No. 3 (Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications) the Division considers that a significant increase in emissions is the potential to emit above the major stationary source significant level in Colorado Regulation No. 3, Part D, Section II.A.44.

According to the application, the east-west transfer line, T80 jumper project will not affect the operation of any upstream process units or refinery utilities (e.g. hydrogen plant, sulfur recovery plant, boilers, cooling towers, etc.). Since the refinery currently has the capability to transfer finished product gasoline between Plants 1 and 2 for loading, the loading racks are not affected by this project. It is expected that in addition to new piping components, affected sources include three tanks (T80, T75 and T34). The change in emissions from this project are below the significance level, as shown in the table below; therefore, this project qualifies as a minor modification.

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>Increase in VOC Emissions (tons/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fugitive VOCs from new piping components</td>
<td>0.04</td>
</tr>
<tr>
<td>Tank T80</td>
<td>3.32</td>
</tr>
<tr>
<td>Tank T75</td>
<td>1.37</td>
</tr>
<tr>
<td>Tank T34</td>
<td>6.56</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>11.29</strong></td>
</tr>
<tr>
<td>PSD/NANSR Significance Level (T5 Minor Mod Level)</td>
<td>40</td>
</tr>
</tbody>
</table>
Discussion

Fugitive VOC emissions from new piping components were estimated as indicated in the table below:

<table>
<thead>
<tr>
<th>Component Type</th>
<th>No. of Components</th>
<th>Service</th>
<th>Emission Factor (lb/component/hr)</th>
<th>Control Efficiency</th>
<th>Emission Factor Source</th>
<th>Emissions (lbs/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Valves</td>
<td>8</td>
<td>Light liquid</td>
<td>0.02403</td>
<td>95%</td>
<td>“Protocol for Equipment Leak Emission Estimates”, EPA-453/R-95-017, November 1995, Table 2-2 (emission factors) and Table 5-3 (control efficiencies)</td>
<td>84</td>
</tr>
<tr>
<td></td>
<td></td>
<td>gaseous</td>
<td>0.05908</td>
<td>96%</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Heavy Liquid</td>
<td>0.00051</td>
<td>N/A</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Flanges/Connectors</td>
<td>3</td>
<td>Any</td>
<td>0.00055</td>
<td>81%</td>
<td></td>
<td>3</td>
</tr>
<tr>
<td>Relief Valves</td>
<td></td>
<td>gaseous</td>
<td>0.35274</td>
<td>95%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total (lbs/yr)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>87</td>
</tr>
<tr>
<td>Total (tons/yr)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.04</td>
</tr>
</tbody>
</table>

1 Control efficiencies are from the following sources. **Valves** - Table 5-3 of EPA’s Protocol for Equipment Leaks (EPA-453/R-95-017), HON. **Flanges/Connectors** - Table 5-3 of EPA’s Protocol for Equipment Leaks (EPA-453/R-95-017) the monitoring requirements in Colorado Reg 7 (annual monitoring) are consistent with the monitoring frequency required by the HON MACT. **Relief Valves and Pumps** Control efficiency is assumed to be 95%, which is consistent with the Division’s policy for flare and is consistent with the requirement for closed vent systems and control devices in 40 CFR Part 60 Subparts VV and VVa.

Emission increases from the tanks were estimated using EPA TANKs vers 4.09d and are based on the difference between baseline actual emissions and projected actual emissions. The baseline period was January 1, 2012 through December 31, 2013. Projected actual emissions were based on the following assumptions:

- Tank T80 increase in throughput of 6,000 barrels per day (this is the maximum potential volume of debutanized gasoline rundown from Plant 2 FCCU) and assumes year round storage of highest vapor pressure of debutanized gasoline (RVP 13).
- Tank T75 increase in throughput of 540,000 barrels per year (assumes all reformate used for blending at Plant 2 would be transferred to Plant 1).
- Tank T34 projected actual emissions are based on permitted throughput for this tank but at a higher vapor pressure (RVP 15).

Tanks T80 and T75 are grandfathered (no permit limits for throughput and emissions), thus no permit revisions are necessary for these tanks.

Since emissions from new piping components are below the APEN de minimis level (1 ton/yr), permit limits are not required for the new piping components. Emissions from the new components shall be reported on the plant wide APEN for fugitive VOC emissions.

As part of this modification, the source has requested a change to the allowable vapor pressure for materials stored in Tank T34. Although the source has requested an increase in the stored material vapor pressure, requested emissions are lower than current permitted emissions (9.6 tpy requested, 14 tpy current permit limit). The source indicated in the application that when the tank was permitted in 2001 that emissions were incorrectly estimated using EPA Tanks. Specifically, the tank was permitted assuming the tank’s unslotted guidepoles are equipped with an ungasketed sliding cover. However, the sliding cover for T34’s unslotted guidepoles is equipped with a
gasket, thus the lower requested emissions. It should be noted that baseline actual emissions were estimated with the appropriate fittings for T34. The change in permitted emissions from T34 is – 4.4 tpy.

**Modeling Requirements**

This project results in a decrease in permitted emissions for Tank T34, projected increases in emissions from grandfathered tanks T80 and T75 and a slight increase in VOC emissions from new piping components. Although VOC is a precursor for ozone, in general accurate and cost effective methods for modeling ozone impacts from stationary sources are not available. Therefore, individual source ozone modeling is not routinely requested for permit modifications.

4. **February 26, 2016 Modification (Replace Centrifuge)**

The purpose of the February 26, 2016 modification is to replace the centrifuge.

**Modification Type**

The replacement centrifuge serves the same purpose as the original centrifuge, there is no associated change to the wastewater treatment system emissions, no change to the control device and the permit does not list a specific make, model or serial number for the centrifuge. The centrifuge system is listed in Section I, Condition 5.1 of the permit and indicates that the centrifuge system consists of a mix/frac tank and the centrifuge. There will be no mix/frac tank associated with the replacement centrifuge; therefore, the primary change to the permit is a minor revision to the equipment description in Section I, Condition 5.1 and various other references in the permit to “centrifuge system”. The Division considers this to be a minor administrative change and thus considers that this modification qualifies as an administrative amendment and the source submitted the application as an administrative amendment.

**Modeling Requirements**

This modification does not change permitted emissions for the wastewater treatment system; therefore, modeling is not required.

5. **May 20, 2016 Modification (Replace Blower for AIRS pt 634, Zone 4)**

The purpose of the May 20, 2016 modification is to replace a blower for one of the remediation systems (AIRS pt 634, zone 4). The replacement blower is similar, same manufacturer but different model number and has a slightly higher flow rate (850 scfm vs. 800 scfm). The application notes that there will be a nominal increase in emissions with the higher throughput rate on the new blower but no change in the emission limit is necessary.

**Modification Type**

The replacement blower is similar to the existing blower, serves the same purpose and utilizes the same control device, although the replacement unit has a slightly higher capacity. No changes are necessary to emission limits. The only changes to the permit necessary are the model and serial number of the blower and the blower capacity. The blower serial number is listed in Section I, Condition 5.2 (table) and the blower capacity is listed in Section I, Condition 5.2 (table) and Section II, Condition 68.6.2. The Division considers these changes are minor administrative changes and thus considers that this
modification qualifies as an administrative amendment and the source submitted the application as an administrative amendment.

**Modeling Requirements**

This modification does not change permitted emissions for the AIRS pt 634 SVE system; therefore, modeling is not required.


The purpose of the May 31, 2016 modification is to revise the NSPS Ja compliance methodology for the asphalt unit (Plant 3) flare and to revise the permitted gas consumption and emission limitations.

The source submitted modification applications addressing the AU flare in December 2014 and June 2015 to include NSPS Ja requirements (Ja was expected to be triggered in the 2016 turnaround) and to set emission limits. The requested revisions to the AU flare were reflected in the February 1, 2016 revised Title V permit.

**Modification Type**

The December 2014 and June 2015 applications were processed as minor modifications. The source has submitted this application as a minor modification.

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications “are not otherwise required by the Division to be processed as a significant modification” (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that “any change that causes a significant increase in emissions” be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.A.7.a). According to Part G of Regulation No. 3 (Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications) the Division considers that a significant increase in emissions is the potential to emit above the major stationary source significant level in Colorado Regulation No. 3, Part D, Section II.A.44. As noted under the “Discussion” section below, requested emissions from the AU flare, as well as the change in permitted emissions, are below the significance level. Therefore, the Division agrees that this modification can be processed as a minor modification.

**Discussion**

In the December 2014 modification application, the source indicated that the AU flare would comply with NSPS Ja requirements through the alternative monitoring requirements for flares equipped with water seals (see 60.107a(g)). This alternative is available for flares that are categorized as an emergency flare, secondary flare or flare with a flare gas recovery device and relies on monitoring the pressure in the flare gas header between the knock-out pot and water seal. Flares that comply with the alternative requirements are not subject to certain sulfur and flow monitoring requirements. However, this alternative may only be used for flares that have four or fewer pressure exceedances in any 365-consecutive calendar day period.

According to the May 31, 2016 application, the AU flare exceeded the four or fewer
pressure exceedances and can no longer rely on the alternative monitoring method in 60.107a(g). Therefore, the source will install H₂S, (total reduced sulfur) TRS and flow monitors for the flare.

In addition, the source requested a change in the allowable throughput to the flare to address a higher sweep gas flow rate and to revise the quantity of process gases that will be combusted by the flare based on recent data from the No. 3 crude unit startup and shutdown. The source has also revised the SO₂ emissions to reflect a higher H₂S content. Previously the AU flare was permitted based on the NSPS Ja limit of 162 ppmv but for this modification requested that SO₂ emissions be based on an H₂S content of 20,000 ppmv. It should be noted that the flare H₂S limit of 162 ppmv does not apply to process upset gases (gases generated by a refinery process unit or ancillary equipment as a result of startup, shutdown, upset or malfunction), thus permitting at a H₂S concentration higher than the limit is not inconsistent with the NSPS Ja requirements.

Requested emissions from the flare are as follows:

<table>
<thead>
<tr>
<th></th>
<th>NOₓ</th>
<th>CO</th>
<th>PM/PM₁₀/PM₂.₅¹</th>
<th>SO₂²</th>
<th>VOC³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Requested Emissions</td>
<td>1.19</td>
<td>5.42</td>
<td>0.13</td>
<td>16.8</td>
<td>11.53</td>
</tr>
<tr>
<td>Current Permitted</td>
<td>0.87</td>
<td>4.0</td>
<td>0.10</td>
<td>0.14</td>
<td>7.3</td>
</tr>
<tr>
<td>Emissions</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Change in Emissions</td>
<td>0.32</td>
<td>1.42</td>
<td>0.03</td>
<td>16.66</td>
<td>4.23</td>
</tr>
</tbody>
</table>

| PSD/NANSR           |      |      |                  |      |      |
| significance level  | 40   | 100  | 25/15/10         | 40   | 40   |
| (T₅ Minor Mod Level)|      |      |                  |      |      |

¹PM = PM₁₀ = PM₂.₅. PM/PM₁₀/PM₂.₅ was not considered in the application but is based on the requested throughput and emissions factors from AP-42; Section 1.4 (dated 7/98), Table 1.4-2.
²SO₂ emissions from sweep and pilot gas (natural gas) are based on a sulfur content of 0.55 grains per 100 scf. SO₂ emissions from process gases are based on 20,000 ppmv H₂S.
³The VOC emission factor was changed since the submittal of this application, thus the VOC emissions were revised to reflect the new emission factor and requested throughput.

The May 30, 2016 requested emissions limits for PM, PM₁₀ and PM₂.₅ are all below the APEN de minimis level and because emissions are all based on emission factors and the requested throughput limit, emission limitations for these pollutants will not be included in the permit.

Modeling Requirements

The AU flare is equipped with a flare gas recovery unit and as a result the combustion of process gases in the AU flare is an intermittent process. According to the application, process gases from a plant turnaround and the flare skid down time are generated over a period of days. Emissions associated with a plant turnaround would generally consist of startup, shutdown and malfunction of the process unit, as process units are shut down during a plant turnaround to conduct maintenance activities. Plant turnarounds are generally conducted every five years.

In a March 1, 2011 EPA Memorandum from Tyler Fox to Regional Air Division Directors, “Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO₂ National Ambient Air Quality Standard”, EPA asserts that “existing modeling guidelines provide sufficient discretion for reviewing authorities to exclude
certain types of intermittent emissions from compliance demonstrations”. Therefore, the Division considers that, for the AU flare modeling of emissions from the combustion process gases is not warranted for the short term national ambient air quality standards (NAAQS).

As shown in the table below, requested annual emissions (including emissions from process gases) and short-term emissions from non-intermittent sources (i.e., pilot and sweep gas) are below the modeling thresholds, therefore, modeling is not warranted for this modification.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Modeling Threshold</th>
<th>Project Emissions¹</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Annual</td>
<td>Short-Term</td>
</tr>
<tr>
<td>SO₂</td>
<td>40 tons/yr</td>
<td>0.46 lbs/hr</td>
</tr>
<tr>
<td>NO₂</td>
<td>40 tons/yr</td>
<td>0.46 lbs/hr</td>
</tr>
<tr>
<td>CO</td>
<td>100 tons/yr</td>
<td>23 lbs/hr</td>
</tr>
<tr>
<td>PM¹₀</td>
<td>15 tons/yr</td>
<td>82 lbs/day</td>
</tr>
<tr>
<td>PM₂.⁵</td>
<td>5 tons/yr</td>
<td>11 lbs/day</td>
</tr>
</tbody>
</table>

¹For annual emissions, emissions are based on requested emissions. Hourly emissions are based on emissions from non-intermittent flows, i.e., pilot and sweep gas.

In addition, this project results in an increase in permitted VOC emissions of 4.23 tons/yr. Although VOC is a precursor for ozone, in general accurate and cost effective methods for modeling ozone impacts from stationary sources are not available. Therefore, individual source ozone modeling is not routinely requested for permit modifications.

7. **July 11, 2016 Modification (Address 3,000 Gal Sump at Pipeline Receipt Station)**

In September 2013, the source submitted an application for the pipeline receipt station. This project is discussed in the technical review document (beginning on page 10) prepared in support of the May 7, 2014 revised Title V permit. Permitted equipment associated with the pipeline receipt station were fugitive emissions from new piping components and an emergency generator. The purpose of the July 11, 2016 modification is to appropriately permit a 3,000 gallon underground sump that was installed as part of the initial project but was not addressed in the September 2013 permit application.

**Modification Type**

The initial pipeline receipt station application was submitted and processed as a minor modification. This application to address the changes to the initial project was submitted as a minor modification. Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications “are not otherwise required by the Division to be processed as a significant modification” (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that “any change that causes a significant increase in emissions” be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.A.7.a). According to Part G of Regulation No. 3 (Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications) the Division considers that a significant increase in emissions is the potential to emit above the major stationary
source significant level in Colorado Regulation No. 3, Part D, Section II.A.42.

In addition to the 3,000 gallon underground sump, this modification also addresses the final piping component count associated with project. The table below indicates estimated emissions from the entire pipeline receipt station project, which are below the significance level. Thus the Division agrees that this project qualifies as a minor modification.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Pollutant (tons/yr)</th>
<th>Unit</th>
<th>Pollutant (tons/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipeline Receipt Station – Fugitive VOC emissions from leaking components</td>
<td>PM/ PM$<em>{10}$/ PM$</em>{2.5}$</td>
<td>SO$_2$</td>
<td>NO$_X$</td>
</tr>
<tr>
<td>Emergency Generator$^{2,3}$</td>
<td>$2.15 \times 10^{-2}$</td>
<td>$1.50 \times 10^{-3}$</td>
<td>0.18</td>
</tr>
<tr>
<td>Underground Sump$^3$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$2.15 \times 10^{-2}$</td>
<td>$1.50 \times 10^{-3}$</td>
<td>0.18</td>
</tr>
<tr>
<td>PSD/NANSR significance level (T5 Minor Mod Level)</td>
<td>25/15/10</td>
<td>40</td>
<td>40</td>
</tr>
</tbody>
</table>

1Requested emissions for the May 7, 2014 revised permit for piping components (fugitive VOCs) from the pipeline receipt station were 1.56 tons/yr.

2Emissions based on 500 hours per year of operation per a September 5, 1995 EPA memo indicating that potential to emit from emergency generators may be based on 500 hours per year of operation. Emissions are as indicated in the technical review document (page 12) to support the May 7, 2014 revised permit.

3Since emissions from this equipment is below the APEN de minimis level, emission limits were not included in the permit for this equipment.

**Modeling Requirements**

As previously discussed, the pipeline receipt station was initially permitted in the May 7, 2014 revised Title V permit and as discussed in the technical review document to support that modification (see pages 12-13), modeling was not warranted for that project.

This revision results in an increase in VOC emissions of 0.29 tons/yr. As indicated in the technical review document to support that modification (see page 12), individual source ozone modeling is not routinely requested for permit modifications.

**Discussion**

In the July 11, 2016 modification the source did not submit revised emission calculations for the revised component count but noted the difference in the count. Based on the revised component count, fugitive emissions are based on the following:
The July 11, 2016 application includes a discussion of applicability to various regulatory requirements for the underground sump. Specifically the source noted that the sump is subject to the requirements in 40 CFR Part 61 Subpart FF § 61.343 (BWON tank requirements), specifically 61.343(b).

The application also notes that the tank is subject to the requirements in Colorado Regulation No. 7, Section VI.A.1 and indicates that while the tank is potentially subject to the requirements in Section VI.B.3 (petroleum liquid storage tanks less than 40,000 gal), the requirements do not apply since Section VI.B.3 addresses the transfer of petroleum liquids into tanks and not the tank itself. Petroleum liquids enter the sump via pipeline and are not received via a delivery vessel thus the requirements do not apply. The Division agrees with that assessment.

The application goes on to indicate, that the requirements in Regulation No. 7, Section VI.C do not apply as the sump is not a gasoline terminal (VI.C.2) and is not a bulk station (VI.C.3).

The application did not address the requirements in Reg 7, Section III.A, which apply to the sump and Sections IV.B.2 and VII, which don’t apply because the tank is less than 40,000 gallons.

Also not mentioned in the application is that the pipeline receipt station sump is not subject to the requirements in NSPS Kb, since the tank is less than 75 m³ (~20,000 gallons) and is not subject to storage vessel requirements in MACT CC, since the tank is less than 40 m³ (~10,000 gallons).

8. September 7, 2016 Modification (Install New SVE)

The purpose of the September 7, 2016 modification is to install a new soil vapor extraction (SVE) system for the Plant 1 analytical laboratory to address hydrocarbon vapors detected. The SVE system will consist of a blower, rated at 107 scfm routed to two carbon canisters in series.
Modification Type

The source indicated that this modification would qualify as a minor modification.

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications “are not otherwise required by the Division to be processed as a significant modification” (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that “any change that causes a significant increase in emissions” be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.A.7.a). According to Part G of Regulation No. 3 (Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications) the Division considers that a significant increase in emissions is the potential to emit above the major stationary source significant level in Colorado Regulation No. 3, Part D, Section II.A.44.

Since this is a new, unpermitted SVE system, potential to emit is based on uncontrolled emissions and as indicated in the table below, both uncontrolled and controlled VOC emissions are below the significance level:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emissions (tons/yr)</th>
<th>PSD/NANSR Significance Level (T5 Minor Mod Level)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Uncontrolled</td>
<td>Controlled</td>
</tr>
<tr>
<td>VOC</td>
<td>14.6</td>
<td>0.29</td>
</tr>
</tbody>
</table>

1Emissions are based on the measured VOC concentration (2,000 ppm), the blower design rate (107 scfm) and 8760 hours per year of operation. Controlled emissions are based on a control efficiency of 98% for two carbon canisters in series.

Discussion

Although the laboratory SVE system is being permitted well after the initial remediation equipment was permitted, the provisions related to the Sand Creek remediation equipment still apply, including provisions to keep emissions from the remediation project below the significance level. To that end, the limit on VOC emissions from insignificant activities and provisions for relaxing emissions in Section II.70 would still apply.

The source submitted a cancellation notice for the north guard shack SVE (AIRS pt 626) on June 14, 2016 but never submitted an application to remove this unit from the permit. However, based on the draft permit language submitted with this modification, the source has removed references from AIRs pt 626 and in some instances is replacing those references with the proposed new laboratory SVE. It appears that the north guard shack equipment (or similar equipment) is being used for the laboratory SVE (e.g., the same identifier (CC-SUN-2) is used for the carbon canisters). The September 7, 2016 application seems to confirm that is the case. Therefore, the Division is removing the north guard shack SVE system as part of this modification.

The limit for insignificant activities has been revised to reflect permitted emissions from the remediation equipment as a result of this modification, which includes the removal of the north guard shack SVE and the addition of the laboratory SVE. The limit was set in the same manner as discussed in the technical review document (page 24) for the current Title V permit (last revised February 1, 2016). Specifically, VOC emissions from insignificant activities are based on 39.9 tons per year minus permitted VOC emissions.

Page 16
With the removal of the north guard shack SVE and the addition of the laboratory SVE, permitted VOC emissions from the AS/SVE and AS systems, the tanks and tank loading is 27.3 tons/yr.

9. **November 8, 2016 Modification (Include Hydrogen Cyanide (HCN) Permit Limit for Fluid Catalytic Cracking Unit (FCCU))**

The purpose of the November 8, 2016 modification is to include a federally enforceable limit on HCN emissions from the FCCU.

**Modification Type**

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications “are not otherwise required by the Division to be processed as a significant modification” (Colorado Regulation No. 3, Part C, Section X.A.6). Significant modifications are defined in Colorado Regulation No. 3, Part C, Section I.A.7 and Section I.A.7.h specifies that every change that “seeks to establish or change a permit term or condition for which there is no corresponding applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject” be processed as a significant permit modification. There is no underlying requirement for limits on specific HAP compounds and HAP limits are generally only included permits in order for a source to become a minor source for HAP emissions. In this situation, the source is requesting a federally enforceable limit on HCN emissions in order to avoid reporting requirements under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and Emergency Planning and Community Right-to-Know-Act (EPCRA). Reporting emissions as a continuous release is not required if the release is federally permitted. Since the purpose for the HCN emission limit is to avoid CERCLA and EPCRA reporting requirements, the Division considers that this modification should be processed as a significant modification. The source submitted the application as a significant modification.

**Modeling Requirements**

There are no federal or Colorado ambient air quality standards for HCN, therefore, modeling is not required.

**Discussion**

The HCN limit is based on the results of a performance test conducted on September 2, 2015. The test was conducted for purposes of CERCLA/EPCRA reporting, in lieu of using the HCN emission factor that was included in the April 2015 revisions to AP-42, Section 5.1 (an HCN emission fact had not previously been included in this section of AP-42).

The December 1, 2015 revisions to 40 CFR Part 63 Subpart UUU, required that a one-time performance test for HCN be conducted on FCCUs by August 1, 2017. The source received approval from EPA to use the September 2, 2015 performance test to meet the Subpart UUU testing requirement (the regulation allowed sources to use tests conducted between March 31, 2011 and February 1, 2016 to fulfill the test requirement).
The annual HCN limit will be based on the lb/1000 lb coke burn-off rate, in lieu of the lb/barrel emission factor included in the application, since HCN is generated during regeneration of the catalyst. The source submitted information on November 29, 2016 indicating the requested annual coke burn-off rate and emissions based on that rate. A federally enforceable permit limit must also be practically enforceable, therefore, in addition to including the requested HCN limit in the permit, the permit will also include an annual throughput (coke burned-off) limit. Compliance with the annual limits shall be monitored by recording throughput and calculating emissions monthly. In addition, the permit will require a one-time performance test to monitor compliance with the annual emission limit.

10. **December 20, 2016 Modification (Change Responsible Official’s Designated Representative)**

The purpose of the December 20, 2016 modification is to change the Responsible Official’s Designated Representative.

**Modification Type**

This modification qualifies as an administrative amendment as provided for in Colorado Regulation No. 3, Part A, Section I.B.1.a.(ii).

11. **December 28, 2016 Modification (NSPS GGGa Applicability Update)**

The purpose of this modification is to reflect the applicability of NSPS GGGa to various process units due to maintenance activities conducted during the 2016 and 2011 turnarounds. With respect to NSPS GGGa applicability, a modification can be triggered by the addition and replacement of components if such installation is triggered by a capital expenditure. The application indicates that the addition and replacement of components during the 2016 and 2011 turnarounds were considered modifications and triggered NSPS GGGa requirements for several process units. The application also notes that an NSPS GGGa modification was not triggered for some process units (cryogenic vapor recovery unit, P1 fuel gas system, No. 4 HDS, rerun unit and vapor recovery unit), however, the source is opting to follow the NSPS GGGa requirements for those process units anyway.

The application only addresses an update for NSPS GGGa applicability to various process units and does not address an increase in emissions from new components. According to the application, emission increases as a result of the 2016 turnaround, as well as emission increases from other modifications and/or maintenance activities that occurred outside of the 2016 turnaround were addressed in previously submitted modification applications.

**Modification Type**

The source submitted this modification as a minor modification.

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications “are not otherwise required by the Division to be processed as a
significant modification” (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that “any change that is considered a modification under Title I of the Federal Act” be processed as a significant permit modification (Colorado Regulation No. 3, Part C, Section I.A.7.b). Part G of Regulation 3 Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications describes more specifically what constitutes a modification under Title I of the Federal Act and it indicates that a modification which triggers either Section 111 (new source performance standards (NSPS)) or 112 (national emission standards for hazardous air pollutant (NESHAP)) requirements is considered a Title I modification. The Division considers that modifications that trigger either NSPS or NESHAP requirements that are already included in the Title V permit for another emission unit may be processed as a minor modification, since the specific NSPS or NESHAP requirements are already addressed in the permit. The NSPS GGGa requirements are already included in the Title V permit for other emissions units. Therefore, the Division agrees that this modification can be processed as a minor modification.

Modeling Requirements

There are no emission increases associated with this modification, so modeling is not required.

Discussion

The source submitted information on January 25 and 30, 2017 to address some questions the Division had regarding the information in the application. In the January 25, 2017 additional information submittal, the source agreed that sources subject to NSPS GGGa requirements did not have to comply with the MACT CC requirements and that the MACT CC requirements could be removed from Section II.34 (fugitive VOC equipment leaks with permit limits), since all component groupings in this section were subject to NSPS GGGa requirements only. In addition, they noted that that they were not aware of any remaining process units that were subject to NSPS GGG requirements, so the NSPS GGG requirements could be removed from Section II.33 (fugitive VOC equipment leaks without permit limits), as well as from Section II.51 (NSPS GGG requirements).

In the January 30, 2017 submittal, the source clarified that there can be components subject to MACT CC requirements but not NSPS GGGa requirements, thus the MACT CC requirements in Section II.33 and the NSPS VV requirements in Section II.65 should remain in the permit. Note that the MACT CC requirements refer to NSPS VV.


The purpose of this modification is to address the new equipment necessary to meet the requirements for miscellaneous process vents (MPVs) in the December 1, 2015 Refinery Sector Rule Revisions. The December 1, 2015 revisions primarily addressed revisions to the refinery MACTs (40 CFR Part 63 Subparts CC and UUU), although minor revisions were also made to the refinery NSPS requirements (40 CFR Part 60 Subparts J and Ja). The December 1, 2015 revisions removed “episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring and catalyst transfer operations” from the exception to the definition of
miscellaneous process vent, making this equipment newly subject to the MACT CC requirements. In addition, the December 1, 2015 revisions to MACT CC included provisions to identify some MPVs as maintenance vents, which are subject to work practice standards.

Under the MACT CC revisions, Group 1 MPVs need to reduce emissions using a flare. The February 10, 2017 modification, addresses the new equipment necessary to route MPVs to the Plant 1, Plant 3 and GBR flares and the increased throughput and emissions to the flares as a result of the revised requirements.

In order to comply with the new MPV requirements, the source is proposing to install new connections to the flare header systems. The new flare connection systems will consist of permanent, direct equipment connections as well as purge manifolds for as needed, temporary connections. The installation of purge manifolds and other flare header connections will allow the source to prepare equipment for maintenance by purging with steam and/or nitrogen to the flare and will result in routing materials to the flares that were previously routed directly to the atmosphere. The purge manifolds will be located in process units throughout the refinery and will include a knock out manifold fabricated from piping, with several hose connections available to temporary equipment connections. Vapors routed to the purge manifolds will be directed to the flare and any collected liquid will be drained to the process sewer system. The installations will be steam traced for freeze protection. The application is based on a conservative assumption indicating that 30 purge manifolds will be installed, although it is anticipated that fewer manifolds will actually be needed.

In reviewing this application, the Division requested clarification, corrections or additional information on the information submitted. Responses to these information requests were submitted on March 15, April 18 and April 26, 2017. Revised spreadsheets were submitted on April 26, 2017.

A separate application was filed for the Plant 2 equipment which is addressed in a separate Title V permit (95OPAD108), although emission increases from both permits are aggregated together for applicability purposes. This application and the Plant 2 application noted that Plant 2 has several group 1 MPVs but did not identify any group 1 MPVs associated with Plants 1 or 3.

Modification Type

The source indicated that this modification would qualify as a minor modification. Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications “are not otherwise required by the Division to be processed as a significant modification” (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that “any change that causes a significant increase in emissions” be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.A.7.a). According to Part G of Regulation No. 3 (Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications) the Division considers that a significant increase in emissions is the potential to emit above the major stationary source significant level in Colorado Regulation No. 3, Part D, Section II.A.44.

The application indicates that based on the major stationary source applicability test
conducted in accordance with the requirements in Colorado Regulation No.3, Part D, Section I.B (actual-to-projected-actual emissions for existing equipment and actual-to-potential for new equipment), that increases from the project (which includes the Plant 2 equipment (identified in a separate Title V permit (95OPAD108)), are below the significant level. The results of the applicability test are indicated in the table below:

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>Increase in Actual Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM/PM$<em>{10}$/PM$</em>{2.5}$</td>
</tr>
<tr>
<td>P1/3 Fugitive VOCs from New Components$^1$</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>P2 Fugitive VOCs from New Components$^1$</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Plant 1 Flare$^2$</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Plant 2 Flare$^2$</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Plant 3 Flare$^2$</td>
<td>0.07</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>GBR Flare$^2$</td>
<td>0.17</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>P1/3 Boilers$^2$</td>
<td>0.02</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>P2 Boilers$^2$</td>
<td>0.04</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>0.30</td>
</tr>
<tr>
<td>PSD/NANSR Significance Level (T5 Minor Mod Level)</td>
<td>25/15/10</td>
</tr>
</tbody>
</table>

$^1$New Equipment. Emission increases are based on potential (requested) emissions (actual emission = 0 for new equipment).

$^2$Existing Equipment. Emission increases are based on the projected actual emissions minus baseline actual emissions.

In regards to whether a modification qualifies as a minor modification, in addition to the major stationary source applicability test, the Division reviews the change in permitted emissions to see if the project would also qualify as a Title V minor modification.

Although not necessarily part of the project, the source has requested to update the flare emission factors to the current AP-42 emission factors and revise the emission limits appropriately. For the Plant 1 and 3 flares, only the VOC emission factor needs to be changed. The current permit (last revised February 1, 2016) includes the April 2015 revised AP-42 emission factors and only the VOC emission factor was revised in December 2016. The Plant 1 flare is not subject to emission limitations, thus the change in emission factors qualifies as a minor modification (no change in permitted emissions). The emission factors from the GBR flare are not the specific AP-42 factors although the CO emission factor relies on AP-42, so the source has requested that the emission factor for CO be revised. The change in permitted emissions from the GBR and Plant 3 flare are shown in the table below:
### Emission Unit

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM/PM\textsubscript{10}/PM\textsubscript{2.5}	extsuperscript{1}</th>
<th>SO\textsubscript{2}</th>
<th>NO\textsubscript{X}</th>
<th>CO</th>
<th>VOC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>P3 Flare</strong></td>
<td>Requested Emissions</td>
<td>0.13</td>
<td>16.9</td>
<td>1.2</td>
<td>5.43</td>
</tr>
<tr>
<td></td>
<td>Current Permitted Emissions</td>
<td>0.10</td>
<td>0.14</td>
<td>0.87</td>
<td>4.0</td>
</tr>
<tr>
<td></td>
<td>Change in Emissions</td>
<td>0.03</td>
<td>16.76</td>
<td>0.33</td>
<td>1.43</td>
</tr>
<tr>
<td><strong>GBR Flare</strong></td>
<td>Requested Emissions</td>
<td>0.31</td>
<td>0.21</td>
<td>2.9</td>
<td>11.1</td>
</tr>
<tr>
<td></td>
<td>Current Permitted Emissions</td>
<td>0.31</td>
<td>0.21</td>
<td>2.9</td>
<td>13.2</td>
</tr>
<tr>
<td></td>
<td>Change in Emissions</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Fugitive VOCs from new components</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Change in Emissions</strong></td>
<td></td>
<td>0.03</td>
<td>16.76</td>
<td>0.33</td>
<td>-0.67</td>
</tr>
<tr>
<td>PSD/NANSR Significance Level (T5 Minor Mod Level)</td>
<td></td>
<td>25/15/10</td>
<td>40</td>
<td>40</td>
<td>100</td>
</tr>
</tbody>
</table>

\textsuperscript{1} The current permit does not include emission limits for PM/PM\textsubscript{10}/PM\textsubscript{2.5}. Current permitted emissions are based on current permitted throughput and AP-42 emissions from Section 1.4 (dated 7/98), Table 1.4-2 (total PM, converted to lb/MMBtu based on a heat content of 1020 Btu/scf per footnote a)

\textsuperscript{2} Current permitted emissions are based on the emissions in the February 1, 2016 revised Title V permit and not the emissions requested in the May 31, 2016 minor modification application. Given the close proximity of the MPV project and the May 31, 2016 minor modification application, this level is more appropriate.

Note that the change in permitted emissions is due both in part to additional flow to the flares based on the MPV project, as well as the change in emission factors and fugitive VOC emissions from new piping components. Since the change in permitted emissions for the Plant 3 and GBR flares and new piping components are below the significance level, the modification to the Plants 1 and 3 permit qualifies as a minor modification.

**Modeling Requirements**

A modeling analysis is generally conducted based on requested (permitted) emissions, thus a modeling analysis would be triggered based on the change in permitted emissions. Since no change in permitted emissions was requested for the P1 flare or the boilers, the emission increases for these units are not factored into the decision to determine if modeling is warranted.

There is an increase in permitted VOC emissions for both the Plants 1/3 and Plant 2 equipment (flares and new piping components). Although VOC is a precursor for ozone, in general accurate and cost effective methods for modeling ozone impacts from stationary sources are not available. Therefore, individual source ozone modeling is not routinely requested for permit modifications.

For the other pollutant emissions, the increase in permitted emissions from both the Plant 1/3 permit (96OPAD120) and Plant 2 permit (95OPAD108) are summarized below:
### Modeling Threshold Change in Permitted Emissions

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Modeling Threshold</th>
<th>Change in Permitted Emissions¹</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Annual</td>
<td>Short-Term</td>
</tr>
<tr>
<td>SO₂</td>
<td>40 tons/yr</td>
<td>0.46 lbs/hr</td>
</tr>
<tr>
<td>NO₂</td>
<td>40 tons/yr</td>
<td>0.46 lbs/hr</td>
</tr>
<tr>
<td>CO</td>
<td>100 tons/yr</td>
<td>23 lbs/hr</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>15 tons/yr</td>
<td>82 lbs/day</td>
</tr>
<tr>
<td>PM₂.₅</td>
<td>5 tons/yr</td>
<td>11 lbs/day</td>
</tr>
</tbody>
</table>

¹Change in permitted emissions, based on current P1/3 permit (96OPAD120) and does not reflect the requested change in emissions from the May 31, 2016 minor modification application.

Note that the increase in annual emissions for all pollutants is below the modeling thresholds, thus modeling is not warranted with respect to the annual emissions. The Division’s Stationary Sources Program PS Memo 10-01 (see pages 47-48) specifies that for minor sources with requested emissions below 40 tons/yr of NOₓ and SO₂, that a compliance demonstration is not required for the short-term (hourly) SO₂ and NO₂ national ambient air quality standard (NAAQS). Therefore a modeling analysis was not conducted for the 1-hr SO₂ and NO₂ NAAQS. With respect to the short-term CO, PM₁₀ and PM₂.₅ NAAQS, it is not expected that the short-term increases in CO, PM₁₀ and PM₂.₅ emissions would be above the modeling thresholds as the anticipated increases in throughput to the flares from routing MPVs to them are low and are not expected to occur all at one time (i.e., all increases vent to a flare in an hour or day). Therefore modeling was not warranted for short-term CO, PM₁₀ and PM₂.₅ NAAQS.

### Discussion

Except for the new piping components, the units affected by this modification are existing units. Therefore, the major stationary source applicability test is based on a comparison of baseline actual emissions (BAE) to projected actual emissions (PAE).

Emissions from the new piping components are based on the following emission factors and component counts:

<table>
<thead>
<tr>
<th>Component Type</th>
<th>No. of Components</th>
<th>Service</th>
<th>Emission Factor (lb/component/hr)</th>
<th>Control Efficiency¹</th>
<th>Emission Factor Source</th>
<th>Emissions (lbs/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>P1/3</td>
<td>P2</td>
<td></td>
<td></td>
<td></td>
<td>P1/3</td>
</tr>
<tr>
<td>Valves</td>
<td>86</td>
<td>91</td>
<td>Light liquid</td>
<td>0.02403</td>
<td>95%</td>
<td>905</td>
</tr>
<tr>
<td></td>
<td>278</td>
<td>164</td>
<td>Gaseous</td>
<td>0.05908</td>
<td>96%</td>
<td>5,755</td>
</tr>
<tr>
<td>Flanges/Connectors</td>
<td>647</td>
<td>509</td>
<td>Any</td>
<td>0.00055</td>
<td>81%</td>
<td>593</td>
</tr>
<tr>
<td>Sampling Systems</td>
<td>Any</td>
<td></td>
<td></td>
<td>0.03307</td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td>Pumps</td>
<td>1</td>
<td></td>
<td>Light liquid</td>
<td>0.25133</td>
<td>88%</td>
<td>264</td>
</tr>
<tr>
<td>Relief Valves</td>
<td>1</td>
<td></td>
<td>Gaseous</td>
<td>0.35274</td>
<td>N/A</td>
<td>154</td>
</tr>
<tr>
<td>Total (lbs/yr)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>7,407</td>
</tr>
<tr>
<td>Total (tons/yr)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3.70</td>
</tr>
</tbody>
</table>

¹Control efficiencies are from the following sources. **Valves and Pumps** - Table 5-3 of EPA’s Protocol for Equipment Leaks (EPA-453/R-95-017). **Flanges/Connectors** - Table 5-3 of EPA’s Protocol for Equipment Leaks (EPA-453/R-95-017) the monitoring requirements in Colorado Reg 7 (annual monitoring) are consistent with the monitoring frequency required by the HON MACT.

For the boilers, the source estimated the incremental increase in fuel consumption...
necessary to supply the steam for the steam tracing necessary for the new purge manifolds. The application notes that the steam demand may be handled by changes in other operations at the plant but has conservatively assumed that the boilers will be required to produce the incremental steam production.

According to the application, although the new purge manifolds will be equipped with drain lines, no operational changes or increases in emissions are expected for the wastewater collection and treatment systems, since any material drained through the new purge manifolds would have otherwise been drained to the sewer system as part of current practices for maintenance preparation.

Flares - BAE

For the flares, BAE is based on the period of January 1, 2013 through December 31, 2014 and BAE was adjusted to reflect changes to the CO and VOC emission factors for the flares that occurred after the baseline period. The AP-42 emission factor changes for the flare resulted in a higher VOC emission factor and a lower CO emission factor. Note that for the Plant 2 flare (addressed in 95OPAD108), the VOC emission factor used is based on the actual composition of flared gases and a presumed destruction and removal efficiency (DRE). Although Colorado Regulation No. 3, Part D, Section II.A.4.b, only allows BAE to be adjusted downward to reflect emissions that were not in compliance with limits established during the baseline period or limits that currently apply, the Division considers that it is appropriate for BAE and PAE to be compared on the same basis, with the same emission factors, since the emission factors are unrelated to the project.

In addition, the revised emission factors indicate a better estimate of emissions from the flares and represents what emissions would have been during the baseline period, had those factors been available. Thus correcting BAE to reflect the revised emission factors is appropriate.

As specified in Colorado Regulation No. 3, Part D, Section II.A.4.b.(ii) BAE shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the baseline period. SO\textsubscript{2} emissions for the P2 flare during the baseline period exceeded the emission limitation requested in a minor modification application on January 4, 2010, so BAE was adjusted downward to reflect the emission limitation for SO\textsubscript{2}.

Flares (PAE)

The source projected that actual emissions (PAE) for all but the Plant 1 flare would be based on current permitted levels (including those that had been requested in minor modification applications but not yet incorporated into the respective permits) plus the increased flow rate (and subsequent emissions) anticipated due to routing MPVs to the flares in order to comply with the MPV requirements in 40 CFR Part 63 Subpart CC.

For the Plant 1 flare, which has no permitted emission limits, the source projected PAE of PM, PM\textsubscript{10}, PM\textsubscript{2.5}, NO\textsubscript{X} and CO based on the emission factors and highest monthly throughput during the baseline period (August 2014), annualized, i.e., multiplied by twelve plus the increased flow rate (and subsequent emissions) anticipated due to routing MPVs to it. For SO\textsubscript{2} emissions from the Plant 1 flare, projected PAE is based on
the highest monthly SO\textsubscript{2} emissions (February 2014) during the baseline period, annualized plus the increased flow rate (and subsequent emissions) anticipated from the flares due to routing MPVs to it.

The estimated emissions and flow due to routing MPVs to the flare are shown in the table below:

<table>
<thead>
<tr>
<th>Unit</th>
<th>Throughput (MBtu/yr)</th>
<th>Emissions (tons/yr)</th>
<th>CO</th>
<th>NO\textsubscript{x}</th>
<th>VOC</th>
<th>PM/PM\textsubscript{10/2.5}</th>
<th>SO\textsubscript{2}</th>
</tr>
</thead>
<tbody>
<tr>
<td>P1 Flare</td>
<td>1,075,998</td>
<td></td>
<td>0.17</td>
<td>0.04</td>
<td>0.36</td>
<td>4.01E-03</td>
<td>1.68</td>
</tr>
<tr>
<td>P3 (AU) Flare</td>
<td>84,578</td>
<td></td>
<td>0.01</td>
<td>2.88E-03</td>
<td>0.03</td>
<td>3.15E-04</td>
<td>0.06</td>
</tr>
<tr>
<td>GBR Flare</td>
<td>343,636</td>
<td></td>
<td>0.05</td>
<td>0.01</td>
<td>0.11</td>
<td>1.28E-03</td>
<td>2.54E-06</td>
</tr>
<tr>
<td>P2 Flare</td>
<td>4,189,367</td>
<td></td>
<td>0.65</td>
<td>0.14</td>
<td>0.73</td>
<td>0.02</td>
<td>0.02</td>
</tr>
</tbody>
</table>

Flares – Adjustments to PAE

PAE may be adjusted downward to reflect emissions that the unit could have accommodated during the baseline period and that are unrelated to the project, including increased utilization due to demand growth.

For the P1, GBR and P2 flares, the source estimated PM, PM\textsubscript{10}, PM\textsubscript{2.5}, NO\textsubscript{x}, CO and VOC emissions that could have been accommodated based on the emission factors and highest monthly throughput during the baseline period, annualized. In order to use this method, the monthly throughput would have to be consistently achievable for the annual period, i.e., the annualized throughput could not have exceeded any throughput or emission limitations that applied during the baseline period. The highest monthly throughputs used were based on August 2014 for the P1 flare, October 2014 for the GBR flare and November 2014 for the P2 flare. The October 2014 data used for the GBR flare was, when annualized, below an annual throughput limit that was applicable for 4 months during the baseline period (January thru April 2013).

The above method was not used for the P3 (AU) flare, since the flare was generally operated with a consistent flow rate (emissions were from combustion of pilot and sweep gas) that is determined based on hours of operation. Therefore, the source estimated PM, PM\textsubscript{10}, PM\textsubscript{2.5}, NO\textsubscript{x}, CO and VOC emissions that could have been accommodated based on the emission factors and the highest monthly flow rate divided by 31 and multiplied by 365.

For the P1 and GBR flares, the source estimated SO\textsubscript{2} emissions that could have been accommodated based on the highest monthly SO\textsubscript{2} emissions during the baseline period, annualized. The highest monthly SO\textsubscript{2} emissions were February 2014 for the P1 flare and November 2013 for the GBR flare.

The above method was not used for the P3 (AU) flare, since the flare was generally operated with a consistent flow rate (emissions were from combustion of pilot and sweep gas) that is determined based on hours of operation and a consistent SO\textsubscript{2} concentration (gases combusted were natural gas). Therefore, the source estimated SO\textsubscript{2} emissions that could have been accommodated based on the emission factors and the highest monthly SO\textsubscript{2} emissions divided by 31 and multiplied by 365.
BAE for the P2 flare exceeded the SO\textsubscript{2} emission limit, therefore, BAE was adjusted down to reflect permitted SO\textsubscript{2} emissions. Capable of accommodating emissions were estimated to be permitted SO\textsubscript{2} emissions from the P2 flare.

The resulting emissions increases for the flares, based on the applicability test are shown in the table below:

<table>
<thead>
<tr>
<th></th>
<th>Emissions (tons/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CO</td>
</tr>
<tr>
<td><strong>P1 Flare</strong></td>
<td></td>
</tr>
<tr>
<td>Baseline</td>
<td>39.12</td>
</tr>
<tr>
<td>PAE</td>
<td>96.52</td>
</tr>
<tr>
<td>Capable of Accommodating</td>
<td>96.36</td>
</tr>
<tr>
<td>Excludable\textsuperscript{1}</td>
<td>57.24</td>
</tr>
<tr>
<td>Adjusted PAE</td>
<td>39.28</td>
</tr>
<tr>
<td><strong>Change in Emissions\textsuperscript{2}</strong></td>
<td>0.16</td>
</tr>
<tr>
<td><strong>P3 (AU) Flare</strong></td>
<td></td>
</tr>
<tr>
<td>Baseline</td>
<td>2.42</td>
</tr>
<tr>
<td>PAE</td>
<td>5.43</td>
</tr>
<tr>
<td>Capable of Accommodating</td>
<td>2.42</td>
</tr>
<tr>
<td>Excludable\textsuperscript{1}</td>
<td>0.00E+00</td>
</tr>
<tr>
<td>Adjusted PAE</td>
<td>5.43</td>
</tr>
<tr>
<td><strong>Change in Emissions\textsuperscript{2}</strong></td>
<td>3.01</td>
</tr>
<tr>
<td><strong>GBR Flare</strong></td>
<td></td>
</tr>
<tr>
<td>Baseline</td>
<td>5.06</td>
</tr>
<tr>
<td>PAE</td>
<td>11.09</td>
</tr>
<tr>
<td>Capable of Accommodating</td>
<td>3.55</td>
</tr>
<tr>
<td>Excludable\textsuperscript{1,3}</td>
<td>0.00</td>
</tr>
<tr>
<td>Adjusted PAE</td>
<td>11.09</td>
</tr>
<tr>
<td><strong>Change in Emissions\textsuperscript{2}</strong></td>
<td>6.03</td>
</tr>
<tr>
<td><strong>P2 Flare</strong></td>
<td></td>
</tr>
<tr>
<td>Baseline</td>
<td>50.52</td>
</tr>
<tr>
<td>PAE</td>
<td>66.97</td>
</tr>
<tr>
<td>Capable of Accommodating</td>
<td>75.71</td>
</tr>
<tr>
<td>Excludable\textsuperscript{1,4}</td>
<td>24.54</td>
</tr>
<tr>
<td>Adjusted PAE</td>
<td>42.43</td>
</tr>
<tr>
<td><strong>Change in Emissions\textsuperscript{2,5}</strong></td>
<td>0.00</td>
</tr>
</tbody>
</table>

\textsuperscript{1}Excludable emissions equal capable of accommodating minus baseline emissions.

\textsuperscript{2}Change in emissions is adjusted PAE minus baseline.

\textsuperscript{3}If capable of accommodating emissions are below baseline emissions, excludable emissions are zero.

\textsuperscript{4}Excludable emissions cannot include emission related to the project. Although capable of accommodating emissions are based on baseline emissions and thus not related to the project (newly defined MPVs were not routed to the flare during the baseline period), excludable emissions are based on capable of accommodating minus baseline emissions from the project.

\textsuperscript{5}If the change in emissions is negative (i.e. adjusted PAE > baseline), then the change in emissions is zero, since reductions cannot be included in determining project emissions. Emissions reductions would be included in a netting analysis, if warranted.

Miscellaneous

Colorado Regulation No. 3, Part D, Section I.B.4 specifies that the information
submitted for the applicability analysis shall be included in an appendix of the Title V permit for sources that conduct the actual-to-projected actual test for a project that requires a minor permit modification under Colorado Regulation No.3, Part C, Section X. Presumably, Regulation No. 3 requires that this information (i.e., the actual-to-projected-actual applicability test) be included in an appendix, so that the Division can determine whether projected emissions predicted by the project are exceeded and pursue an investigation, if applicable, to determine if the increases above the projected level were caused by the project.

For the asphalt unit (P3) flare, the GBR unit flare and the plant 2 flare (address in 95OPAD108), projected actual emissions are the same as requested (permitted) emissions, thus including this information in an appendix would not be necessary. However, the main (P1) flare has no permitted emission limits, thus the applicability analysis will be included in an appendix of the permit. Note that the applicability analysis includes equipment from both operating permits associated with this facility 96OPAD120 (Plants 1/3) and 95OPAD108 (Plant 2).

13. **Modification Summary**

The modifications addressed in this technical review document were submitted as individual modifications. Since a number of modifications were submitted within a period of approximately 18 months, this summary is intended to discuss whether the modifications were appropriately addressed for purposes of major stationary source permit requirements (PSD and NANSR).

Twelve submittals are noted in the table on page 1 of this document and all were minor modifications for purposes of PSD and/or NANSR requirements. One submittal was technically not a permit modification, since no permit revisions were necessary for the project. Of the remaining submittals, a few did not result in any change in emissions.

Two of the modifications addressed the Sand Creek Remediation Project, however, since permitted emissions from this project remain below the significance level, there are no major stationary source permitting issues associated with that project.

There were also two modifications that addressed the asphalt unit (P3) flare, the May 31, 2016 modification and the February 10, 2017 MPV project. The major stationary source applicability analysis for the MPV project encompasses both projects (projected actual emissions used in the analysis include both the May 31, 2016 increases, as well as the February 10, 2017 increases), thus there does not appear to be any major stationary source permitting issues for the P3 flare.

The remaining modifications address individual emission units, none of which appear to be related to or dependent upon each other. Therefore, the Division concludes that the applications were appropriately addressed as separate minor modifications for major stationary source permitting purposes (PSD and NANSR).

A summary of the change in permitted emissions from all of the modifications covered in this permit revision can be found on pages 49-50 of this document.
SECTION III - Discussion of Modifications Made

The following discussion related to modifications is with respect to the current Title V permit (last revised February 1, 2016) and unless specifically noted as “new”, the condition numbers identified in this document reflect the condition numbers in the current (February 1, 2016) Title V permit. Because some permit conditions in the current Title V permit have been removed, reorganized and/or reformatted as part of this permitting process, the condition numbers discussed in this document may not reflect the condition numbers in the draft Title V permit.

1. **Source Requested Modifications**

The Division addressed the source’s requested modifications as follows:

1.1 **November 2, 2015 Modification (Tank Degassing Thermal Oxidizer)**

The following changes were made to the permit to address this modification:

**Section I – General Activities and Summary**

- Added tank degassing to the table in Condition 5.1.

**“New” Section II.70 – Tank Degassing**

In the current permit (last revised February 1, 2016), Section II.70 includes Project Wide Requirements for the Sand Creek Remediation Project but due to the removal of other requirements those requirements are now included in Section II.69.

- Added a new section II.70 for tank degassing. The requirements include emission and throughput limits, as well as opacity, RACT and NSPS (Subparts J and Ja) requirements. Requirements for operation of the thermal oxidizer include a requirement to maintain the temperature at or above 1400 °F.

As requested in their February 28, 2017 comments, the requirement to use the thermal oxidizer only applies to floating roof tanks containing a liquid with a true vapor pressure greater than or equal to 0.75 psia. The permit will however require that emissions from degassing of floating roof tanks containing liquids with a true vapor pressure less than 0.75 psia calculation emissions from degassing and include those in the annual or monthly emission calculations for assessing compliance with annual limits and/or for APEN reporting purposes, as applicable.

**Appendices**

- Added tank degassing to the tables in Appendices B and C.

1.2 **February 17, 2016 Modification (East-West Transfer Line, Tank T80)**

The following changes were made to the permit to address this modification:

**Section II.3 – Tanks with Unique Requirements, NSPS Kb and MACT CC (Group 1)**

- Revised the emission limit for Tank T34 in Condition 3.1.
• Revised the vapor pressure limit on the throughput for Tanks T34 in Condition 3.10.

1.3 February 26, 2016 Modification (Replace Centrifuge)
The following changes were made to the permit to address this modification:

Section I – General Activities and Summary

• References to the “centrifuge system” in Section I, Condition 5.1 were revised to indicate “centrifuge” and removed the sentence indicating that the centrifuge system consists of a mix/frac tank and the centrifuge.

Section II.23 – Plant 1 Wastewater Treatments System (WWTS)

• References to the “centrifuge system” were revised to indicate “centrifuge.”

Section II.66 – BWON

• References to the “centrifuge system” were revised to indicate “centrifuge.”

1.4 May 20, 2016 Modification (Replace Blower for AIRS pt 634)
The following changes were made to the permit to address this modification:

Section I – General Activities and Summary

• Revised the blower model, serial number and capacity for pt 634, zone 4 in the table in Condition 5.2.

Section II.68 – Sand Creek Remediation Project – AS/SV and AS Systems

Note that due to the removal of other requirements, this section was renumbered to Section II.67. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

• Revised the blower capacity for pt 634 in Condition 68.6.2.

1.5 May 31, 2016 Modification (AU Flare – Revise NSPS Ja Monitoring and Emission Limits)
The following changes were made to the permit to address this modification:

Section II.30 – AU Flare

• Revised the SO₂, CO and VOC emission limits in Condition 30.1 and added emission limits for NOₓ. In addition, the VOC emission factor for VOC in Condition 30.1 was revised.

• The summary table was revised to indicate that SO₂ emissions would be monitored using a TRS monitor (Condition 30.1), that gases combusted would be monitored using a flow meter (Condition 30.6) and that the NSPS Ja fuel gas limit would be monitored using an H₂S continuous monitoring system (Condition 30.10).

• The following changes were made to Condition 30.6 (limit on gases combusted):
Revised the limit for gases combusted in Condition 30.6.

Condition 30.6.1 was revised to indicate that only the pilot gas flow is determined based on hours of operation and that the Btu content of pilot gas will be based on 920 Btu/scf (per 40 CFR Part 63 Subpart CC §63.670(j)(5)).

Condition 30.6.2 was revised to indicate that the flare continuous flow meter would be used to monitor the quantity of sweep and process gases. In addition, this condition was revised to indicate that the Btu content of sweep gas will be based on 920 Btu/scf (per 40 CFR Part 63 Subpart CC §63.670(j)(5)) and that records be kept indicating how the portion of flow is determined to be sweep or process gas for determining the Btu content of combusted gases.

Condition 30.9 was revised to indicate that hours of operation are used only to determine the monthly quantity of pilot gas combusted.

Section II.46 – 40 CFR Part 60 Subpart Ja

The notes regarding the AU flare (F2) were removed from Conditions 46.8 (flare H₂S limit), 46.9 (performance test requirements), 46.14 (H₂S monitoring requirements), 46.19 (exemption from sulfur monitoring requirements), 46.20 (flow monitoring requirements) and 46.22 (excess emission requirements) since the AU flare will be equipped with H₂S, TRS and flow monitors.

Condition 46.21 (alternative monitoring in 60.107a(g)) was removed since the AU flare (F2) no longer qualifies for the alternative.

Appendix H – SO₂ Emission Calculation Methodology

Revised the emission limit for the AU flare in Table 1-1.

Revised the AU flare SO₂ emission calculation methodology as indicated in the application, except for the following:

- A note was added to indicate that flared gas includes sweep gas. The note regarding the sweep gas was added since previously sweep gas was addressed in Appendix H separately from process gases.
- The daily SO₂ emissions (lb/day) from pilot gas was corrected (this should be 0.002 lb/day, not 0.006 lb/day).
- Under the calculation method for annual emissions, the only change made to Appendix H was to correct the equation for daily emissions (daily emissions = lb SO₂/day flared gas + SO₂/day pilot gas).

1.6 July 11, 2016 Modification (Address 3,000 Gal Sump at Pipeline Receipt Station)

The following changes were made to the permit to address this modification:

Section I – General Activities and Summary

- The table in Condition 5.1 was revised to add the 3,000 gal sump and to indicate the startup date for the pipeline receipt station (fugitive VOCs).
Section II.1 – Tanks, Construction Permits not Required

- Added the pipeline receipt station sump to the list in the section header. Added a note under the summary table indicating that the tank is not subject to APEN reporting requirements as long as actual uncontrolled emissions are below the APEN de minimis level.

- Condition 1.2 (MACT CC requirements) was revised to indicate that the pipeline receipt station sump is not subject to these requirements.

- Condition 1.3.2 (Reg 7, Section VI.B.2.b requirements) was revised to indicate that the pipeline receipt station sump is not subject to these requirements.

- Added a “new” Condition 1.5 for the BWON requirements. Only the pipeline receipt station sump is subject to the BWON requirements.

Section II.34 – Fugitive VOC Equipment with Permitted Emissions

- Revised the emission limit for the pipeline receipt station (F200) in Condition 34.1

Section II.41 – RACT for Storage and Transport of Petroleum Liquids (Reg 7, Section VI)

- The pipeline receipt station was listed in Condition 41.2.2 (Section VI.B.2.b) as a tank that is not subject to these requirements.

Section II.54 – MACT CC Requirements

Note that due to the removal of other requirements, this section was renumbered to Section II.53. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Added language to Condition 54 to indicate that the pipeline receipt station sump is not subject to the storage vessel requirements in MACT CC (tank is less than 40 cubic meters).

Section II.66 – BWON Requirements

- Added language indicating that the pipeline receipt station is subject to the BWON requirements (Condition 66), specifically the tanks requirements, Section 61.343.

Appendices B and C

- Added the pipeline receipt station sump to the tables.

1.7 September 7, 2016 Modification (Install New SVE)

The following changes were made to this permit to address this modification and the June 14, 2016 cancellation notice submitted for the north guard shack SVE:

Section I – General Activities and Summary

- The north guard shack SVE was removed from the tables in Conditions 5.1 and 5.2
and the laboratory SVE was added to the tables in Conditions 5.1 and 5.2

Section II.68 – Sand Creek Remediation Project – AS/SV and AS Systems

Note that due to the removal of other requirements, this section was renumbered to Section II.67. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Removed the north guard shack SVE and added the laboratory SVE to the list under the Section II.68 header.
- Revised Condition 68.1 to remove the emission limit for the north guard shack SVE (pt 626) and add the emission limit for the laboratory SVE (pt 637).
- Revised Condition 68.6.2 to remove the north guard shack SVE information and include information for the laboratory SVE.

Section II.70 – Sand Creek Remediation Project – Project Wide Requirements

Note that due to the removal of other requirements, this section was renumbered to Section II.69. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Revised the VOC emission limit for insignificant activities in Condition 70.1 to take into account changes to permitted emissions of VOC.
- Revised the table in Condition 70.2 to remove AIRS pt 626 (north guard shack) and add AIRS pt 637 (laboratory) and to change the current permit limit to 27.3 tpy of VOC.

Appendices B and C

- Removed the north guard shack SVE and added the laboratory SVE to the tables.

1.8 November 8, 2016 Modification (Include HCN Permit Limit for FCCU)

The following changes were made to the permit to address this modification:

Section II.22 – FCCU

- Included the coke burn-off limit in Condition 22.6 and revised the language to require that daily coke burn-off be summed to get monthly values and to use those in a rolling 12 month total.
- Included the HCN limit in Condition 22.14, with the requirement to calculate emissions monthly and conduct a one-time performance test.

1.9 December 20, 2016 Modification (Change Responsible Official’s Authorized Representative)

The following changes were made to the permit to address this modification:
The Responsible Official’s Authorized Representative was revised.

1.10 December 28, 2016 Modification (NSPS GGGa Applicability Update)

Section II.33 – Fugitive VOC Equipment Leaks without Permit Limits

- Minor revisions were made to this section title.
- Removed Subpart GGG and added Subpart GGGa to the NSPS requirements in Condition 33.4.
- Added a note to Condition 33.2 (MACT CC) indicating that sources subject to requirements in 40 CFR Part 60 Subpart GGGa only have to comply with the requirements in Subpart GGGa.

Section II.34 – Fugitive VOC Equipments Leaks with Permit Limits

- Minor revisions were made this section title.
- Condition 34.2 was revised to indicate that all component groupings, except F101 are subject to NSPS GGGa and to remove NSPS GGG and MACT CC. Per MACT CC sources subject to NSPS GGGa requirements only have to comply with the requirements in Subpart GGGa.

Section II.47 – NSPS GGGa

- Revised the language under Condition 47 to indicate those sources subject to GGGa.
- Updated the paragraph in Condition 47 to indicate the version of the GGGa requirements that have been included in the permit.

Section II.51 – NSPS GGG

- Removed this section since the source indicated that NSPS GGG does not apply to any process units.

Section II.54 – MACT CC

Note that due to the removal of other requirements, this section was renumbered to Section II.53. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Listed the component groupings that fall under the overlap provisions for equipment leaks (NSPS GGGa, 63.640(p)(2)).

Section II.65 – 40 CFR Part 60 Subpart VV

Note that due to the removal of other requirements, this section was renumbered to
Section II.64. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Removed the reference to 40 CFR Part 60 Subpart GGG requirements in the first paragraph since the Subpart GGG requirements have been removed.

1.11 February 10, 2017 Modification (Miscellaneous Process Vent (MPV) Project)

The following changes were made to the permit to address this modification:

Section I – General Activities and Summary

- Added miscellaneous process vents and components associated with MPV project (F202) to the table in Condition 5.1.

Section II.29 – Main Plant (P1) Flare (F1)

- Revised the VOC emission factor in Condition 29.1 due to updates to AP-42 December 2016.
- Added a new condition (29.10) to address upcoming MACT CC requirements for flares used as control devices. (Since the flare will be controlling emissions from MPVs, these requirements will apply in the future).
- Added language to Condition 29.8 (NSPS flare requirements, §60.18) to indicate that after the flare is in compliance with the MACT CC requirements, compliance with these requirements is presumed as long as the flare is in compliance with the MACT CC requirements. Note that since the Consent Decree (CD) stipulated that the flare comply with the NSPS 6018, the language does not indicate that the requirements in 60.18 no longer apply.

Section II.30 – Asphalt Unit (P3) Flare (F2)

- Revised the emission and throughput limits (Conditions 30.1 and 30.6).
  Note that emission limits for PM, PM_{10} and PM_{2.5} were not included in the permit because using the emission factor (AP-42, Section 1.4 (dated 7/98), Table 1.4-2, converted to lb/MMBtu based on a heat content of 1020 Btu/scf (per footnote a)) and requested throughput, emissions are below the APEN de minimis. Note that although an emissions limit for these pollutants was not included in the permit, emissions from these pollutant shall be reported on APENs.
- Added a new condition (30.11) to address upcoming MACT CC requirements for flares used as control devices. (Since the flare will be controlling emissions from MPVs, these requirements will apply in the future).
- Added language to Condition 30.8 (NSPS flare requirements, §60.18) to indicate that after the flare is in compliance with the MACT CC requirements, compliance with these requirements is presumed as long as the flare is in compliance with the MACT CC requirements. Note that since the CD stipulated that the flare comply with the NSPS 6018, the language does not indicate that the requirements in 60.18 no longer apply.
Section II.31 GBR Unit Flare (F3)

- Revised the emission and throughput limits (Conditions 31.1 and 31.6) and the CO emission factor (Condition 31.1).

  Note that emission limits for PM, PM\textsubscript{10} and PM\textsubscript{2.5} were not included in the permit because using the emission factor (AP-42, Section 1.4 (dated 7/98), Table 1.4-2, converted to lb/MBtu based on a heat content of 1020 Btu/scf (per footnote a)) and requested throughput, emissions are below the APEN de minimis.

  In addition, emission limits for SO\textsubscript{2} were not included in the permit because using the emission factor (material balance) and the requested throughput limit, emissions are below the APEN de minimis. Although the SO\textsubscript{2} emission factor is not constant (based on material balance), based on the gas streams going to the flare, the SO\textsubscript{2} emissions are not expected to vary much as the gas streams are inherently low in sulfur.

  Note that although an emissions limit for these pollutants was not included in the permit, emissions from these pollutant shall be reported on APENs.

- Added a new condition (31.10) to address upcoming MACT CC requirements for flares used a control devices. (Since the flare will be controlling emissions from MPVs, these requirements will apply in the future).

- Added language to Condition 31.8 (NSPS flare requirements, §60.18) to indicate that these requirements no longer apply after the flare complies with the MACT CC requirements.

Section II.34 – Fugitive VOC Equipment Leaks with Permitted Emission Limits

- Added emission limits and requirements for equipment leaks associated with the MPV project (F202).

Section II.47 – 40 CFR Part 60 Subpart GGGa

- Added F202 (equipment leaks associated with the MPV project) to the list of sources subject to these requirements.

Section II.54 – 40 CFR Part 63 Subpart CC

Note that due to the removal of other requirements, this section was renumbered to Section II.53. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Noted that equipment leaks associated with the MPV project (F202) fall under the overlap provisions for equipment leaks in 63.640(p)(2) (sources subject to NSPS GGGa only have to comply with NSPS GGGa).

Prior to the December 1, 2015 revisions to Subpart CC, the MPV requirements did not apply and thus were not included in the permit. Revisions were made to the definition of MPV thus rendering the source’s MPVs subject to these requirements. In addition, fairly significant revisions to the Subpart CC requirements were made on December 1, 2015, thus this section has been revised to include the new requirements, as well as to more appropriately address the applicable requirements in MACT CC.
The following discussion addresses how these requirements were addressed and notes which requirements were not included and the reasons for that.

Note that the requirements in 63.649 (alternative means of emission limit: connectors in gas/vapor or light liquid service), 63.651 (marine tank vessel loading), 63.652 (emissions averaging), 63.653 (monitoring and recordkeeping for emissions averaging) and 63.657 (delayed coking and decoking standards) were not include as they do not apply. In addition requirements from 63.641 (definitions) and 63.656 (implementation and enforcement) were not included as they do not include active requirements.

- Added a statement to the beginning of this section, indicating which version of the rule is included, whether any proposed rules have been published and that the permittee is subject to the most recent versions of the requirements.

- **63.640 (applicability):** No requirements from 63.640 are included in the current permit (last revised February 1, 2016). For this modification, included the requirements in 63.640(a) (applicability), (d) & (g) (equipment/processes not subject to requirements) and (h) (compliance dates). Added a note to this section that the overlap provisions in this section (603.640(n), (o), (p), (r) & (s) are included in the equipment specific sections. The provisions in 63.640(c) (affected sources) and (e) (determining if storage vessels are part of an affected source) were not included as they are not necessary (affected sources and storage vessels are clearly identified) and 63.640(i), (j), (k), (l) and (m) were not included as additions or changes to process units and subsequent MACT applicability would be addressed in the permitting actions for those activities.

- **63.642 (general standards):** The current permit (last revised February 1, 2016) includes 63.642(c) (general provisions) with some of the specific general provisions (subpart A) and 63.642(e), (j) and (k). 63.642(c) was revised and the appropriate general conditions included. Note that only general conditions that were likely to apply were included, so requirements for compliance extensions, alternatives or waivers were not necessarily included as they would not necessarily apply. Under this method, none of the notification requirements in 63.9 were included as the ones that apply are not actionable. 63.642(e), (g) and (k) were revised.

In addition, 63.642(b) (standards apply at all times), (d) (performance test requirements, (f) (submittal of reports) and (n) (good operation practices) were included. Note that 63.642(a) (requirement to apply for T5 permit), 63.642(l) (averaging) and (m) (state can preclude averaging) and 63.642(h) (requirement for new sources) were not included as the requirement is past, source does not use emissions averaging and the refinery is not new.

- **63.643, 63.644 & 63.645 (miscellaneous process vents):** These sections are not included in the current permit (last revised February 1, 2016) but now apply, so the requirements have been included. Note that miscellaneous process vents will be controlled with a flare, thus the requirements related to flares are included. Requirements excluded for this reason include 63.643(a)(2) (TOC/HAP - 98% reduction or outlet limit), 63.643(b) (requirements for process heaters/boilers), 63.644(a)(1), (3) & (4) (incinerator and boiler/process heater options), 63.644(b) (alternative monitoring) was not.

The requirements in 63.645(a) specify that the source shall follow the requirements in 63.116 (Subpart G), except for 63.116(a)(1), (d) and (e). Since the source has
indicated that Group 1 MPVs will be controlled by a flare (not meeting the percent reduction requirement or outlet limit), only the requirements in 63.116(a) apply. The requirements in 63.645(c) (use organic HAP list in CC) and (d) (boilers/process heaters) do not apply and won’t be included.

- **63.646 (storage vessels):** This section is included in the current permit (last revised February 1, 2016). Revisions were made to address the specific requirements that apply, revisions made to MACT CC and to more appropriately identify requirements. The overlap provisions in 63.640(n)(1), (n)(2), (n)(5) and (n)(8) were included. The other provisions did not apply to any of the tanks at Plants 1/3.

- **63.647 (wastewater provisions):** This section is included in the current permit (last revised February 1, 2016). All paragraphs from this section were included in the permit.

- **63.648 (equipment leak standards):** This section is included in the current permit (last revised February 1, 2016). This section was revised to include any new or revised requirements. The current permit (last revised February 1, 2016), only includes the requirements in 63.648(a), so the requirements were reviewed to determine which may or may not apply. To that end, the requirements in 63.648(b) were not included as they are past requirements (i.e. refer to monitoring data prior to August 18, 1995. The requirements in 63.648(c), (d) and (e) do not apply as they apply to new units or an alternative (Subpart H requirements) that have not been utilized.

- **63.650 (gasoline loading rack provisions):** This section is included in the current permit (last revised February 1, 2016). This section was revised to include any new or revised requirements. The current permit (last revised February 1, 2016), only includes the requirements in 63.650(a), so the requirements were reviewed to determine which may or may not apply. To that end, since the compliance date for gasoline loading racks has passed, 63.650(c) was not included. In addition, the overlap provisions in 63.640(r) were also included.

- **63.654 (heat exchange systems):** This section is not included in the current permit (last revised February 1, 2016). No revisions were made to this section with the December 1, 2015 and July 13, 2016 revisions but the requirements 63.652(f) were expanded and the Y-2 cooling tower was added as a source subject to these requirements.

- **63.655 (reporting and recordkeeping):** This section is included in the current permit (last revised February 1, 2016). Revisions were made to address new and revised requirements. The section was also reviewed to include requirements that had not previously been included and/or to expand requirements that had been included. To that end, 63.555(c) was not included because it does not apply (applies to marine storage tank vessels). The following requirements apply to emissions averaging and/or delayed coking and also were not included as they do not apply: 63.655(f)(5), (g)(8), (g)(12), (h)(3) and (i)(7). 63.655(h)(4) was not included as it applies to different parameters for MPVs and emissions averaging. The following requirements were “reserved” and were not included: 63.655(g)(4), (h)(1) and (i)(10).

- **60.658 (fenceline monitoring):** This section is not included in the current permit (last revised February 1, 2016). The applicable requirements from this section have been included in the permit.
• **63.660 (storage vessel provisions):** This section is not included in the current permit (last revised February 1, 2016). These storage vessel provisions were included in the December 1, 2015 revisions to MACT CC and are intended to replace the requirements in 63.646. The overlap requirements in 63.640 related to tanks were included as discussed under 63.646. These requirements allow the source to comply with either the requirements in 40 CFR Part 63 Subpart SS or WW. The renewal application (submitted on September 16, 2016), includes only the Subpart WW requirements, thus the Division only included the Subpart WW requirements. The requirements in 63.660(d) (tanks that weren't Group 1 storage vessels prior to February 1, 2016) was not included as there are no such tanks associated with Plants 1 and 3. In addition, since the source is not complying with the requirements in Subpart SS, 63.660(i) was not included.

• **60.670 & 60.671 (flare requirements):** This section is not included in the current permit (last revised February 1, 2016). The compliance date for these requirements is January 30, 2019 and while options are provided, it is not clear at this point which options the source will utilize. Therefore, all the applicable requirements from this section have been included in the permit.

**Section II.58 – Flare Requirements**

Note that due to the removal of other requirements, this section was renumbered to Section II.57. The below discussion is based on the numbering in the current permit (last revised February 1, 2016)

• Added language to this Condition to indicate that these requirements no longer apply after flares are in compliance with the MACT CC requirements and noted the flares subject to MACT CC requirements (F1, F2 and F3).

**Section III – Permit Shield**

• Removed the facility wide provision for 40 CFR Part 63 Subparts G and CC (sections 63.343, 644 and 645 only) from the table for "specific non-applicable requirements" in Section III.1. The MPV provisions in 63.343, 63.344 and 63.345 now apply and additional sections in Subpart G also apply to MPVs.

**Appendices B and C**

• Added miscellaneous process vents and components associated with MPV project (F202) to the tables.

**“New” Appendix K**

• Included the applicability analysis for the MPV project.

**1.12 February 28, 2017 comments on the draft permit and technical review document**

Comments on the draft permit and technical review document were received on February 28, 2017. The following changes were made to the permit based on those comments:
Section I – General Activities and Summary

- The table in Condition 5.1 was revised to remove the centrifuge thermal oxidizer (TO), AIRS pt 148, and to reflect the other equipment, in addition to the API headworks and centrifuge, that is currently routed to the wastewater treatment system regenerative thermal oxidizer (RTO). The other equipment includes the API lift station and the T60 lift station.

Section II.23 - P1 WWTS

- Removed the emission limits for the centrifuge TO in the summary table.
- Removed Conditions 23.1.3 and 23.10 as they are related to the centrifuge TO.
- Condition 23.12.2.2 was renumbered to a higher level, since these requirements are specific to the centrifuge operation. The first sentence was revised since the centrifuge is now controlled by the RTO.
- Removed the reference to Condition 23.1.3 (centrifuge/TO) emission limits in Condition 23.13 (hours of operation).

Section II.56 – 40 CFR Part 60 Subpart VVa

Note that due to the removal of other requirements, this section was renumbered to Section II.55. The below discussion is based on the numbering in the current permit (last revised February 1, 2016)

- Revisions were made to the note in Condition 56 regarding requirements that have been stayed.
- Added place holders for 60.482-1a(g) and 60.482-11a and added a note that these requirements were stayed until further notice.

 Appendices B and C

- Removed the “centrifuge system/TO” from the tables.

2. Other Modifications

In addition to the requested modifications made by the source, the Division used this opportunity to include changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this modification.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments on other permits, to the Suncor - Plants 1 and 3 Operating Permit with the source’s requested modifications. These changes are as follows:
General

In anticipation of removing and/or adding condition numbers or permit sections (e.g. Section II.51), the permit was revised to include automatic cross references so that references remain up to date when changes are made to the permit. During this process, a number of incorrect condition number references and other administrative errors were found and corrected. The changes are noted below by specific section (e.g. Section II.55).

Section I – General Activities and Summary

• The tables in Conditions 5.1 and 5.2 were revised to move Pt 636 (northwest boundary uncontrolled AS system) so that AS, AS/SVE and/or SVE systems are in order by AIRS ID.

Section II.1 – Tanks, Construction Permits not Required

• Added Tank T776 to the list in the section header.

• Added Tank T64 to Condition 1.3.3 (Reg 7, Section VI.B.2.c(ii)(C) requirements). Condition 41.2.3 (Reg 7, Section VI.B.2.c requirements) indicates that tank T64 is subject to these requirements.

Section II.13 – Boilers B6 and B8

• The typo for the fuel consumption limit in the summary table (Condition 13.5) for B8 was corrected (table listed fuel limit of 1,210,360,000 Btu/yr but it should be 1,410,360,000 as noted in the text portion of Condition 13.5 and the underlying construction permit (02AD0327).

Section II.18 – Heaters H-33 and H-37

The February 1, 2016 revisions to the Plants 1/3 Title V included a project for the No. 3 crude unit. The purpose of the No. 3 crude unit project was to replace the stacks on heaters H-33 and H-37 to address draft problems with the heaters. In addition, the H-37 burners would be replaced with ultra-low NOx burners (the design rate of H-37 would remain the same). This project was expected to be completed during the 2015 turnaround.

Initially approved permits expire if the owner or operator of the source for which the permit was issued does not commence construction or operation of the source within 18 months of either the date of issuance of the permit (construction permit) or the date on which such construction or activity was scheduled to commence (see Colorado Regulation No. 3, Part B, Section III.F.4.a). A Title V minor modification can take the place of a construction permit, thus the construction requirements apply to a Title V minor modification, except that the date the complete minor modification was submitted takes the place of the issued minor source construction permit. Generally a requirement to commence construction is included in the construction permit or for a minor modification, in the “draft” and issued Title V permit. A permit condition stipulating the construction requirements in Colorado Regulation No. 3, Part B, Section III.F.4 was not
included in the February 1, 2016 revised Title V permit with respect to the No. 3 crude unit project.

The source indicated that construction did not commence on the No. 3 crude unit project during the 2015 turnaround for economic reasons. Extensions to the date for commencing construction may be granted but such extensions cannot exceed 18 months (see Colorado Regulation No. 3, Part B, Section III.F.4.b). At the request of the Division, the source indicated in a January 9, 2017 email that the No. 3 crude unit project had been rescheduled for the 2021 turnaround, which is beyond the time frame to extend approval for the project. Therefore, the source would need to re-permit the project at a later date and the Division is removing the requirements related to the project. Note that when the No. 3 crude unit project was addressed in the February 1, 2016 revised permit, separate emission and throughput limits were set for H-33 and H-37, in lieu of the combined limit and the separate limits will remain. The following changes will be made to the permit to address this issue:

- Removed the lower NOx limit for H-37 from Condition 18.1 and changed the emission factor.
- Removed Condition 18.4 (NSPS Ja) and revised Condition 18.3 (NSPS J) to indicated that it applies to both heaters. (Note that Condition 46 (NSPS Ja) was revised to indicate that H-33 is not subject NSPS Ja requirements.)
- Removed Conditions 18.10 (H-37 performance test) and 18.11 (startup notice).

Section II.19 – Requirements for Heaters and Boilers

- Corrected the condition number reference in Condition 19.3.

Section II.20 – SRU

- Corrected the condition number reference in Condition 20.11.2.

Section II.21 – Heaters H-1716 and H-1717

- Condition 36.2 was removed from Condition 21.2 of the summary table to be consistent with the text language for Condition 21.2.

Section II.22 – FCCU

- Corrected the condition number references in the summary table under Condition 22.13 (CAM requirements).
- Removed “and 6, Part B” from Condition 22.3. The SO\textsubscript{2} limit in Condition 22.3 is the Reg 1 limit, not the Reg 6, Part B limit.
- Corrected the condition number references in Conditions 22.8.2 and 22.10.3.

Section II.23 - P1 WWTS

- Corrected the SO\textsubscript{2} emission limit and factor for controlled sources in the summary table (Condition 23.1).
• Corrected the condition number references in Conditions 23.1.2, 23.3.5 and 23.12.3.

• Revised performance test language in Condition 23.12.3 to current language.

Section II.24 – Rail Loading Rack

• Corrected the condition number references in the summary table for Conditions 24.1 and 24.2.

Section II.25 – Truck Loading Rack

• Removed Regulation No. 7, Section VI.C.4.b from Condition 25.3. The provisions in Regulation No. 7, Section VI.C.4.b were removed from the permit in the February 1, 2016 modification because these requirements apply to tank truck owner/operators.

Section II.27 – Process Heater H-2101

• Corrected the condition number reference in Condition 27.8.

Section II.29 – Main Plant (P1) Flare (F1)

• Included emission factors for PM and PM$_{10}$ in Condition 29.1. Source will be required to calculate emissions of PM and PM$_{10}$ for purposes of APEN reporting and fees.

Section II.32 Plant 3 Wastewater Treatment System

• Condition 32.4 was revised to simply indicate that the CPI separator is subject to the requirements in 40 CFR Part 63 Subpart CC, rather than identify specific sections.

Section II.33 – Fugitive VOC w/out Permit Limits

• Corrected the condition number references in Condition 33.3 of the summary table.

Section II.34 – Fugitive VOC w/ Permit Limits

• Removed F101 (P3 wastewater treatment system drains) from Condition 34.2 (NSPS and MACT equipment leak requirements), since drains aren’t subject to equipment leak requirements.

Section II.38 – SO$_2$ Emission Limits

• Removed Condition 46 from the note under Condition 38.2, as this is an incorrect reference.

• Condition 38.2 (NSPS J requirements for fuel gas burning equipment) was revised as follows:
  o Made minor revisions to the paragraph under Condition 38 regarding the version of the requirements that are included.
  o Added 60.105(b) (procedure for demonstrating fuel gas stream is inherently low in sulfur).
Other conditions were renumbered and/or combined. Minor language changes were made to some conditions.

Section II.41 – RACT for Storage and Transport of Petroleum Liquids (Reg 7, Section VI)

- Tank T52 was included in Condition 41.2.3 (Reg 7, Section VI.B.2.c(ii)(C) requirements) as a tank that is only subject to the recordkeeping requirements in Section VI.B.2.c.(ii)(C). Condition 4.5 indicates that these requirements apply.

Section II.43 for Petroleum Refineries (Reg 7, Section VIII)

- Corrected the reg citation in Condition 43.8 (summary table) and the condition number reference in Condition 43.1.3.1.

Section II.44 – RACT for Gasoline Terminals (Reg 7, Section XV)

- Corrected the condition number reference in Condition 44.2.1.

Section II.45 – 40 CFR Part 60 Subpart J Requirements (FCCU and Claus Unit)

- Corrected the condition number references in Conditions 45 (first line) and 45.4.

Section II.46 – 40 CFR Part 60 Subpart Ja

- Made minor revisions to the note regarding the version of the requirements that are included.
- Removed H-33 from the list of modified equipment subject to these requirements.
- Added §60.102a(g)(1) under Condition 46.1.
- Added §60.107a(a) as “new” Condition 46.13. Existing Conditions 46.13 and after, are re-numbered.
- Moved Conditions 46.14.1 (60.107a(2)(v) and 46.14.2 (60.107a(a)(2)(vi)) under Condition 46.13 (H₂S monitoring requirement, 60.107a(a)(2)).
- Condition 46.19 (exemption from sulfur monitoring requirements, 60.103a(e)(4)) was renumbered under Condition 46.18 (sulfur monitoring for flares, 60.103(e)), as Condition 46.18.4.

Section II.47 – 40 CFR Part 60 Subpart GGGa

- The following changes were made to be consistent with the draft renewal for the Plant 2 permit (95OPAD108):
  - Added 60.592a(c) as a “new” condition.
  - Condition 47.5 includes the exceptions in one condition. Separate “new” conditions were added for the exceptions (60.593a(a) through (d), (f) and (g)).

Note that conditions following “new” conditions will be re-numbered.
Section II.48 – 40 CFR Part 60 Subpart Kb

- Made minor revisions to the note regarding the version of the requirements that are included.
- Corrected the CFR references in Conditions 48.6.1 and 48.8.
- Added 60.116b(a) as a “new” condition. Note that conditions following the “new” condition are renumbered.

Section II.54 – MACT CC

Note that due to the removal of other requirements, this section was renumbered to Section II.53. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Added language to indicate that tank D-20 is not a storage vessel subject to MACT CC and removed tank D-20 from Condition 54.5.1 (overlap with NSPS Kb).
- Removed F101 under the list of sources subject to MACT CC equipment leak requirements (under “Equipment Leak Standards (63.648”) F101 is defined as the P2 wastewater treatment system individual drain systems, which are not subject to equipment leak requirements.

Section II.55 – MACT UUU

Note that due to the removal of other requirements, this section was renumbered to Section II.54. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Corrected the condition number reference in Condition 55.23.
- Removed the condition number references in Conditions 55.5, 55.9 and 55.11 as they do not appear to provide the information indicated.

Section II.56 – 40 CFR Part 60 Subpart VVa

Note that due to the removal of other requirements, this section was renumbered to Section II.55. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

- Revisions were made to the note in Condition 56 regarding the version of the requirements that are included.
- Added the requirements in 60.482-1a(c) and 60.482-1a(f)(2) & (3). This is consistent with the VVa language in the Plant 2 draft renewal permit (95OPAD108).
- Corrected the language in Conditions 56.54 and 56.55.
- Conditions 56.63.1 and 56.63.2 belong under “new” Condition for 60.482-9a(d). The citations for Conditions 56.63.1 and 56.63.2 were also corrected.
• Sub-conditions were added under Condition 56.63 (60.482-9a(c)).
• Corrected the citation in Condition 56.67.
• Added provisions for §§ 60.483-1a, 60.483-2a, 60.485a, 60.486a and 60.487a.

**Section II.66 – BWON**

Note that due to the removal of other requirements, this section was renumbered to Section II.65. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

• Revisions were made to the note in Condition 66 regarding the version of the requirements that are included.
• Included T4517 in the paragraph under Condition 66.
• Corrected the condition number references in Conditions 66.13.4 and 66.17.2.

**Section II.68 – Sand Creek Remediation Project – SVE Systems**

Note that due to the removal of other requirements, this section was renumbered to Section II.67. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

• Corrected the citation in Condition 68.8.

**Section II.69 – Sand Creek Remediation Project – Tanks and Tank Truck Loading**

Note that due to the removal of other requirements, this section was renumbered to Section II.68. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

• Removed Condition 69.5 (MACT CC requirements) as tank D-20 is not subject to these requirements.

**Section II.70 – Sand Creek Remediation Project – Project Wide Requirements**

Note that due to the removal of other requirements, this section was renumbered to Section II.69. The below discussion is based on the numbering in the current permit (last revised February 1, 2016).

• The table in Condition 70.2 was revised to include AIRS pt 635 and to replace "TBD" with 636.

**Section III – Permit Shield**

• Corrected the Reg 7 reference (should be “IX”, not “X”) under “applicable requirement” in the third row in the table in Section 1 (specific non-applicable requirements).
• Corrected the condition numbers in the first column in the table in Section 3.
Appendices B and C

- The tables were revised to move Pt 636 (northwest boundary uncontrolled AS system) so that AS, AS/SVE and/or SVE systems are in order by AIRS ID.

Appendix G – Consent Decree (CD) LDAR and Flaring Events

- Removed the reference to Condition 46.10.1 on page 11 and replaced it with the CD paragraph number, which is consistent with the CD language. There has been a Condition 46.10.1 in the permit and it appears that paragraph 184 of the CD was never included in Section II of the permit.

Appendix H – SO\textsubscript{2} Emission Calculation Methodology

- Table 1-1 was revised to include the SO\textsubscript{2} emission limit for process heater H-6 and correct the SO\textsubscript{2} limits for H-33 and H-37 (the heaters now have separate limits).

- Corrected the condition number references related to the SRU emission limit (pages 21 and 23).

Appendix J – Plant 1 FCCU Opacity Plan

- The first reference to Condition 35.2 on page 5 was revised to reference Condition 35.7.2 as this permit conditions explains that removal of catalyst buildup is considered “soot blowing.” The phrase “monitoring provisions of” just prior to this condition number reference was replaced with “as noted in.”
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT
Stationary Sources Program / Air Pollution Control Division

INTER-OFFICE COMMUNICATION

PS Memo 10-01

TO: Stationary Sources Staff, Local Agencies, Regulated Community

FROM: Kirsten King and Roland C. Hea

DATE: September 20, 2010

RE: Permit Modeling Requirements for the 1-Hour NO₂ and SO₂ NAAQS

The Division is establishing this guidance for use by minor stationary sources of nitrogen dioxide (NO₂) and sulfur dioxide (SO₂) in evaluating whether modeling is necessary for permitting purposes to determine whether a permit applicant’s emissions will comply with the new 1-hour NO₂ and/or the new 1-hour SO₂ National Ambient Air Quality Standard (NAAQS). The United States Environmental Protection Agency (EPA) published implementation guidance on June 28, 2010 and August 23, 2010 regarding demonstrating compliance with the new standards for Prevention of Significant Deterioration (PSD) sources.¹ The Division finds it useful to publish this supplemental state guidance to ensure that minor sources are addressed in a manner consistent with the EPA guidance for PSD sources.

Under federal rules, an ambient air quality impact analysis is required for each pollutant that a PSD source has the potential to emit in significant amounts. Such analysis includes modeling. The metric used by EPA to measure significant amounts is the significant emissions rate (SER). Federal rules currently define the SER for NO₂ and SO₂ as 40 tons per year (tpy). (40 CFR 52.21(b)(23)(i); 40 CFR 51.166(b)(23)(i)). EPA recently evaluated and decided to apply on an interim basis the 40 tpy SER to major source permitting compliance demonstrations for the hourly NO₂ and SO₂ standards. EPA concludes and states that an ambient air quality impact analysis is not necessary for PSD sources with projected NO₂ or SO₂ emissions rates below the SER. (Wood Memoranda at p.11 and p.4)

The Division has evaluated EPA's rationale for establishing NO₂ and SO₂ SERs for modeling the 1-hour NO₂ and SO₂ standards. The Wood Memoranda guidance set forth EPA's reasoning that its SER for SO₂ (a pollutant with shorter-term 3-hour and 24-hour averaging times) is 40 tpy, and, for this pollutant, ambient air quality impact analyses have not been necessary at levels below the SER. EPA has concluded that this reasoning applies to the one-hour NO₂ and SO₂ standards on an interim basis. EPA states it intends to conduct an evaluation of screening tools available to permitting agencies. In the interim, it recommends the continued use of the existing SER for NO₂ and SO₂ emissions with respect to the 1-hour NO₂ and SO₂ standards, and thus ambient air quality impact analyses are not necessary for either NO₂ or SO₂ emissions below the 40 tpy SER.

EPA’s Wood Memoranda guidance address PSD sources. The Division believes that the same principles apply to minor sources, in part, to ensure consistency of treatment in permitting and to ensure that it is not imposing different requirements on minor sources than those to which PSD sources are subject. The Division is aware of no factual basis to impose more stringent requirements on minor sources than EPA would impose on the largest air pollution sources. Therefore, the Division will apply EPA’s SERs for NO₂ and SO₂ to the 1-hour NO₂ and 1-hour SO₂ standards for all stationary source permitting activities, including determining when ambient air quality impact analyses are necessary for permitting, pending the consideration of any further guidance issued by EPA on this subject.
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