TECHNICAL REVIEW DOCUMENT
for
RENEWAL / MODIFICATIONS TO OPERATING PERMIT 95OPAD108

Suncor Energy (USA), Inc. – Commerce City Refinery, Plant 2 (East Plant)
Adams County
Source ID 0010003

Prepared by Jacqueline Joyce
August thru September and November 2013, August 2014 thru December 2014
June 2016 thru July 2017, April 2018 thru February 2020
Revised June 2020 through February 2021

Reviewed by:

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SECTION I - PURPOSE

This document establishes the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewal and modifications of the Operating Permit for the Suncor Commerce City Refinery – Plant 2 (East Plant). The initial Operating Permit for this facility was issued on October 1, 2006 and was last revised on June 15, 2009. The expiration date for the permit was October 1, 2011. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. The source submitted a renewal application on October 1, 2010. Prior to and after submittal of the renewal application, the source submitted applications to modify their permit as indicated in the table below.

Modification Applications		
Date Received	Modification Type	Modification Description
3/10/2009	Administrative Amendment	Source Description Corrections (Section I, Condition 5.1)
3/31/2009	Minor Mod	NO_X Limit for Fluid Catalytic Cracking Unit (FCCU)
7/30/2009	Minor Mod	Crude Unloading Dock
12/30/2009	Minor Mod	Storage Tank T-24
1/4/2010	Minor Mod	Main Plant (P2) Flare Emission Calculation Methodology
5/14/2010	Minor Mod	Incorporate Emergency Generator (CP 08AD0789)
5/14/2010	Minor Mod	Crude Furnace
11/1/2010	Minor Mod	FCCU – Incorporate CP 09AD0961
7/27/2011	Administrative Amendment	Remove Tanks T31, T55 and T56
9/16/2011	Minor Mod[1]	Mixed Butanes Project
9/28/2011	Minor Mod	Address Reg 7 Requirements for Terminals
12/19/2011	Minor Mod	NO_X Limit for FCCU
3/21/2012	Minor Mod	Tank T29
5/25/2012	Minor Mod	Plant 2 Wastewater Treatment System
10/11/2012	Significant Mod	Include New Boilers – Incorporate CPs 09AD1422 and 09AD1423
5/8/2013	Minor Mod	Install Controls on Plant 2 APIs
11/29/2013	Minor Mod	Install Emergency Air Compressor Engine
6/17/2014	Administrative Amendment	Change Responsible Official
8/4/2014	Minor Mod	FCCU SO_2 Limits
8/8/2014	Administrative Amendment	Remove Emergency Air Compressor Engine
1/14/2015	Significant Mod	Apply NSPS Ja to Plant 2 (P2) flare
4/15/2015	Minor Mod	Tank T62
6/10/2015	Minor Mod	Revise VOC emissions limits for cooling towers
10/28/2015	Significant Mod	Mod to allow cleaning and degassing activities controlled by a thermal oxidizer.

Modification Applications		
Date Received	Modification Type	Modification Description
10/28/2015	Significant Mod	Mod to address fugitive VOC from components that were not previously addressed (required per COC).
4/20/2016	Minor Mod	Mod to include sulfur recovery plant SO_2 limit (required by Consent Decree (CD)) into the T5 permit.
11/22/2016	Significant Mod	Set HCN limit for FCCU **A request to cancel this application was submitted on December 3, 2019.**
12/20/2016	Administrative Amendment	Add Responsible Official's Authorized Representative
2/10/2017	Minor Mod	Miscellaneous process vent (MPV) Project
7/10/2017	Minor Mod	Upgrade P2 flare to comply with MACT CC requirements
7/31/2017	Minor Mod	Include temperature and O_2 indicators for MACT UUU monitoring for the Sulfur Recovery Unit (SRU)
12/4/2017	Minor Mod	Tank T26
2/9/2018	Minor Mod	Install Emergency Air Compressor Engine (No. 2 FCCU)
6/14/2018	Minor Mod	Plant 2 Rail Rack – Emission Calculation Methodology
7/17/2018	Minor Mod	Install Emergency Air Compressor Engine (Old Boiler House)
12/27/2018	N/A[2]	FCCU cold resid project
1/8/2019	Minor Mod	Tank T058
1/30/2019	Minor Mod	P2 rail rack Flare RSR Project
10/22/2019	Minor Mod	P2 truck rack vapor combustion unit emission calculation methodology
2/19/2020	Minor Mod	Convert Tank T011 from an internal floating roof (IFR) to an external floating roof (EFR) tank

[1]This application was submitted as a minor modification and logged into the Title V permit tracking system (OPIE) as a modification but no changes to the permit are necessary for the modification. Since this project involved physical changes or changes to the method of operation, the emission increase from this project was assessed.

[2]The source submitted this as a minor modification but no changes to the permit were necessary for this modification, so it was not logged into the Title V permit tracking system (OPIE) as a modification. Since this project involved physical changes or changes to the method of operation, the emission 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 renewal application submitted on October 1, 2010, the modification applications listed in the above table, the additional information noted in the table below, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division's website at www.colorado.gov/cdphe/airTitleV. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Additional Information Submittals	
Date Submitted	Description
April 17, 2009	Cancel APEN for Black Oil Heater
August 2, 2012	Plant 2 wastewater treatment system
December 13, 2013	Tank T29 and P2 API mod
February 13, 2014	Plant 2 cooling tower
March 31, 2014	Boilers B504 & B505 RATA
May 1, 2015	Tank T62
August 31, 2015	P2 flare Ja
September 29, 2015 & January 28, 2016	Fugitive VOCs from components required by COC
November 12, 2015	Cancel APEN and construction permit for security center emergency generator
February 11 and December 5, 2016 and June 25 and August 21 & 27, 2020	Tank Degassing Thermal Oxidizer
September 1, 19, 20, 22 & 23, 2016	Response to general info request
March 15 & April 18 & 26, 2017	MPV modification
April 17, 2017	Truck Dock Flare (EPA applicability determination)
December 15, 2017 & February 14, April 13, June 12, July 6 & 9 & August 3, 2018	P2 Flare RSR project
April 27, 2018	Cancel APENs for Tanks 24, 40 & 41
May 4, 2018	Cancel APEN for emergency air compressor (No. 2 FCCU)
August 3, 2018 & January 30, 2019	P2 rail rack – emission calculation methodology
October 10, 2018	Cancel emergency air compressor application (old boiler house)
February 12, March 12 & September 27, 2019	Net (lower) heating value of P2 waste gas
January 10, 2019	Tank T058
May 2, 2019	FCCU Cold Resid Project
December 3, 2019	FCCU HCN limit
May 11 and September 28, 2020	Comments on draft permit and technical review document
June 25 & 30 and September 30, 2020	Information submitted to support May 11, 2020 comments
October 19, 2020	Information submitted to support September 28, 2020 comments

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 SOURCE

This facility is classified as a petroleum refinery under Standard Industrial Code 2911.

The facility is located at 5801 Brighton Boulevard in Commerce City, CO. The Denver

Metro Area, including Commerce City, is classified as attainment/maintenance for particulate matter less than 10 microns (PM_{10}) and carbon monoxide. Under that classification, all SIP-approved requirements for PM_{10} and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver Metro Area is classified as nonattainment for ozone and is part of the 8-hour Ozone Control Area as defined in Regulation No. 7, Section II.A.1.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park and Eagles Nest National Wilderness Area, both Federal Class I designated areas, are within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit has been modified to reflect the updated potential to emit (PTE) of criteria pollutants due to changes that may have occurred in emission units, emission factors and/or emission limitations since the previous permit was issued and to reflect actual emissions. As indicated in the table below the facility is a major stationary source with respect to prevention of significant deterioration (PSD) and/or non-attainment area new source review (NANSR) requirements. Emissions in (tons/yr) for the facility are as follows:

Potential To Emit (PTE)

Pollutant	Emissions (tons/yr)		
	Plants 1 & 3 (96OPAD120)	Plant 2 (95OPAD108)	Total Emissions
PM	138.15	53.34	191.49
$PM_{10}/PM_{2.5}$	138.15	53.34	191.49
SO_2	396.51	389.73	786.24
NO_X	692.69	266.41	959.10
CO	741.80	311.29	1,053.09
VOC	405.16	373.95	779.11

Actual Emissions

Pollutant	Emissions (tons/yr)		
	Plants 1 & 3 (96OPAD120)	Plant 2 (95OPAD108)	Total Emissions
PM	90.87	34.04	124.91
$PM_{10}/PM_{2.5}$	90.87	34.04	124.91
SO_2	147.45	41.02	188.47
NO_X	331.55	149.28	480.83
CO	225.12	132.68	357.80
VOC	184.68	133.91	318.59

Detailed information on potential to emit (i.e., potential to emit by emission unit and method to estimate potential to emit) and actual emissions for Plant 2 is shown on the tables beginning on page 148. Potential to emit and actual emissions for Plants 1 and 3 (96OPAD120) shown in the above tables is based on the information provided in the

TRD for the Plants 1 and 3 renewal (issued October 1, 2012), which also includes detailed information on those emissions (i.e., emissions per emission unit and method to estimate potential to emit).

1. National Emission Standards for Hazardous Air Pollutant (NESHAP) Requirements

NESHAPs are included in 40 CFR Part 61 and 40 CFR Part 63. The requirements in 40 CFR Part 61 address a specific hazardous air pollutant (HAP), such as benzene, and apply to sources that meet the applicability requirements. Significant changes were made to the Federal Clean Air Act in 1990 with respect to HAP emissions and those changes are reflected in the NESHAPs promulgated under 40 CFR Part 63. The requirements in 40 CFR Part 63 apply to specific source categories, are technology based and are frequently referred to as “MACT requirements”.

40 CFR Part 61 Requirements

As indicated in the current permit (last revised June 15, 2009) the facility is subject to the requirements in 40 CFR Part 61 Subpart FF, National Emission Standard for Benzene Waste Operations, otherwise known as “BWON”. The specific BWON requirements that apply to the facility have changed since the current permit was issued (last revised June 15, 2009) and the appropriate BWON requirements will be included in the permit.

40 CFR Part 63 Requirements

The facility is a major source for HAPs and as such the MACT requirements in 40 CFR Part 63 apply to specific equipment at the facility. The current permit (last revised June 15, 2009) includes the requirements from 40 CFR Part 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries) and 40 CFR Part 63 Subpart UUU (National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units).

The requirements from 40 CFR Part 63 Subpart GGGGG (National Emission Standards for Hazardous Air Pollutants: Site Remediation) are included in the permit shield for non-applicable requirements in the current permit (last revised June 15, 2009) because site remediation at Plant 2 is required by an order under RCRA section 7003 and is therefore exempt from the Site Remediation MACT requirements per 63.7881(b)(3).

Note that on May 13, 2016, EPA proposed to remove the exemption for site remediation required by an order under RCRA section 7003, which would make the facility subject to the requirements in Subpart GGGGG. The Residual Risk and Technology Review (RTR) for the Site Remediation MACT was proposed on September 3, 2019. In the RTR EPA requests additional comments on how the Site Remediation MACT should be amended if the RCRA exemption were removed. EPA indicate they did not intend to take final action with respect to the exemption in the RTR but to gather information in anticipation of addressing this issue in a separate action. Since it is not expected that Plant 2 will become subject to Subpart GGGGG requirements in the near future, it will remain in the permit shield.

Since issuance of the current permit (June 15, 2009), the following MACT requirements have been determined to apply to equipment at the facility.

Reciprocating Internal Combustion Engines (40 CFR Part 63 Subpart ZZZZ)

The reciprocating internal combustion engine (RICE) MACT was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. Under this rulemaking only RICE that were > 500 hp and located at major sources of HAPS were subject to the requirements. Subsequent revisions were made to the RICE MACT to address new engines $\leq$ 500 hp located at major sources and new engines of all sizes at area sources (final rule published January 18, 2008), existing compression ignition engines $\leq$ 500 hp at major sources and all sizes at area sources (final rule published March 3, 2010) and existing spark ignition engines $\leq$ 500 hp at major sources and all sizes at area sources (final rule published August 20, 2010). Revisions have been made to the RICE MACT requirements since then; however, those revisions did not change the applicability requirements for the engines at this facility.

The insignificant activity list indicates that there are internal combustion engines at the facility, although no specific engines are listed. In response to a request for information received on September 1, 2016, the source indicated that other than the security center emergency generator, there are no additional stationary internal combustion engines associated with Plant 2.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was published in the Federal Register on September 13, 2004. Under 40 CFR Part 63 Subpart DDDDD most of the boilers and process heaters were not subject to any substantive requirements (existing units $\leq$ 10 MMBtu/hr were not subject to any requirements and existing units > 10 MMBtu/hr were only subject to the initial notification requirements). However, the Boiler MACT was vacated July 30, 2007. Due to the vacatur, EPA was required to re-promulgate requirements for this source category.

Final Boiler MACT requirements were published in the Federal Register on March 21, 2011. The final rule does not include emission limits for natural gas or refinery gas fired units but instead specifies work practice requirements. Sources will be required to conduct tune-ups on new and existing units. Final revisions to the Boiler MACT were published in the Federal Register on January 31, 2013 and November 20, 2015 The January 31, 2013 final rules have no affect on the applicability of the Boiler MACT to the boilers and process heaters at this facility, although the frequency of tune-ups were revised. The November 20, 2015 revisions were the result of the reconsideration of various provisions of the January 31, 2013 revisions and also addressed technical corrections and clarifications. The appropriate applicable requirements from the Boiler MACT will be included in the permit.

Note that proposed revision to the Boiler MACT were published in the Federal Register on August 24, 2020. The proposed revisions amend several emission limits and set new compliance date, provide further explanation on the use of CO as a surrogate for organic HAPs and make technical corrections. These revisions are not expected to significantly revise any requirements for the boilers and process heaters addressed in this permit. In the event that the revisions are made final prior to permit issuance, they will be included in the permit.

2. New Source Performance Standards (NSPS)

EPA has promulgated NSPS requirements for new source categories since the current permit was issued for this facility. NSPS requirements generally only apply to new or modified equipment and the Divisions is not aware of any modifications to existing equipment or additions of new equipment that would render equipment at this facility subject to NSPS requirements. However, because the recently promulgated NSPS requirements address equipment that may not be subject to APEN reporting or minor source construction permit requirements, the applicability of some of the newly promulgated requirements are being addressed here.

NSPS Subpart JJJJ – Stationary Spark Ignition Engines

NSPS Subpart JJJJ applies to stationary spark ignition engines that commenced construction, reconstruction or modification after June 12, 2006 and were manufactured after specified dates. The date the engine commenced construction is the date the engine was ordered by the owner/operator. The Division is not aware of any spark-ignition engines at this facility that meet the applicability requirements (commence construction and manufacture dates). The source indicated in a September 1, 2016 response to a request for additional information that the only stationary internal combustion engine located at the facility is the security center emergency generator (a compression ignition engine).

NSPS Subpart IIII – Stationary Compression Ignition Engines

NSPS Subpart IIII applies to stationary compression ignition engines that commenced construction, reconstruction or modification after July 11, 2005 and were manufactured after specified dates. The date the engine commenced construction is the date the engine was ordered by the owner/operator. Other than the security center emergency generator, the Division is not aware of any other compression-ignition engines at this facility that meet the applicability requirements (commence construction and manufacture dates). The source indicated in a September 1, 2016 response to a request for additional information that the only stationary internal combustion engine located at the facility is the security center emergency generator (a compression ignition engine).

3. Regulation No. 7 Requirements

Since the permit was issued initially in 2006, revisions have been made to Regulation No. 7 and the applicability of those requirements with respect to Plant 2 are discussed below.

Revisions to Regulation No. 7 were adopted by the Colorado Air Quality Control Commission (AQCC) on December 19, 2019 (effective February 14, 2020). The revisions include a reorganization of Regulation No. 7. The regulation was reorganized into parts and the various sections are renumbered and assigned to a part (e.g. Part B). Except for newly added sections and as otherwise noted, the below discussion utilizes the numbering prior to the December 19, 2019 revisions.

Also, as part of the December 19, 2019 revisions two new sections were included that are applicable state-wide (Part D, Sections VI (requirements for natural gas transmission and storage facilities) and V (requirements for emission inventories from oil and natural gas operations)) but these sections do not apply to refineries.

Colorado Regulation No. 7, Section X.E – Control of Industrial Cleaning Solvent Operations

The provisions in Section X.E were adopted into Colorado Regulation No. 7 on November 17, 2016 (effective January 14, 2017) to address EPA's control technique guidelines (CTG) for industrial solvent cleaning operations. These requirements apply to sources that have total, combined, uncontrolled actual VOC emissions from industrial solvent cleaning operations of 3 tons/yr of VOC emissions on a calendar year basis.

The Division requested information from the source to determine whether or not actual, uncontrolled VOC emissions from industrial solvent cleaning operations might exceed 3 tons in any calendar year. The source did not provide any emission information but it appears that industrial solvent cleaning operations during a turnaround (which occurs approximately every five years) may trigger these requirements.

In their response to the Division's query, the source noted that during a turnaround equipment is cleaned out using a solvent and then vented to the flare, as required by 40 CFR Part 63 Subpart CC (specifically the requirements for miscellaneous process vents in 63.343) and believes that the MACT CC requirements qualify the industrial solvent cleaning activities during a turnaround for an exemption. The Division considers that this does not qualify for the exemption, as the MACT CC requirements do not specifically apply to industrial solvent cleaning operations. In addition, the exemption language in Section X.E.4.a.(i), which exempted sources subject to a NESHAP, was removed.

Since the source has not provided any information indicating that the emissions are below the 3 ton/yr threshold, or that any industrial solvent cleaning operations are subject to an exemption, the requirements in Section X.E will be included in the permit.

Colorado Regulation No. 7, Part C, Section II.F – General Solvent Use

This was a new section included in the December 19, 2019 revisions adopted by the Colorado AQCC and in accordance with Section II.F.1.a applies to operations within the 8-hour ozone control area that use solvents with uncontrolled, actual VOC emissions greater than or equal to two (2) tons per year that existed at a major source of VOC emissions (50 tons/yr or greater) as of January 27, 2020 (date of re-designation to serious non-attainment). These requirements do not apply to operations that are subject to a solvent work practice or emission control requirements in another federally enforceable section of Regulation Number 7 that constitutes RACT (see Reg 7, Part C, Section II.F.2.a). Since the Division considers that the industrial cleaning solvent operations likely apply to the facility, the requirements in Part C, Section II.F would not apply.

Colorado Regulation No. 7, Sections XII and XVIII – Requirements for Oil and Gas Operations in the 8-hour Ozone Control Area

Oil refineries are specifically exempt from the requirements in Section XII as provided for in Section XII.A.2. The requirements in Section XVIII apply to pneumatic controllers actuated by natural gas and located at, or upstream of natural gas processing plants. While there is no language in Section XVIII that states that these requirements do not apply to oil refineries, these requirements were clearly not intended to apply to an oil refinery.

Section XVII – Statewide Requirements for Oil and Gas Operations

Oil refineries are specifically exempt from the requirements in Section XVII as provided for in Section XVII.B.4.

Colorado Regulation No. 7, Sections XVI - Requirements for Engines and Other Combustion Equipment in the 8-Hour Ozone Control Area and Section XIX – Control of Emissions from Specific Major Sources of VOC and NO_X

The requirements in Regulation No. 7, Section XVI previously applied to natural gas-fired engines located in the 8-hour ozone control area and set control requirements for engines greater than 500 hp. Non-road engines and emergency generators that are exempt from APEN requirements are not subject to the control requirements as provided in Section XVI.C.1 and 3. This facility is located in the 8-hour ozone control area but there are no natural gas-fired engines greater than 500 hp located at this facility, therefore the requirements in Section XVI do not apply.

The AQCC adopted provisions in Regulation No. 7 on November 17, 2016 (effective January 14, 2017) to address requirements that were triggered from the bump-up from

Marginal to Moderate nonattainment for the 8-hour ozone control area (also referred to as the Denver Metro/North Front Range (DMNFR) area).

These revisions included combustion process adjustment requirements for combustion sources located at major sources of NO_X in the 8-hour ozone control area in Section XVI.D, as well as requirements for major sources of NO_X in Section XIX that apply to this facility since it is a major source of NO_X.

The combustion process adjustment requirements in Section XVI.D applies to boilers, duct burners, process heaters, engines and combustion turbines thus these requirements applied to equipment at this facility. Under Section XIX.B, Suncor was required to submit a RACT analysis for the boilers located at both Plants 1 and 2 by December 31, 2017 and two emergency air compressor engines located at Plant 1 were required to comply with the requirements in 40 CFR Part 60 Subpart IIII, 40 CFR Part 60 Subpart JJJJ and/or 40 CFR Part 63 Subpart ZZZZ per Section XIX.C. (Note that equipment located at Plant 1 are addressed in 96OPAD120.) Suncor submitted the required RACT analysis for the Plants 1 and 2 boilers on November 1, 2017 and the Plant 1 Title V permit (96OPAD120) includes the appropriate requirements in 40 CFR Part 60 Subpart IIII and 40 CFR Part 63 Subpart ZZZZ for the emergency air compressor engines.

The AQCC adopted revisions in Regulation No. 7 on July 19, 2018 (effective September 14, 2018) to address the RACT analyses for combustion equipment that major sources submitted as required by Section XIX.B. As part of the July 19, 2018 revisions, Section XIX and XVI.D were revised.

Under Section XIX.A, the two emergency air compressor engines located at Plant 1 are required to comply with the requirements in 40 CFR Part 60 Subpart IIII, 40 CFR Part 60 Subpart JJJJ and/or 40 CFR Part 63 Subpart ZZZZ. As previously stated, the Plant 1 equipment is addressed in Operating Permit 96OPAD120, so these requirements are not applicable to this permit.

The requirements in Section XVI.D apply to stationary combustion equipment that existed at a major source of NO_X as of June 3, 2016 located in the 8-hour ozone control area. Sources subject to emission limitations in Section XVD.4 must comply with those limits by October 1, 2021. Section XVI.D also includes requirements for exemptions (XVI.D.2), compliance demonstrations (XVI.D.5), combustion process adjustment (XVI.D.6), recordkeeping (XVI.D.7) and reporting (XVI.D.8). This facility was a major source as of June 3, 2016 and has combustion equipment (boilers, process heaters and engines) that existed as of June 3, 2016, therefore, the requirements in Section XVI.D apply.

The equipment located at Plant 2 that are potentially subject to requirements in Section XVI.D include engines, boilers and process heaters. The emission limitations in Section XVI.D.4 apply to boilers and compression ignition engines but not process heaters. Specifically, the emission limits apply to boilers with a design heat capacity greater than or equal to 100 MMBtu/hr and to compression ignition engines with a power output greater than or equal to 500 hp. The boilers at this facility are subject to the emission limitations but there are no compression ignition engines that existed at this facility as of June 3, 2016 that are greater than 500 hp.

The combustion process adjustment requirements in Section XVI.D.6 apply to boilers (any size), process heaters and stationary reciprocating internal combustion engines (any size, not restricted to compression ignition engines) that existed at this facility as of June 3, 2016 and have actual, uncontrolled emissions greater than or equal to 5 tons per year. Note that although not specified in Section XVI.D.6, the Division considers that the emission trigger is based on calendar year emissions since the statement of basis indicates that the Commission intended sources to look to the current APENs to determine applicability (see discussion in Section XX.O regarding combustion process adjustment requirements).

The AQCC adopted revisions to Regulation No. 7 on November 15, 2018 (effective January 14, 2019) to include RACT requirements for breweries and wood furniture manufacturing, correct some EPA concerns regarding metal furniture surface coating, miscellaneous metal surface coating and industrial solvent cleaning operations. In addition, typographical, grammatical, and formatting errors were corrected. The November 15, 2018 revisions have minimal effect on the requirements for equipment at this facility.

No substantive changes were made to the Section XVI.D requirements that apply to the equipment at this facility in the December 19, 2019 revisions. The revisions expanded the applicability of these requirements to sources that existed at a major source of NO_X (greater than or equal to 50 tons/yr of NO_X) as of the serious designation date [January 27, 2020].

In addition, the provisions in Section XIX that required the Plant 1 emergency air compressors to comply with the requirements in 40 CFR Part 60 Subpart JJJJ, 40 CFR Part 60 Subpart IIII, and/or 40 CFR Part 63 Subpart ZZZZ by January 1, 2017 was not changed in the December 19, 2019 revisions. As discussed previously, the Plant 1 equipment is addressed in Operating Permit 96OPAD120, so these requirements are not applicable to this permit.

The AQCC adopted revisions to Regulation No. 7 on September 23, 2020 (effective November 14, 2020) to revise some of the oil and gas provisions in Part D, as well revisions to the requirements for natural gas-fired engines in Part E, Section I (formerly Section X33VI.A thru C). The primary revisions to the engine requirements was to reduce emissions from natural gas-fired engines greater than 1,000 hp. The September 2020 revisions do not affect the equipment at Plant 2, as the facility is not engaged in oil and natural gas operations, nor are there any natural gas-fired engines at the facility.

The AQCC adopted revisions to Regulation No. 7 on December 18, 2020 (effected February 14, 2021) to revise some of the oil and gas provisions in Part D, as well as revisions to major source RACT requirements for combustion equipment in Section II.A (formerly Section XVI.D) and to include RACT for foam product manufacturing. The substantive revisions to Part E, Section II.A were to revise the NO_X emission limits for combustion turbines that commenced construction on or before February 18, 2005 and boilers $\geq$ 50 MMBtu/hr and < 100 MMBtu/hr located at major sources of NO_X (greater than or equal to 50 tons/yr as of January 27, 2020). These revisions do not affect the equipment addressed in this permit.

The appropriate requirements from Section XVI.D will be included in the permit and are addressed more specifically later in this document.

4. Compliance Assurance Monitoring (CAM) Requirements

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. In their October 1, 2010 renewal application, the source indicated that the CAM requirements applied to the FCCU with respect to the PM emission limitation. CAM is addressed in greater detail under the discussion on the renewal application (see Section III.1.8 of this document).

5. Greenhouse Gases

Greenhouse gas (GHG) emissions from the Commerce City Refinery exceed 100,000 tpy CO_2e. Future modifications at the refinery will have to be evaluated to determine if GHG emissions are subject to regulation.

SECTION III - DISCUSSION OF MODIFICATIONS MADE

The following discussion related to modifications is with respect to the current Title V permit (last revised June 15, 2009) and unless specifically noted as “new”, the condition numbers identified in this document reflect the condition numbers in the current Title V permit (last revised June 15, 2009). Because some permit conditions in the current Title V permit (last revised June 15, 2009) 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.

Note that the changes discussed below, use the Regulation No. 7 numbering prior to the December 19, 2019 revisions (effective February 14, 2020), unless otherwise noted. The revised permit will include the numbering in the December 19, 2019 revision (effective February 14, 2020); however, unless otherwise noted, the TRD will continue to use the numbering convention from the previous Regulation No. 7 version (adopted November 15, 2018, effective January 14, 2019).

1. Source Requested Modifications

The source’s requested modifications were addressed as follows:

1.1 March 10, 2009 Modification (administrative amendment) – Source Description Correction

The purpose of this modification was to correct inconsistencies in the assignment of permit IDs and several inaccurate source descriptions. The changes are administrative in nature and no increase in emissions is associated with this modification. Since this modification was submitted in March 2009, Suncor initially indicated that they no longer wanted the changes requested in this modification addressed. However, as noted in their September 1, 2016 response to a request for information, the source indicated that they did not want to completely cancel this modification.

The modification primarily addressed source descriptions and identification numbers and covers several areas of the permit, mainly the summary table in the Section I, Condition 5.1 and the sections in Section II that address specific equipment at the refinery. The changes to the Section II sections mainly identified the equipment listed in Section I, Condition 5.1 in the summary table headers and clarified in the text of individual permit conditions which equipment was subject to specific requirements. One of the more significant changes to the descriptions was to remove the requirements for the black oil heater (Section II.11). The source submitted a cancellation notice on April 17, 2009 indicated that the heater has been decommissioned, isolated from the process and is out of service.

In general revisions to the permit were made in the spirit of the application, except for the following:

- The changes to the polymerization unit in both the table in Section I, Condition 5.1 and Section II.4 were not made as the polymerization unit has been removed from Section II of the permit (emissions from catalyst loading and unloading are below the APEN de minimis level, as discussed later in this document). Fugitive emissions from the polymerization unit are included in the table in Section I, Condition 5.1 under the fugitive VOC emission sources.
- The following changes were not made to Section II.5 (sulfur recovery plant):
  - The requirements in 40 CFR Part 63 Subpart UUU apply to the sulfur recovery unit (P015), so the request to say that these requirements apply to the incinerator will not be made. Similar to the Plants 1/3 permit a note was added to indicate that emissions from the sulfur recovery unit are routed through the incinerator was added under the section II.5 header.
  - Many of the requested revisions to Conditions 5.8, 5.9 and 5.10 were not made, as the language in these sections is directly from the EPA PSD permit.
- The suggested change to the Reg 7 citation in Condition 15.6 was not made, as it doesn’t appear that the suggested change is correct.
- The suggested modification includes individual tanks and tank groups listed under Section II.18 (fugitive VOC equipment leak emissions with permit limits). The

modification does not suggest specific identification of fugitives associated with tanks under other locations of the permit. It isn't clear what the purpose of these suggested changes serves, therefore, the changes were not made. The Division has made other revisions to the permit to more clearly indicate requirements for sources of fugitive emissions from leaking components, whether or not such components are subject to emission limitations.

1.2 March 31, 2009 and December 19, 2011 Modifications (minor modifications) – NO_X Limit for Fluid Catalytic Cracking Unit (FCCU)

The purpose of the March 31, 2009 modification is to limit NO_X emissions from the FCCU to meet the interim system-wide NO_X limitations in the Consent Decree (CD) (69.2 ppm at 0% O_2 on a 365-day rolling average). The proposed NO_X limit in the March 31, 2009 application was 90 ppm NO_X, on a 365-day rolling average.

The purpose of the December 19, 2011 modification is to limit NO_X emissions from the FCCU to meet the final system-wide NO_X limitations in the CD (33.4 ppm at 0% O_2 on a 365-day rolling average). The proposed NO_X limits in the December 19, 2011 modification are 80 ppm NO_X at 0% O_2 on a 365-day rolling average and 160 ppm NO_X at 0% O_2 on a 7-day rolling average.

Since the December 19, 2011 modification represents the FCCU NO_X limits to meet the final system-wide NO_X limits, those limitations will be included in the permit. Note that the March 31, 2009 modification included requirements for the NO_X CEMS and specifically noted that either a Relative Accuracy Audits (RAA) or Relative Accuracy Test Audits (RATA) were to be conducted every three years but according to 40 CFR Part 60 Appendix F, an RAA or RATA is to be conducted once every four quarters. The permit will require that the NO_X CEMS meet the requirements in 40 CFR Part 60 Appendix F which require annual RAAs or RATAs.

The following changes were made to the permit to address these modification applications:

<u>Section II. 2 - FCCU</u>

- NO_X limits were included in Condition 2.11 of the permit. (Note that in the current permit (last revised June 15, 2009) Condition 2.11 includes performance test requirements.)

1.3 July 30, 2009 Modification (minor modification) – Crude Unloading Dock

The purpose of this modification is to replace the underground piping for the Crude Oil Unloading Rack No. 1 (North or "old" rack) with aboveground piping and to increase the crude unloading limit for the racks from 378,000,000 gallons/yr to 614,880,000 gallons/yr. Replacing underground piping with above ground piping will result in an increase in emissions due to potential leaks to components. According to the application, unloading crude does not result in an increase in emissions. (Emissions from loading a tank via a truck would be reflected in tank emissions.) The emission limits in the current permit (last revised June 16, 2009) are from construction permit 93AD592 which indicates the emission limitations are based on emissions from leaking components. Thus the increase in emissions is due solely to the piping changes associated with replacing the underground piping and is not related to the requested throughput increase.

In the application, Suncor indicated that there would be no upstream or downstream affected sources. Since there are no units upstream of the crude unloading (the refining process begins with crude unloading) there are no affected upstream units. Suncor indicates that there are no downstream affected units as an increase in crude delivery by truck would be offset by a decrease in crude deliveries via pipeline. The Division is not aware of any physical changes to the facility that would indicate the change in the requested throughput limit for the crude oil unloading rack is a means to increase the overall refinery production rate and that the Division understands the increase has been requested as a means to provide flexibility in crude deliveries. The increase in emissions associated with this project is as follows:

VOC Emissions (tons/yr)		
Requested Emissions	Current Permitted	Change in Emissions
9.4	3.9	5.5
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]		40

[1]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

The following revisions were made to the permit to address the changes to the crude oil loading racks:

Section II.7 – Crude Unloading/Gasoline Tank Truck Loading

- Revised Condition 7.1 to increase the VOC emission limitation for crude unloading to 9.4 tons/yr.
- Increased the crude oil throughput limit in Condition 7.6 to 614,880,000 gal/yr.

1.4 December 30, 2009 Modification (minor modification) – Storage Tank T024 and April 27, 2018 Information Submittal to Cancel APEN for Tank T024

The purpose of this modification is to increase the current permitted throughput for tank T-24. In the application, the source indicates that Tank T-24 is a gas sales tank and that tank T-24 must be able to handle additional throughput when other gas sales tanks are out-of-services for inspections. The gas sales tanks are equipped with internal floating roofs and must be removed from service and visually inspected every 10 years.

Although the source is requesting an increase in throughput from Tank T-24, the source is not requesting an increase in emissions. Current permitted emissions from Tank T-24 were estimated using EPA TANKS but the guide pole controls were not correctly represented at that time and when the correct guide pole controls are included the calculation, emissions are actually lower. The change in emissions from this project are as follows:

VOC Emissions (tons/yr)		
Requested Emissions	Current Permitted	Change in Emissions
0.95	1.9	-0.95
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]		40

[1]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

On April 27, 2018 Suncor submitted a request to cancel the APEN for Tank T024 which indicated that the tank had been permanently removed from service and asked that it be removed from the Title V permit. See the discussion under 1.32 for the changes made to the permit to address the April 27, 2018 submittal.

1.5 January 4, 2010 Modification (minor modification) – Main Plant (P2) Flare Emission Calculation Methodology

The purpose of this modification is to correct the emissions calculation methodology for the main plant flare and to revise the emission limitations to reflect that methodology. An underlying construction permit (88AD134) provides the emission and processing limits for the main plant flare. The current Title V permit (revised June 15, 2009) does not include the requirements from the most recent version of construction permit 88AD134 (issued November 8, 2006) but includes requirements from the January 5, 1998 version of construction permit 88AD134. The Division's 2005 annual inspection noted compliance issues with the main plant flare emission limitations and these issues were addressed in Compliance Order on Consent (COC) 2005-059, signed on June 2, 2006. The COC directed Suncor to address the issue in two phases. The first phase was to revise the construction permit and rely on NO_X, CO and VOC emission factors from AP-42, Section 5.1 for Petroleum Refineries (these emission factors predict emissions from the flare based on the quantity of barrels of refinery feed) and the November 8, 2006 construction permit was issued as a result of this phase 1. The second phase was to install, repair and modify monitoring equipment for the flare to obtain valid data regarding flow to the flare and the heat and sulfur content of waste gases, to collect and analyze such data in order to allow Suncor to use emissions factors from AP-42, Section 13.5 for Industrial Flares (these emission factors are in lb/MMBtu). Following analysis of such data, the source was required to submit a permit application to revise the emission and processing limits for the main plant flare. The January 4, 2010 application fulfills phase 2 of the COC to address the flare compliance issue.

In addition, both the current Title V permit (revised June 15, 2009) and the most recent version of construction permit 88AD143 included a limit on the amount of crude processed since some the emission limitations were based on emission factors in units of lb/Mbbl. With the January 4, 2010 modification, this limit on the amount of crude processed by the facility will be replaced with a limit on the quantity of waste gas combusted by the flare (in MMBtu/yr). The limit on the quantity of waste gas combusted by the flare is a more direct measure of emissions from the flare and is consistent the flare emission factors in AP-42, Section 13.5, which are in units of lb/MMBtu.

It should be noted that the source requested emission and throughput limits based on a leap year (366 days, 3784 hours). It is Division policy to permit based upon a standard year (365 days, 8760 hours), therefore, the emission and throughput limits were revised to reflect that. In addition, the SO_2 emission factor is based on 162 ppm of hydrogen sulfide (H_2S) in the flared gas and the emission factor was based on a standard molar volume of 379 scf/lb-mole. For EPA purposes a standard molar volume of 385.3 scf/lb-mole should be used and the SO_2 requested emissions were revised to reflect that.

There has not been a physical change or change in the method of operation of the flare and the requested modification does not result in a change in actual emissions from the flare. The purpose of this modification is to change the method used to quantify emissions from the flare. The changes in “permitted” emissions from the flare are as follows:

Pollutant	Emissions (tons/yr)			
	Requested[1]	Current Permit[2]	Change in Emissions	PSD/NANSR Significance Level (T5 Minor Mod Level)[3]
PM/PM_{10}	1.9	N/A	1.91	25/15
SO_2	4.6	172	-167.4	40
NO_X	17.4	120.7	-103.3	40
CO	94.8	27.47	67.33	100
VOC	35.9	5.11	30.79	40

[1]The APEN submitted with the application did no request PM/PM10 emissions but were calculated based on requested throughput and the emission factor from AP-42, Section 1.4 (dated 7/98), Table 1.4-2, converted to lb/MMBtu by dividing by 1020 Btu/scf per footnote a.

[2]Values shown are the limitations in the November 8, 2006 version of construction permit 88AD123, which had not been incorporated into the T5 permit. Note that construction permit did not include limits for PM/PM_{10}.

[3]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

The following revisions were made to the permit to address the changes to the flare:

<u>Section II.8 – Refinery Flare</u>

- Revised the NO_X, CO, VOC and SO_2 emission limits and factors in Condition 8.1.

- Included a limit on the gases combusted by the flare (in Btu/year) in "new" Condition 8.6. (In the current permit (last revised June 15, 2009) Condition 8.8 includes requirements for determining the heat input to flare and Condition 8.6 includes NSPS GGG requirements.)

Section II.34 – Production Limit

- Condition 34 (production limit) was removed. Note that Section II.34 was revised to include the NSPS VV requirements.

1.6 May 14, 2010 Modification (minor modification) and November 12, 2015 Additional Information Submittal– Incorporate Emergency Generator (CP 08AD0789)

Construction permit 08AD0789 was issued for an emergency generator on September 2, 2008. The purpose of the May 14, 2010 modification is to incorporate the requirements from construction permit 08AD0789 into the Title V permit.

At the time the emergency generator was permitted, Colorado Regulation No. 3, Parts A and B included "catch-all" language that required sources that would otherwise be APEN and/or minor source construction permit exempt to file an APEN and obtain a minor source construction permit if the emissions unit was subject to requirements in an NSPS or NESHAP that had been adopted into Colorado Regulations. Since the emergency generator was subject to the requirements in NSPS Subpart IIII, which were adopted into Colorado Regulation No. 6, Part A, a construction permit was required for the engine.

Effective April 14, 2014, the "catch-all" provisions in Colorado Regulation No. 3, Parts A and B, were removed. Therefore, as long the emergency generator is exempt from the APEN reporting and/or minor source construction permit requirements and there is no other need for a construction permit (e.g. to limit potential to emit below the significance level) then the construction permit is not required.

The source submitted a request on November 12, 2015 to cancel the construction permit for this emergency generator. Actual, uncontrolled emissions from the emergency generator are below the APEN de minimis level (1 tpy of NO_X) thus the unit is exempt from APEN and minor source construction permit requirements. In addition, potential to emit from this engine is below the significance level (based on 500 hours per year of operation), thus a construction permit is not required to limit potential to emit.

Note that although the APEN and construction permit can be canceled, this engine is still subject to the "catch-all" requirements in Colorado Regulation No. 3, Part C. Therefore, because the engine is subject to requirements in NSPS Subpart IIII it cannot be considered an insignificant activity and the engine must remain in Section II of the permit.

An APEN is not required unless annual hours of operation reach 3,239 hours in any calendar year. Therefore, emission and throughput limits will not be included in the permit for this engine.

The appropriate applicable requirements for this engine, include the following:

- Except as provided for below, visible emissions shall not exceed 20% opacity (Reg 1, Section II.A.1)
- Visible emissions shall not exceed 30% opacity, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)

  Based on engineering judgment, the Division believes that the operational activities of fire building, cleaning of fire boxes and soot blowing do not apply to diesel engines. In addition, since this engine is not equipped with control equipment the operational activities of adjustment or occasional cleaning of control equipment do not apply to this engine. Finally, based on engineering judgment, it is unlikely that process modifications will occur with this engine. Therefore, for this unit the 30% opacity provision only applies during startup. The 20% opacity requirement (noted in the above bullet) applies at all other times. Note that expected startup time is not projected to exceed 30 minutes.

- SO_2 emission shall not exceed 0.8 lbs/mmBtu (Reg 1, Section VI.B.4.b.(i))

  The SO_2 requirement will be streamlined for the more stringent fuel requirements in 40 CFR Part 60 Subpart IIII (15 ppm or 0.0015% sulfur). This condition is noted in the permit shield for streamlined conditions (Section III.3 of the permit).

- SO_2 emissions shall not exceed 0.3 lb/bbl/day (Reg 1, Section VI.B.4.e)

  The SO_2 emission limit for refineries was not included in the construction permit, but since the unit is located at a refinery, it applies and Appendix H (SO_2 Emissions Calculation Methodology) included emissions from the emergency generator. Compliance with the SO_2 limit is based on daily calculations, so requirements were added to record daily fuel consumption for the engine (based on hours of operation and the maximum hourly fuel consumption rate).

- 40 CFR Part 60 Subpart IIII Requirements
- 40 CFR Part 63 Subpart ZZZZ requirements

Note that since this engine existed as of June 3, 2016, the combustion process adjustment requirements in Colorado Regulation No. 7, Section XVI.D would apply if actual, uncontrolled emissions are above 5 tons/year. Based on the NSPS NO_X emission limit (4.7 g/kW-hr) and design rate (59.6 kW), NO_X emissions from the engine at 8760 hours per year of operation are below 5 tons/yr, so these requirements have not been included in the permit for this engine, as they do not apply.

The following revisions were made to the permit to address the emergency generator:

<u>Section I – General Activities and Summary</u>

- The engine was included the table in Section I, Condition 5.1

<u>"New" Section II.11 – Emergency Generator (this section previously addressed the Black Oil Heater)</u>

- The provisions for this engine were included in Section II.11 of the permit.

<u>Appendices</u>

- The engine was included in the tables in Appendices B and C.

1.7 May 14, 2010 Modification (minor modification) – Crude Furnace

The purpose of this modification is to update the emission and throughput limitations from the crude furnace. Construction permit 12AD032-1 set the underlying emission and throughput limits for the crude furnace and the June 7, 2006 version of this construction permit has not been incorporated into the Title V permit. The purpose of this modification is to incorporate the provisions of the June 7, 2006 version of construction permit 12AD032-1 into the Title V permit. The change in permitted emissions are as follows:

Source	Emissions (tons/yr)				
	NO_X	CO	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2
Requested Emissions[1]	55.85	55.19	3.61	4.99	17.77
Current Title V permit Emissions[2]	32.76	32.37	2.12	2.92	17.3
Change in Emissions	23.09	22.82	1.49	2.07	0.47
PSD/NANSR Significance Level (T5 Minor Mod Level)[3]	40	100	40	25/15/10	40

[1]Emissions in Construction Permit 12AD032-1 issued June 7, 2006.

[2]Emissions in June 15, 2009 revised Title V permit

[3]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

The following revisions were made to the permit to address the changes to the crude furnace:

<u>Section II.1 – Crude Distillation Unit</u>

- Revised the PM, PM_{10}, NO_X, CO, VOC and SO_2 emission limits for the crude heater in Condition 1.1.
- Removed the statement after the construction permit citation in Condition 1.1 indicating that the underlying construction permit (12AD032-1) had been modified to reflect revised emissions factors since the permit now includes the June 7, 2006 version of the construction permit.
- Revised the heat input limit for the crude heater in Condition 1.5.

1.8 October 1, 2010 Renewal Application

The renewal application includes a number of changes and also includes the changes addressed in the modification requests that were submitted prior to the renewal application. Many of the renewal application changes are superseded by applications that followed and/or revisions to regulations (e.g. MACT CC and UUU). Therefore, not all changes are discussed or listed here. Suncor specifically noted some changes in the cover letter for the application, these include the following:

- Create a refinery (plant 2) wide emission unit to which facility wide obligations can be tied.

  As discussed in Section III.2, a “new” Section II.23 was included for facility (plant 2) wide requirements. While an “emission unit” will not be created and included in the table in Section I, Condition 5.1, a line for “facility (plant 2) wide requirements” will be included in the tables in Appendices B and C.

- Numbering all paragraphs.

  In the renewal application Suncor indicated a desire to number all paragraphs. Additional numbering was done in the draft permit and important paragraphs were numbered. However, not all paragraphs were numbered. If the source requests additional numbering during subsequent reviews, those changes will be made as warranted.

- Suncor noted that an applicability review had been conducted with respect to CAM requirements and noted that the FCCU was subject to CAM for the PM limits in NSPS Subpart J (1 lb/1,000 lbs coke burn-off) and submitted a CAM plan for the FCCU.

  Although Suncor noted that a CAM applicability review had been conducted, the review was not submitted to the Division, just the results of the review (i.e., FCCU subject to CAM). CAM is discussed in detail later in this section.

Some of the more noteworthy changes requested in the renewal application are addressed below:

<u>NSPS Subparts A and J for Process Heaters</u>

In the renewal application, the source requested that conditions be added to reflect that the crude unit, FCCU and reformer heaters are subject NSPS A and J requirements via the CD (No. SA-05-CA-0569, entered November 23, 2005) and that they comply via an H_2S CEMS per the CD. The NSPS J requirements are already included in the current permit (last revised June 15, 2009). Therefore new conditions will not be added for NSPS J, as requested, but language will be added to current conditions to indicate that the CD stipulates that the heaters comply with the requirements in NSPS J. New conditions however, will be added for the NSPS Subpart A requirements. The following changes were made to address this request.

- <u>Section II.1</u>. Revised Condition 1.3 to indicate that NSPS J and compliance via H_2S CEMS is required by the CD and added a “new” condition to address NSPS Subpart

A.

- Section II.3. Revised Condition 3.3 to indicate that NSPS J and compliance via H_2S CEMS is required by the CD and added a “new” condition to address NSPS Subpart A.

Section II.23 – Reg 7, Section III Requirements’

These requirements were moved to “new” Section II.24, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.24 includes the Reg 7, Section IV requirements.

- The source requested that language be added to the last paragraph in Condition 23.1 to indicate that material vapor pressure records could be maintained to show compliance with the vapor loss requirements for all tanks storing materials with a vapor pressure less than 0.65 psia. This change was not made in the draft renewal. In order to be consistent with the Plant 1/3 permit, the language was revised to require semi-annual monitoring for all tanks as discussed in Section III.2 of this document.

Section II.27 – Reg 7, Section VIII Requirements

These requirements were moved to “new” Section II.28, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.28 includes the Reg 7, Section VIII requirements.

- The source requested that language be added to indicate that compliance with the requirements in Section VIII.C.4.a.(i)(D) (monitor within 24 hours with a VOC detector, any component from which VOC liquids are observed leaking) be presumed if the component is automatically considered a leak if it cannot be monitored within 24 hours. This change was not made as it is not consistent with the requirements in regulation.

“New” Section II.31 – NSPS J

Note that in the current permit (last revised June 15, 2009), Section II.31 includes the requirements in NSPS QQQ.

- The source requested that the NSPS J requirements specific to the FCCU (CO, PM and opacity requirements) be included in the permit. These requirements were included in “new” Section II.31.

  According to the CD, the FCCU is also subject to requirements in NSPS J for SO2 but the renewal application does not address the SO_2 emission limit, although when asked, the source indicated that they were meeting the SO_2 emission limit in 60.104(b)(2) (20 lb/ton coke burn-off). Therefore, only the monitoring requirements related to the 60.104(b)(2) limit were included. In general, the requirements related to the SO_2 limit in 60.104(b)(2) are readily apparent, so a detailed discussion of requirements that were not included is not necessary. It should be noted that except for the SO_2 test methods for the FCCU, the provisions in 60.106 (test methods and procedures) were not included, as these requirements in general apply to the initial performance test requirements, which have been completed.

Section II.33 – MACT UUU

These requirements were moved to "new" Section II.41, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009).

- In the renewal application, the source requested changes to the MACT UUU language to reflect the compliance options and to remove requirements that were one-time requirements that had been completed or did not apply. The MACT UUU requirements were revised after submittal of this renewal application. The MACT UUUU revisions are discussed under the September 2016 additional information submittals in Section III.1.25 of this document.

Section II.38 – BWON Requirements

These requirements were moved to "new" Section II.39, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.39 includes language related to emission factors.

In the renewal application, the source requested that the BWON requirements for the following sections be included: 61.342 (general), 61.343 (tanks), 61.345 (containers), 61.347 (oil-water separators), 61.349 (closed vent system and control device), 61.350 (delay of repair), 61.351 (tank alt standards), 61.354 (monitoring), 61.355 (testing), 61.356 (recordkeeping) and 61.357 (reporting). Since most of the equipment at Plant 2 is not subject to BWON control requirements, the Division asked the source what requirements to include. In a September 1, 2016 response to an information request from the Division the source indicated that they wanted the BWON section in the Plant 2 permit to look like the BWON section in the Plants 1 and 3 permit (96OPAD120). To that end, the sections requested in the renewal application were included as well as section 61.346 (drain systems).

Appendix H – SO_2 Emissions Calculation Methodology

In the renewal application, the source requested that language related to the Plant 1 truck and rail rack flares and the Plant 2 truck and railcar dock flares alternative monitoring plans (AMPs), as well as the attached AMPs be removed, since they have requested that the AMPs be rescinded. As discussed in Section III.2 of this document, Appendix H will be removed and the requirements incorporated as appropriate into Section II of the permit, thus Plant 1 equipment will not be addressed. In addition, EPA has indicated the AMPs for the Plant 2 truck and railcar dock flare are part of a 1999 CD thus cannot be rescinded or otherwise addressed until the CD is terminated. Thus the AMPs for these flares remain in the place.

CAM Requirements

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. The renewal application indicated that the FCCU was subject to CAM for particulate matter emissions (the FCCU is equipped with a third stage separator to reduce PM emissions). However, there are additional emission units with control devices and the renewal application does not indicate the reasons that these other emission units are not subject to the CAM requirements. Therefore, the Division conducted an analysis to determine whether any additional emission units are subject to CAM.

Sulfur Recovery Plant (SRP) (P009): In the current Title V permit, the SRP is equipped with a tail gas incinerator. Tail gas, which includes H_2S, as well as other sulfur compounds is routed through the tail gas incinerator which converts the H_2S and other sulfur compounds to SO_2. The SRP has permitted emission limits for SO_2 and H_2S, and presumably relies on the tail gas incinerator to meet the H_2S limit. Uncontrolled emissions of H_2S are above the major source level (approximately half of permitted SO_2 emissions). Thus CAM potentially applies with respect to the H_2S limit.

Based on the fuel consumption limit for the tail gas incinerator and the VOC emission factors, VOC emissions are well below the APEN de minimis thus an emission limit was not included in the permit for VOC emissions. Although the tail gas incinerator can certainly reduce any VOC compounds that may be in the tail gas based on the fuel consumption limit, the emission factor in the permit and assuming a control efficiency of 99%, uncontrolled VOC emissions are below the major source level.

At the request of the Division, the source addressed the CAM issue for the SRP. The source made a claim that the tail gas incinerator is actually a safety device (to destroy H_2S emissions which at high levels can be dangerous), rather than a control device and thus should be considered inherent process equipment. However, AP-42, Section 8.13 (sulfur recovery) lists incinerators as control devices. In addition, other available literature indicates that incinerators are used to treat the tail gas from sulfur recovery units in order to primarily meet emission standards. So, while the tail gas incinerator may serve a safety purpose to reduce H_2S emissions, the Division is not convinced that it is inherent process equipment and not a control device.

The current Title V permit (last revised June 15, 2009) does not indicate how the source monitors compliance with the H_2S limit. However, a review of the files indicates that for the January 5, 1998 construction permit (12AD032-3) that H_2S emissions were estimated based on the SO_2 emissions (H_2S were assumed to be 4% of SO_2). Information from inspection reports indicate that the source is still estimating H_2S emissions based on this assumption. SO_2 emissions from the SRP are monitored using a continuous emission monitoring system. Therefore, the Division considers that CAM does not apply to the SRP because the Title V permit specifies a continuous compliance determination method (SO_2 CEMS), so the SRP is exempt from CAM in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(vi).

Truck Loading Dock Flare (C001) and Railcar Dock Flare (C002): Both the truck dock and the railcar dock flare have permitted emission limits for VOC (24.1 tons/yr and 28.3

tons/yr) and rely on the flares to comply with the VOC emission limits. Assuming a reasonable flare control efficiency of 95%, uncontrolled VOC emissions are above the major source level. Since these flares use a control device to comply with a VOC emission limit, CAM potentially applies. The current Title V permit (last revised June 15, 2009) indicates that both flares are subject to the requirements in 40 CFR Part 60 Subpart A, § 60.18 (included in Section II, Condition 37 of the current permit), which specifies that flares be operated with a flame present at all times (60.18(b)(2)) and that the presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame (60.18(f)(2)). In addition, the truck dock flare is subject to a temperature monitoring requirement (maintain a 12-hour rolling average). Therefore, the Division considers that CAM does not apply to the railcar and truck dock flares, because the Title V permit specifies a continuous compliance determination method (thermocouple or equivalent to detect the presence of a flame and temperature monitoring (truck dock flare)), these units are exempt from CAM in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(vi).

Main Plant (P2) Flare (C005): The main plant (P2) flare is subject to permitted VOC emission limits. While the P2 flare is used to control VOC emissions from some equipment to meet certain regulatory requirements, the P2 flare is not strictly a control device. Flares are used at the refinery for startup, shutdown and malfunction of process units and are more appropriately considered to be safety devices. Flares are listed as affected facilities under 40 CFR Part 60 Subpart J and Ja. Affected facilities are defined in 60.2 as “any apparatus to which a standard is applicable.” Typically NSPS subparts do not include control devices as an affected facility, which seems to bolster the position that the flare is not primarily a control devic

Under CAM, control devices do not include inherent process equipment, which is defined as

> Equipment that is necessary for the proper or safe functioning of the process, or material recovery equipment that the owner or operator documents is installed and operated primarily for purposes other than compliance with air pollution regulations. Equipment that must be operated at an efficiency higher than that achieved during normal process operations in order to comply with the applicable emission limitation or standard is not inherent process equipment. For the purposes of this part, inherent process equipment is not considered a control device.

The Division considers that the main plant (P2) flare is more appropriately considered inherent process equipment and thus not subject to CAM because it is not considered a control device.

It should be noted that the current Title V permit (last revised June 15, 2009) specifies that the P2 flare is also subject to the requirements in §60.18 as discussed above for the truck and railcar dock flares. Thus if the P2 flare were considered a control device, it would also be exempt from CAM as discussed above for the truck and railcar dock flares.

FCCU

The Division agrees that the FCCU is subject to CAM with respect to the PM emission limitation of 1 lb/1,000 lbs coke burn-off in 40 CFR Part 60 Subpart J. CAM also applies with respect to the annual PM and PM_{10} emission limitations that were included in the construction permit (09AD0961) which is being incorporated into the Title V permit as discussed in Section III.1.9 of this document.

Note that while the CD required a program of NO_X and SO_2 reductions from the FCCU and required Suncor to request emission limits based on these reductions, the Division does not consider that CAM applies with respect to NO_X and SO_2 emissions for the following reason. It is not clear that the methods to reduce NO_X and SO_2 emissions, such as reducing catalysts would meet the definition of a control device as specified in the CAM rule. In general, the CAM definition of a control device generally considers control devices to be equipment that is used to destroy or remove air pollutants prior to discharge to the atmosphere, which seems to preclude the use of a catalyst. Therefore the Division considers that the FCCU does not utilize a control device for NO_X and SO_2 emissions, thus CAM does not apply with respect to the NO_X and SO_2 emission limitations.

The source submitted a CAM plan with the renewal application. Controlled PM and PM_{10} emissions from the FCCU are below the major source threshold (24.1 tpy) and the CAM plan indicates that uncontrolled PM emissions are 178.65 tpy (86.5% control efficiency, therefore CAM would apply. Since controlled PM and PM_{10} emissions are below the major source threshold for CAM, the required frequency of monitoring is daily.

In their CAM plan, the source proposed opacity as the indicator, since the FCCU is equipped with a continuous opacity monitoring system (COMS), so monitoring of opacity will be continuous. The source proposed an indicator range of 30% opacity, except for one 6-minute average opacity reading in any 1-hour period. The source's justification was that this is the compliance method specified in 40 CFR Part 63 Subpart UUU for metal HAP emissions for units subject to NSPS Subpart J particulate matter requirements and the approach was selected for consistency, since the unit is subject to both requirements.

As specified in 64.4(b)(4), the CAM rule indicates that presumptively acceptable monitoring includes "monitoring included for standards exempt from this part pursuant to 64.2(b)(1)(i) or (vi) to the extent such monitoring is applicable to the performance of the control device (and associated capture system) for the pollutant specific emission unit".

The FCCU PM and PM_{10} limits (1 lb/1,000 lbs coke burn-off) are CD limits and are the same as the NSPS J particulate matter limits for FCCUs. The FCCU is also subject to requirements in 40 CFR Part 63 Subpart UUU and those emission limitations are exempt from CAM under 64.2(b)(1)(i) (standards under Section 111 or 112 proposed after November 15, 1990). One of the emission limitations options in MACT Subpart UUU for metal HAP emissions is to meet the NSPS Subpart J PM requirements (1 lb/1,000 lbs/ton coke burn-off and 30% opacity except for one 6-minute average opacity reading in any 1-hour period). Since the CD stipulated that the FCCU is subject to the NSPS Subpart J PM requirement, this is the compliance option Suncor must use to comply with the metal HAP limit in MACT Subpart UUU. In addition to recordkeeping requirements (daily average coke burn-off rate and hours of operation for each catalyst regenerator), continuous compliance with the MACT Subpart UUU metal HAP emission limit is monitored by using the COMS and maintaining each 6-minute average opacity at or below 30% (except for one 6- minute average during a 1-hour period) until August 1, 2017. Beginning August 1, 2017, FCCUs complying with the NSPS J PM requirements will be subject to an operating limit (maintain a 3-hr rolling average opacity no higher than 20%). The monitoring proposed by Suncor represents presumptively acceptable CAM, since it is equivalent to the MACT UUU/NSPS J opacity limit.

Although Suncor's proposal for CAM is considered presumptively acceptable CAM, the Division considers that since the FCCU is subject to a more stringent opacity limitation (the Reg1 20% opacity limit), the indicator range should be based on the lower opacity limit (except during those periods, when that limit does not apply). The Division considers that since this monitoring is similar to the monitoring for the metal HAP limit in 40 CFR Part 63 Subpart UUU this is acceptable monitoring for CAM.

Note that a CAM plan will not be included in the permit since the COMS is being used to monitor the indicator. Under the CAM requirements COMS that meet the requirements in 40 CFR Part 60 or 75 meet the general design criteria in § 64.3(a) and (b) (see 40 CFR Part 64 § 64.3(d)(2)).

The CAM requirements were included in the permit as follows:

- In Section I, a "new" Condition 6 was added to address CAM.
- The CAM requirements were included in Section II, "new" Condition 2.19.

1.9 November 1, 2010 Modification (minor modification) - FCCU – Incorporate CP 09AD0961

The purpose of this modification is to incorporate the provisions of Construction Permit 09AD0961 into the permit. Construction permit 09AD0961 was issued on October 1, 2009 to allow for the replacement of the air grid on the fluidized catalytic cracking unit (FCCU) and the installation of the third stage separator (TSS) to control particulate matter emissions. Installation of the TSS was necessary to the meet the particulate matter emission limits specified in the CD. The provisions of construction permit 09AD0961 apply to the FCCU regenerator (P004) and were incorporated into the permit in Section II.2, with the following exceptions. Note that the coke burn-off limit in Condition 6 was converted to lbs, instead of tons, because the PM and PM_{10} emission factors are in terms of lbs of coke burn-off not tons.

Section II.2 - FCCU

- Conditions 1 (commence construction), 2 (startup notice), 5 (mark permit no. on equipment), 12 (submit T5 mod appl), 13 (submit recordkeeping format) and 14 (self-cert) will not be included in the permit since they have been completed.
- Condition 11 (APENs) will not be identified in the permit as a specific condition but are included in Section IV (General Conditions) of the permit, condition 22.e.
- Conditions 3 (Reg 1 20% opacity), 4 (Reg 1 30% opacity), 15 (Reg 1 SO_2 – 0.3 lb/bbl SO_2), 17 (Reg 6, Part B SO_2 – 0.3 lb/bbl SO_2), 18 (Reg 7, Section VIII refinery requirements), 26 (MACT CC) and 27 (MACT UUU – general requirements) are already included in the permit. Section II.2 of the permit will refer to these requirements as appropriate. Note that the current permit does not identify the specific compliance option that will be followed for MACT UUU, therefore, this will be noted in the renewal permit.
- Condition 10 (public access requirements) will be included in "new" Section II.23 for facility wide requirements.
- Condition 22 (notifications related to NSPS parts A and J) will not be included. This condition indicates that lodging of the CD satisfies the notification requirements for 40 CFR Part 60 Subparts A and J, with respect to PM, opacity and CO. Since the source was required to comply with the provisions of NSPS Subparts A and J by December 31, 2009, the notification requirements have passed and this condition is no longer necessary.
- Condition 24 (system wide FCCU limits) identifies interim final and system wide NO_X limits for the Valero FCCUs. Since this permit only addresses the Denver/Commerce City refinery, these requirements have not been included in the permit. Note that the requested NO_X limits for the FCCU at this facility, which will ensure that the system-wide NO_X limits are met have been included in the permit. The requested FCCU NO_X limits were submitted as modification applications and are addressed in Section III.1.2 of this document.
- Condition 25 (FCCU limits for NO_X) stipulates that when complying with the system wide FCCU NO_X limits (Condition 24) that no FCCU shall have NO_X limits higher than 80 ppmvd at 0% O_2 on a 365-day rolling average. Since the requested annual NO_X limit does not exceed this value, this requirement will not be included in the permit.
- Notes to permit holder, item 1. This note indicates that the FCCU regenerator is subject to the CO requirements in NSPS Ja (with the replacement of the air grid, there would likely be an increase in the short-term CO emission rate, thus NSPS Ja was triggered). Since the Division had not adopted the NSPS Ja requirements at the time of CP issuance, these requirements were only included in the permit notes. The Division has since adopted the NSPS Ja provisions, so the NSPS Ja CO provisions will be included in the permit for the FCCU regenerator. Note that the NSPS Ja CO limit is essentially the same as the NSPS J and CD CO emission limitations, thus the

NSPS J (CD and construction permit) CO emission limits will be streamlined from the permit (included in Section III.3 of the permit).

Note that in addition to incorporating the requirements from construction permit 09AD0961, formatting changes were made to this Condition 2, as well as more substantive changes. Specifically the following changes were made:

- Separate summary tables were made for the preheater (B002), the regenerator (P004) and FCCU catalyst handling (P014) and FCCU fugitive sources (F002). Since the specific applicable requirements and the monitoring requirements are not the same for the preheater (B002) and the regenerator (P004), separate tables are more appropriate. FCCU catalyst handling (P014) and FCCU fugitive sources (F002) are not subject to many requirements, therefore, they were also included on a separate summary table.
- Conditions within Section II.2 were renumbered so that condition numbers are shown more sequentially in the summary table.
- Condition 2.9 of the current Title V permit (revised June 15, 2009) includes some specific requirements related to the SO_2 CEMS. A new CEMS section of the permit was included in "new" Condition II.45 and the specific SO_2 CEMS requirements are included in that new condition.
- Condition 2.11 of the current Title V permit (revised June 15, 2009) includes the CD requirement to conduct an initial performance test on the FCCU preheater (B002) to verify compliance with the NO_X limits (low NO_X burners were installed and NO_X limits were taken to meet system-wide NO_X limits for boilers and heaters in the CD).

  The initial test was conducted in March 2009, thus the CD requirement for an initial performance test will be removed. The results of the test indicated NO_X emissions of 0.039 lb/MMBtu, which is about 43.8% of the emission factor/rate (0.089 lb/MBtu). Therefore, no future performance testing will be required on this unit.
- Condition 2.12 of the current Title V permit (revised June 15, 2009) addresses the vacatur of the requirements in Subpart DDDDD and notes potential future requirements for a case-by-case MACT application. Since the requirements in Subpart DDDDD were finalized on March 20, 2011, case-by-case MACT requirements no longer apply. The permit was revised to include the appropriate Subpart DDDDD requirements.

1.10 July 27, 2011 Modification (administrative amendment) – Remove Tanks T31, T55 and T56

The purpose of the July 27, 2011 modification is to remove tanks T -31, T-55 and T-56. These tanks were replaced by tank T-79. With the commissioning of T-79, tanks T-31, T-55 and T-56 were removed from service and on March 19, 2010 the demolition of the tanks was completed.

The following changes were made to the permit to remove tanks T-31, T55 and T-56 from the permit:

Section I – General Activities and Summary

- The tanks were removed from the table in Section I, Condition 5.1

Section II.14 – Group D Tanks

- The tanks were removed from the table header in Condition 14.

Appendices

- The tanks were removed from the tables in Appendices B and C.

1.11 September 16, 2011 Modification (minor modification) – Mixed Butanes Project

The purpose of this modification is to add and modify process piping to allow a portion of the n-butane/isobutane product stream from the propane-butane splitter (W-69) to be fed into the Plant 2 de-isobutanizer (DIB) column (T-298). The n-butane/isobutane stream is an intermediate stream produced at Plant 1. Currently Suncor blends a portion of this stream into gasoline and sells the remainder of the stream as a feedstock to the chemical industry. However, in its current composition this stream is not ideal for either application. N-butane is a better gasoline blending component, whereas isobutane is a higher value feedstock than the current mixture. With this change the intermediate stream will be separated into n-butane and isobutane.

In their application, the source indicates that the DIB column is not itself a source of emissions and there will be no physical change of change in the method of operation of the unit beyond the increased throughput, which will be below the unit's maximum capacity. However, the proposed project will require the installation of a new butane/steam exchanger to preheat the feed stream to the DIB. The application also indicates that the project will not require the installation of new combustion sources and will not result in any physical change or change in the method of operation of any existing process units.

The new piping to transfer the feed to the DIB tower will require the installation of new fugitive components such as valves, flanges and connectors, which will be source of emissions.

The increase in production of n-butane and isobutane may result in a change to the throughput and loading of certain products. The n-butane can be used as a gasoline blending component and there may be a slight increase in the gasoline production, thus a slight increase in emissions from final product storage tanks and the Plant 1 Truck Rack. The source also noted that there may be a slight increase in shipments of isobutane at the Plant 2 rail rack and that those potential increases are included in the Plant 2 rail rack.

The application also noted that a small amount of additional steam may be required to support the increased utilization of the DIB tower, which will increase the fuel firing at the Plant 2 boilers.

Although there will be no new or modified equipment (other than the additional piping components), the incremental increases in emissions from the equipment discussed above were evaluated for the project.

The source estimated total project emissions from new components and increased utilization of existing equipment as follows:

Source	Emissions Increase (tons/yr)				
	NO_X	CO	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2
Fugitive VOCs from new components			0.74		
Gasoline Loading (P1 Truck Rack)[1]	0.01	0.06	0.07		
Butane Loading (P2 Rail Rack)[1]	0.03	0.13	0.05	0.01	
Gasoline Storage (T2010, T78)[1,2]			0.01		
Plant 2 Boilers[3]	0.08	0.11	0.01	0.03	0.04
Total	0.12	0.30	0.88	0.04	0.04
PSD/NANSR Significance Level (T5 Minor Mod Level)[4]	40	100	40	25/15/10	40

[1]Not a modified emission unit and no increase in permit limits were requested. Increased emissions are from the incremental increase in emissions due to increased throughput.

[2]Emissions in table are from tank with highest estimated emissions, which is T2010

[3]Not a modified emission unit and no increase in permit limits were requested. Increased emissions are from the incremental increase in emissions due to increased steam demand.

[4]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

An APEN was submitted with this application but did not specifically identify the emission unit. Since the source is not requesting an increase in permitted emissions from the boiler, loading racks and/or storage tanks, an APEN is not required for these emission units. There are new components associated with this project but since emissions from the new components are below the APEN de minimis level (1 ton/yr) an APEN is not required for this project. No changes to the permit are necessary with this modification.

1.12 September 28, 2011 Modification (minor modification) – Address Reg 7 Requirements for Terminals

The purpose of this modification is to include the requirements in Colorado Regulation No. 7, Section VI.D.2 into the permit. These requirements apply to the Plant 2 truck rack but are not included in the permit. There has been no physical change or change in the method of operation of the Plant 2 truck rack, nor is there any emissions increase associated with this modification. The purpose of this modification is simply to revise the permit to include requirements that apply to the Plant 2 truck rack but were inadvertently not included in the permit.

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

Section II.25 – RACT Reg 7 Section VI (Storage and Transfer of Petroleum Liquids)

These requirements were moved to "new" Section II.26, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.26 includes the Reg 7, Section VII requirements.

- Added a new Condition 25.5 for the requirements in Reg 7, Section VI.D.2.a as suggested in the modification application. In addition, the following statement was added to be consistent with the language in the Plants 1/3 permit (96OPAD120): "Suncor shall maintain a computerized system with information on certified trucks with an interlock system that prevents the loading of uncertified trucks."

1.13 March 21, 2012 Modification (minor modification) – Tank T29

The purpose of this modification is to design and construct a new external floating roof on Tank 29 (Tank 29 is intended to replace Tank 19), which will meet the requirements in 40 CFR Part 60 Subpart QQQ as required by a Compliance Order on Consent (COC), No. 2011-049, effective March 28, 2012. Tank 29 is an existing 1.05 million gallon wastewater tank that has been out of service since November 2009. According to the COC, construction of the new roof must commence by July 31, 2012 and the tank must be in operation by December 31, 2013. The March 21, 2012 application also notes that the tank will be an external floating roof tank to meet the control requirements in NSPS QQQ and that the floating roof will have a built in oil skimmer that is designed to recover oil from the top of the liquid surface just below the floating roof. The skimming ensures that less oil is transferred throughout the rest of the wastewater treatment system and reduces overall emissions. Submittal of the Title V minor modification application fulfills the requirement in the COC to submit a complete permit application and obtain a permit prior to commencing construction (sources can operate under the provisions of a minor mod application upon submittal of a complete application).

Requested emissions from Tank 29 and new components associated with the tank are below the VOC significant level (40 tons/yr) and are shown in the table below:

Source	VOC Emissions (tons/yr)
Tank T29	1.71
Fugitive VOCs from New Components	0.16
Total	1.87
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]	40

[1]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone

non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

An APEN was submitted for Tank T29 indicating the requested throughput and emission limitations. Since emissions from the new components are less than the APEN de minimis level of 1 ton/yr, an APEN is not required for these new components, these emissions shall be reported on the plant wide fugitive VOC APEN (for components without permit limits).

Regulatory Applicability Discussion

In the application, the source noted that Tank T29 is subject to the requirements in 40 CFR Part 60 Subparts Kb and QQQ. The application also noted that the tank is not subject to the requirements in 40 CFR Part 63 Subpart CC because the tank is not considered a storage vessel under Subpart CC. While not specifically addressed in the application, the draft permit submitted with the application indicates that tank T29 is subject to the requirements for oil-water separators in Colorado Regulation No. 7, Section VIII.A.2.

The application also notes that the fugitive components associated with the skim line are subject to the requirements in Colorado Regulation No. 7, Section VIII.C, 40 CFR Part 60 Subpart GGG and 40 CFR Part 63 Subpart CC.

A letter was submitted on December 13, 2013 further addressing the applicability of various requirements to Tank T029. The December 13, 2013 letter indicates that the tank is subject to the requirements in 40 CFR Part 63 Subpart CC 63.647 (wastewater provisions) and that the tank will be controlled for BWON. The BWON requirements will be met with an external floating roof that meets the requirements in NSPS Kb (§63.112b(a)(2)). Under the overlap provisions in 40 CFR Part 63 Subpart CC §63.640(o)(1), a group 1 wastewater stream managed in equipment subject to 40 CFR Part 60 Subpart QQQ, only has to comply with the requirements in 40 CFR Part 63 Subpart CC. Tank T29 falls under this provision, thus the requirements in NSPS QQQ do not apply.

The application did not address the applicability of storage tank requirements in Colorado Regulation No. 7. The definitions for oil-water separators are different in NSPS QQQ, BWON and Regulation No. 7, Section VIII.A. Tank T029 is clearly an oil-water separator under NSPS QQQ and BWON, thus although the Reg 7 definition is more vague, the Division considers that Tank T29 is an oil-water separator under Reg 7. Since tank T29 is considered an oil-water separator under subject to requirements for oil-water separators under Section VIII.C, it is not subject to the requirements for storage and transfer of petroleum liquids in Section VI or the general requirements for tanks in Section III.A.

The following changes were made to the permit to include Tank T29:

<u>Section I – General Activities and Summary</u>

- Tank T29 was included in the table in Section I, Condition 5.1.

<u>Section II.10 – Wastewater Treatment System</u>

- The provisions from Tank T29 were included in Section II.10 with the waste water treatment system equipment. The application indicated that the tank would be included in Section II.15 with the Group E tanks. The Division considers that including this tank with the Plant 2 wastewater treatment system is consistent with the way the Plants 1 and 3 wastewater treatment systems have been addressed.
- Added a requirement for NSPS Kb, since tank T29 is subject to requirements in NSPS Kb.

<u>Appendices</u>

- The tank was included in the tables in Appendices B and C.

1.14 May 25, 2012 and May 8, 2013 Modifications (minor modifications) – Plant 2 Wastewater Treatment System and Install Controls On Plant 2 APIs

The purpose of the May 25, 2012 modification is to address the Plant 2 wastewater treatment system (WWTS) to appropriately address the applicable requirements that apply to the Plant 2 WWTS. The May 25, 2012 modification indicates that the Plant 2 WWTS operates as follows:

Process wastewater drains (equipped with water seals) are routed through the Upper and Middle API separators. The Upper API is occasionally routed through the Lower API during high rain events. Oil from the Upper, Middle and Lower API separators are accumulated in V-114 (the crude settler). From V-114 oil is transferred via vacuum truck to Tank 20. Water from the three API separators is accumulated in Tank 19 (which will be replaced by Tank 29) prior to being routed to the Plant 1 wastewater treatment plant.

For the May 25, 2012 application, emissions from the Plant 2 WWTS were estimated as shown in the table below. Since Tank 29 is considered part of the Plant 2 WWTS, emissions from that project are also shown below.

Source	Emission Estimation Method	VOC Emissions (tons/yr)
Upper, Lower and Middle APIs and Tank 19[1, 2]	WATER9 Model	24.65
Gas Plant Sewers	Guideware[3]	0.023
Sour Water Stripper Sewers	Guideware[3]	0.027
Wastewater Settler (V114)	TANKS	0.114
Tank T29 + Fugitive VOCs from New Components	TANKS and emission factors from EPA's Protocol for Equipment Leaks	1.87
Total		24.814
PSD/NANSR Significance Level (T5 Minor Mod Level)[4]		40

[1]Since Tank 19 will be replace with Tank 29, emissions from the tank are double-counted in this analysis.

[2]The Plant 2 WWTS sources that were actually addressed in the WATER9 model run included the following: lift stations for each API and sumps for the upper and middle API.

[3]Guideware is Suncor's fugitive emissions tracking program. Guideware estimates emissions based on actual leak data for components that are screened and emission factors and assumed control efficiencies for components that are not screened.

[4]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

The Division noted deficiencies in the regulatory review for the May 25, 2012 application and a revised application was submitted on August 2, 2012.

The May 25 (and August 2), 2012 applications reflected the Plant 2 WWTS as it existed at the time of the application. However, a COC, No. 2011-049, effective March 26, 2012 stipulated that controls be designed for the Upper, Middle and Lower APIs by May 31, 2013 and in place and operating by November 30, 2013. To that end an application was submitted on May 8, 2013 to address the controls that were to be installed on the APIs.

The API separators will each be installed with fixed covers and vapors from the APIs will be routed to carbon canisters. Each of the APIs will have an independent carbon canister system (single canister) and will have two available paths (one for normal operation (low flow) and one for high flow events). The upper and lower APIs will each have one carbon canister for the low flow path and one carbon canister for the high flow path. The middle API carbon canister system will have one carbon canister for the low flow path and two carbon canisters in parallel for the high flow path. The carbon canister systems for each API will control emissions from the API and the lift station and sump associated with it.

In the May 8, 2013 application, the source chose to estimate emissions from the API separators using assumed VOC concentrations and gas flow rates through the carbon canisters. This emission estimation method resulted in much higher uncontrolled emissions from the APIs than were estimated with the WATER9 model. However, controlled emissions (95% presumed for the carbon canisters) from the APIs were below the emission estimated from the WATER9 model. Estimated emissions from this project are shown in the table below:

Source	VOC Emissions (tons/yr)[1]	
	Uncontrolled	Controlled
Upper API	26.83	1.34
Middle API	37.11	1.86
Lower API	35.02	1.75
Total	98.96	4.95
PSD/NANSR Significance Level (T5 Minor Mod Level)[2]		40

[1]Emisssions are based on 1,000 hours per year of high flow operations and 8760 hour per year of normal (low) flow operations. Controlled emissions rely on 95% control efficiency for the carbon canisters. Note that this is conservative, as hours of operation cannot exceed 8,760 hrs/yr.

[2]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

Modification Type Discussion for May 8, 2013 Application

The source indicated that the May 8, 2013 modification to install controls on the Plant 2 APIs would qualify as a minor modification. With the revised emission estimates for the APIs, further justification for the use of the minor modification procedures is required.

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 F 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, which is 40 tons/yr for VOC. Potential to emit is based on maximum design rate, 8760 hours per year of operation and does not rely on controls, unless the emission unit is subject to a federally enforceable requirement to control emissions.

According to the modification application submitted by Suncor uncontrolled emissions from all three API separators (APIs) together exceed 40 tons/yr of VOC. Previously, Suncor submitted an application on May 25, 2012 indicating uncontrolled emissions from the Plant 2 wastewater treatment system (WWTS) of 24.82 tpy. Emissions from the Plant 2 WWTS in the May 25, 2012 application were primarily estimated using EPA’s WATER 9 program. However, in the May 8, 2013 application Suncor estimated emissions from the API separators based on conservative inlet VOC concentrations and flow rates based on engineering estimates. The emission calculation methodology used for the May 8, 2013 application results in much higher emission estimates. The Plant 2 APIs are all included in the current Title V permit but only the middle API is currently subject to a VOC emission limitation (emissions are limited to 4.80 tons/yr). It would appear that this project would not meet the criteria for a minor modification since potential to emit of the APIs is above the significance level but the Division considers that this project does qualify as a minor modification for the following reasons.

First of all, all three APIs are subject to the requirements in NSPS Subpart QQQ Suncor is installing controls on these units in order to meet the requirements of Subpart QQQ. As noted above, potential to emit is based on uncontrolled emissions, unless the unit is subject to a federally enforceable requirement to control emissions. The requirements in

NSPS Subpart QQQ are federally enforceable and Subpart QQQ specifies that vapor recovery control devices meet a control efficiency of 95%, which is the control efficiency assumed for the carbon canisters in this modification application.

Secondly, the APIs are in the current Title V permit and the purpose of this modification is to reduce emissions from the APIs, although the reduction cannot be easily quantified from the upper and lower APIs since these units are not subject to emission limitations in the current permit. So, this change does not cause a significant increase in emissions because the change actually reduces emissions from all three APIs.

Finally, the addition of a control device is generally not considered a “modification” by itself unless such control device would result in an increase in the emission rate from a regulated pollutant or result in the emission of a regulated pollutant that was not previously emitted. The addition of the carbon canisters will neither increase the emission rate of pollutants currently emitted, nor cause the emission of pollutants not previously emitted by the APIs. Since the addition of the carbon canisters would not qualify as a modification, a construction permit is not required to install the carbon canisters.

For all three reasons the Division considers that this modification does not cause a significant increase in emissions and can be processed as a minor modification.

Colorado Regulation No. 3, Part C, Section X.A.4 specifies that those changes that “do not seek 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” can be processed as a minor modification. Although uncontrolled emissions from all three APIs together are above the VOC significance level this project is not considered to be a situation in which the addition of control devices were installed in order to take emission limitations in order to avoid an applicable requirement to which the source would otherwise be subject.

Uncontrolled emissions from the APIs in the modification application are higher than were previously estimated for these units. The increase in uncontrolled emissions from the APIs from the previous WATER 9 estimates is not a modification and would not by itself trigger PSD and/or NANSR review requirements. In the general when emissions from an existing emission unit are estimated using a newer method, the Division considers that emissions were always at that emission rate during startup of that emission unit and would investigate whether any PSD and/or NANSR review requirements were triggered.

According the December 1999 revised Title V permit application, the upper, lower and middle APIs commenced operation in 1972, 1951 and 1979, respectively and that the upper API was modified in 1984. It’s not clear what the modification to the upper API would have been but it is likely that the modification was not to the API itself but that new drain systems were routed to the API. At any rate, these units commenced construction and/or possible modifications on separate dates and would not be considered as single project. Therefore, each API would be viewed separately to see if the revised emissions estimates indicate that PSD and/or NANSR would have been triggered as a result of the better emission estimates. The upper and lower API commenced operation prior to promulgation of the first PSD requirements. In addition, uncontrolled VOC emissions from each of the APIs are below the significance level, therefore, PSD and/or NANSR review would not be triggered, so the addition of the carbon canisters is not necessary to retroactively reduce emissions from the APIs to avoid PSD and/or NANSR review requirements. As previously stated, the purpose of installing the carbon canisters is to meet the requirements of NSPS QQQ and the addition of the carbon canisters is not considered a modification.

The control devices that will be installed as part of this modification and the requested emission limitations for the Plant 2 WWTS are not being taken to avoid an applicable requirement; therefore, this modification can be processed as a minor modification.

Discussion of Plant 2 WWTS Emission Limitations and Applicability of Various Regulations

In the May 25, 2012 application, emissions from the Plant 2 WWTS include emissions from the three APIs, Tank T19, the wastewater settler and the gas plant and sour water stripper sewers. For the May 8, 2013 modification, emissions were only estimated for the three APIs. Tank T19 will be replaced with Tank T29 (which has separate emission limitations) and the fugitive emissions from the gas plant are also addressed separately. Therefore, only the wastewater settler and the sour water stripper sewers are not subject to permitted emission limitations. Since emissions from neither are above the APEN de minimis level, it is acceptable that sources of emissions are not subject to emission limitations. Note that the entire refinery is subject to the BWON recordkeeping requirements.

In a letter submitted on December 13, 2013, the source indicated that the APIs are subject to 40 CFR Part 63 Subpart CC §63.647(c) since Group 2 wastewater streams are routed through the APIs.

The draft permit submitted with the May 8, 2013 application indicates that the APIs are subject to the requirements in NSPS Subpart QQQ and Colorado Regulation No. 7, Section VIII.A.2.

In response to questions regarding the May 8, 2013 application, the source indicated that once the carbon canisters are installed the APIs will no longer separate water and oil but will be simply used to convey wastewater. Under the definition of oil-water separators in Subpart QQQ, the APIs are still considered oil-water separators since the definition includes tanks between individual drain systems and oil-water separators (the APIs are upstream of Tank T29 and the Plant 1 APIs). In response to recent requests from the Division, the source indicated that there is still a connection at each API to remove oil using a vacuum truck, so they still technically qualify as oil-water separators, even though they won't be used in that manner. Although the definition of oil-water separators is different in Reg 7, Section VIII.A.1, the Division considers that the Plant 2 APIs are still subject to the requirements for oil-water separators in Section VIII.A.2, since they still have the capability to separate water and oil.

In the current T5 permit (last revised June 15, 2009), only the upper API is listed as subject to the requirements in NSPS QQQ. A review of the files, indicate that the NSPS QQQ was likely triggered for the upper API with the gas plant sewers (installed after the NSPS QQQ applicability date) and are routed to the upper API (installation of a new individual drain system constitutes a modification). NSPS QQQ was triggered for the middle API with the installation of the drain system for the new boilers. NSPS QQQ was triggered for the lower API, since there is a lineup wherein wastewater can be routed from the upper API to the lower API instead of the Plant 1 API. Since the upper API is subject to the requirements in NSPS QQQ, then it follows that the lower API would also be subject to NSPS QQQ.

The May 8, 2013 application indicates that the APIs are subject to recordkeeping requirements under BWON (emissions are used to meet the 6BQ). The May 25 (revised August 2), 2012 application indicated that tank T20 was subject to the control requirements under BWON and the March 21, 2012 application indicated that T29 is subject to control requirements under BWON

The following changes were made to the permit to address the modifications to the Plant 2 WWTS:

<u>Section I – General Activities and Summary</u>

- Added language to the table in Condition 5.1 to indicate that the APIs are equipped with carbon canisters. In addition, since the permit limit for the APIs and associated equipment (lift stations and sumps) are subject to a combined emission limit, the AIRs pt numbers were revised.
- The boiler sewers were added to the Plant 2 WWTS in the table in Condition 5.1, since they are subject to requirements NSPS QQQ and that will be noted in Section II, Condition 10. Note that the table notes that emission limitations and other requirements are addressed under fugitive VOC equipment leaks with permitted emissions (Section II1.8).

<u>Section II.10 – Plant 2 WWTS</u>

- The boiler sewers are included in this section since they are subject to requirements in NSPS QQQ.
- Revised Condition 10.1 to include emission limits for the Plant 2 WWTS (all APIs and associated equipment (lift stations and sumps)). Note that previously only the middle API was subject to emission limitations. Also included the emission factors used to estimate emissions from the Plant 2 WWTS. In addition a note was added to the summary table to include equipment addressed in the emission limitation and

to note equipment that is not included.

- Changes were made to the table with respect to the RACT, MACT and benzene (BWON) requirements. The table now generally refers to the permit conditions that include these requirements, rather than listing specific requirements such as inspections and inspection frequency.
- Added a condition to record hours of operation. The emission factors for the Plant 2 WWTS are in lb/hr, thus the need to record hours.

<u>Section II.15 – Group E Tanks</u>

- Added a condition to note that Tank T20 is subject to the BWON requirements.

<u>Section II.27 – Regulation No. 7, Section VIII Requirements</u>

These requirements were moved to “new” Section II.28, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.28 includes the Reg 7, Section XV requirements.

- The requirement to conduct annual inspections was removed. For the upper, middle and lower APIs compliance with these requirements shall be met by complying with the requirements in NSPS QQQ.
- Added language indicating that Tank T29 is subject to these requirements and specifying that compliance is met by complying with NSPS Kb. In addition, a requirement to inspect secondary seals semi-annually was also added.

<u>Section II.31 – NSPS QQQ Requirements</u>

These requirements were moved to “new” Section II.28, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.38 includes the BWON requirements.

- Added language indicating that in accordance with 40 CFR Part 63 Subpart CC § 63.640(o)(1) that group 1 wastewater streams that are managed in a piece of equipment that is subject to Subpart QQQ only have to meet the requirements in Subpart CC. This applies to Tank T29.
- Added additional requirements for oil-water separators (specifically those under 60.692-3(a)) and noted that the APIs meet the requirements in 60.692-3(b) using carbon canisters.
- Removed the requirements in Condition 31.17 (60.692-3(c)(1)) since they do not apply.
- Added the relevant applicable requirements for closed vent systems and control devices (60.692-5), monitoring operations (60.695) and performance test methods and procedures (60.6969)
- Added the reporting requirements in 60.698(d)(3)(ii).

Note that there are requirements related to monitoring (60.695(a)(3)) and reporting (60.698(d)(3)) requirements that imply that continuous monitoring of the exhaust vent VOC concentration is required for carbon absorbers. However, there is also sufficient evidence in the monitoring (60.695(a)(3)(ii)), recordkeeping (60.697(f)(3)(x)(B)) and reporting requirements (60.698(d)(3)(ii)) to indicate that this only applies with carbon absorbers that are regenerated on-site, not to carbon canisters that are replaced and regenerated off-site. The permit includes requirements specific for carbon absorbers that are regenerated off-site.

Section II.38 – BWON Requirements

These requirements were moved to "new" Section II.39, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). In the current permit (last revised June 15, 2009), Section II.39 includes language related to emission factors.

- Added language indicating that tanks T20 and T29 are subject to control requirements.

1.15 October 11, 2012 Modification (significant modification) and March 31, 2014 Additional Information Submittal – Include New Boilers – Incorporate CPs 09AD1422 and 09AD1423

The purpose of this modification is to include the requirements for the new boilers and fugitive VOCs from the components related to the new boilers found in construction permits 09AD1422 and 09AD1423. The modification application also requested that references to the old boilers be removed.

On March 25, 2014, the Division issued a letter to the source allowing for RATAs on the boiler CEMS to be conducted at 37% load for B504 and 32% load for B505, as that represented "normal" operating conditions. The March 31, 2014 additional information submittal requests that the approval to conduct RATAs at the levels specified in March 25, 2014 letter from the Division be addressed in the Title V permit.

The following changes were made to the permit to include the requirements for the new boilers and components associated with the new boilers found in construction permits 09AD1422 and 09AD1423:

Section I – General Activities and Summary

- The permit numbers for the boiler and fugitive emissions from the boilers (09AD1422 and 09AD1423) were included in the list in Condition 1.4. The construction permit for the old boilers (87AD184) was removed.
- The old boilers were removed from the table in Condition 5.1 and the new boilers and the fugitive VOC emissions from equipment leaks from the new boilers were added to the table.

Section II.6 – Utilities - Boilers

The applicable requirements from permit 09AD1422 were included as indicated in the permit with the following exceptions and/or corrections:

- Condition 1 (removal of equipment and operational restrictions). This condition specified equipment that was to be removed upon commencing operation of the boilers. This condition also allowed two of the old boilers to remain operable until the testing of the new boilers was completed. Since all the equipment that was to be removed as part of this project has been removed or rendered inoperable, this condition was not included.
- Conditions 2 (commence construction), 3 (startup notice), 4 (provide make, model and S/N with startup notice), 5 (mark permit no. on equipment), 6 (submit recordkeeping format), 7 (self-cert), and 15 (submit T5 mod appl) will not be included in the permit since they have been completed.
- Condition 14 (APENs) will not be identified in the permit as a specific condition but are included in Section IV (General Conditions) of the permit, condition 22.e.
- Condition 10 (H_2S fuel gas limit of 162 ppmvd, on a 3-hr rolling average) was not included. This requirement was included in the permit shield for streamlined conditions (Section III.3), since it is as stringent as the NSPS Ja H_2S fuel gas limit.
- Condition 13 (public access to facility) will be included in the facility wide requirements in "new" section II.24. (Note that in the current permit (last revised June 15, 2009), Section II.24 includes the Reg 7, Section IV RACT requirements).
- Conditions 16 (Reg 1 20% opacity), 17 (Reg 1 30% opacity), 18 (Reg 1 – PM), 19 (Reg 1 SO_2 – 0.3 lb/bbl SO_2) and 22.b (Reg 6, Part B, Section II – 20% opacity) are already included in the permit. Section II.6 will refer to these conditions as appropriate.
- Condition 21 (NSPS Subpart Db). The construction permit included the wrong citation for the NO_X limit. The following should be noted for this unit.

  This unit is only subject to NO_X limits under Subpart Db, since it burns only natural gas (as defined in 60.41b)

  - The boilers are high heat release rate boilers and so only the NO_X limit for high heat release rate has been included.
  - The requirement to submit a notification for initial startup (60.49b(a)) and to submit the results of the initial performance test and CEMS performance evaluation (60.49b(b)) were not included since these requirements have been completed.
  - The provisions for retaining records for two years in 60.49b(o) were streamlined in favor of the Title V recordkeeping requirements.
- Conditions 22.a (Reg 6, Part B, Section II – PM) and 23 (Reg 6, Part B SO_2 – 0.3 lb/bbl SO_2) have been streamlined for other requirements that are as stringent or more stringent and are included in Section III.3 of the permit for streamlined condition.

- Condition 24 (MACT requirements) addresses the case-by-case MACT requirements (at the time the 09AD1422 was issued the requirements in 40 CFR Part 63 Subpart DDDDD were vacated) which no longer apply (requirements in 40 CFR Part 63 Subpart DDDDD were promulgated on March 21, 2011), so the appropriate requirements in Subpart DDDDD will be included in "new" Condition 44 with a reference to Subpart DDDDD in Section II.6. Since construction of the boilers commenced prior to June 4, 2010.

NSPS Ja Requirements

Although not specifically identified in the permit, the boilers are also subject to the requirements in 40 CFR Part 60 Subpart Ja. References to Subpart Ja are included in Section II.6 of the permit and the bulk of the Subpart Ja requirements are included in "new" Section II.32. (Note that in the current permit (last revised June 15, 2009), Section II.32 includes the requirements in 40 CFR Part 63 Subpart CC.) Note that these boilers are only subject to the SO_2 requirements under NSPS Ja and not the NO_X requirements. The NO_X requirements in NSPS Ja apply to process heaters and the boilers do not meet the definition of a process heater.

Correction for Consent Decree Requirements

The November 24, 2009 construction permit application indicated that the new boilers were necessary in order to comply with the CD. In that application the source indicated that the 0.03 lb/MMBtu NO_X emission factor used for the boiler was necessary to achieve compliance with the CD requirement to limit system-wide NO_X emissions limit for heaters and boilers.

During discussions with EPA regarding terminating the CD for Plant 2, it became clear that in order to consider boilers and heaters for the system-wide NO_X emissions limit, NO_X emission limits in lb/MMBtu were to be included in permits. The November 24, 2009 construction permit application did not indicate that a lb/MMBtu NO_X limit was necessary, nor did the application cite any relevant paragraphs from the CD. Paragraph 27.a indicates that such NO_X limit, in lb/MMBtu, shall be included as a 365-day rolling average, if based on a CEMS. Paragraph 29.a requires that covered heaters and boilers with a heat input capacity of greater than 150 MMBtu/hr, shall use a NO_X CEMS to comply with the NO_X limit. Since both boilers had a heat input capacity of 150 MMBtu/hr a NO_X CEMS is required (note that the boiler are also subject to NSPS Db requirements, which requires a NO_X CEMS). It is apparent that if the source intended to rely on NO_X emissions from the new boilers to meet the system-wide NO_X reduction requirements in the CD, then NO_X emission limits in lb/MMBtu were necessary. The November 24, 2009 application did not make that clear, nor did the Division realize at the time that such limits were necessary. Therefore, the Division included NO_X emission limits of 0.03 lb/MMBtu, in the draft permit.

Suncor submitted comments on the draft permit on May 11, 2020 and in their comments objected to the 0.03 lb/MMBtu limit and indicated that the limit should be set at 0.044 lb/MMBtu. The Division indicated we would be fine with a limit of 0.044 lb/MMBtu provided the 365-day limit was consistent with the annual ton/yr limit. Suncor submitted an APEN on June 30, 2020 to revise the NO_X emission limit to 36.4 tons/yr. The requested NO_X limit is based on the currently permitted heat input limit (1,655,640

MMBtu/yr) and the requested 0.044 lb/MMBtu CD limit.

Relaxation Provisions

The construction permit (09AD1422) for the boilers was permitted as a true minor source. The boilers are not permitted at design rate (MMBtu/hr), they are permitted at approximately 50% capacity, as the source indicated in their construction permit application that 50% capacity represented the maximum capacity due to limitations in the boiler feed water system. The Division confirmed and concurred with this. However, the boilers were permitted at a NO_X emission rate of 0.03 lb/MMBtu. According to the source's May 11, 2020 comments on the draft permit, the boilers cannot be operated at this level without potential non-compliance. Thus NO_X emissions at the 0.03 lb/MMBtu emission rate does not represent potential to emit, thus the initial project may not in fact have been a true minor source.

At the time these boilers were permitted (initial approval construction permit issued May 14, 2010), the significance level for NO_X was 40 tpy. Since the boilers were installed at a major stationary source, emissions would have to remain below the significance level in order to avoid PSD and NANSR requirements. Sources that avoid PSD and/or NANSR requirements by taking enforceable limits are subject to PSD and/or NANSR requirements if they relax those limitations above the significance level at some later date. Suncor requested a CD limit of 0.044 lb/MMBtu, which they indicated was in accordance with a March 30, 2012 letter to EPA (included as an attachment to the comments), however the cited letter actually indicated that the boilers would operate at a rate of 0.046 lb/MMBtu. While NO_X emissions at either 0.044 lb/MMBtu or 0.046 lb/MMBtu at the permitted throughput rate would still be below the significance level (40 tpy), the Division considers that it is more appropriate to base maximum emissions (i.e. potential to emit) from these units at the NSPS Db level (0.20 lb/MMBtu), which is a federally enforceable requirement above which Suncor cannot relax above via a permit modification. At the NSPS Db level, NO_X emissions are 165.6 tpy, which is above the significance level, thus the boilers are not a true minor source but a synthetic minor source, so the relaxation provisions in Regulation No. 3, Part D, Sections V.A.7.b and VI.B.4 apply and will be included in the permit.

Reg 7, Section XVI.D Requirements

In addition, following the issuance of the construction permit for these boilers, revisions were made to Colorado Regulation No. 7, Section XVI.D that includes requirements for combustion equipment that existed as of June 3, 2016 at a major source for NO_X located within the 8-hr ozone control area.

<u>Emission limitations, compliance demonstrations, recordkeeping (unrelated to combustion process adjustments) and reporting</u>

Since the boilers have a design rating greater than 100 MMBtu/hr, they are subject to the NO_X emission limits in Section XVI.D.4.a.(i) – NO_X shall not exceed 0.2 lb/MMBtu or 165 ppmv corrected to 3% O_2. Compliance with the NO_X limit must be demonstrated by October 1, 2021, using a continuous monitoring system (averaging time is a 30-day rolling average). The continuous emission monitoring system (CEMS) requirements specify that sources equipped with a NO_X CEMS for purposes of demonstrating compliance with an applicable subpart of 40 CFR Part 60 shall use the definition of operating day, data averaging methodology and data validation requirements of the applicable subpart. The boilers are subject to NO_X emission limits in 40 CFR Part 60 Subpart Db, which includes a NO_X emission limit of 0.2 lb/MMBtu, on a 30-day rolling average and requires that a NO_X CEMS be installed. Therefore, the emission limitation (XVI.D.4.a.(i)), as well as the compliance demonstration requirements (XVI.D.5, XVI.D.5.a.(i)(A) and XVI.D.5.a.(i)(A)(2) will be streamlined in favor of the NSPS Db requirements. Streamlined conditions are included in the permit shield for streamlined conditions (Section III.3).

Note that the requirements in Sections XVI.D.5.a(i)(A)(1) and (3) (including (3)(a) and (3)(b)) do not apply, as there are options for sources that are not required to have a NO_X CEMS to meet the requirements of a Subpart under 40 CFR Part 60. In addition, the requirements in Sections XVI.D.5.a.(i)(A)(4) (sources with a common stack), XVI.D.5.a.(ii) (performance testing), XVI.D.5.a.(iii) (sources with production or output based limits) and XVI.D.5.a.(iv) (flow monitor) do not apply and were not included in the permit since the units do not share a stack, use NO_X CEMS rather than performance tests, do not have output or production based emission limits and Method 19 can be used to determine NO_X emission rates in terms of lb/MMBtu.

The Division considers that the recordkeeping requirements in Sections XVI.D.7.c (record type and amount of fuel used), XVI.D.7.d (annual capacity factor - calendar year), and XVI.D.7.e (retain records to comply with reporting requirements) and the reporting requirements in Section XVI.D.8.a and a.(i) will be streamlined and included in the permit shield for streamlined conditions (Section III.3). The requirements in Sections XVI.D.7.a (limits for units burning multiple fuels), XVI.D.7.b (units using CERMS) and XVI.D.7.g (sources qualifying for an exemption) do not apply and were not included in the permit since the units only burn gaseous fuel, do not rely on CERMS and are not exempt.

Combustion process adjustment and associated recordkeeping

The boilers are also subject to the combustion process adjustment and associated recordkeeping requirements in Sections XVI.D.6 and XVI.D.7.f and these requirements will be included in the permit. Note that as indicated above, the requirements in Section XVI.D.7.f.(i)(F) were not included since the boilers are only permitted to burn gaseous fuel.

Section II.18 – Fugitive VOCs with permitted emissions

The applicable requirements from permit 09AD1423 were included with the following exceptions:

- Conditions 1 (commence construction), 2 (startup notice), 3 (submit recordkeeping format), 4 (self-cert), and 8 (submit T5 mod appl) will not be included in the permit since they have been completed.
- Condition 6 (public access to facility) will be included in the facility wide requirements in “new” section II.24. (Note that in the current permit (last revised June 15, 2009), Section II.24 includes the Reg 7, Section IV RACT requirements.)

- Condition 7 (APENs) will not be identified in the permit as a specific condition but are included in Section IV (General Conditions) of the permit, condition 22.e.
- Condition 11 (NSPS QQQ) will be addressed in the wastewater treatment section of the permit (Section II.10 in the current permit (revised June 15, 2009)).
- Condition 12 (MACT CC) is already addressed in the permit.

Although not specifically identified in the permit, leaks from components associated with the boilers are also subject to the requirements in 40 CFR Part 60 Subpart GGGa. References to Subpart GGGa are included in Section II.18 of the permit and the bulk of the Subpart GGGa requirements are included in “new” Section II.37. (Note that in the current permit (last revised June 15, 2009), Section II.37 includes the flare requirements).

“New” Section II.32 – NSPS Ja Requirements

Note that in the current permit (last revised June 15, 2009), Section II.32 contains the requirements in 40 CFR Part 63 Subpart CC.

- The NSPS Ja requirements relevant to the boilers were included in this new section.

  Note the following regarding how the requirements were incorporated:

  - As previously stated, the boilers are only subject to SO_2 requirements. NSPS Ja allows fuel gas-burning devices to either comply with an outlet SO_2 limit or a limit on the H_2S content of the fuel gas. The source will comply with the fuel gas requirements in lieu of the SO_2 requirements, thus only the requirements related to the fuel gas limit have been included in the permit.
  - The requirements for “alternative means of emissions limitation” in 60.103a(j) were not included as the source has not and is not expected to ask for such a determination.

“New” Section II.34 – NSPS VV Requirements

Note that in the current permit (last revised June 15, 2009), Section II.34 contains the production limits.

- The requirements in NSPS GGG reference sections of NSPS VV, thus the requirements in VV were included in this new section.

“New” Section II.35 – NSPS VVa Requirements’

Note that in the current permit (last revised June 15, 2009), Section II.35 contains the Equipment Leak VOC Emissions provisions

- The requirements in NSPS GGGa reference sections of NSPS VVa, thus the requirements in VVa were included in this new section.

  Note that 60.482-1a(g) was not included since that paragraph has been stayed until further notice.

“New” Section II.37 – NSPS GGGa Requirements

Note that in the current permit (last revised June 15, 2009), section II.37 contains the flare requirements.

- The NSPS GGGa requirements were included in this new section.

  Note that the exception in 60.593a(e) was not included as it does not apply (60.593a(e) applies to equipment located on the Alaskan Northern Slope)

<u>"New" Section II.42 – Boiler MACT Requirements</u>

- The requirements in 40 CFR Part 63 Subpart DDDDD that apply to the boilers have been included in this section.

  The boilers are rated above 10 MMBtu/hr. Note that there are no new units or process heaters less than 10 MMBtu/hr at Plant 2. Nevertheless, the requirements related to new units and to units below 10 MMBtu/hr have been included in the permit, in the event that equipment is added to the facility at a later date that may meet those requirements.

<u>"New" Section II.45 – Continuous Emission Monitoring and Continuous Opacity Monitoring Requirements</u>

- The Division included a requirement in the new CEMS section to allow for RATAs to be conducted at or above 37% load for B504 and 32% load for B505, as that represents "normal" operating conditions. The RATA requirement also requires that records of boiler operating parameters be maintained and that the Division may require that RATAs be conducted at a higher load if data indicates that these units operate at a higher load.

<u>Section III – Permit Shield</u>

- The following changes were made to the table for non-applicable requirements (Section III.1):
  - Changed the boiler numbers.
  - Removed the shield for 40 CFR Part 60 Subpart Db and revised the justifications for 40 CFR Part 60 Subpart Dc.
  - Removed the Subpart J, 60.105(a) requirements since the boilers do not meet the Subpart J applicability requirements (they commenced construction after May 14, 2007)
- The following requirements were included in the table for streamlined conditions (Section III.3):
  - The requirement in 09AD1422, Condition 10 (H_2S fuel gas limit) in favor of the NSPS Ja limit.
  - The requirements in Reg 6, Part B, Section II.C.2 – PM and Reg 6, Part B, Section IV.C.2 SO_2 limits in favor of the Reg 1 .limits.
  - The requirements in 40 CFR Part 60 Subpart Db §60.49a(o) in favor of the T5 recordkeeping requirements.
  - The requirements in Regulation No. 7, Sections XVI.D.4.a.(i) (NO_X limit), XVI.D.5 (comply by October 1, 2021), XVI.D.5.a.(i)(A) (use a NO_X CEMS) and

XVI.D.5.a.(i)(A)(2).

- The requirements in Regulation No. 7, Sections XVI.D.7.c (keep records of type and amount of fuel used), XVI.D.7.d (keep records of annual capacity factor), XVI.D.7.e (maintain records generated for reports for 5 years) and XVI.D.8.a and a.(i) (sources using a CEMS submit either quarterly or semi-annual excess emission reports).

Appendices

- The old boilers were removed from the tables in Appendices B and C and the new boilers were added. In addition the fugitive VOCs from the new boilers were also added to the tables in appendices B and C.

1.16 November 29, 2013, August 8, 2014 and February 9 and July 17, 2018 Modifications (minor modification, administrative amendment, minor modification and minor modification) – Install Emergency Air Compressor, Remove Emergency Air Compressor, Install Emergency Air Compressor Engine and Install an Additional Emergency Air Compressor

The purpose of the November 29, 2013 application (minor modification) was to install a diesel fuel-fired engine driving an air compressor at Plant 2. The diesel air compressor is intended to be used in the event that air pressure is lost in the instrument air system due to a malfunction of one of five electrically driven air compressors. The engine was a Caterpillar C18 ACERT, rated at 575 hp and 429 kW.

The August 8, 2014 application (administrative amendment) was submitted to remove the emergency air compressor from the permit (the application indicated the engine was removed from the site on July 14, 2014). According to the application, Suncor successfully completed a project to refurbish and relocate electrically-driven air compressors in Plant 2, therefore, the emergency air compressor was no longer needed.

The purpose of the February 9, 2018 application is to again install an emergency air compressor engine in the event that the refinery were to lose air pressure in the instrument air system. The engine is a Cummins Model No. QSX15 525, rated at 525 hp (391.4 kW) that meets Tier 4 final requirements and is equipped with selective catalytic reduction (SCR) and a particulate filter, although an emergency engine is only subject to the Tier 3 requirements.

The purpose of the July 17, 2018 application was to install an additional emergency air compressor engine in the event that the refinery were to lose air pressure in the instrument air system. The engine is a Cummins Model No. QSX15 535, rate at 535 hp (399 kW) that meets the Tier 4 interim standards, although an emergency engine is only subject to the Tier 3 requirements.

According to the July 17, 2018 application, the source indicated that the engine addressed in this application supports the old boiler house and the engine addressed in the February 9, 2018 application supports the No. 2 FCCU.

In an October 10, 2018 email, the source requested that the July 17, 2018 application be cancelled as the emergency air compressor engine at the old boiler house had been permanently removed from service and would be removed at the earliest available date.

The reciprocating internal combustion engine APEN was submitted with the February 9, 2018 application and indicated requested NO_X emissions of 0.09 tons/yr. Emissions were based on the Tier 4 emission limitations and took credit for the SCR. The Division directed Suncor to use the Tier 3 emission limitations to estimate emissions, as those are the emission limitations that this emergency engine is subject to under NSPS IIII and to submit the appropriate revised APEN (the APEN for stationary internal combustion engines was submitted but the diesel engine APEN should have been submitted). An APEN for diesel engines was submitted on April 13, 2018 and indicated that emissions were below the APEN de minimis level. At the request of the Division, Suncor submitted an APEN cancellation form for the engine on May 4, 2018.

Potential to emit for the emergency air compressor engine was estimated based on 500 hours per year of operation (in accordance with the September 6, 1995 EPA Memo, "Calculating Potential to Emit (PTE) for Emergency Generators") and are shown in the table below. Note that although the September 6, 1995 EPA memo addresses emergency generators, the Division considers that the provisions in this memo (PTE based on 500 hours per year) are applicable to any emergency engine.

Scenario	NO_X	CO	VOC	$PM/PM_{10}/PM_{2.5}$[1]	SO_2
Emission Factor[2] (g/kW-hr)	4.0	3.5		0.20	
Emission Factor (lb/Mgal)[3,]					0.21
Emission Factor (lb/hp-hr)[4]			2.5×10^{-3}		
Emissions (lb/hr)[5]	3.45	3.02	1.31	0.17	5.25×10^{-3}
Emissions (tons/yr) at 500 hrs/yr[5]	0.86	0.76	0.33	0.04	1.31×10^{-3}
Emissions (tons/yr) at 8,760 hrs/yr[5, 6]	15.11	13.23	5.75	0.76	0.02
PSD/NANSR significance level (T5 Minor Mod Level)[7]	40	100	40	25/15/10	40

[1]$PM = PM_{10} = PM_{2.5}$

[2] Emission factors are NSPS Subpart IIII limitations for emergency engines (Tier 3 requirements). Although the engine meets Tier 4 final requirements, the Tier 3 requirements were used as this engine is being permitted as an emergency engine and avoids other requirements by being classified as such. The NSPS NO_X limit is actually for non-methane hydrocarbons and NO_X so it is conservative to consider this as an emission factor for NO_X only.

[3]SO_2 emission factor based on 15 ppm S in fuel limit from NSPS Subpart IIII and fuel density of 7.05 lb/gal.

[4]VOC emission factors from AP-42, Section 3.3 (dated 10/96), Table 3.3-1 (TOC exhaust plus crankcase)..

[5]Emissions from this engine are based on maximum design rates: 525 hp, 391.4 kW and 25 gal/hr.

[6] Annual emissions from this engine based on 8,760 hours per year of operation are shown for information purposes only. As noted above, the Division considers that the PTE of emergency engines is appropriately based on 500 hours per year of operation.

[7]Indicates the NANSR significance level on the date the complete minor modification application was submitted.

Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

The air compressor engine is subject to requirements in 40 CFR Part 60 Subpart IIII and those requirements are met by purchasing a certified engine. In addition, the requirements in 40 CFR Part 63 Subpart ZZZZ apply (submittal of an initial notification).

APENs are not required for this engine unless annual hours of operation reach 580 hours in any calendar year. Therefore emission and throughput limits will not be included in the permit.

This engine is subject to the following applicable requirements:

- Except as provided for below, visible emissions shall not exceed 20% opacity (Reg 1, Section II.A.1)
- Visible emissions shall not exceed 30% opacity, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)

  Based on engineering judgment, the Division believes that the operational activities of fire building, cleaning of fire boxes and soot blowing do not apply to diesel engines. Although this engine has a control device, it either does not control PM emissions or is not anticipated to be cleaned or adjusted while the engine is in operation. Finally, based on engineering judgment, it is unlikely that process modifications will occur with this engine. Therefore, for this unit the 30% opacity provision only applies during startup. The 20% opacity requirement (noted in the above bullet) applies at all other times. Note that expected startup time is not projected to exceed 30 minutes.
- SO_2 emissions shall not exceed 0.8 lbs/MMBtu (Reg 1, Section VI.B.4.b.(i))

  The SO_2 requirement will be streamlined for the more stringent fuel requirements in 40 CFR Part 60 Subpart IIII (15 ppm or 0.0015% sulfur). This condition is noted in the permit shield for streamlined conditions (Section III.3 of the permit).
- SO_2 emissions shall not exceed 0.3 lb/bbl/day (Reg 1, Section VI.B.4.e)

  The SO_2 emission limit for refineries. Compliance with the SO_2 limit is based on daily calculations, so requirements were added to record daily fuel consumption for the engines (based on hours of operation and the maximum hourly fuel consumption rate) and to calculate daily SO_2 emissions for use in monitoring compliance with the refinery SO_2 limit.
- 40 CFR Part 60 Subpart IIII Requirements
- 40 CFR Part 63 Subpart ZZZZ requirements
- Reg 7, Section XVI.D requirements

Since this engine was not in existence at this major source as of June 3, 2016, it did not become subject to the Reg 7 requirements for major source NO_X until the December 19, 2019 revisions, which expanded the applicability to major sources at the 50 tpy threshold for serious non-attainment areas. Since this is a diesel fuel-fired engine greater than 500 hp, it is potentially subject to the emission limitations in Section XVI.D.4. Since the engine is an emergency engine it is anticipated that actual, uncontrolled emissions from this engine will never exceed 5 ton/year of NO_X (at 500 hours per year, NO_X emissions are less than 1 tpy, and the engine would have to be operated for 2,897 hours to exceed 5 tons/yr), thus the engine would be exempt from the emission limitation, as well as the monitoring, reporting and most recordkeeping requirements. In addition, since actual, uncontrolled emissions are expected to be less than 5 tons/yr of NO_X, the combustion process adjustment requirements do not apply. Sources are required to maintain records if they are exempt from the emission limitations, therefore, the permit will include requirements to maintain records that the engine qualifies for the exemption. Note that sources are not required to maintain records demonstrating that they are exempt from the combustion process adjustment requirements.

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

<u>Section I – General Activities and Summary</u>

- The engine was included the table in Section I, Condition 5.1

<u>"New" Section II.11 – Emergency Generator (this section previously addressed the Black Oil Heater)</u>

- The provisions for this engine are included in Section II.11 of the permit.

<u>Appendices</u>

- The engine was included in the tables in Appendices B and C.

1.17 February 13, 2014 Additional Information Submittal and June 10, 2015 Modification (minor modification) – Cooling Tower Y-2

During the processing of a modification for the Plants 1 and 3 Title V permit (96OPAD120), the Division requested information on the emissions from the cooling towers at the refinery and the dates the equipment commenced operation and/or modification. Based on the information provided in a February 13, 2014 additional information submittal, the Plant 2 cooling tower (Y-2) was constructed and/or modified after February 1, 1972 and thus would have been subject to construction permit requirements as long as emissions were above the APEN de minimis level. The information in the February 13, 2014 submittal indicated that emissions of PM, PM_{10} and VOC all exceeded the APEN de minimis level, while $PM_{2.5}$ emissions were below the APEN de minimis level. Thus throughput and emission limitations will be included for the cooling tower.

The June 10, 2015 submittal requests that VOC emissions be based on a higher VOC concentration. The VOC limits requested in the February 13, 2014 submittal were based on twice the action level for monthly monitoring specified in 40 CFR Part 63 Subpart CC (action level is 6.2 ppmv, requested emissions were based on 12.4 ppmv). The provisions in 40 CFR Part 63 Subpart CC allow for delay of repair, in certain situations as long as the leak is below the delay of repair action level (62 ppmv). Therefore, under the provisions of 40 CFR Part 63 Subpart CC, a cooling tower with a leak above the action level (6.2 ppmv) can delay repair thus increasing VOC emissions. In order to reflect what is allowable under 40 CFR Part 63 Subpart CC, the source has requested that VOC emissions for the cooling towers be based on a higher VOC content (62 ppmv).

Based on the June 10, 2015 application submittal cooling tower emissions from the P2 cooling tower are as follows:

Source	Emissions Increase (tons/yr)		
	PM/ PM_{10}	$PM_{2.5}$	VOC
P2 cooling tower	4.8	0.1	23.1
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]	25/15	25/15/10	40

[1]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

During processing of the May 11, 2020 comments on the draft permit, the Division asked for information regarding the North and South Cooling towers in order to indicate the startup dates of the two towers in the Table in Section I, Condition 5.1. Initial information on the cooling tower indicated it was a single structure with four cells, subsequent information indicated it was considered two towers, the North and South Towers. Following the May 11, 2020 comments, it became clear, that the towers are operated as four separate towers (each cell considered a separate tower). Suncor submitted information on September 30, 2020 providing information on the four towers. Note that while the cooling structure is considered four towers, the maximum circulation rate has not changed and is consistent with the information provided in the February 13, 2014 submittal.

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

Section I – General Activities and Summary

- Updated the information for the cooling tower(s) in the table in Condition 5.1.

Section II.4 – Plant 2 Cooling Tower (this section previously address the Polymerization Unit)

The Plant 2 cooling tower was included in this section. The applicable requirements for the cooling towers include the following:

- 20% opacity (Regulation No. 1, Section II.A.1)

  Based on engineering judgment, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling towers. In addition, there is really no "startup" involved in operating a cooling tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit since the specific operating activities under which it applies do not occur with the cooling towers.

- Emission and throughput limits

  The throughput limit (7,253,280,000 gal/yr) is based on the maximum circulation rate (13,800 gal/min) and 8760 hours per year of operation.

  The emission limits included in the revised permit, include the requested emissions shown on the APEN submitted on June 10, 2015 (shown in the above table). PM emission limits are based on the maximum expected TDS concentration (3,200 ppm), the maximum circulation rate and the percent drift for each tower. PM_{10} is conservatively presumed to be equal to PM. In accordance with a January 30, 2011 Report by Eric A. Anderson (see page 152), $PM_{2.5}$ emissions are presumed to be 2% of PM emissions. Note that since $PM_{2.5}$ emissions are below the APEN de minimis level, limits for $PM_{2.5}$ were not included in the permit.

  VOC emission limits are based on the El Paso Method, and assume a strippable VOC concentration of 62 ppm.

- MACT CC requirements

<u>Appendices</u>

- Updated the description of the cooling tower(s) in the tables in Appendices B and C.

1.18 June 17, 2014 Modification (administrative amendment) – Change Responsible Official

In the June 17, 2014 modification request, the source indicated that the previous responsible official was retiring and requested that the new responsible official be included in the permit. The Responsible Official changed again in 2017, thus the revised permit reflects the current Responsible Official. The following change was made to the permit to address this request.

<u>Page following cover page</u>

- The responsible official was changed.

1.19 August 4, 2014 Modification (minor modification) – FCCU SO_2 Limits

The purpose of the August 4, 2014 modification is to request short and long-term SO_2 limits for the FCCU. The CD (SA-05-CA-0569), entered November 23, 2005, specifies at paragraph 88.g that the source is to propose short (7-day rolling) and long (365-day rolling) term SO_2 limits for the FCCU in their demonstration report and shall comply with those limits unless and until EPA sets short and long-term SO_2 FCCU limits based on the demonstration report.

Suncor submitted their demonstration report and proposed short and long-term FCCU limits to EPA on May 2, 2011. In a July 15, 2014 letter, EPA rejected Suncor's proposed SO_2 and stipulated lower limits. The August 4, 2014 submittal includes the SO2 limits set by EPA.

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

Section II.2 - FCCU

- SO_2 limits were included in Condition 2.10 of the permit. (Note that in the current permit (last revised June 15, 2009) Condition 2.10 includes the NSPS J requirements for the preheater.)

1.20 January 14, 2015 Modification (significant modification) – Apply NSPS Ja to Plant 2 (P2) Flare

The purpose of the January 14, 2015 modification is to reflect the NSPS Ja requirements for the Plant 2 flare. The January 14, 2015 application indicates that work conducted during the 2012 P2 Turnaround triggered a modification for the P2 flare and requested that the NSPS Ja requirements be included in the permit for the flare. In their application, the source indicated that the actions taken during the 2012 Turnaround did not result in an increase in emissions from the flare.

NSPS Subpart Ja defines modifications to a flare in 60.100a(c) as connecting any new piping from a refinery process units, including ancillary equipment, or a fuel gas system to a flare or physically altering the flare to increase the flow capacity. The Division requested additional information from the source to indicate what the modifications were and information supporting no increase in emissions.

In an August 31, 2015 email, the source indicated that NSPS Ja had been triggered due to the addition of new pressure relief valves and piping components. The source indicated that the components themselves (based on component emission factors) were below the APEN de minimis level and noted that a subsequent modification would be submitted for the relief valves. The October 28, 2015 application to address piping components that were previously not permitted and/or included in Suncor's LDAR program noted that the application included the pressure relief valves that triggered the NSPS Ja requirements for the flare.

As to whether there was an emissions increase for the flare, the source indicated in a January 28, 2016 response to an information request on the October 28, 2015 application, that an increase in the emission limits for the flare was not necessary due to the new pressure relief valves. The January 4, 2010 application revised the emission limits for the flare and all pollutants are permitted below the significance level.

This modified flare will be required to comply with the requirements in NSPS Subpart Ja on November 11, 2015 or upon startup of the modified flare, whichever is later. Typically the requirements in NSPS Subpart J would not apply, since the flare would no longer meet the applicability criteria (flare was modified after June 24, 2008. However, the CD stipulates that the requirements in NSPS Subparts A and J apply. Unless otherwise determined by EPA and the Division's Compliance and Enforcement Unit, the NSPS Subpart J requirements, which are required via CD will apply after the NSPS Subpart Ja compliance date. It does not appear that the flare modifications will affect the CD/NSPS J requirements, although the CD/NSPS requirements are as or less stringent than the NSPS Ja requirements, therefore, they have been streamlined from the permit.

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

<u>Section II.8 – Refinery Flare</u>

- Conditions 8.3 and 8.4 were removed. These conditions are from the CD and require that the flare meet the good practices requirement in NSPS Subpart A (60.11(d)), conduct a root cause failure analysis and comply with NSPS J. The NSPS J requirements and the CD root cause failure analysis is as or less stringent than the requirements in NSPS Ja. Therefore, the CD requirements to comply with NSPS Subparts A and J and the root cause failure analysis requirements will be streamlined from the permit (included in Section III.3 of the permit). Note that the flare will still be subject to the requirements in Subpart A, via Ja.
- Added "new" Condition 8.9 to include the NSPS Ja requirements. (Note that in the current permit (last revised June 15, 2009), Condition 8.9 includes opacity requirements.)
- Added "new" Condition 8.10 for the NSPS General Provisions. (Note that in the current permit (last revised June 15, 2009), Condition 8.10 includes the flare requirements.)

<u>"New" Section II.32 – NSPS Ja Requirements</u>

Note that in the current permit (last revised June 15, 2009), Section II.32 contains the requirements in 40 CFR Part 63 Subpart CC.

- The NSPS Ja requirements relevant to the Plant 2 flare were included in this new section.

<u>Section III – Permit Shield</u>

- The requirements from the CD that stipulated that the flare is subject to the requirements of NSPS J, the NSPS good practices requirement (60.11(d)) and the root cause failure analysis requirement were included in the permit shield for streamlined conditions.

Appendix H – SO_2 Emissions Calculation Methodology

- Revised the language to indicate that SO_2 emissions would be determined using the total reduced sulfur (TRS) monitor required by NSPS Ja.

1.21 April 15, 2015 Modification (minor modification) – Tank T62

The purpose of this modification is to permit tank T62 appropriately. According to the application, tank T62 is connected to a pipeline that has direct access to Denver International Airport and supplies it with jet fuel, which makes it unlikely that the contents stored in tank T62 will change.

In the current permit (last revised June 15, 2009), Tank T62 is permitted to store light straight gasoline, reformate, naphtha and FCC gasoline with an emission limit of 3.76 tons/yr.

According the application, Tank T62 is an internal floating roof tank that is equipped with slotted guide poles and was addressed in a 1999 CD. The 1999 CD required that the tank be equipped with certain guide pole emissions control technology and according to the 1999 CD, tank T62 was appropriately equipped with those controls.

However, as noted in the application, one of the control measures was replaced with equipment that did not provide similar control technology, rendering the tank out of compliance with the 1999 CD requirement. Since tank T62 is currently storing liquids with a much lower vapor pressure, and subsequently much lower emissions, Suncor has requested that the tank be permitted based on the materials stored.

Although not stated in the application, presumably since tank T62 no longer stores high vapor pressure liquids, EPA has approved the replacement of the gasketed float with the radar gauge and there are no compliance issues with the 1999 CD.

The change in emissions associated with this application is as follows:

VOC Emissions (tons/yr)		
Requested Emissions	Current Permitted	Change in Emissions
0.13	3.76	-3.63
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]		40

[1]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

Regulatory Applicability Discussion

The application did not discuss whether there were any changes to the regulatory requirements for this tank due to storing material with a much lower vapor pressure, however, this information was provided in a May 1, 2015 email. According to the May 1, 2015 email, the tank was constructed in 1953 and modified in 1993. The tank meets the definition of a Group 2 tank when storing jet fuel and is exempt from the requirements in Colorado Regulation No. 7, Section IV.B.2 and 3 (per Section VI.B.1.(a)(ii)). The May 1, 2015 email also noted that the tank is subject to the recordkeeping requirements (60.116b(b)) in NSPS Kb but not the control requirements. However, upon further review, the Division considers that the tank is exempt from the NSPS Kb requirements since the vapor pressure of the stored material is less than 3.5 kPa (0.51 psia) per 60.110b(b).

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

<u>Section II.15 – Group E Tanks</u>

- Revised the emission and throughput limits for Tank T062 in Conditions 15.1 and revised the throughput limits in Condition 15.10.
- Revised the RACT requirements in Conditions 15.4 and 15.5 (Reg 7, Sections VI.B.2.a and b) indicating that T062 is not subject to these requirements. Added language to the permit to require that records of the materials stored in T062 be kept to verify that exempt materials are stored in the tank.
- Added a “new” Condition 15.9 to indicate that if Tank T062 ever stores materials that trigger control requirements in NSPS Kb that the source shall submit an application to revise the permit and that the guide poles meet the control requirements in NSPS Kb. (Note that in the current permit (last revised June 15, 2009), condition 15.9 include MACT CC requirements.)

<u>Section II,25 – Reg 7, Section VI Requirements</u>

These requirements were moved to “new” Section II.26, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.26 includes the requirements in Reg 7, Section VII.

- Remove T062 from the list of tanks subject to the requirements in Condition 25.2.1.

<u>Section II.29 – NSPS Kb</u>

These requirements were moved to “new” Section II.33, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.33 includes the 40 CFR Part Subpart UUU requirements.

- Removed Tank T062 from the list of tanks subject to the NSPS Kb requirements and added a statement indicating that Tank T062 was no longer applicable upon submittal of the April 15, 2015 minor modification because the vapor pressure of the materials stored is below the applicability level.

1.22 October 28, 2015 Modification (significant modification) – Thermal Oxidizer for Tank Cleaning and Degassing

The purpose of the October 28, 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 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 cleaning should be addressed in the permit.

Note an application for tank degassing using a thermal oxidizer was processed and included in the Plants 1 and 3 Title V permit (96OPAD120) as part of the February 22, 2018 revision to that permit.

<u>Modification Type</u>

Prior to the October 28, 2015 submittal, the source submitted a minor modification application on September 29, 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 F 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 29, 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 PSD and/or 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 29, 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 October 28, 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 29, 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 October 28, 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 Plants 1/3 permit (96OPAD120), addressing the same specific thermal oxidizer.

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 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 that were based upon an agreed upon method to estimate emissions from tank degassing. Those methodologies were included in the draft permit when it was sent to the source for a pre-public comment review on March 11, 2020 and the February 22, 2018 revised permit for Plants 1 and 3 (96OPAD120). Details on those calculation methods can be found in the TRD to support the February 22, 2018 revised permit for Plants 1 and 3 (96OPAD120).

In the March 11, 2020 transmittal letter for the draft permit, the Division noted that revisions to AP-42, Section 7.1 included specific emission calculation methodologies for tank cleaning and asked the source to re-evaluate emission calculation methodologies, as well as permitted emissions to determine whether changes are necessary. AP-42 Section 7.1 (Organic Liquid Storage Tanks) did not previously include equations for calculating emissions from tank cleaning. The source submitted emission calculations on June 25, 2020 using the tank cleaning methods set forth in AP-42, Section 7.1, which are utilized in TankESP (a software program). Revised calculations for combustion emissions were submitted on August 21, 2020 and an APEN was submitted on August 27, 2020 to revise the requested emission and throughput limits.

Similar to the previous calculation methodology, the June 25, 2020 calculations rely on the largest tank storing the highest vapor pressure material (gasoline RVP 15) and a control efficiency of 95% for the thermal oxidizer. The methodology is based on five steps involved in tank cleaning and degassing, as discussed below:

- Floating Roof Landings: Section 7.1.3.3.1 of AP-42 indicates that once the roof is landed, a breather vent is actuated to prevent the formation of a vacuum from liquid removal, which could result in damage to the tank. Suncor indicated that they remove vapors during the liquid removal by introducing a vapor extraction hose into the vapor space and routing the vapors to a thermal oxidizer. Emission calculations utilize equation 3-7. The equation relies on the number of days and the source assumed that the roof landing emissions account for one (1) day of operation.
- Vapor Space Purge: The vapor space purge includes the first air change out upon startup of forced ventilation and emission calculations utilize equation 4-2 from Section 7.1.3.4. These vapors are routed to the thermal oxidizer.
- Stock Removal (Continued Forced Ventilation): Forced ventilation refers to the removal of vapors from a tank by means of eductors, fans, or blowers. As long as volatile material remains in the tank, some portion of the volatile material will evaporate into the air being moved through the tank. Emissions from continued forced ventilation are estimated using equation 4-10 (continued forced ventilation) in Section 7.1.3.4. The equation utilizes the number of days and the source assumed three (3) days may be necessary to ensure liquid is removed from the tank.
- Diesel Flush (Continued Forced Ventilation): Remaining liquids or sludge may be removed from a storage tank bottom by flushing the area with diesel. Emissions from this step are estimated using equation 4-10 (continued forced ventilation) in Section

7.1.3.4. Note equation 4-10 uses the average vapor concentration in the vapor space (which may be reported as a percent of the lower explosive limit (LEL)) and depending on the residual liquid in the tank, the diesel flush serves to lower the LEL of the tank vapor space by lowering the vapor pressure of the residual liquid. As a result, emissions from this step are lower than for the stock removal step, although emissions are still routed to the thermal oxidizer during this step. This process may be repeated for a number of days and the source assumed four (4) days for this step.

- <u>Sludge Removal (Continued Forced Ventilation may be used):</u> The final step is to remove sludge from the tanks once the tank is safe to access. The source indicates that forced ventilation may be used in this step but vapors from the tank are not routed to the thermal oxidizer during this step. The June 25, 2020 analysis for this step presumed continued forced ventilation for one (1) day for this step. Therefore emissions from this activity are uncontrolled.

VOC emissions from tank cleaning and degassing operations from this modification are as follows:

Activity	VOC Emissions (tons/yr)			
	Uncontrolled		Requested/Controlled	
	One Tank	Ten (10) Tanks	One Tank	Ten (10) Tanks
Roof Landing	3.48	34.8	0.17	1.70
Vapor Space Purge	4.88	48.8	0.24	2.40
Stock Removal	21.9	219	1.10	11.0
Diesel Flush	0.62	6.2	0.03	0.3
Sludge Removal	0.15	1.50	0.15	1.50
Combustion Emissions (see table below)	N/A	0.21	N/A	0.21
Total	31.04	310.51	1.69	17.11

Requested emissions of criteria pollutants from combustion of propane in the thermal oxidizer are based on the design rate of the thermal oxidizer (20 MMBtu/hr) and eight (8) days of operation per tank and ten (10) tank degassings per year (1,920 hours per year of operation) as indicated in the tables below:

Pollutant	Emission Factor[1]	Emissions (tons/yr)[2, 3]	
		At 1,920 hours per year	At 8760 hours per year
$PM/PM_{10}/PM_{2.5}$	0.7 lb/1000 gal	0.15	0.67
SO_2	0.09S lb/1000 gal (0.018 lb/1000 gal)	3.78×10^{-3}	0.02
NO_X	13 lb/1000 gal	2.73	12.4
VOC	1 lb/1000 gal	0.21	0.96
CO	7.5 lb/1000 gal	1.57	7.2

[1]From AP-42, Section 1.5 (dated 7/08), Table. 1.5-1. S= sulfur content in gr/100 ft^3 and S was assumed to be 0.2 gr/100 ft^3.

[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.

[3]Requested (permitted) emissions are based on 1,920 hour per year. Emissions at 8760 hours per year are presented to show emissions at maximum operating time.

Since emissions of PM, PM_{10}, $PM_{2.5}$, and SO_2 are below the APEN de minimis level at the requested throughput (38,400 MMBtu/yr), limits for those pollutants will not be included in the permit. However, emissions must be calculated and reported on APENs.

Based on comments submitted on the Plants 1/3 permit (96OPAD120) in early 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 and submitted information indicating that emissions from degassing those tanks were below the APEN de minimis level (1 ton/yr). Although the Division asked the source to re-evaluate emissions using the new AP-42 emission factors for tank degassing in the March 11, 2020 transmittal letter, the source has not conducted a similar evaluation for tanks storing liquids with a TVP less than 0.75 psia, so the draft permit was revised to require the thermal oxidizer to be used in all tank degassings.

As discussed previously, provisions for tank degassing are included in the Title V permit for Plants 1/3 (96OPAD120), based on the previously relied upon emission calculation methods (see the TRD for the Plants 1/3 permit (96OPAD120) issued on February 22, 2018) and that limit applies only to the Plants 1/3 equipment. Based on the higher estimated VOC emissions (17.2 tpy vs 5.0 tpy) and the lower significance level (25 tpy) due to the serious nonattainment area classification, the source will be required to include emissions from all tanks in assessing compliance with the limit, although only emissions from Plant 2 tank degassings are to be included on the Plant 2 APEN. The source will need to revise the Plants 1/3 permit (96OPAD120) to include the revised emission calculation methodology and limit and to indicate that the emission limit applies to all tank degassings at the refinery.

Regulatory Requirements

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

The Reg 1 SO_2 limit for refineries (0.3 lb/bbl/day)

RACT requirements. 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 and 7 apply. Use of the thermal oxidizer and the requested VOC emission limit are considered to be RACT.

NSPS Requirements. 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 H_2S limit for fuel gas and subsequent monitoring requirements (continuous H_2S 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 October 28, 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 SO_2 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.

Relaxation Provisions. As discussed previously, the application to permit a thermal oxidizer for tank degassing had to be processed as a significant modification because limits were being taken to keep emissions below the significance level and avoid NANSR requirements. Sources that avoid NANSR requirements by taking enforceable limits are subject to NANSR requirements if they relax those limitations above the significance level at some later date. Therefore, the relaxation provisions in Regulation No. 3, Part D, Section V.A.7.b apply and will be included in the permit.

Although the application was submitted October 28, 2015 and the significance level at that time was 40 ton/yr of VOC, since the provisions addressed in the October 28, 2015 application do not take effect until the permit is issued, the lower significance level of 25 tpy applies in this case.

The following revisions 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.46 – Tank Degassing

- Added a new section II.46 for tank degassing. The requirements include emission and throughput limits, as well as the Reg 1 opacity and SO_2 limits, RACT, the NSPS (Subparts J and Ja) requirements and the relaxation provisions. Requirements for operation of the thermal oxidizer include a requirement to maintain the temperature at or above 1400 ºF.

Appendices

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

1.23 October 28, 2015 Modification (significant modification) – Permitting Fugitive VOCs from Equipment Leaks as Required by COC

The purpose of the October 28, 2015 modification is to permit a number of piping components that had previously been unidentified in the source's leak detection and repair (LDAR) program. According to the application, the source conducted a LDAR field review of piping components in Plant 2. As a result of the review, the source found a significant number of existing components that were subject to LDAR monitoring requirements but were not identified and included In their LDAR inventory and inspection program. Failure to include these piping components in their LDAR program was noted in a COC (2014-122/123) and the source was required by the COC to submit an APEN for permitting these components. The APEN was submitted on September 29, 2015, prior to submittal of the application.

According to the application, the source is unable to determine the actual date the components were placed in service but they noted that the components addressed in the application include 15 relief valves which were connected to the plant 2 main flare and triggered NSPS Ja requirements for the flare (which was addressed in a January 14, 2015 modification application).

Although the components are associated with various process units and not related to a single project, the component grouping will be permitted as a group, with an emission limit for the group. The requested emissions associated with this modification are 9.55 tons/yr of VOC.

Discussion

Requested emissions from the fugitive components addressed in this modification are based on the following emission factors and component count. Note that the component count and emission estimate in the modification application is slightly different from the September 29, 2015 APEN submittal and both the APEN submittal and the mod application indicate a component count different than that noted in the 2014 COC. Emissions were based on the following:

Component Type	No. of Components	Service	Emission Factor (lb/component/hr)	Control Efficiency[1]	Emission Factor Source	Emissions (lbs/yr)
Valves	383	Light liquid	0.02403	95%	"Protocol for Equipment Leak Emission Estimates", EPA-453/R-95-017, November 1995, Table 2-2 (emission factors) and Table 5-3 (control efficiencies)	4,021
	376	gaseous	0.05908	96%		7,784
Flanges/ Connectors	1888	Any	0.00055	81%		1,732
Relief Valves	15	Gaseous	0.35274	95%		2,317
Pumps	8	Heavy liquid	0.25133	0%		3,244
Total (lbs/yr)						19,098
Total (tons/yr)						9.55

[1]Control efficiencies are from the following sources. **Valves** - Table 5-3 of EPA's Protocol for Equipment Leaks (EPA-453/R-95-017) based on monitoring consistent with proposed HON NESHAP. **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 NESHAP. **Relief Valves** Control efficiency is assumed to be 95% as required by 40 CFR Part 60 Subpart VV § 60.482-10 (closed vent systems and control devices). The use of closed vent systems and controls devices under VV are listed as compliance options in § 60.482-4a(c). NSPS GGG relies on the requirements in NSPS VV. Note that as discussed below the fugitive equipment leaks associated with the flare are subject to 40 CFR Part 60 Subpart GGG, which specifies that sources meet requirements from Subpart VV.

The application indicates that projects dating back to the 2012 turnaround triggered 40 CFR Part 60 Subpart GGGa for several process units. The application further implies that only NSPS GGGa applies to all process units except the P2 main flare.

In response to a request for information, the source submitted information on January 28, 2016 indicating that NSPS GGGa was triggered for all process units except the P2 main flare. The January 28, 2016 information also indicates that NSPS GGGa was triggered for the East and South Tank Farms, although the current definition of process unit excludes tanks. A revised definition of process unit that included tanks has been indefinitely stayed for both NSPS GGG and GGGa since June 2, 2008. The source has indicated that they are proactively treating these tank farms as subject to NSPS GGGa in anticipation of the stay being lifted. Since tanks are not currently regulated under either NSPS GGG or GGGa, the permit will not indicate that the NSPS GGGa applies to the East and South Tank Farms.

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

<u>Section I – General Activities and Summary</u>

- Added the fugitive components to the table in Condition 5.1.

<u>Various Parts of Section II</u>

The draft permit submitted with the application included revisions for Sections II.1 (crude unit), II.2 (FCCU), II.3 (naphtha hydrotreater and reformer), II.4 (polymerization unit), II.5 (SRU) and II.6 (utilities) to indicate that emissions from these process units are subject to NSPS GGGa rather than NSPS GGG. The suggested changes were not made.

The components associated with these process units are not subject to emission limitations and emissions from these are grouped on the APEN for plant wide fugitive emissions not subject to emission limitations. The permit will be revised to include more detailed requirements for plant wide fugitive emissions not subject to emission limitations (in "new" Section II.19) and that section will detail whether component groupings are subject to NSPS GGG or GGGa. The individual sections (e.g. II.2) will refer to the section for plant wide fugitive emissions not subject to emission limitations ("new" Section II.19).

Section II.18 – Fugitive VOC equipment leak emissions with permitted limits

- Included the emission limits for this component grouping.
- Added language noting that some process units are subject to NSPS GGGa and that the MACT CC requirements do not apply to components subject to NSPS GGGa.

Section II.30 – NSPS GGG

These requirements were moved to "new" section II.36, the below discussion addressed the requirements as they appear in the current Title v permit (last revised June 15, 2009).

- The language in this section was revised to indicate that just the refinery flare fugitives (F018) are subject to these requirements.
- Although not specifically requested in the draft permit, the language in the section was revised to indicate that F034 (piping modifications to product handling system (SEP)) and F031 (tank T79 fugitives) are subject to these requirements. Section II.18 of the current Title V permit (last revised June 15, 2009) indicates that these sources are subject to NSPS GGG requirements and the draft permit associated with this modification does not indicate that this status has changed.

"New'" Section II.37 – NSPS GGGa

Note that in the current permit (last revised June 15, 2009), Section II.37 contains the flare requirements.

- The NSPS GGGa requirements were included in this new section.

  Note that in addition to the sources subject to these requirements that were noted in the proposed draft permit submitted with the application, the Division also included the permitted fugitive sources that are subject to these requirements, specifically F012 (gas plant fugitive emissions) and F035 (second stage of crude oil desalting project).

Appendices B and C

- Added to the fugitive components to the tables.

1.24 April 20, 2016 Modification (minor modification) – Include SO_2 limit for sulfur recovery plant

The purpose of this modification is to include a mass-based SO_2 limit on the sulfur recovery plant (SRP). The requested SO_2 limit is based on a requirement in the

Consent Decree (paragraph 223) to complete an SRP optimization study, implement recommendations of the study and to submit to EPA for approval a proposed mass-based SO_2 limit for the SRP.

The change in permitted emissions associated with this modification is shown in the table below:

SO2 Emissions (tons/yr)		
Requested Emissions	Current Permitted	Change in Emissions
271	344	-73
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]		40

[1]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

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

Section II.5 – Sulfur Recover Plant

- The annual SO_2 emission limit in Condition 5.1 was revised.

1.25 September 2016 Additional Information Submittals

Information was submitted on September 1, 22 and 23, 2016 to address a July 14, 2016 request for additional information from the Division. The September 1 submittal addressed the majority of the information requested in the July 14, 2016 information request. The September 22 submittal provided a revised insignificant activity list and the September 23 submittal included language to the Refinery Sector Rule (RSR) revisions that apply to the facility.

Cancellation notices were submitted on September 19 and 20, 2016 for Tanks T004, T005 and T042 in response to the Division's inquiry regarding the APEN status for tank T004 and T005.

The following changes were made to the permit to address these submittals

Section I – General Activities and Summary

- Tanks T004, T005 and T042 were removed from the table in Condition 5.1.

Sections II.13 &14 – Group C and D Tanks

- Tanks T004 and T005 (Group C) and T042 (Group D) were removed from the description in these sections.

Section II.32 – MACT CC

These requirements were moved to “new” Section II.40, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.40 includes language related to maximum achievable control technology.

Fairly significant revisions to the requirements in MACT CC 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. At the request of the Division, the source submitted information on September 23, 2016 indicating the MACT CC applicable requirements. Revisions were made to the MACT CC requirements on July 13, 2016, November 26, 2018 and February 4, 2020 and the most recent revisions were included in the permit.

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 included 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 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.
- <u>63.640 (applicability):</u> No requirements from 63.640 are included in the current permit (last revised June 15, 2009). For the renewal, 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.
- <u>63.642 (general standards)</u>: The current permit (last revised June 15, 2009) includes 63.642(c) (general provisions), some of the specific general provisions (subpart A), 63.642(e) and Condition 32.9 (which combines 63.642(g), (k) and (i)). 63.640(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 actionable. 63.642(e) was revised and Condition 32.9 was separated into 63.642(g), (k) and (i).

  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 requirements 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 June 15, 2009) but now apply, so the requirements have been included. Note that miscellaneous process vents will be controlled with a flare, thus only the requirements related to flares are included. The following requirements were excluded because address other compliance options: 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) and 63.644(b) (alternative monitoring).

  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 June 15, 2009). Revisions were made to address the specific requirements that apply and be consistent with the language in the Plants 1/3 permit (96OPAD120). Note that only the overlap provisions in 63.640(n)(1), (n)(2) and (n)(8) were included. The other provisions either apply to new sources or tanks subject to NSPS K or Ka and 40 CFR Part 62 Subpart Y and thus don't apply to any of the tanks at Plant 2.

  The definition of Group 1 storage vessel was revised with the December 1, 2015 revisions. The September 23, 2016 submittal indicates that two tanks T037 and T058 are now classified as Group 1 storage vessels, thus the permit was revised to indicate this change (the current Title V permit (last revised June 15, 2009) indicated that these were Group 2 tanks).

- 63.647 (wastewater provisions): This section is included in the current permit (last revised June 15, 2009).

- 63.648 (equipment leak standards): This section is included in the current permit (last revised June 15, 2009). This section was revised to include any new or revised requirements. The current permit (last revised June 15, 2009), 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 June 15, 2009). This section was revised to include any new or revised requirements. Note that since the compliance date for gasoline loading racks has passed, 63.650(c) was not included. In addition, the relevant Subpart R and XX requirements have been included since the MACT CC requirements for gasoline loading racks relies on the provisions in 40 CFR Part 63 Subpart R (which relies on the provisions in 40 CFR Part 60 Subpart XX), neither of which are included in the current permit (last revised June 15, 2009).

- 63.654 (heat exchange systems): This section is not included in the current permit (last revised June 15, 2009). The appropriate applicable requirements from this section have been included. Note that the requirements for once-through systems in 63.654(c)(2), (c)(6)(i) and (f)(3)(i) and the requirements for new units in 63.654(c)(5) were not included since they do not apply to the Plant 2 cooling towers.

- 63.655 (reporting and recordkeeping). This section is included in the current permit (last revised June 15, 2009), although the recordkeeping and reporting requirements were previously in 63.654. Revisions were made to address new and revised requirements. Note that 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 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 June 15, 2009). 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 June 15, 2009). 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. In the red-lined RSR submittal, the source did not indicate which they would comply with. However, the Plant 1/3 Title V(96OPAD120) renewal application (submitted on September 16, 2016), includes only the Subpart WW requirements, thus the Division assumes that Subpart WW would also apply to the Plant 2 tanks. The requirements in 63.660(d) (tanks that weren't Group 1 storage vessels prior to February 1, 2016) was included since Tanks T037 and T058 were considered Group 2 storage tanks prior to February 1, 2016. In addition, since the source is not complying with the requirements in Subpart SS, 63.660(g) and 63.660(i) was not included.

- 60.670 & 60.671 (flare requirements): This section is not included in the current permit (last revised June 15, 2009). The compliance date for these requirements is January 30, 2019. On July 10, 2017, the source submitted an application for revisions to the P2 flare to comply with the new flare requirements in MACT CC. Based on these revisions, the Division attempted to include only the relevant requirements from these sections. Note that in some cases a discussion of what is included is noted in the permit, although some requirements that were not included are discussed here. To that end, the requirements in 63.670(f) and (n) were not included since the flare does not use perimeter assist and the requirements in 63.671(e) were not included since the source will not use a gas chromatograph.

Section II.33 – MACT UUU

These requirements were moved to "new" Section II.41, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009).

Fairly significant revisions to the requirements in MACT UUU 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. At the request of the Division, the source submitted information on September 23, 2016 indicating the MACT UUU applicable requirements. Revisions were made to the MACT CC requirements on July 13, 2016, November 26, 2018 and February 4, 202 and the most recent revisions were included in the permit.

Note that the requirements in 63.1560 (purpose of this subpart), 63.1561 (is the plant subject to this subpart) and 63.1578 (implementation and enforcement) were not included as they do not include actionable requirements. Except for the definition of "hot standby", the requirements in §63.1579 (definitions) were not included for the same reason.

- Added a statement to the beginning of this section, indicating which version of the rule is included and that the permittee is subject to the most recent version of the requirements.
- 63.1562 (what parts of plant are covered). No requirements from 63.1562 are included in the current permit (last revised June 15, 2009). For the renewal it seemed appropriate to include the affected sources (63.1652(b)) and the relevant sources that are not affected (63.1652(f)(4) and (5)).
- 63.1563 (compliance date). Some requirements in this section are in the current permit (last revised June 15, 2009) and either don't apply or have passed. Although the permit will not be issued before August 1, 2017, the new compliance date has been included (63.1563(d)(1)). The requirements in 63.1563(a) (initial compliance date for new sources), (b) (initial compliance date for existing sources), (c) (compliance extension for catalytic cracking units) and (e) (area sources increasing emissions) were not included since they do not apply, were not utilized or dates have passed.
- 63.1564 (metal HAP emissions from FCCUs). This section is included in the current permit (last revised June 15, 2009) but does not include the requirements based on chosen or required compliance options. Therefore, revisions were made to include those as well as address any new or revised requirements or requirements that should have been included. The requirements in 63.1564(b)(3) (set site specific operation limit) and 63.1564(b)(4) (initial compliance demonstration) were not included as they do not apply to sources subject to NSPS J that comply using option 1a. The requirements in 63.1564(c)(3) and (c)(4) do not apply, as they apply to options 3 and 4, which the source is not relying on.

- 63.1565 (organic HAP emissions from FCCUs). This section is included in the current permit (last revised June 15, 2009) but does not include the requirements based on the chosen or required compliance options. Therefore, revisions were made to include those as well as address any new or revised requirements or requirements that should have been included. Conditions 33.24 (63.1565(b)(2)) and 33.25 (63.1565(b)(3)) were not included as the FCCU is subject to NSPS requirements and site-specific operating limits are not required.
- 63.1566 (organic HAP emissions from catalytic reforming units). This section is included in the current permit (last revised June 15, 2009) but does not include the requirements based on the chosen compliance option. In the September 23, 2016 red-lined MACT UUU section, the source did not indicate the compliance option but it (flare, option 1) was noted in the October 1, 2009 renewal application. Therefore, revisions were made to include those as well as address any new or revised requirements or requirements that should have been included. Conditions 33.39 (63.1566(b)(4)), 33.40 (63.1566(b)(4)(ii)) and 33.41 (63.1566(b)(5)) were removed as these requirements do not apply to the compliance option chosen (flare).
- 63.1567 (inorganic HAP emissions from catalytic reforming units). This section is included in the current permit (last revised June 15, 2009) but does not include the requirements based on the chosen compliance option. In the September 23, 2016 red-lined MACT UUU section, the source did not indicate the compliance option but it (30 ppm HCl limit, option 1) was noted in the October 1, 2009 renewal application. Therefore, revisions were made to include those as well as address any new or revised requirements or requirements that should have been included.
- 63.1568 (HAP emissions from sulfur recovery units). This section is included in the current permit (last revised June 15, 2009) but does not include the requirements based on the chosen compliance option. In the September 23, 2016 red-lined MACT UUU section, the source did not indicate the compliance option but it (300 ppm total reduced sulfur (TRS) limit, option 2) was noted in the October 1, 2009 renewal application. Therefore, revisions were made to include those as well as address any new or revised requirements or requirements that should have been included.
- 63.1569 (bypass lines). This section is included in the current permit (last revised June 15, 2009). In the September 23, 2016 red-lined MACT UUU section, the source included the provisions in 63.1569 (with no compliance option identified), however, in the 2009 renewal application, the source indicated that there were no bypass lines and so these requirements should be removed. Past inspection reports indicate that the source has noted that they have no bypass lines. Therefore, these requirements were removed.
- 63.1570 (general requirements). This section is included in the current permit (last revised June 15, 2009). This section was revised to address any new or revised requirements or requirements that should have been included. Note that 63.1570(e) is “reserved” and so not included in the permit.
- 63.1571 (performance test/initial compliance demonstrations). This section is included in the current permit (last revised June 15, 2009). This section was revised

to address any new or revised requirements or requirements that should have been included. Note that the provisions in 63.1571(a)(3) and (4) were not included as they apply to new units. The provisions in 63.1571(a)(5)(i) were not included as the FCCU does not have a PM CEMS.

- 63.1572 (monitoring installation, operation and maintenance requirements). This section is included in the current permit (last revised June 15, 2009). This section was revised to address any new or revised requirements or requirements that should have been included.
- 63.1573 (monitoring alternatives). This section is included in the current permit (last revised June 15, 2009). In the 2009 renewal application, the source indicated that these requirements should be removed since the alternatives were not being used. In the September 23, 2016 red-lined MACT UUU section, the source did not indicate that these requirements should be removed. The Division confirmed with the source that the monitoring alternatives are not being used and can be removed.
- 63.1574 (notifications). This section is included in the current permit (last revised June 15, 2009). This section was revised to address any new or revised requirements or requirements that should have been included. Note that 63.1574(b), (c), and (e) were not included as they do not apply (requirements apply to new units or compliance extensions).
- 63.1575 (reports). This section is included in the current permit (last revised June 15, 2009). This section was revised to address any new or revised requirements or requirements that should have been included. Note that the requirements in 63.1575(h) and (j) have not been included since (h) is reserved and (j) does not apply (applies to FCCUs served by a wet scrubber).
- 63.1576 (records). This section is included in the current permit (last revised June 15, 2009). This section was revised to address any new or revised requirements or requirements that should have been included.
- 63.1577 (general provisions). This section is included in the current permit (last revised June 15, 2009), although the specific general provisions that are listed in Table 44 are not included. This section has been revised to include some of the relevant general provisions. Note that only general conditions that were likely to apply or are actionable were included, so requirements for compliance extensions, alternatives, waivers and requirements that have been completed (i.e. initial notification) were not included as they would not necessarily apply.

Section III – Permit Shield

The table for non-applicable requirements in Section III.1 was revised to reflect the September 1, 2016 submittal, with the exceptions noted in the table below. In general the justification noted in the September 1, 2016 submittal was included, although in some cases the justification was corrected and/or revised for clarity.

Emission Unit/Regulation	Reason for not including in Section III.1
	Colorado Regulations

Emission Unit/Regulation	Reason for not including in Section III.1
Tank T012, Reg 7, VI.B.2.c.(ii)(C)	Suncor's justification indicates that the tank does not receive petroleum liquids with a true vapor pressure of 1.0 or greater. Since the current Title V permit includes these requirements, tank is not subject to any restrictions on contents or emissions and the source has not provided any actual information on tank contents, the shield will not be granted for these requirements.
LPG storage truck and rail facility, Reg 7, VI.B & C, CP 89AD031, condition 2	Suncor's justification indicates that only LPG is stored and transferred but the permit allows petroleum products to be processed, thus the shield was not granted.
Tank T006, Reg 7, VII	Suncor's justification indicates that this tank does not store crude oil but Suncor had previously indicated that it does store crude oil.
Pilot gas for various equipment, 40 CFR Part 60 Subpart J – 50.105(a)	Subpart J specifically notes § 660.105(a)(4)(iv)(A) that monitoring is not required for pilot gas for heater and flares, thus the shield is not necessary and was not granted.
South and north crude unloading fugitive sources, Reg 7, VI.c.4.b	Suncor's justification indicated that there is no loading of petroleum transport trucks that serve locations required to be equipped with vapor recovery but has submitted no information to support this, therefore, the shield has not been granted.
	New Source Performance Standards
Tank T025 (Group G tank), 40 CFR Part 60 Subpart K, Ka and Kb	Suncor's justification was that this tank was constructed prior to June 11, 1973. However, information in the December 1999 Title V permit application indicates that the tank was converted to an IFR in October 1996.
Wastewater treatment plant, 40 CFR Part 60 Subpart QQQ §§ 60.692-5, 60.695, 60,696(b)-(c), 60.697(f)(3) & 60.698(b)(2)	Suncor's justification was that the unit does not include any control devices or a closed drain or closed vent system to comply with Subpart QQQ. Since the APIs have been equipped with carbon canisters to meet the NSPS QQQ requirements, the shield will not be granted.
South & north crude unloading fugitive sources & truck loading dock 40 CFR Part 60 Subpart GGG	Suncor's justification is that crude unloading and gasoline tank truck loading does not have a compressor, nor is there equipment within a process unit. EPA promulgated a revised definition of process unit that includes feed, intermediate and final product tanks and product loading. Although this definition is stayed, the Division considers that it is not appropriate to include this as a permit shield as the stay may be lifted in the near future.
	Maximum Achievable Control Technology (MACT)
Reformer unit, 40 CFR Part 63 Subpart CC § 63.648	Suncor's justification was that the compressor is in hydrogen service and that the hydrogen content can reasonably always be expected to exceed 50% by volume. These provisions in 60.648(g) only exempt the compressor from the requirements in 60.648(a) & (c) thus the shield cannot be granted for the entire section. In addition, it is likely that other components from the reformer unit are subject to these requirements but are not addressed in the justification.

<u>Appendix A – Insignificant Activity List</u>

- The insignificant activity list in the current permit (last revised June15, 2009) was replaced with the list included in the September 22, 2016 submittal.

<u>Appendices B and C</u>

- Tanks T004, T005 and T042 were removed from the tables.

1.26 November 22, 2016 Modification (significant modification) and December 3,

2019 Submittal (cancel modification) – Hydrogen Cyanide (HCN) limit for FCCU

The purpose of the November 22, 2016 modification is to include a voluntarily requested federally enforceable limit on HCN emissions from the FCCU. The requested HCN limit is based on a performance test conducted on October 11, 2016. The test was conducted to fulfill the requirement to conduct a one-time performance test as required by the December 1, 2015 revisions to 40 CFR Part 63 Subpart UUU.

Suncor met with the Division on November 12, 2019 to discuss the status of the HCN permitting at the Plant 2 FCCU. The Division and Suncor discussed the value in conducting additional monitoring of the HCN emissions and to have Suncor refine and consider the emission limit request based on additional actual emissions data. During the meeting both the Division and Suncor discussed and agreed that a letter should be submitted requesting the cancellation of the modification in order to conduct additional monitoring of the HCN emissions and refine and consider the emission limit request. As agreed during the November 12, 2019 meeting, on December 3, 2019, Suncor submitted a request to cancel this modification application. In that submittal, the source indicated that HCN CEMS testing had been and was being conducted in order to determine a more robust emission factor and emission limit. Thus it is anticipated that at some point in the future, an application will be submitted to include an HCN emission limit.

Although the draft permit does not include an HCN limit for the FCCU, as noted the Division expects that there will be one in the future after sufficient testing has been conducted. As a result, the Division is including information in this document regarding the modeling analyses that have been conducted by the Division to demonstrate that the impacts from the anticipated HCN limit would be below health-based guidelines. Note that should any requested HCN limits exceed the levels relied upon in the modeling analysis, revised modeling would be conducted to ensure those levels are also below health-based guidelines.

During the processing of a modification to include an HCN limit for the Plant 1 FCCU in the Plants 1 and 3 Title V permit (96OPAD120), the Division modeled HCN emissions in October 2017 to determine the levels of HCN that would be present at the fenceline. The Division modeled HCN emissions at the requested levels for both the Plant 1 and Plant 2 FCCUs (12.8 ton/yr for P1 and 1.44 ton/yr for P2). The results of the modeling indicated that the maximum concentration of HCN that would be present at the fenceline is 0.005 ppm (1-hour average). The Division discussed these results in the TRD (see page 18) that supported the February 22, 2018 revised permit for Plants 1 and 3 (96OPAD120) and noted that the levels were below several HCN safety levels.

On April 17, 2018, EPA received a petition from Earthjustice on behalf of a number of environmental and community groups on the February 22, 2018 revised Title V permit for Plants 1 and 3 (96OPAD120). The petition objected to the HCN emission limit and noted that EPA set a health protective inhalation reference concentration (RfC) of

0.0008 mg/m^3 (0.0007 ppm) for chronic (long-term) exposure to HCN. This EPA RfC threshold for chronic (long-term) exposure was not one of those the Division used to compare the results of the HCN modeling analysis to and is lower than the short-term impacts predicted by the Division's modeling analysis.

Comparing a long-term standard (the EPA RfC value) to a short-term impact (the Division's October 2017 HCN modeling result) is not an appropriate comparison, therefore, the Division reviewed the modeling analysis conducted for the February 22, 2018 revised Plants 1 and 3 permit (96OPAD120). During the review, the Division discovered that the emission rate used in the modeling analysis for the P1 FCCU was incorrect (an emission rate of 3.68 grams per second was used and it should have been 0.368 grams per second). In the revised modeling analysis, results were provided for both short-term (1-hr) and long-term (annual) impacts. The short-term impacts are appropriate to compare to acute limitations and the long-term impacts are appropriate to compare to chronic limitations, such as EPA's RfC value.

The results of the Division's HCN modeling analysis were 0.611 parts per billion (ppb) on a one-hour average (acute exposure) and 0.0309 ppb on an annual average (chronic exposure). The one-hour (acute) concentration is 400 times lower than the acute health-based guideline listed in Table B below and the annual (chronic) concentration is 20 times lower than the chronic health-based guideline listed in Table B below.

On September 14, 2018, Suncor submitted an application to revise the HCN limit for Plant 1, as a required performance test indicated higher emission rates. The Division's modeling analysis was revised in June 2019 to consider the higher requested HCN limit for Plant 1 (19.9 tons/yr), and to model the Plant 2 FCCU at the same emissions level (19.9 tons/yr) as a conservative assumption. During the 2019 modeling process, the Division noted nearby structures may need to be included and asked Suncor to provide updated information on nearby structures and to verify stack parameters (height, temperature, diameter and flow). The results from the June 2019 modeling analysis are provided in Table A below.

Diagrams mapping the 5-year average short-term (1-hour) and long-term (annual) concentrations are provided on pages 155 and 156. The highest 1-hour impact (2.35 ppb) is 100 times lower than the short-term (acute) health-based guideline listed in Table B below and the highest annual impact (0.140 ppb) is five times lower than the chronic health-based guideline listed in Table B below.

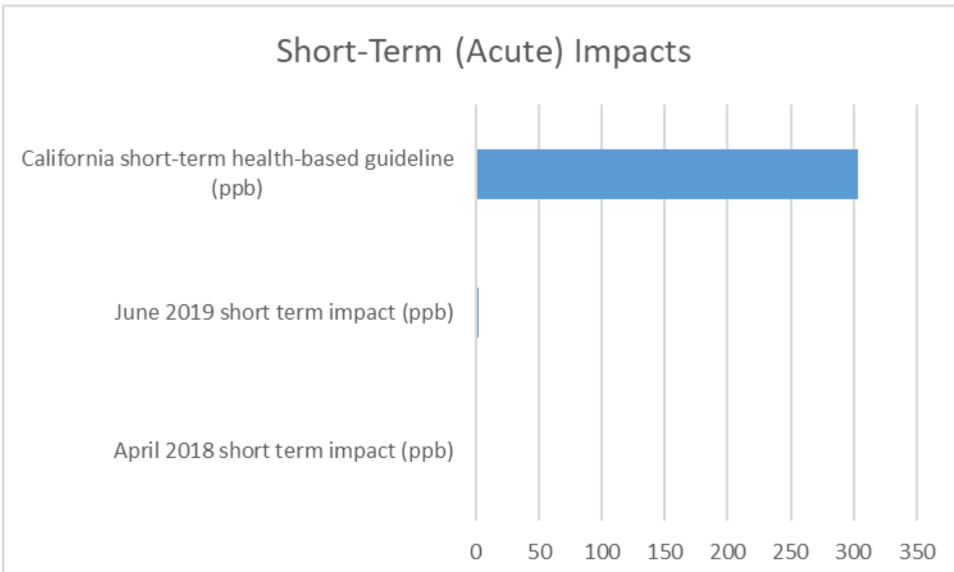
Table A – June 2019 HCN Modeling Results

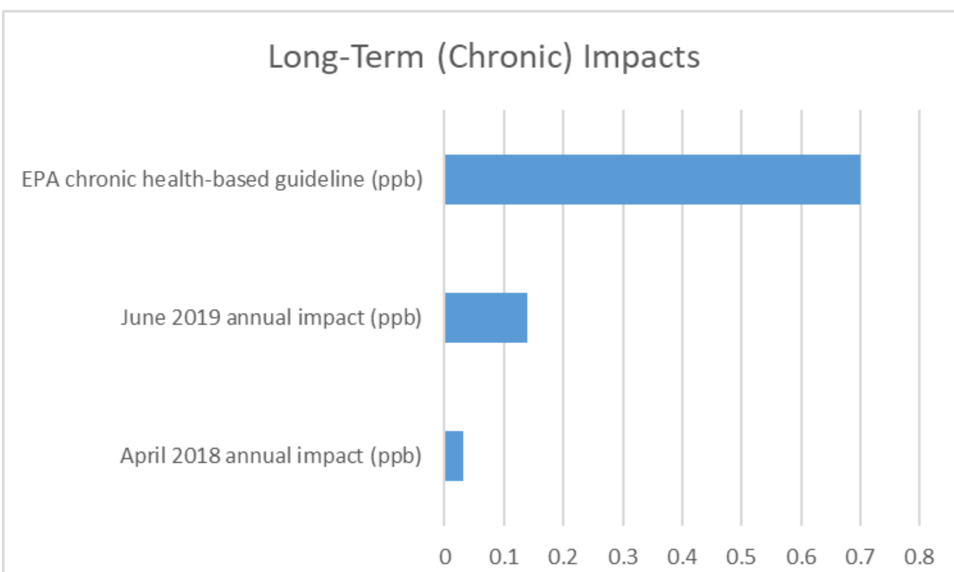
Met Data	Maximum Impact (ppb)	
	1-Hour (Acute)	Annual (Chronic)
Asarco 1993	2.22	0.140
Asarco 1994	2.35	0.130
Asarco 1998	2.18	0.126
Asarco 1999	2.09	0.122
Asarco 2000	2.15	0.110
5-Year Average	2.20	0.126

Table B – HCN Health-Based Guidelines		
Source	Guideline	Guideline Type
California Office of Environmental Health Hazard Assessment (OEHHA)[1]	303 ppb (340 µg/m^3)	Acute
EPA's Integrated Risk Information System (IRIS) Inhalation RfC[2]	0.7 ppb (8 x 10^{-4} mg/m^3)	Chronic

[1] https://oehha.ca.gov/chemicals/hydrogen-cyanide
[2] https://cfpub.epa.gov/ncea/iris/iris_documents/documents/toxreviews/0060tr.pdf (see page 83)

The following charts depict a comparison of the results from both the April 2018 and June 2019 modeling results to the relevant health-based guidelines.





1.27 December 20, 2016 Modification (administrative amendment) – Responsible Official's Designated Representative

The purpose of this modification was to change the Responsible Official's Designated Representative. The current Title V permit (last revised June 15, 2009) does not include a Responsible Official's Designated Representative on the page following the cover page, but the Division considers that making this revision would qualify as an administrative amendment. In their May 11, 2020 comments on the draft permit, the source requested that the Responsible Official's Designated Representative be revised.

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

<u>Page Following Cover Page</u>

- The "responsible official's authorized representative" was added to be consistent with the permit for Plants 1 and 3.

1.28 February 10, 2017 Modification (minor modification) – Miscellaneous Process Vent (MPV) Project

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 RSR 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.

Also addressed in this application is a change in emission factors for the Plant 2 flare. AP-42 emissions factors for flares (Section 13.5) were revised April 2015 and the VOC emission factor was revised again on December 2016. Per the January 4, 2010 modification, NO_x, CO and VOC emissions are estimated using the AP-42, Section 13.5 emissions factors. While the emission factor change has been included in this application, this change is separate from the MPV modification but appears to have been addressed with this modification as a matter of convenience.

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 2 flare and the increased throughput and emissions to the flare 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 for 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.

The application notes that Plant 2 has a number of process vessels and pumps that are from which water is drained on a routine basis, i.e. water draws, which currently result in venting of process gases. These vents, while episodic, occur under normal operations and cannot be classified as maintenance vents. Therefore, the application notes that these ten (10) water draws, are classified as Group 1 MPVs.

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.

Note that a separate application was filed for the Plants 1 and 3 equipment which is addressed in a separate Title V permit (96OPAD120), although emission increases from both permits are aggregated together for applicability purposes.

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 F 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 Plants 1 and 3 equipment (identified in a separate Title V permit (96OPAD120)), are below the significant level. The results of the applicability test are indicated in the table below:

Emission Unit	Increase in Actual Emissions				
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
P1/3 Fugitive VOCs from New Components[1]					3.71
P2 Fugitive VOCs from New Components[1]					2.55
Plant 1 Flare[2]	0	1.68	0.03	0.16	0.35
Plant 2 Flare[2, 3]	0.02	13.62	0.14	0.65	0.73
Plant 3 Flare[2]	0.07	16.85	0.66	3.01	6.40
Gasoline Benzene Reduction (GBR) Flare[2]	0.17	0.02	1.57	6.03	14.31
P1/3 Boilers[2]	0.02	0.07	0.31	0.14	0.01
P2 Boilers[2]	0.04	0.04	0.11	0.15	0.02
Total	**0.32**	**32.28**	**2.82**	**10.14**	**28.08**
PSD/NANSR Significance Level (T5 Minor Mod Level)[4]	25/15/10	40	40	100	40

[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. For the flares the applicability test is shown in Table 1 below (see page 85).

[3]For the P2 flare, due to the requested decrease in the throughput limit, the applicability test indicated emission reductions for all pollutants except SO_2. Therefore, the increase in emissions for all pollutants except SO_2 is based on emissions estimated for the project itself (see the table on page 84). SO_2 emissions are based on the applicability test shown in Table 2 below (see page 86).

[4]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

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

Although not necessarily part of the project, the source has requested to update the flare emission factors since the AP-42 emission factors (Section 13.5) were revised (the January 4, 2010 modification application relied on those factors for NO_X, CO and VOC), initially in April 2015 and the VOC emission factor was revised again in December 2016. For the Plant 2 flare, the source has requested to use the AP-42 emission factor for CO, which is lower than the previous emission factor. For VOC, the source has opted to use an emission factor based on the composition of the gases routed to the flare and relying on a flare destruction and removal efficiency (DRE) of 98%. The material balance emission factor is lower than AP-42 and in order to reduce permitted emissions to allow this project to move forward as a T5 minor modification, the source has requested that the throughput limit requested in the January 4, 2010 modification be reduced.

Note that typically the Division does not allow the use of a flare DRE or control efficiency above 95% for flares without requiring a performance test. However, in this case, the Plant 2 flare will be required to comply with additional monitoring requirements set forth in MACT CC by January 30, 2019. The purpose of the additional flare monitoring is to ensure flares achieve a 98% DRE as noted in 79 FR 36942 (June 30, 2014) so the Division considers it is acceptable to allow a 98% DRE.

Since the update in the Plant 2 flare emission factors is not related to the MPV mod the Division is viewing the February 10, 2017 project as two separate projects for purposes of Title V permitting. The change in permitted emissions from each project are below the significance level as shown in the table below and thus individually the two projects qualify as Title V minor modifications.

Flare Emission Factor Change

	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Requested[1]	1.6	4.6	14.5	66.3	74.2
Current Permitted[2]	1.9	4.6	17.4	94.7	35.9
Change in Emissions	-0.3	0	-2.9	-28.4	38.3
Total	-0.3	0	-2.9	-28.4	38.3
PSD/NANSR Significance Level (T5 Minor Mod Level)[3]	25/15/10	40	40	100	40

[1]assume SO_2 emission increase is based only on the change in throughput requested for the emission factor change.

[2]Based on January 4, 2010 Requested Emissions (adjusted to consider 365 day year and I lbmole = 385.3 scf)

[3]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

MPV Mod

	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Requested[1]	1.6	18.2	14.7	67.0	75.0
Current Permitted[2]	1.6	4.6	14.5	66.3	74.2
Change in Emissions	0	13.6	0.2	0.7	0.8
New Fugitive Components					2.5
Total	0	13.6	0.2	0.7	3.3
PSD/NANSR Significance Level (T5 Minor Mod Level)[3]	25/15/10	40	40	100	40

[1]Assume the SO_2 emission increase is an outcome of the MPV mod and not the emission factor change.

[2]Based on requested due to emission factor change (see above table, includes lower throughput limit)

[3]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

<u>Modeling Requirements</u>

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:

Pollutant	Modeling Threshold		Change in Permitted Emissions (tons/yr)[1]			
	Annual	Short-Term	P3 Flare	GBR Flare	P2 Flare	Total
SO_2	40 tons/yr	0.46 lbs/hr	16.76	0	13.6	30.36
NO_2	40 tons/yr	0.46 lbs/hr	0.33	0	-2.7	-2.37
CO	100 tons/yr	23 lbs/hr	1.43	-2.1	-27.7	-28.37
PM_{10}	15 tons/yr	82 lbs/day	0.03	0	-0.3	-0.27
$PM_{2.5}$	5 tons/yr	11 lbs/day	0.03	0	-0.3	-0.27

[1]Change 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 (begins on page 153) specifies that for minor sources with requested emissions below 40 tons/yr of NO_X and SO_2, that a compliance demonstration is not required for the short-term (hourly) SO_2 and NO_2 national ambient air quality standard (NAAQS). Therefore a modeling analysis was not conducted for the 1-hr SO_2 and NO_2 NAAQS. With respect to the short-term CO, PM_{10} and $PM_{2.5}$ NAAQS, it is not expected that the short-term increases in CO, PM_{10} and $PM_{2.5}$ 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, PM_{10} and $PM_{2.5}$ NAAQS.

<u>Discussion</u>

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:

Component Type	No. of Components		Service	Emission Factor (lb/component/hr)	Control Efficiency[1]	Emission Factor Source	Emissions (lbs/yr)	
	P1/3	P2					P1/3	P2
Valves	86	91	Light liquid	0.02403	95%	"Protocol for Equipment Leak Emission Estimates", EPA-453/R-95-017, November 1995, Table 2-2 (emission factors) and Tables 5-1 and 5-3 (control efficiencies)	905	958
	278	164	gaseous	0.05908	96%		5,755	3,395
Flanges/ Connectors	647	509	Any	0.00055	81%		593	467
Sampling Systems			Any	0.03307	N/A			
Pumps		1	Light liquid	0.25133	88%			264
Relief Valves	1		gaseous	0.35274	N/A		154	
Total (lbs/yr)							7,407	5,084
Total (tons/yr)							3.70	2.54

[1] Control 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 fare (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_2 emissions for the P2 flare during the baseline period exceeded the emission limitation requested in a minor modification application submitted on January 4, 2010, so BAE was adjusted downward to reflect the emission limitation for SO_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_{10}, $PM_{2.5}$, NO_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_2 emissions from the Plant 1 flare, projected PAE is based on the highest monthly SO_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 flares (i.e. project emissions) are shown in the table below:

Unit	Throughput (MBtu/yr)	Emissions (tons/yr)				
		CO	NO_X	VOC	PM/PM_{10}/ $PM_{2.5}$	SO_2
P1 Flare	1,075,998	0.17	0.04	0.36	4.01E-03	1.68
P3 (AU) Flare	84,578	0.01	2.88E-03	0.03	3.15E-04	0.06
GBR Flare	343,636	0.05	0.01	0.11	1.28E-03	2.54E-06
P2 Flare	4,189,367	0.65	0.14	0.73	0.02	0.02

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_{10}, $PM_{2.5}$, NO_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_{10}, $PM_{2.5}$, NO_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_2 emissions that could have been accommodated based on the highest monthly SO_2 emissions during the baseline period, annualized. The highest monthly SO_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_2 concentration (gases combusted were natural gas). Therefore, the source estimated SO_2 emissions that could have been accommodated based on the highest monthly SO_2 emissions divided by 31 and multiplied by 365.

BAE for the P2 flare exceeded the SO_2 emission limit, therefore, BAE was adjusted down to reflect permitted SO_2 emissions. Capable of accommodating emissions were estimated to be equal to baseline emissions (i.e. permitted SO_2 emissions from the P2 flare).

The resulting emissions increases for the flares, based on the applicability test (PAE minus BAE) are shown in tables below.

Table 1: Actual Emission Increases (MPV Project)					
	Emissions (tons/yr)				
	CO	NO_X	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2
P1 Flare					
Baseline	39.12	8.58	83.29	0.94	36.42
PAE	96.52	21.17	205.50	2.32	167.52

Table 1: Actual Emission Increases (MPV Project)					
	Emissions (tons/yr)				
	CO	NO_X	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2
Capable of Accommodating	96.36	21.14	205.15	2.32	165.84
Excludable[1]	57.24	12.56	121.86	1.38	129.42
Adjusted PAE[2]	39.28	8.61	83.64	0.94	38.10
Change in Emissions[3]	**0.16**	**0.03**	**0.35**	**4.00E-03**	**1.68**
P3 (AU) Flare					
Baseline	2.42	0.53	5.16	5.82E-02	1.20E-02
PAE	5.43	1.19	11.56	0.13	16.86
Capable of Accommodating	2.42	0.53	5.16	5.83E-02	1.20E-02
Excludable[1]	0.00E+00	0.00E+00	0.00E+00	1.00E-04	0.00E+00
Adjusted PAE[2]	5.43	1.19	11.56	0.13	16.86
Change in Emissions[3]	**3.01**	**0.66**	**6.40**	**7.17E-02**	**16.85**
GBR Flare					
Baseline	5.06	1.28	11.61	0.14	1.18E-02
PAE	11.09	2.85	25.92	0.31	0.21
Capable of Accommodating	3.55	0.91	8.29	0.10	0.19
Excludable[1, 4]	0.00	0.00	0.00	0.00	0.18
Adjusted PAE[2]	11.09	2.85	25.92	0.31	0.03
Change in Emissions[3]	**6.03**	**1.57**	**14.31**	**0.17**	**0.02**
P2 Flare					
Project Emissions[5, 6]	**0.00**	**0.00**	**0.00**	**0.00**	**13.62**

[1]Excludable emissions equals capable of accommodating minus baseline emissions.
[2]Adjusted PAE equals PAE minus excludable emissions.
[3]Change in emissions is adjusted PAE minus baseline.
[4]If capable of accommodating emissions are less than or equal to baseline emissions, excludable emissions are zero.
[5]As indicated in Table 2 below, the change in CO, PM, PM_{10}, $PM_{2.5}$, NO_X and VOC emissions for the P2 flare are all negative due to the request to reduce the throughput limit for the flare. In part 1 of the PSD/NANSR applicability analysis (assess project emissions), only increases are included. So if the applicability test (i.e. PAE minus BAE) were negative the emissions increase would be zero for part 1 of the analysis. In order to appropriately assess project emissions, the increase from the P2 flare is the emissions estimated for the project alone (see table on page 84). In accordance with Regulation No. 3, Part D, Section II.A.38.b.(iii), emissions related to the project cannot be excluded.
[6]SO_2 emissions are based on the applicability test shown in Table 2 below.

Table 2: Plant 2 Change in Actual Emissions (MPV Modification)					
	P2 Flare Emissions (tons/yr)				
	CO	NO_X	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2
Baseline	50.52	11.08	56.55	1.22	4.59
PAE	66.97	14.69	74.97	1.61	18.21
Capable of Accommodating	75.71	16.61	84.75	1.82	4.59
Excludable[1,]	25.19	5.53	28.20	0.60	0.00
Adjusted PAE[2]	41.78	9.16	46.77	1.01	18.21
Change in Emissions[2,]	**-8.74**	**-1.92**	**-9.78**	**-0.21**	**13.62**

[1]Excludable emissions equals capable of accommodating minus baseline emissions.
[2]Adjusted PAE equals PAE minus excludable emissions.

[3]Change in emissions is adjusted PAE minus baseline.

Plant 2 Flare Emission Factor Change

The Plant 2 flare commenced operation in 1989 and since the refinery is a major stationary source, permitted emissions above the significance level for such an emissions unit could mean either that the emission unit went through major stationary source permitting (i.e., PSD and/or NANSR) or that the net emissions increase was below the significance level (i.e. the source netted out). The construction permit (88AD134) issued for the flare initially included emissions of pollutants above the significance level, however, with the January 4, 2010 minor modification emissions from all criteria pollutants were below the significance level, thus there were no longer any apparent PSD/NANSR issues.

As discussed previously, included with the MPV modification, the source requested changes to permitted emissions based on revised emission factors, since the AP-42 Section 13.5 emission factors were revised in April 2015 and again in December 2016. The change in an emission factor, by itself, is not considered a physical change or change in the method of operation. Changes in published emission factors generally represent a better estimate of emissions from a piece of equipment and the “new” emission factor represents what emissions have always been for the emission unit. Requested VOC emissions in the MPV modification, due to the revised emission factors alone (not including the increased flow to the flare due to MPVs) are above the significance level, thus indicating a potential PSD/NANSR issue for the P2 flare. As discussed above, permitting the flare in 1989 with VOC emissions above the significance level would have meant that the flare would be subject to PSD and/or NANSR permitting requirements or would have had to net out.

As noted previously, the initial construction permit (88AD134) for the flare included emission limits above the significance level for a number of pollutants. A review of information in the file indicates that the Division considered the flare a replacement, even though the permit allowed the previous flare to be used as a back-up when the new flare wasn’t operating. The preliminary analysis for the initial construction permit (88AD134, issued July 5, 1988) indicated that the net emission change would be zero because it is replacing an existing flare and emission factors are based on refinery feed (bbls). It appears that “project netting” may have been relied upon in the issuance of the initial permit, i.e., reductions from the project were considered in determining the emissions increase associated with the project.

If “project netting” was relied upon for the initial construction permit, it was not appropriate for the PSD/NANSR rules in place at the time of initial permitting (1988). The appropriate analysis would be to consider the flare to be a “new” emission unit and in order to “net out” all increases and decreases over the contemporaneous period would be considered to determine if the net emissions increase was significant.

A brief file review was conducted to determine whether any new equipment was installed during the contemporaneous period, which was five years prior to startup

(1984 – 1989). The only pollutant of concern is VOC, since requested emissions are above the significance level, only VOC emission increases associated with any new equipment were considered. Based on the initial approval permits for the new equipment permitted during the contemporaneous period, the total VOC emissions are below the significance level, which indicates that the net significant emissions increase from the flare, at the time it was initially permitted, would likely have been below the significance level and thus PSD/NANSR requirements would not have applied. Note that the Division did not review any potential decreases from equipment other than the flare, nor were actual emissions from the "old" flare assessed, as this information was not readily available. Therefore, the Division considers that the requested VOC emissions above the significance level don't present a PSD/NANSR issue.

Note that EPA's PSD reform rules (published in Federal Register on December 31, 2002, approved in Colorado's SIP in 2012), include provisions for replacement units to be treated as existing units, which generally alleviates the need to conduct a netting analysis for replacement of identical or functionally equivalent emission units, although the units to be replaced must be permanently removed from the facility or barred from operation. Thus under current rules, the replacement of the P2 flare would most likely not have triggered a netting analysis and although the 1988 initial approval construction permit allowed the old unit to be used as a back-up, those provisions were removed from the construction permit in the January 5, 1998 revision.

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. Regulation No. 3 requires that this information (i.e., the actual-to-projected-actual applicability test) be included in an appendix, presumably so that the Division can determine whether projected emissions predicted by the project are exceeded and pursue an investigation, if necessary, to determine if the increases above the projected level were caused by the project.

For the asphalt unit (P3) flare, the GBR unit flare (both addressed in 96OPAD120) and the plant 2 flare, 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. Although the P1 flare is not included in this permit (95OPAD108), the Division has included the applicability analysis in order to be consistent with how the MPV mod was addressed in the Plants 1/3 permit (96OPAD120). Note that the applicability analysis includes equipment from both operating permits associated with this facility 96OPAD120 (Plants 1/3) and 95OPAD108 (Plant 2).

Revisions to Permit

The following changes were made to the permit based on this modification:

Section I – General Activities and Summary

- Added miscellaneous process vents and components associated with the MPV project (F038) to the table in Condition 5.1.

Section II.8 – Refinery Flare

- Revised the NO_X, CO, VOC and SO_2 emission limits in Condition 8.1 and the CO and VOC emission factors. In addition, Condition 8.1 was revised to add PM and PM_{10} emission limits and emission factors.
- Revised the limit on gases combusted (previous limit requested with the January 4, 2010 modification (see Section III.1.5 of this document)) in "new" Condition 8.6. (In the current permit (last revised June 15, 2009) Condition 8.8 includes requirements for determining the heat input to flare and Condition 8.6 includes NSPS GGG requirements.)
- Added a "new" condition (8.11) 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).

Section II.18 – Fugitive VOC Equipment Leak Emissions with Permitted Limits

- Added emissions limits and requirements for equipment leaks associated with the MPV project (F038).

"New" Section II.37 – NSPS GGGa

Note that in the current permit (last revised June 15, 2009), section II.37 contains the flare requirements.

- Included the MPV project fugitives (F038) to the list of sources subject to these requirements. In addition, the application indicated that NSPS GGGa was triggered for components associated with the P2 flare, so the P2 flare components (F018) were added to the list of sources subject to those requirements.

Section II.32 – MACT CC

These requirements were moved to "new" Section II.40, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.40 includes language related to maximum achievable control technology.

The revisions to MACT CC, which include the requirements for MPVs, were incorporated with other additional information submittals in September 2016. The discussion of the MACT CC requirements that were included can be found in Section II.1.25 of this document.

- Noted that equipment leaks associated with the MPV project (F038) and the P2 flare (F018) 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).

"New" Section II.47 – Miscellaneous Process Vents

- Added requirements for miscellaneous process vents.

Appendices B and C

- Added miscellaneous process vents and components associated with the MPV project to the tables.

"New" Appendix H

Note that in the current permit (last revised June 15, 2009), Appendix H includes the SO_2 emissions calculation methodology.

- Included the applicability analysis for the MPV project.

1.29 July 10, 2017 Modification (minor modification) – Upgrade P2 flare to comply with MACT CC

The purpose of this modification is upgrade the P2 flare in order to comply with the flare requirements in the December 1, 2015 RSR 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 to MACT CC included requirements for flares used as control devices for emission points addressed in MACT CC.

The new flare requirements in MACT CC are essentially an enhancement of the requirements in 40 CFR Part 63 Subpart A § 63.11(b) (operate with a flame present at all times, no visible emissions and exit velocity and flare gas Btu content requirements) by requiring monitoring to ensure the flares are properly operated to achieve the 98 percent reduction efficiency that was expected for flares used to comply with MACT CC requirements.

The December 1, 2015 MACT CC flare revisions primarily require additional monitoring requirements, thus there is no expectation that additional waste gases will be combusted by flares or that the operation of any of the refinery process units will be changed as a result of this project. However, under the MACT CC requirements, sources are required to maintain the net heating value of the flare combustion zone gas at or above 270 Btu/scf, determined on a 15-minute block period, when regulated material is routed to the flare for at least 15 minutes. While refinery flares were previously subject to requirements in either 40 CFR Part 60 Subpart A § 60.18 or 40 CFR Part 63 Subpart A § 63.11(b), which required that they to be used only when the net heating value of gases combusted were at or above 300 Btu/scf (for steam- or air-assisted flares), §§ 60.18 and 63.11(b) did not specify any ongoing monitoring for this requirement. Since MACT CC requires continuous monitoring of the heat content of gases in the flare combustion zone, Suncor anticipates that supplemental gas will be necessary to ensure that the flare can comply with the combustion zone gas heat content requirements, which will result in an increase in flare emissions. As part of the project, new piping components (i.e. flanges, valves, etc.) will be installed and result in a slight emissions increase.

In reviewing this application, the Division requested clarification, corrections or additional information regarding the information submitted. Responses to these information requests were submitted on December 15, 2017 and April 13, 2018. Revised spreadsheets were submitted on April 13, 2018.

<u>Modification Type</u>

The source indicated that this modification qualifies 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 F 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 are below the significant level. The results of the applicability test are indicated in the table below:

Emission Unit	Increase in Actual Emissions				
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Fugitive VOCs from New Components[1]					0.16
P2 Flare[2]	0.23	15.58	2.08	9.46	10.50
Total	**0.23**	**15.58**	**2.08**	**9.46**	**10.66**
PSD/NANSR Significance Level (T5 Minor Mod Level)[3]	25/15/10	40	40	100	40

[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. For the P2 flare, because the throughput limit in effect during the baseline period is higher than the current throughput limit (current throughput is per the MPV mod (submitted February 10, 2017)), the applicability test indicates emission increases for all pollutants except SO_2 are less than emissions estimated for the project itself (see table 3 on page 95). Therefore, the increase in emissions for all pollutants except SO_2 is based on emissions estimated for the project itself (see table 3 on page 95). SO_2 emissions are based on the applicability test shown in Table 4 below (see page 96).

[3]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

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

Change in Permitted Emissions

	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Requested - Flare	1.84	18.3	16.8	76.4	84.8
Current Permitted - Flare[1]	1.6	18.2	14.7	67.0	74.3
Change in Emissions	0.24	0.1	2.1	9.4	10.5
New Piping Components					0.16
Total	**0.24**	**0.1**	**2.1**	**9.4**	**10.66**
PSD/NANSR Significance Level (T5 Minor Mod Level)[2]	25/15/10	40	40	100	40

[1]Based on requested emissions on APEN submitted April 26, 2017 (to support the February 10, 2017 MPV modification), except that VOC emissions have been adjusted to reflect the corrected VOC emission factor (0.344 lb/MMBtu vs. 0.347 lb/MMBtu (see discussion under P2 flare - BAE)).

[2]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

This application was submitted under the presumption that the various projects to bring the flares at this facility into compliance with the flare requirements in MACT CC are separate projects and should not be aggregated for purposes of determining whether major stationary source permitting requirements apply. After further review, as discussed below (beginning on page 96), the Division agreed that the various flare projects are separate. Note that as discussed in the P2 RSR application, the flares potentially subject to the MACT CC requirements are the Plant 1 main flare, P2 main flare, Plant 3 flare, GBR flare and the Plant 1 rail rack flare. Not mentioned in the application is the Plant 2 rail rack flare which is also potentially subject to the MACT CC requirements.

<u>Modeling Requirements</u>

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.

There is an increase in permitted VOC emissions from the flare 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. The magnitude of the emission increase (VOC – 10.66 ton/yr and NO_X – 2.08 ton/yr) is not at a level for which individual source ozone modeling would be required.

For the other pollutant emissions, the increase in permitted emissions are summarized below:

Pollutant	Modeling Threshold[1]		Change in Permitted Emissions[2]	
	Annual	Short-Term	Annual (ton/yr)	Short term[3]
SO_2	40 tons/yr	0.46 lbs/hr	0.1	0.02 lb/hr
NO_2	40 tons/yr	0.46 lbs/hr	2.1	0.47 lb/hr
CO	100 tons/yr	23 lbs/hr	9.4	2.16 lb/hr
PM_{10}	15 tons/yr	82 lbs/day	0.24	1.26 lb/day
$PM_{2.5}$	5 tons/yr	11 lbs/day	0.24	1.26 lb/day

[1]Note that the Division's May 2018 draft Modeling Guidelines (page 22), indicate no annual threshold for PM_{10} and CO.
[2]Change in permitted emissions from table on page 92.
[3]The increase in emissions is based on supplemental fuel, not additional anticipated flaring, thus emissions are presumed to be relatively consistent, so short term emissions are based on annual emissions divided by either 8760 hours per year or 365 days per year.

Note that the increase in annual emissions for all pollutants and the increase in short-term emissions for all emissions, except NO_2, is below the modeling thresholds, thus modeling is not warranted with respect to those pollutants. The Division's Stationary Sources Program PS Memo 10-01 (begins on page 153) specifies that for minor sources with requested emissions below 40 tons/yr of NO_X and SO_2, that a compliance demonstration is not required for the short-term (hourly) SO_2 and NO_2 national ambient air quality standard (NAAQS). Therefore a modeling analysis was not conducted for the 1-hr NO_2 NAAQS.

Discussion

Except for new piping components, the unit affected by this modification, the P2 flare, is an existing emission unit. 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.

Component Type	No. of Components	Service	Emission Factor (lb/component/hr)	Control Efficiency[1]	Emission Factor Source	Emissions (lbs/yr)[2]
Valves	11	gaseous	0.05908	96%	"Protocol for Equipment Leak Emission Estimates", EPA-453/R-95-017, November 1995, Table 2-2 (emission factors) and Table 5-3 (control efficiencies)	228 [5,693]
Flanges/ Connectors	18	Any	0.00055	0%		87
Total (lbs/yr)						315 [5,780]
Total (tons/yr)						0.16 [2.89]

[1]Control efficiencies are from the following sources. **Valves** - Table 5-3 of EPA's Protocol for Equipment Leaks (EPA-453/R-95-017) based on monitoring consistent with proposed HON NESHAP. With this application, the Division reconsidered the control efficiency previously allowed for flanges and connectors. Although Colorado Reg 7 requires annual monitoring for flanges (per Section VIII.C.4.a.(i)(A)), the leak definition in Reg 7 (10,000 ppm) is higher than that in the HON NESHAP (500 ppm), thus the 81% control efficiency listed in Table 5-3 is not appropriate and no control efficiency was allowed for flanges. The Division would agree that some control may be appropriate for flanges due to annual monitoring, however, the source did not propose an alternative for this application. Note that NSPS

GGGa includes similar monitoring for flanges/connectors as the HON NESHAP, however, these requirements have been stayed.
[2]Emissions in "[ ]" are uncontrolled. Note that the control efficiency, and subsequently controlled emissions are based on required monitoring.

Plant 2 flare - BAE

For the P2 flare, 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. Rather than adjust VOC emissions to reflect the revised AP-42 emission factor, the source used an emission factor 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 flare 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_2 emissions for the P2 flare during the baseline period exceeded the emission limitation requested in a minor modification application submitted on January 4, 2010, so BAE was adjusted downward to reflect the emission limitation for SO_2.

BAE for this modification is from the same time period (January 1, 2013 through December 31, 2014) as the MPV modification (application submitted February 10, 2017) and thus it would be expected that BAE should be the same but this is not the case for the following reasons.

The VOC emission factor used in the MPV modification was based on a material balance, assuming a DRE of 98%. During the process of reviewing the various flare RSR applications, the Division discovered an error in the method used to determine the VOC emission factor, which resulted in a slightly lower VOC emission factor (0.344 lb/MMBtu vs 0.347 lb/MMBtu). This emission factor was used to estimate BAE, as well as PAE.

In the July 10, 2017 application, capable of accommodating (COA) emissions did not match the information in the MPV modification, specifically SO_2 COA emissions were incorrectly noted to be 18.21 tons/yr (the SO_2 emission limit during the baseline period was 4.59 tons/yr) and COA emissions of other pollutants were calculated differently. The Division directed the source to estimate COA emissions of pollutants, other than SO_2, as they did in the MPV mod application. Thus the COA emissions for all pollutants except VOC and SO_2 were consistent with the COA in the MPV mod application. The

COA emissions for VOC were slightly lower based on the change in the VOC emission factor as discussed above. The COA emissions for SO_2 was also lower for the reasons discussed below.

In addition, in the MPV modification, the source adjusted BAE downward for SO_2 by considering the two year average actual emissions (i.e. BAE) equal to the annual SO_2 emission limit (4.59 tons/yr). However, in another RSR flare application, the source adjusted BAE downward to ensure that the 12 month rolling totals were below the annual emission limit. This resulted in adjusting emissions downward for specific months and resulted in the two year average actual emissions (i.e. BAE) that were below the annual emission limits. The Division directed the source to do the same thing for SO_2 emissions from the Plant 2 flare and the source submitted revised calculations to that effect on April 13, 2018.

Plant 2 Flare - (PAE)

The source projected that actual emissions (PAE) for the Plant 2 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 supplemental gas (and subsequent emissions) needed to meet the combustion zone heat content requirements.

The estimated emissions and flow due to the additional supplemental fuel necessary to meet the heat content requirements for flares in MACT CC are as follows:

Table 3 – Throughput and Emissions from Increased Supplemental Fuel (P2 Flare RSR Project)

Unit	Throughput (MBtu/yr)	Emissions (tons/yr)				
		CO	NO_X	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2[1]
P2 Flare	61,046,255	9.46	2.08	10.5	0.23	0.05

[1]SO_2 emissions are based on a throughput level of 66.35 MMscf, based on a natural gas heat content of 920 Btu/scf.

Plant 2 Flare – 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 P2 flare, the source estimated PM, PM_{10}, $PM_{2.5}$, NO_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 throughput used was based on November 2014.

In the April 13, 2018 revised calculations, the source indicated that SO_2 COA emissions were 4.59 tons/yr, the permitted emission limit for SO_2. As indicated in the above discussion regarding the Plant 2 flare BAE, the SO_2 emission limit was exceeded during the baseline period. Also as discussed above under the Plant 2 flare BAE, the downward adjustment was done differently for this modification than the MPV mod application, so adjusted BAE was below the permit limit for SO_2.

Presumably the source determined the SO_2 COA emissions by multiplying the highest monthly SO_2 emissions by 12 and then adjusting this number downward to comply with the emission limit at the time. In order to determine COA emissions based on a maximum monthly emission rate, the monthly emissions would have to be consistently achievable for the annual period, i.e., the annualized emissions could not have exceeded any emission limitation that applied during the baseline period. Thus the source's method in this case was not appropriate, so SO_2 COA emissions are presumed to equal BAE.

The resulting emission increases for the P2 flare, based on the applicability test are shown in the table below:

Table 4 – Plant 2 Flare - Change in Actual Emissions (P2 Flare RSR Project)					
	P2 Flare Emissions (tons/yr)				
	CO	NO_X	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2
Baseline	50.52	11.08	56.06	1.22	2.68
PAE	76.43	16.77	84.82	1.84	18.26
Capable of Accommodating	75.71	16.61	84.02	1.82	2.68
Excludable[1,]	25.19	5.53	27.96	0.60	0.00
Adjusted PAE[2]	51.24	11.24	56.86	1.24	18.26
Change in Emissions[2,]	**0.72**	**0.16**	**1.8**	**0.02**	**15.58**
PSD/NANSR Significance Level (T5 Minor Mod Level)[4]	100	40	40	25/15/10	40

[1]Excludable emissions equals capable of accommodating minus baseline emissions.

[2]Adjusted PAE equals PAE minus excludable emissions.

[3]Change in emissions is adjusted PAE minus baseline.

[4]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

Flare RSR Application Concerns

The July 10, 2017 application for the P2 flare RSR project indicated that Suncor initiated a single capital project to complete the necessary upgrades to the Plant 1, Plant 2, Plant 3, GBR and potentially the Plant 1 Oil Movements Division (OMD) loading dock flare (i.e., the P1 rail rack flare). Given that the applications for the projects would be submitted within a short time frame, the projects are funded as a single project and the overall plan involves upgrading all plant flares to meet the RSR requirements, the Division considered whether sufficient information was provided to justify that the various flare RSR projects are in fact separate projects.

The Plant 2 application included a justification for considering the various flare RSR projects separate, as well as justification to consider the MPV project and the various flare RSR projects separate. Suncor submitted an application for the P3 flare (to be addressed in a separate Title V permit (96OPAD120) for Plants 1 and 3) on September

12, 2017 and in general the justification for considering the various flare RSR projects separate was nearly identical to the Plant 2 flare application, except for an explanation of why an irrelevant document was included in Appendix D of the application (see footnote 12 on page 4-6) and to indicate on page 4-7 that “the flares are designed and operated to receive vent gases from specific, separate refinery process units and there is no overlap in the independent operation of these systems that would drive Suncor to complete upgrades to an additional flare (to serve, for example, solely as a compliant “backup” for another flare).”

While the applications note and the Division agrees that the flares are independent and that upgrades to one flare do not depend either technically or economically on upgrades to another flare, the Division still had concerns regarding treating the flares as separate projects. The Division sent an email expressing our concerns and Suncor responded with a memo on February 14, 2018 providing further justification for considering the flare RSR projects as separate projects.

Applications were submitted for the P1 and GBR flares on February 6 and March 6, 2018, respectively. These applications included a more robust discussion regarding why the flare RSR projects should be considered separately. In addition, unlike the P2 and P3 flare applications, the more recent applications indicated that the flare RSR projects were funded by three capital projects: one project to address the Plant 2 and Plant 3 flares, one project to address the Plant 1 and GBR flares and a third to address the Plant 1 OMD rack (Plant 1 rail rack) flare. Since the information in these applications was contrary to the information in previous applications, as well as the February 14, 2018 memo justifying the flare RSR projects as separate, which also indicated funding was via a single capital project, the Division sought an explanation from the source for this discrepancy.

The source submitted information on June 12, July 6 and July 9, 2018 to address the Division’s concerns regarding the discrepancy in the funding information from the flare RSR applications submitted in 2017 (Plants 2 and 3) versus the applications submitted in 2018 (Plant 1 and GBR). Based on that information, it was evident that the flare projects had been funded under separate capital projects prior to submittal of the 2017 applications, nevertheless, the source included incorrect information in those applications.

The Division expressed some remaining concerns that more than one flare may receive waste streams from a specific refinery process unit, which appear to be contrary to the claims in the Plant 3 RSR flare application which indicated that each flare receives vent gases from specific, separate process units (see discussion on page 97). In response to these concerns, the source submitted a memo on August 3, 2018 providing further justification that the flare RSR projects should be considered separate projects. It should be noted that the date on the memo submitted on August 3, 2018, is February 13, 2018, the same date as the memo submitted on February 14, 2018. This appears to be an error on the part of the memo’s author, as the August 3, 2018 memo is clearly different.

Based on the February 14, 2018 memo submitted by the source, the information in the 2018 flare RSR applications, the source’s responses to the Division’s inquiries regarding project funding, and the August 3, 2018 memo, the Division agrees that the flare RSR projects (Plant 2, Plant 3, Plant 1, GBR and Plant 1 OMD rack (Plant 1 rail rack)) are separate projects. The Division sent an email on August 17, 2018 to the source indicating that we agreed that the flare RSR projects were separate. The various flare RSR projects are independent and do not rely either technically or economically on the other flare projects to be viable. The flare RSR projects are not expected to increase the production at the refinery, nor is the refinery expected to receive any economic benefit from the projects. The flare RSR projects are related only in that the projects must be done in order to comply with the requirements in MACT CC.

The Plant 1 OMD loading rack (Plant 1 rail rack) application was submitted on June 14, 2018. The purpose of this application is to replace the flare with an enclosed combustor which would not be subject to the MACT CC flare requirements. This application included emission increases at the Plant 2 rail rack flare as project emissions since Suncor plans to move gasoline loading from the Plant 2 rail rack to the Plant 1 rail rack. The Division agrees that the project to cease loading gasoline at the Plant 2 rail rack (for which an application has yet to be submitted) and the Plant 1 rail rack should be aggregated, since the Plant 2 rail rack project relies upon the Plant 1 rail rack project.

The July 10, 2017 application indicates that the MPV project addressed a separate set of requirements from MACT CC which requires some previously exempt process vents to be controlled. MACT CC does not stipulate what type of control method must be used and routing these previously uncontrolled process vents to a flare did not trigger the new MACT CC flare requirements, as the flares were already controlling various process streams regulated by MACT CC. The Division accepted that the MPV and various flare RSR projects were in fact separate and did not ask for any additional justification.

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. Regulation No. 3 requires that this information (i.e., the actual-to-projected-actual applicability test) be included in an appendix, presumably so that the Division can determine whether projected emissions predicted by the project are exceeded and pursue an investigation, if necessary, to determine if the increases above the projected level were caused by the project.

For this application, projected actual emissions for the P2 flare are the same as requested (permitted) emissions, thus including this information in an appendix would not be necessary.

Revisions to Permit

The following changes were made to the permit based on this modification:

Section I – General Activities and Summary

- Added components associated with the P2 RSR flare project (F045) to the table in

Condition 5.1.

Section II.8 – Refinery Flare

- Revised the NO_X, CO, VOC and SO_2 emission limits in Condition 8.1 and the VOC emission factor.
- Removed Condition 8.10 (flare operating requirements – 60.18) as the draft permit will not be revised until after the MACT CC flare compliance date (January 30, 2019) and these requirements will no longer apply.
- The following changes were made to "new" Condition 8.6, limit on gases combusted: (Note that in the current permit (last revised June 15, 2009) Condition 8.8 includes requirements for determining the heat input to flare and Condition 8.6 includes NSPS GGG requirements.)
  - Revised the limit on gases combusted (previous limit requested with the February 10, 2017 MPV modification (see Section III.1.28 of this document))
  - Revised the language regarding how the flare heat input will be determined to reflect MACT CC requirements.

Section II.18 – Fugitive VOC Equipment Leak Emissions with Permitted Limits

- Added emissions limits and requirements for equipment leaks associated with the P2 flare RSR project (F045).

  Note that although an APEN was submitted for equipment leaks associated with the P2 flare RSR project (F045), draft permit language was not included in the application for this equipment. The Division is presuming that these components are subject to the requirements in NSPS GGGa and MACT CC, as well as the Reg 7, Section VIII.C requirements. The refinery flare fugitives (F018) are subject to the requirements of NSPS GGGa and MACT CC, thus the Division believes these sources are subject to these requirements also.

Section II.37 – Flare Requirements

These requirements were moved to "new" Section II.43, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009)

- Revised this section to indicate that the P2 main flare (C005) is no longer subject to these requirements.

"New" Section II.37 – NSPS GGGa

Note that in the current permit (last revised June 15, 2009), section II.37 contains the flare requirements.

- Included the P2 flare RSR project fugitives (F045) to the list of sources subject to these requirements.

Section II.32 – MACT CC

These requirements were moved to “new” Section II.40, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.40 includes language related to maximum achievable control technology.

The revisions to MACT CC, which include the requirements for flares, were incorporated with other additional information submittals in September 2016. The discussion of the MACT CC requirements that were included can be found in Section II.1.25 of this document.

- Noted that equipment leaks associated with the P2 flare RSR project (F045) 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).

Appendices B and C

- Added the components associated with the P2 flare RSR project (F045) to the tables.

1.30 July 31, 2017 Modification (minor modification) – Include Temp and O_2 indicator for sulfur recovery unit (SRU)

The purpose of this modification is to include the specific values for the temperature and oxygen (O_2) concentrations that are parameters monitored for the SRU in order to comply with requirements in 40 CFR Part 63 Subpart UUU.

The compliance date for the Subpart UUU requirements for the SRU on April 11, 2005 and the current permit (last revised June 15, 2009) does not include the Subpart UUU compliance method or identify the operating limit(s) that are monitored. The source also did not provide the Subpart UUU compliance method or the operating limit(s) and parameter values that are monitored for the SRU in their September 23, 2016 red-lined MACT UUU section.

It appears that the source conducted a performance test in June 2017 to set new operating limits (temperature and O_2 concentration), as the temperature sensor that was previously used did not meet the requirements in Table 41 of Subpart UUU (revisions to the table were made in the December 1, 2015 RSR revisions). Following the establishment of new operating limits (temperature and O_2 concentrations), the source submitted an application to include the SRU operating limits in the permit.

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

Section II.5 – Sulfur Recovery Plant

- Added the temperature and O_2 concentration values to Condition 5.4 (MACT UUU requirements).

1.31 December 4, 2017 Modification (minor modification) – Tank T26

The purpose of this modification is to increase the allowable RVP of materials stored in the tank, as well as decreasing the permitted throughput limit and increasing the emission limit.

The change in emissions from this project are as follows:

VOC Emissions (tons/yr)		
Requested Emissions	Current Permitted	Change in Emissions
6.83	4.58	2.25
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]		40

[1]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

The following revisions were made to the permit to address the changes to Tank T26:

Section II.15 – Group E Tanks

- Revised the VOC emission limit for Tank T26 in Condition 15.1 In addition, revised the language to indicate that TankESP be used to estimate emissions rather the EPA TANKS.
- Revised the allowable RVP level and throughput limit in Condition 15.10.

1.32 April 27, 2018 Information Submittal - Cancel APENs for Tanks T024, T040 and T041

On April 27, 2018, Suncor submitted APEN cancellation forms for tanks T024, T040 and T041 because these tanks have been permanently removed from service. Suncor also noted in the cover letter that these tanks should be removed from the facility's Title V permit. Although this submittal was not submitted to the Title V permit unit, nor was it submitted as a permit modification, this request is being addressed in the renewal permit.

The following revisions were made to the permit to address this request:

Section I – General Activities and Summary

- Removed construction permit number 00AD0183 from Condition 1.4.
- Removed tanks T024, T040, and T041 from the table in Condition 5.1

Section II.12 – Group B Tanks

- Removed references to Tanks T040 and T041 in this section

Section II.15 – Group E Tanks

- Removed the emission and throughput limits for Tank T024 in Conditions 15.1 and

15.10 and other references in this Section II.15.

Section II.32 – MACT CC

These requirements were moved to “new” Section II.40, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.40 includes language related to maximum achievable control technology.

- Removed tank T024 from the list of Group 1 tanks (above Condition 32.10).

Appendices B and C

- Removed tanks T024, T040, and T041 from the tables.

1.33 June 14, 2018 Modification (minor modification) – Revise Emission Limits and Calculation Methodology for Rail Rack Liquefied Petroleum Gas (LPG) Loading

The purpose of the June 14, 2018 application is to revise the emission limits and calculation methodology for LPG loading at the Plant 2 rail rack. The current Title V permit (last revised June 15, 2009) does not specifically indicate how emissions from LPG loading are to be estimated. In a November 1, 2016 email, the Division requested that Suncor indicate how emissions from LPG loading were estimated so that the methodology could be included in the permit. The June 14, 2018 application is Suncor’s response to that request.

In reviewing this application, the Division requested clarification, corrections or additional information on the information submitted. Responses to these information requests were submitted on August 3, 2018 and January 30, 2019. Revised spreadsheets were submitted on January 30, 2019.

Modification Type

The source indicated that this modification qualifies 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 F 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 are below the significant level. The results of the applicability test are indicated in the table below:

	Emissions (tons/yr)				
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Projected Actual Emissions[1]	1.26×10^{-1}	1.88×10^{-3}	1.10	5.00	37.80
Baseline Actual Emissions[2]	8.45×10^{-2}	1.23×10^{-3}	0.73	3.35	24.55
Change in Emissions	4.15×10^{-2}	6.5×10^{-4}	0.37	1.65	13.25
PSD/NANSR Significance Level (T5 Minor Mod Level)[3]	25/15/10	40	40	100	40

[1]Projected actual emissions are also requested emissions.

[2]Baseline from January 1, 2015 through December 31, 2016. Baseline emissions from gasoline loading are based on the limit in 40 CFR Part 63, Subpart R § 63.422(b) 10 mg/l loaded (note that 40 CFR Part 63 Subpart CC, § 63.650(a) refers to Subpart R).

[3]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

It should be noted that the purpose of the June 14, 2018 submittal was to revise the emission calculation methodology and thus was not submitted due to a physical change or change in the method of operation. However, as a part of the process, throughput and emission limits were revised.

As previously stated, 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 modification (Colorado Regulation No. 3, Part C, Section I.A.7.b). According to Part F of Regulation No. 3 (Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications) modification that trigger PSD and/or NANSR requirements is a Title 1 modification.

The LPG rail rack commenced operation in 1989. Additional loading arms for petroleum products (e.g. gasoline and diesel) were added in 1996. The LPG loading rack was installed in 1989 at an existing major stationary source. The initial construction permit for the rail rack (89AD031, initial approval issued April 5, 1989) included emissions from the rail rack flare (SO_2, NO_X and CO emissions) and a limit of the amount of propane combusted by the flare but did not include limitations for VOC emissions. There was little information in the files to explain why no limit was included for VOC emissions but it is possible that the Division and/or the source assumed that VOC emissions from the flare would be minimal and it is likely that VOC emissions from leaking piping components (fugitive VOCs) were addressed on the construction permit for the saturated and unsaturated gas plant (89AD126) which was issued around the same time (initial approval issued May 10, 1989).

Installation of equipment in 1989 at an existing major stationary source would have triggered major stationary source permitting requirements if there was a significant net emissions increase associated with the installation of that equipment. Permitted emissions from the LPG loading rack flare addressed in construction permit 89AD031 were below the significance level, thus major stationary source permitting requirements did not apply. VOC emissions from the saturated and unsaturated gas plant (construction permit 89AD126), which may have included emissions from leaking piping components from the LPG loading rack, were also below the significance level.

Colorado Regulation No. 3, Part D includes the source obligation requirements which requires sources that were permitted as minor sources or modifications to undergo major stationary source permitting requirements if they became major solely by relaxing enforceable limitations. This source obligation is often referred to as the relaxation restriction.

Since permitted emissions from the LPG loading rack were below the major source level when the equipment was constructed in 1989, if emissions from the LPG loading rack exceed the significance level due to the relaxation of any enforceable requirement, then major stationary source NANSR requirements apply. In this application, the source is requesting a revision to the emission calculation procedures for LPG rail rack loading, as well as changes to the throughput and emission limitations. Since there are no other physical changes, this would be considered a relaxation in enforceable requirements, thus the allowable of emissions from LPG loading rack have to remain below the significance level in order to avoid major NANSR requirements. The Division considers that the relaxation restriction applies to the LPG loading rack, as well as the initial piping components associated with it when the LPG loading rack was first constructed. Additional piping components installed based on other physical changes made to the equipment and the loading of other petroleum products are not included in the restriction since any emissions increase associated with these changes are not due solely to the relaxation of enforceable requirements.

Based on the information submitted on January 30. 2019 to support the June 14, 2018 application, the requested emissions from the LPG loading are below the significance level as indicated in the table below. Therefore, this modification does qualify as a minor modification.

	Emissions (tons/yr)				
Source/Activity	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
LPG rail car loading (routed to the flare)[1]	1.24×10^{-1}	1.83×10^{-3}	1.07	4.89	36.96
LPG flare – pilot and purge gas	2.72×10^{-3}	4.79×10^{-5}	2.42×10^{-2}	0.11	0.83
LPG truck loading					0.90
Uncoupling rail car hose					7.43×10^{-2}
Fugitive VOC from piping components					0.75
Total	1.27×10^{-1}	1.88×10^{-3}	1.09	5.00	39.51
PSD/NANSR Significance Level (T5 Minor Mod Level)[2]	25/15/10	40	40	100	40

[1]Emissions from LPG loading also include distillate loading. VOC emissions from distillate loading are 0.015 tpy. As discussed above, the relaxation restriction issue is related to LPG loading. Loading of other petroleum products were the result of a physical change to the rail loading rack and would by themselves have to be below the significance level.

[2]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a

complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

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.

There is an increase in permitted VOC emissions from the loading rack. 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. The magnitude of the emission increase (VOC 9.5 ton/yr) is not at a level for which individual source ozone modeling would be required.

For the other pollutants there was no increase in permitted emissions (see table below) thus modeling is not required.

	Emissions (tons/yr)				
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Requested Limits					
Rail rack flare[1]	0.13	1.88×10^{-3}	1.10	5.00	37.80
LPG Truck rack					0.9
Equipment leaks from LPG loading at rail rack, rail rack flare and LPG truck rack					0.75
Total Requested	0.13	1.88×10^{-3}	1.10	5.00	39.45
Current Permitted[2]	1.0	1.0	13.8	74.9	28.3
Change in Permitted Emissions	-0.87	-0.998	-12.7	-69.9	11.15

[1]Requested emissions of PM, PM_{10}, $PM_{2.5}$ and SO_2 are well below the APEN de minimis level (2 tpy), therefore, emission limits for these pollutants will not be included in the permit. Although no emission limit is included for these pollutants, actual emissions of these pollutant are to be reported on APENs.
[2]Current permitted emissions are from the LPG rail rack flare only. The LPG truck rack and equipment leaks from LPG loading at the rail rack, rail rack flare and LPG truck rack did not previously have emission limitations.

Discussion

The P2 rail rack is an existing emission unit, therefore the major stationary source applicability test is based on a comparison of baseline actual emissions (BAE) to projected actual emissions (PAE). Since the purpose of the application is to revise the LPG rail car loading method, which is routed to the flare, the applicability test is based on emissions from rail car loading (both LPG and petroleum products).

As previously noted, loading of LPG was permitted as a minor source when installed, thus permitted emissions from the LPG loading rack, include uncontrolled emissions from truck loading and uncoupling the rail car loading hose, as well as fugitive emissions from leaking piping components must be below the significance level. The calculation methods are also described below, under PAE.

General Emission Calculation Methodology for LPG rail car loading

The source used the HYSIS model to estimate emissions and emission factors for LPG rail car loading. A number of scenarios were run for each type of LPG loaded (propane, n-butane and isobutene). Scenarios were run during different ambient temperatures (based on calendar quarters), whether or not the railcar arrived with nitrogen (N_2), varying N_2 pressure (47, 92 and 137 psia) for N_2 containing railcars, the time it takes to load the railcar (1.5, 2 and 2.5 hours), as well as insulated vs uninsulated cars and daytime vs nighttime loading (insulated cars loaded during the daytime were presumed to have the same temperature profile for nighttime loading).

The HYSIS model data provided emissions and heat content estimates (per railcar) for those vapors routed to the flare, as well as emissions from uncoupling the loading arm (vented to atmosphere).

For each LPG type and calendar quarter, the source estimated a seasonal weighted emission factor (lb/railcar or MMBtu/railcar) from the HYSIS data assuming that 25% of cars are insulated and loaded in the daytime (nighttime temperature profile), 25% of the cars are uninsulated and loaded in the daytime, 25% of the cars are insulated and loaded at nighttime and 25% of the cars are uninsulated and loaded at nighttime. A seasonal, weighted emission factor was estimated for non-N_2 railcars and N_2 railcars (at 92 psia only).

The source also estimated "overall" weighted seasonal emission factors assuming that 35% of the railcars arrive without N_2 and 65% arrive with N_2 using the weighted seasonal emission factors discussed in the above paragraph. These "overall" weighted seasonal emission factors were used to estimate BAE.

Using the "overall" weighted seasonal emission factors discussed in the above paragraph, the source calculated a general weighted emission factor for each LPG type assuming the following distribution of cars loaded: 15% in January – March, 35% in April – June, 35% in July – September and 15% in October – December. The general weighted emission factors were used to estimate PAE.

BAE

As discussed previously, the baseline period used was January 1, 2015 through December 31, 2016 and baseline emissions from LPG railcar loading were estimated using the "overall" weighted seasonal emission factor for the LPG type.

In the June 14, 2018 application, BAE for petroleum products (gasoline and diesel) were estimated using the loading loss equation in AP-42, Section 5.2 (dated 6/08), equation 1, assuming a flare control efficiency of 95%. Colorado Regulation No. 3, Part D, Section II.A.4.b.(ii) specifies that 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. The controlled loading loss emission factor for gasoline (3.318×10^{-4} lbs per gallon) resulted in emissions that exceeded the MACT CC limit for gasoline loading of 10 mg/liter (10 mg/liter converts to 8.345×10^{-5} lb/gal). Since the MACT CC limit for gasoline loading is lower, baseline actual emissions for gasoline loading were adjusted downward to reflect the MACT CC limit.

PAE

Projected actual emissions from LPG rail loading were estimated using a general weighted emission factor for each LPG type and the projected number of railcars that are anticipated to be loaded. In the June 14, 2018 application, the source estimated PAE for both gasoline and distillate loading. However, the source had indicated that they would cease loading of gasoline at the P2 rail rack prior to January 30, 2019 in order to avoid having to comply with the new flare requirements in MACT CC. Therefore, in their January 30, 2019 submittal, PAE was based only on distillate loading. PAE for distillate loading relied on the same methodology described above for BAE (e.g. the AP-42 loading loss equation and an assumed control efficiency for the flare).

In the June 14, 2018 application, the HYSIS runs for rail car LPG loading included emission estimates for uncoupling the rail car loading hose (vented to atmosphere). While these emissions were not included in the applicability test, in their January 30, 2019 submittal, the source calculated PAE for this emission source based on the number of rail cars loaded and the maximum emissions estimated for loading hose uncoupling for the LPG type loaded. PAE from rail car loading hose uncoupling are estimated to be well below 1 tpy (0.074 tpy), so an emission limit will not be included in the permit. However, emissions from this activity were assessed in order the ensure emissions from LPG loading are below the significance level.

Emissions from truck loading of LPG occur when loading is complete and the loading hose is uncoupled. Previously emissions from this activity were based on material balance, based on the volume of the hose and the density of the material loaded. In the January 30, 2019 submittal, the source used HYSIS to determine an emission factor for truck loading of LPG. Emissions from truck loading were estimated at 0.9 tpy and an emission limit will be included in the permit for this activity.

The source requested an emission limit for fugitive VOCs from piping components associated with LPG loading in the January 30, 2019 submittal. The emission limit is based on actual emission estimates from Suncor's Guideware. Guideware is Suncor's fugitive emission's tracking software program which estimates emissions based on EPA's "Protocol for Equipment Leak Emission Estimates", EPA-453/R-95-017, November 1995. Guideware estimates emissions based on actual leak data for those components that are screened. In addition, the source committed to following the provisions of 40 CFR Part 60, Subpart GGGa for the components associated with LPG loading.

Emission Factor Discussion

The draft permit submitted with the application included the "overall" weighted seasonal emission factors to use for calculating emissions from LPG railcar loading. The Division considers that this was acceptable for estimating BAE, since the source did not have any information during the baseline period regarding the number of cars arriving with or without N_2. However, since emissions from railcars not containing N_2 are much different than railcars arriving with N_2, the Division considers that moving forward, the source can track whether cars arrive with or without N_2 and so the permit will include the seasonal weighted emission factors for non-N_2 and N_2 cars for each LPG.

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 necessary, to determine if the increases above the projected level were caused by the project.

For the rail rack flare, projected actual emissions are the same as requested (permitted) emissions, thus including this information in an appendix would not be necessary.

Revisions to Permit

The following changes were made to the permit based on this modification:

Section I – General Activities and Summary

- The table in Condition 5.1 was revised to indicate that the storage tanks and truck loading are not controlled by the flare and that they are not grouped under point 284 (tanks are APEN exempt, an APEN was filed for the truck rack and so a new point no. was assigned for that). In addition, fugitive sources from the rail loading rack are addressed as F026 – for equipment leaks associated with petroleum product loading at the rail car dock (no permit limits) and F040 – for equipment leaks associated with LPG loading at the rail car dock, rail car dock flare and truck loading dock (with permit limits).

Section II.9 – LPG Storage, Truck and Rail Facility

- Revised the emission and throughput limits in Conditions 9.1 and 9.7. In addition, added language to Condition 9.1 indicating the emission calculation methodology.
- The RACT requirements in Condition 9.5 were revised to remove Reg 7, Sections VI.C.2, VI.C.4.a and X.V. According to January 30, 2019 revised draft permit, the requirements in Section VI.C.2 and VI.C.4.a no longer apply because only liquids meeting the exemption in XVI.C.1 are loaded. The requirements in Section X.V no longer apply since gasoline will no longer be loaded. Note that Condition 9.5 will be revised to indicate that only exempt materials may be loaded and to require that records be retained to verify that.
- Included an emission limit for LPG truck loading and a limit on the number of trucks that can be loaded.
- Added a “new” requirement to monitor the quantity of pilot and purge gas (propane) to the flare.
- Added emissions limits and RACT requirements for equipment leaks associated with LPG loading at the railcar and truck dock (F040).

- Added a requirement to calculate emissions and RACT requirements for equipment leaks associated with distillate loading at the railcar dock (F026)
- Added a "new" requirement to record the number of trucks and railcars loaded daily and monthly. For railcars, the source will also be required to record the type of LPG loaded, whether the car arrived with N2 and the arrival pressure of the railcar. In addition, the source will be required to maintain records of number of railcars that arrive with a pressure greater than 80 psig (92 psia). If the percentage of cars arriving with pressures greater than 80 psig (92 psia) exceed 15% in any calendar year, the source will be required to notify the Division. The Division will use this information to determine if the emission factors need to be revised. The emission factors are based on a maximum arrival pressure of 80 psig (92 psia) and the information in the application indicates that emissions are higher at higher arrival pressures (125 psig (137 psia). The Division considers that it is necessary to track the number of railcars that arrive above 80 psig because the source indicated that they have no data indicating that 80 psig is the maximum arrival pressure.
- Added a "new" requirement to determine the Btu content and volume of LPG sent to the flare.
- Added a "new" requirement for relaxing emission limits for LPG loading.

Section II.25 – Reg 7, Section VI Requirements (RACT for storage and transfer of petroleum liquids)

These requirements were moved to "new" Section II.26, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.26 includes the requirements in Reg 7, Section VII.

- Revised Condition 25.3 (Section VI.C.2) to indicate that these requirements do not apply to the railcar loading rack.
- Removed Condition 25.4 (Section VI.D.4.a) since this requirement no longer applies to the railcar loading rack.

Section II.32 – MACT CC

These requirements were moved to "new" Section II.40, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.40 includes language related to maximum achievable control technology.

- Revisions were made to indicate that the gasoline loading provisions do not apply to the railcar dock.

Appendix A – Insignificant activity list

- Added LPG railcar loading hose uncoupling to the list under the category of Reg 3, Part C, Section II.E.3.a

Appendices B and C

- Added F040 (equipment leaks associated with LPG loading at the rail car dock, rail car dock flare and truck loading dock) and clarified the description of F026 (equipment leaks associated with petroleum product loading at the rail car dock) in the tables.

1.34 December 27, 2018 (additional information submittal) – FCCU Cold Resid Project

The purpose of the December 27, 2018 submittal is to install two new pumps and two new sections of piping to enable the source to transfer vacuum tower bottoms (resid) from Tank T039 to the cold feed line for the FCCU. The resid is generated in the No. 2 crude unit. The facility currently can transfer resid directly from the No. 2 crude unit to the FCCU as hot feed, meaning it is directly transferred from the No. 2 crude unit to the FCCU (Tank T039 is bypassed). The source has indicated that this change is necessary in order to meet the PM and opacity requirements for FCCUs in MACT UUU. The December 27, 2018 submittal was submitted as a minor modification but the source indicated in the application that no permit revisions were necessary. The submittal indicates that the source expects to begin construction and operation by May 2020.

The Division reviewed the information in the December 27, 2018 submittal and made comments on the calculations and assumptions used in the December 27, 2018 application. Reponses to the comments and revised calculations were submitted via email on May 2, 2019.

The increase in emissions from this project were based on the actual-to-projected-actual emissions test for existing equipment and actual-to-potential emissions for new equipment (piping components). The following items are important to note regarding this application:

- This project is expected to increase FCCU throughput (598 bpd) and steam demand during three months in the winter. The increase in resid feed to the FCCU is projected to increase jet fuel production (504 bpd) over the full year. Since jet fuel is typically shipped by pipeline, the P2 loading racks are not affected. No other process unit or utility is expected to be affected by this project.
- Affected existing emission units include the FCCU regenerator, FCCU preheater, the P2 boilers and Tank T62.
- Baseline period is January 1, 2016 through December 31, 2017. Baseline actual emissions were adjusted downward for the FCCU regenerator and preheater for non-compliant emissions.
- The expected emissions increase from the P2 FCCU cold resid project are included in the table below:

	Emissions (tons/yr)						
Emission Unit	PM[1]	PM_{10}[2]	$PM_{2.5}$[2]	SO_2	NO_X	CO	VOC
FCCU Regenerator (P004)[3]							
Baseline	19.21	26.42	25.85	13.06	28.72	3.17	9.96
Projected actual emissions (PAE)	21.82	30.01	29.37	18.56	32.82	5.78	12.65
Capable of Accommodating	21.48	29.53	28.90	18.27	32.29	5.69	12.45

Emission Unit	Emissions (tons/yr)						
	PM[1]	PM_{10}[2]	$PM_{2.5}$[2]	SO_2	NO_X	CO	VOC
Excludable[4]	2.27	3.11	3.05	5.21	3.57	2.52	2.49
Adjusted PAE[5]	19.55	26.9	26.32	13.35	29.25	3.26	10.16
Emissions Increase[6]	**0.34**	**0.48**	**0.47**	**0.29**	**0.53**	**0.09**	**0.20**
FCCU Pre-heater (B002)[3]							
Baseline	0.28	0.28	0.28	0.17	3.37	3.10	0.20
PAE	0.49	0.49	0.49	0.39	5.82	5.36	0.35
Capable of Accommodating	0.48	0.48	0.48	0.39	5.73	5.28	0.35
Excludable[4]	0.20	0.20	0.20	0.22	2.36	2.18	0.15
Adjusted PAE[5]	0.29	0.29	0.29	0.17	3.46	3.18	0.20
Emissions Increase[6]	**0.01**	**0.01**	**0.01**	**6.24E-03**	**0.09**	**0.08**	**5.62E-03**
Tank T62[3]							
Baseline							5.31E-02
PAE							6.65E-02
Emissions Increase[6]							**1.34E-02**
Boilers B504 & B505[3]	**3.06E-03**	**3.06E-03**	**3.06E-03**	**3.27E-03**	**9.18E-03**	**1.22E-02**	**1.65E-03**
Fugitive VOCs from new components[7]							**0.74**
Total Emissions Increase	**0.35**	**0.49**	**0.48**	**0.30**	**0.63**	**0.18**	**0.96**
PSD/NANSR Significance Level (T5 Minor Mod Level)[8]	25	15	10	40	40	100	40

[1]Condensable PM is not included for purposes of PSD/NANSR applicability for the FCCU (not required, see footnote 2). PM emissions from fuel burning equipment includes condensable PM

[2]Includes filterable plus condensable particulate matter. Per Reg 3, Part D, Section II.A.40.g condensable PM is included in PM_{10} and $PM_{2.5}$ for purposes of PSD/NANSR applicability.

[3]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.

[4]Exludable emissions equal capable of accommodating minus baseline emissions

[5]Adjusted PAE is PAE minus excludable emissions

[6]Change in emissions (emissions increase) is adjusted PAE minus baseline or if PAE not adjusted, PAE minus baseline.

[7]New Equipment.

[8]Indicates the NANSR significance level on the date the information was submitted This submittal did not require a permit revision thus the source was not required to submit the applicability test (see Colorado Regulation No. 3, Part D, Section I.B.4). Sources that conduct an actual-to-projected-actual applicability test for a project that is not part of a major modification are required to document and maintain information related to the project as set forth in Colorado Regulation No. 3, Part D, Sections V.A.7.c.(i) and VI.B.5.a. The area was classified as a serious ozone non-attainment area on January 27, 2020 and beginning on that date, the significance level drops to 25 tons/yr of VOC or NO_X.

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

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. Although the source submitted this application as a minor permit modification, no permit revisions are necessary, therefore, the applicability analysis for this project will not be included in an appendix of the Title V permit.

Although the applicability analysis will not be included in an appendix of the Title V permit, the source is subject to monitoring and reporting requirements for projects that are not part of a major modification and for which the actual-to-projected-actual applicability test was used. These monitoring and reporting requirements are found in Colorado Regulation No. 3, Part D, Sections V.A.7.c and VI.B.5, which are included in the General Permit Conditions (Section IV, Condition 24 of the Title V permit).

1.35 January 8, 2019 (minor modification) – Tank T058

The purpose of the January 8, 2019 application is to return Tank T058 to service. The tank was removed from service in April 2012 for maintenance outage, returned to service in April 2013 but removed from service again in August 2013 when it was determined that the internal floating roof had sunk. At the time the roof sunk the tank was storing naphtha.

In order to return Tank T058 to service, the source has determined that the tank should be retrofitted with a mechanical shoe seal and that the vapor mounted rim seal and secondary wiper removed. A mechanical shoe seal is allowed in both MACT CC and NSPS Kb (although Tank T058 is not currently subject to NSPS Kb). The source indicated that replacing the vapor mounted rim seal and secondary wiper with a mechanical shoe seal will result in an increase in emissions from the tank. Thus the tank is considered to be modified under the provisions of Colorado Regulation No. 3, Part A, Section I.B.28 and is subject to the minor source permitting requirements in Colorado Regulation No. 3, Part B.

The January 8, 2019 application was not considered complete since draft permit language was not submitted and the APEN indicated that the source was not requesting an emission limit for the tank. Since the tank is modified and the minor source permitting requirements were triggered emission limits and modifications to the Title V permit are necessary. Draft permit language was submitted on January 10, 2019.

Tank T058 was previously grandfathered from the minor source permitting requirements (not subject to emission and throughput limits). Requested emissions from Tank T058 are shown in the table below and are below the VOC significant level (40 tons/yr):

Source	VOC Emissions (tons/yr)
Tank T058	4.65
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]	40

[1]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

Regulatory Applicability Discussion

The increase in emissions from Tank T058 is due to replacing the vapor mounted rim seal and secondary wiper with a mechanical shoe seal, not due to a change in tank content, thus this could be considered a modification under NSPS Kb. In the application, the source submitted an applicability determination from the EPA indicating that the replacement of double wiper seals with mechanical shoe seals would qualify as routine replacement and would qualify as replacement of one acceptable control technology with another and not be considered a modification per 60.14(e)(1) and (5).

The project to replace the vapor mounted rim seal and secondary wiper with a mechanical shoe seal does not affect the applicability of the Reg 7 requirements for Tank T058 in the current permit (last revised June 15, 2009). Tank T058 is a Group 1 tank under MACT CC, thus the current permit (last revised June 15, 2009) will be revised to correctly indicate that tank T058 is a Group 1 tank. The MACT CC correction for Tank T058 is also discussed under the September 2016 additional information submittals (see Section III.1.25).

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

Section I – General Activities and Summary

- Tank T058 was moved from the Group G tanks into the Group E tanks since it is no longer considered "grandfathered."

Section II.15 – Group E Tanks

- Added Tank T058 to this section.

Section II.17 – Group G Tanks

- Removed references to Tank T058 from this section.

Appendices B and C

- In the tables Tank T058 was moved from the Group G tanks into the Group E tanks.

1.36 January 30, 2019 (minor modification) – Rail Rack Flare RSR Project

The purpose of the January 30, 2019 application is to shift gasoline loading from the Plant 2 rail rack to the Plant 1 rail rack. On and after January 30, 2019, a flare used as a control device for any emission points subject to MACT CC must meet the requirements for flares in §§ 63.670 and 63.671. Gasoline loading racks are emission points subject to requirements in MACT CC thus any flare used to control emissions from gasoline loading would be subject to the requirements in §§ 63.670 and 63.671. On June 14, 2018, Suncor submitted an application to revise the Plants 1 and 3 Title V permit (96OPAD120) to replace the Plant 1 rail rack flare with an enclosed vapor combustor. An enclosed vapor combustor would not be subject to the requirements for flares in MACT CC and all gasoline railcar loading operations would occur at the Plant 1 rail rack. Railcars would no longer be loaded with gasoline at the Plant 2 rail rack, thus the MACT CC requirements would not apply to the Plant 2 railcar dock flare.

The June 14, 2018 application to revise the emission limits and calculation methodology for LPG loading at the Plant 2 rail rack (discussion under Section III.1.33) was submitted on the same day as the application to replace the Plant 1 rail rack flare with a vapor combustor (application submitted for the Plants 1 and 3 permit (96OPAD120). Projected emissions from the June 14, 2018 application to revise the emission calculation methodology for LPG loading at the Plant 2 rail rack included projected actual emissions that included loading gasoline at the Plant 2 rail rack. The June 14, 2018 application for the Plant 1 rail rack (submitted for the Plants 1 and 3 permit (96OPAD120)) included emission changes from both the Plant 1 and Plant 2 rail racks, since the physical and/or operational changes at the loading racks are considered to be related. The June 14, 2018 application for the Plant 1 rail rack (submitted for the Plants 1 and 3 permit (96OPAD120)) indicated that an application would be submitted for the Plant 2 rail rack at a later date to address the shift to load gasoline railcars at Plant 1 (the shift would be reflected by removing gasoline as an allowable throughput at Plant 2). The application for Plant 2 that was alluded to in the June 14, 2018 application for the Plants 1 and 3 permit (96OPAD12) is this January 30, 2019 application.

The Division had noted deficiencies in the June 14, 2018 application to revise the emission limits and calculation methodology for LPG loading at the Plant 2 rail rack. In addressing these deficiencies, the source submitted revised calculations on January 30, 2019 in which projected actual emissions no longer included gasoline loading at the Plant 2 rail rack. Thus requested emissions from the Plant 2 rail rack flare for the June 14, 2018 application are the same as those requested in this January 30, 2019 application.

The difference between the June 14, 2018 and January 30, 2019 applications is that emission changes from the Plant 1 rail rack flare were included in the January 30, 2019 application. According to the January 30, 2019 application, since the source will be shifting gasoline and distillate loading from one rail rack to another (all gasoline from Plant 2 to Plant 1, possibly one additional railcar of distillate from Plant 1 to Plant 2), that emissions from both loading racks were included. The January 30, 2019 application indicates that since actual emissions from the Plant 2 rail rack will decrease, it is not required to be included in the project emissions analysis. While it is true that emissions from gasoline loading will decrease as a result of the project, the source indicates that more distillate may be loaded at Plant 2, thus there will be an increase in emissions from distillate loading. Since emissions from gasoline loading are higher, it is expected that any increase in emissions from increased distillate loading would be offset by the decrease in gasoline loading, resulting in an overall decrease in emissions from petroleum product loading at the Plant 2 rail rack. LPG loading at the Plant 2 rail rack is not affected by this modification at all but is included in the evaluation since it is loaded at the Plant 2 rail rack and routed to the flare. The Division would agree that generally only emission units that are affected by the project and for which there is an emissions increase would be included in step one of the analysis to determine project emissions. Thus we agree that for the project to shift gasoline loading from the Plant 2 rail rack to the Plant 1 rail rack, only emission increases from the Plant 1 rail rack are required to be considered (emissions would not increase from the Plant 2 rail rack), although the permit would be modified to reflect that no gasoline would be loaded (this would be a change in the throughput limit and a decrease in permitted emissions).

Modification Type

The source indicated that this modification qualifies 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 F 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 are below the significant level. The results of the applicability test that includes emission increases from both the Plants 1 and 2 rail racks are shown in Table 5 below. The results of the applicability test for just the Plant 1 rail rack are shown in Table 6 below. Note that as discussed above the source conservatively included the emission increases from both the Plant 1 and Plant 2 rail racks in the application, although the increases from Plant 2 were not required (actual emissions will not increase from the Plant 2 rail rack with this modification).

Table 5 – Emission Increases from the Plant 1 and Plant 2 Rail Rack (P2 RR Flare RSR Project)

	Emissions (tons/yr)				
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Projected Actual Emissions[1]	0.36	1.73×10^{-2}	5.73	20.44	59.12
Baseline Actual Emissions[2]	0.12	1.94×10^{-3}	1.09	4.98	27.68
Change in Emissions[3]	0.24	1.54×10^{-2}	4.64	15.46	31.44
New Equipment Leak Components (for Plant 1)					2.13
Total Emission Increase	0.24	1.54×10^{-2}	4.64	15.46	33.57
PSD/NANSR Significance Level (T5 Minor Mod Level)[4]	25/15/10	40	40	100	40

[1]Projected actual emissions are also requested emissions.

[2]Baseline from January 1, 2015 through December 31, 2016. Baseline emissions from gasoline loading are based on the limit in 40 CFR Part 63, Subpart R § 63.422(b) 10 mg/l loaded (note that 40 CFR Part 63 Subpart CC, § 63.650(a) refers to Subpart R).

[3]The change in emissions is projected actual emissions minus baseline actual emissions.

[4]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone

non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

Table 6 – Emission Increases from the Plant 1 Rail Rack Only (P2 RR Flare RSR Project)					
	Emissions (tons/yr)				
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Projected Actual Emissions[1]	0.24	1.53×10^{-2}	4.63	15.44	21.32
Baseline Actual Emissions[2]	0.04	7.03×10^{-4}	0.36	1.63	3.13
Change in Emissions[3]	0.20	6.5×10^{-4}	4.27	13.81	18.19
New Equipment Leak Components (for Plant 1)					2.13
Total Emission Increase					20.32
PSD/NANSR Significance Level (T5 Minor Mod Level)	25/15/10	40	40	100	40

[1]Projected actual emissions are also requested emissions.

[2]Baseline from January 1, 2015 through December 31, 2016. Baseline emissions from gasoline loading are based on the limit in 40 CFR Part 63, Subpart R § 63.422(b) 10 mg/l loaded (note that 40 CFR Part 63 Subpart CC, § 63.650(a) refers to Subpart R).

[3]The change in emissions is projected actual emissions minus baseline actual emissions.

[4]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

The increase in emissions shown in both Tables 5 and 6 indicate that emissions are below the significance level, therefore, this modification 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.

There is no increase in permitted emissions from the Plant 2 rail rack. As discussed above, requested emissions from this modification are the same as requested emissions for the June 14, 2018 application (with the January 30, 2019 submittal for that application).

There is an increase in permitted VOC emissions from the Plant 1 rail rack. 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. The magnitude of the emission increase (VOC 16.42 ton/yr) is not at a level for which individual source ozone modeling would be required.

For the other pollutant emissions, the increase in permitted emissions from the Plant 1 rail rack are summarized below:

Pollutant	Modeling Threshold[1]		Change in Permitted Emissions (tons/yr)
	Annual	Short-Term	
SO_2	40 tons/yr	0.46 lbs/hr	0.02 (40 lb/yr)
NO_2	40 tons/yr	0.46 lbs/hr	2.63
CO	100 tons/yr	23 lbs/hr	4.68
PM_{10}	15 tons/yr	82 lbs/day	0.24 (480 lb/yr)
$PM_{2.5}$	5 tons/yr	11 lbs/day	0.24 (480 lb/yr)

[1]Note that the Division's May 2018 draft Modeling Guidelines (page 22), indicate no annual threshold for PM_{10} and CO.

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 (begins on page 153) specifies that for minor sources with requested emissions below 40 tons/yr of NO_X and SO_2, that a compliance demonstration is not required for the short-term (hourly) SO_2 and NO_2 national ambient air quality standard (NAAQS). Therefore a modeling analysis was not conducted for the 1-hr SO_2 and NO_2 NAAQS. With respect to the short-term CO, PM_{10} and $PM_{2.5}$ NAAQS, it is not expected that the short-term increases in CO, PM_{10} and $PM_{2.5}$ emissions would be above the modeling thresholds as the annual emission increases 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, PM_{10} and $PM_{2.5}$ NAAQS.

Discussion

Projected and baseline actual emissions for the Plant 2 rail rack were estimated as discussed previously for the June 14, 2018 application (see Section II.1.33).

For the Plant 1 rail rack, baseline actual emissions were estimated similar to the estimates for gasoline and distillate loading discussed previously for the Plant 2 rail rack flare for the June 14, 2018 application (see Section II.1.33). Baseline emissions were estimated using the loading loss equation in AP-42, Section 5.2 (dated 6/08), equation 1, assuming a flare control efficiency of 95% for distillate and 98.7% for gasoline and jet naphtha loading. Colorado Regulation No. 3, Part D, Section II.A.4.b.(ii) specifies that 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. The controlled loading loss emission factor for gasoline (8.632×10^{-5} lbs per gallon) resulted in emissions that exceeded the MACT CC limit for gasoline loading of 10 mg/liter (10 mg/liter converts to 8.345×10^{-5} lb/gal). Since the MACT CC limit for gasoline loading is lower, baseline actual emissions for gasoline loading were adjusted downward to reflect the MACT CC limit. Projected actual emissions from the Plant 1 rail rack were estimated using the MACT CC limit for gasoline loading and the AP-42 loading loss equation for distillate and jet fuel loading with a vapor combustion unit control efficiency of 95%.

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, presumably so that the Division can determine whether projected emissions predicted by the project are exceeded and pursue an investigation, if necessary, to determine if the increases above the projected level were caused by the project.

For both the Plant 2 rail rack flare and the Plant 1 rail rack vapor combustion unit, projected actual emissions are the same as requested (permitted) emissions, thus including this information in an appendix would not be necessary.

Revisions to Permit

As discussed previously, requested emissions for the Plant 2 rail rack flare in the January 30, 2019 application are the same as those requested for the June 14, 2018 application for the Plant 2 rail rack flare, via the additional information submitted for that application on January 30, 2019. Therefore, the revisions to the permit are discussed under the June 14, 2018 application (see Section II.1.33).

1.37 February 12 and September 27, 2019 Additional Information Submittals

In a February 12, 2019 email, the source indicated that the instrumentation for the flares that monitor and record the net heating value of the flare vent gas measure the net (lower) heating value. The source asked the vendor whether these monitors could be programmed to provide the higher heating value of the flare vent gas in addition to the lower heating value but were told that wasn't possible. The February 12, 2019 email goes on to state that this creates a discrepancy in that the VOC emission factors developed for the P2 flare are based on the higher heating value. In addition, AP-42 emission factors (used for NO_X, CO and PM/PM_{10}) are based on the higher heating value of the fuel. The source proposed to use a conversion factor to convert gas Btu content from lower heating value (LHV) to higher heating value (HHV) and the Division agreed in a March 12, 2019 email. The source submitted initial conversion factors in August 2019 and based on concerns noted by the Division, the conversion factors were revised in a September 27, 2019 submittal. During the course of this review, issues were noted with the initial application with respect to the waste gas emission factor and the determination of necessary supplemental fuel (natural gas).

The waste gas emission factor used the HHV of all components except for hydrogen (H2), which was the LHV. While the Division noted in the process of reviewing the application, using the LHV for H2 resulted in a more conservative (higher) emission factor. In addition, Btu content of supplemental gas was based on the LHV, which resulted in a lower Btu value, thus this was also conservation.

The permit specifies that the Btu limits are based on HHV and directs the source to convert the Btu content to HHV, whether it be natural or waste gas. According to the September 27, 2019 submittal, the source may address the issue with the waste gas emission factor or supplemental fuel determination in a future modification to the P2 flare.

1.38 October 22, 2019 Modification (minor modification) – Revise truck rack vapor combustion unit emission calculation methodology

The purpose of this modification is to revise the emission calculation methodology for the truck rack vapor combustion unit and to address pilot and assist gas. Pilot and assist gas (natural (city) gas) was not addressed previously in permitting actions and the source indicated that they would be installing a flow meter to measure pilot and assist gas.

Modification Type

The source indicated that this modification qualifies 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 F 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.

Requested emissions, as well as the change in permitted emissions, from the truck rack vapor combustion unit are below the significance level, as indicated in the table below:

Pollutant	Emissions (tons/yr)			
	Requested	Current Permit[1]	Change in Emissions	PSD/NANSR Significance Level (T5 Minor Mod Level)[2]
$PM/PM_{10}/PM_{2.5}$	0.30		0.30	25/15/10
SO_2	0.02		0.02	40
NO_X	3.7	3.3	0.4	40
CO	16.9	17.7	-0.8	100
VOC	17.2	24.1	-6.9	40

[1]The current permit does not include emission limitations for $PM/PM_{10}/PM_{2.5}$ and SO_2.

[2]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X.

The Division agrees this modification qualifies as a minor modification. Since requested emissions of PM, PM_{10}, $PM_{2.5}$ and SO_2 are well below the APEN de minimis level (2 tpy), emission limits for these pollutants will not be included in the permit. Although no emission limit is included for these pollutants, actual emissions of these pollutant are to be reported on APENs. In addition, the permit requires that SO_2 emissions be calculated daily and used in assessing compliance with the Reg 1 SO_2 limit.

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. There is a slight increase in permitted NO_X (0.4 tpy), as well as PM, PM_{10}, $PM_{2.5}$ (0.30 tpy) and SO_2 (0.02 tpy) emissions. Note that the increase in PM, PM_{10}, $PM_{2.5}$ and SO_2 emissions is because the current permit does not include limits for these pollutants and absent an increase in loading throughput, this increase is much less. However, the magnitude of these emissions increases does not warrant a modeling analysis.

Discussion

The changes in this application include addressing pilot and assist gas (natural gas) in emission estimates, as those gases were not previously considered in permitting. This includes taking a throughput limit on the quantity of pilot and assist gas.

In addition, previously permitted VOC emissions were based on the MACT CC limit for gasoline loading (10 mg/l loaded) and presumed that only gasoline was loaded. For this application the source, is revising the throughput limit to set specific throughput limits for gasoline and distillate loading (no change to the total throughput limit). VOC emissions from gasoline loading are based on the MACT CC limit of 10 mg/l, while the distillate limit is based on the loading loss equation in AP-42, Section 5.2 and assumes a 95% control efficiency for the vapor combustion unit. In addition, changes to the calculation methodology include the revised CO emission factor from AP-42, Section 13.5.

For this application, the source conducted the major stationary source applicability analysis by comparing potential emissions to baseline actual emissions (January 1, 2017 through December 31, 2018 used as baseline period). Since requested (potential) emissions are below the significance level, such as analysis is not necessary and is not included or addressed here.

Revisions to Permit

The following changes were made to the permit based on this modification:

Section II.7 – Crude Unloading/Gasoline Tank Truck Loading

- Revised the emission limits in Condition 7.1, as well as the CO emission factor.
- Revised the throughput limit to include separate limits for gasoline and distillate (the total (gasoline plus distillate) throughput limit was not changed).
- Included a throughput limit for combustor pilot and assist gas.

1.39 February 19, 2020 Modification (minor modification) – Tank T011

The purpose of this modification is to convert gasoline storage tank T011 from an internal floating roof (IFR) to an external floating roof (EFR) tank. The source indicated in the application that tank T011 currently stores gasoline and will store gasoline when converted. The application indicates that emissions will decrease with the conversion to an EFR, since the EFR has both a primary and secondary seal (as an IFR, the tank has a primary mechanical shoe seal with no secondary seal). The source requested that the tank be permitted with an annual throughput of 5,591,314 bbl of gasoline (RVP 13 psia).

The change in emissions shown in the table below represent the change in emissions between Tank T011 as an IFR and an EFR at the requested throughput. Both the change in emissions and requested emissions are below the VOC significant level (25 tons/yr), as indicated in the table below:

Source	VOC Emissions (tons/yr)
Tank T011 - Requested Emissions (EFR)	4.26
Tank T011 - Current Emissions (IFR)	10.63
Change in Emissions	-6.37
PSD/NANSR Significance Level (T5 Minor Mod Level)[1]	25

[1]Indicates the NANSR significance level for a serious ozone nonattainment area. The area was classified as a serious ozone nonattainment area on January 27, 2020.

Regulatory Applicability Discussion

As indicated in the application, converting Tank T011 from an IFR to an EFR results in a decrease in emissions, thus this project is not a modification and does not trigger the NSPS Kb requirements. In addition, the application indicates that the project does not qualify as a reconstruction (fixed capital costs of the new components exceeds 50% of the fixed capital cost required to construct a comparable entirely new facility).

Converting Tank T011 from an IFR to an EFR does not change the status of the MACT CC requirements, it was and still is a Group 1 tank. However, after the conversion, Tank T011 is no longer subject to the requirements in Reg 7, Section VI.B.2.a and is now subject to the requirements in Reg 7, Section VI.B.2.c

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

Section I – General Activities and Summary

- Tank T011 was moved from the Group B tanks into the Group E tanks since the source requested permit limits. Added language to indicate year tank converted from IFR to EFR.

Section II.12 – Group B Tanks

- Removed references to Tank T011 from this section.

Section II.15 – Group E Tanks

- Added Tank T011 to this section.

Section II.25 – RACT Reg 7 Section VI (Storage and Transfer of Petroleum Liquids)

These requirements were moved to “new” Section II.26, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.26 includes the Reg 7, Section VII requirements.

- Added Tank T011 to the list of tanks in Condition 25.2.3 (Section IV.B.2.c requirements).

Section II.32 – MACT CC

These requirements were moved to "new" Section II.40, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.40 includes language related to maximum achievable control technology.

- Added Tank T011 as a Group 1 tank in Condition 32.11. Since Tank T011 was removed from the Group B tanks, it has to be specifically listed.

Appendices B and C

- In the tables Tank T011 was moved from the Group B tanks into the Group E tanks.

1.40 October 19, 2020 Additional Information Submittal

In their September 28, comments on the draft permit and technical review document, the source asked to include CO, VOC, PM and PM_{10} emission limits that had been included in the underlying construction permit (12AD032-3) but not in the Title V permit. The Division indicated that we were willing to include the limit but had concerns that the emission limits in the 12AD032-3 were not consistent with the throughput limit and the emission factors that were in the current Title V permit (last revised June 15, 2009) and asked that the emission and throughput limits be revised. To that end, the source submitted a revised APEN on October 19, 2020. Although not specifically requested, the revised APEN also indicated a reduction in requested H_2S emissions. H_2S emissions are estimated as a percentage of SO_2 emissions and when Suncor requested a lower SO_2 limit per the April 20, 2016 application (see discussion under Section III.1.24) they did not request a reduction in the H_2S limit but are doing so with the October 19, 2020 revised APEN. The change in permit limits is shown in the table below.

Limit	Requested	Current Permit[1]	Change in Value
NO_X	0.95 tons/yr	5.2 tons/yr	-4.25 tons/yr
CO	0.80 tons/yr	0.6 tons/yr	0.20 tons/yr
VOC	0.05 tons/yr	0.2 tons/yr	-0.15 tons/yr
PM/PM_{10}	0.07 tons/yr	0.4 tons/yr	-0.33 tons/yr
H2S	10.8 tons/yr	13.8 tons/yr	-3.0 tons/yr
Throughput	19,406 MMBtu/yr	21,000 MMBtu/yr	-1,594 MMBtu/yr

[1]Current permit is the current Title V permit (last revised June 15, 2009) for the NO_X and throughput limit and Construction Permit 12AD032-3 (issued January 5, 1998) for CO, VOC and PM/PM_{10} emissions.

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

Section II.5 – Sulfur Recovery Plant

- Condition 5.1 was revised to include emission limits for PM, PM_{10}, CO and VOC and change the NO_X and H_2S limits.

- The throughput limit in Condition 5.6 was revised.

1.41 Modification Summary

The modifications addressed in this TRD were submitted as individual modifications. Suncor has submitted 40 applications (NOT including the renewal application) to modify their Title V permit, since the current permit was issued on June 15, 2009. Modification applications have been received from March 2009 through February 2020, a period of approximately 11 years. The Division evaluated each application submitted to ensure that the applications were in fact individual projects and not related or necessary for other applications submitted for either this permit or the Plants 1 and 3 permit (96OPAD120). Given the number of applications and the fact that some submittals may have been submitted within a short-time frame, this summary is intended to discuss whether the modifications were appropriately addressed for purposes of major stationary source permit requirements (PSD and NANSR)..

All of the 40 applications were minor modifications for purposes of PSD and/or NANSR. Two submittals were technically not permit modifications, since no permit revisions were necessary. Several modifications did not result in any increase in either actual or permitted emissions. Five modifications were to incorporate requirements from construction permits or to include existing, previously unpermitted sources. Five modifications were to include emission limits either required by the Consent Decree or taken voluntarily. Three modifications were to revise the emission factors or emission calculation methodology and subsequently revise permitted emission limits. Four modifications were to revise descriptions, change individuals in the permit or list operating parameters that were not previously listed. Two applications were to include or revise applicable regulations and one application was to remove equipment. Several modifications did result in an increase in actual or permitted emissions.

There were six applications that affected the FCCU, two requests for NO_X limits (received March 31, 2009 and December 19, 2011), one request for SO_2 limits (received August 4, 2014), one request to include an emission limit for HCN (received November 22, 2016), one request to incorporate provisions from the underlying construction permit 09AD0961 (received November 1, 2010) and one request to enable the source to transfer vacuum tower bottoms (resid) from Tank T039 to the cold feed line for the FCCU (received December 27, 2018). On December 3, 2019, the source requested that the application to include the HCN limit be cancelled, although it is anticipated that after further testing is conducted on HCN emissions, a new application will be submitted. The construction permit was issued for the FCCU to replace the air grid, which was necessary for the installation of the third stage separator (TSS). The TSS was necessary in order to meet the particulate matter limits in the CD. The requests for NO_X and SO_2 limits were also requirements in the CD and the request for an HCN limit was a voluntary request by the source, which was withdrawn on December 3, 2019. The source indicated that the application to route resid to the cold feed line of the FCCU was necessary to meet new PM and opacity requirements in MACT UUU. Except for the FCCU cold resid project, which did not result in any modification to the permit, none of the modifications were intended to increase the processing rate of the

FCCU. The FCCU cold resid project is projected to slightly increase FCCU throughput for three months in the winter. The increase is due to routing a refinery intermediate stream to the FCCU and not due to an increase in the FCCU capacity, an increase in crude processing rate or capacity at the refinery or increased capacity or operating rate of other refinery process units. Therefore, the Division considers that the modifications to the FCCU were all appropriately addressed as separate modifications.

There are four modifications related to the Plant 2 flare (i.e. main or refinery flare), one to revise the emission calculation methodology (received January 4, 2010), one to incorporate the NSPS Ja requirements (received January 14, 2015), one to route MPVs to the flare (received February 10, 2017) and one to comply with the new requirements for flares in MACT CC (received July 10, 2017). The 2010 modification was to change the emission calculation methodology for the flare (to use the AP-42 emission factors for flares in Section 13.5). The Division had required the source to change the flare emission calculation methodology in a COC. There was no physical change or change in the method of operation of the flare associated with this modification. The 2015 modification to include the NSPS Ja requirements for the flare indicated that work during the 2012 P2 Turnaround triggered the NSPS Ja requirements. Specifically, the source indicated that the addition or replacement of piping components, including pressure relief valves, triggered the requirements and that no increase in permitted emissions was necessary due to the new pressure relief valves. The February 2017 modification was to route MPVs to the flare in order to meet new requirements under MACT CC which increases the waste gas throughput and emission limits for the flare. The .July 2017 application for the flare to meet the MACT CC requirements also results in an increase in throughput and permitted emissions due to additional supplemental fuel (natural gas) necessary to meet the Btu content requirements. Although there was an increase in emissions projected for the flare, this increase was below the significance level and was not accompanied by physical changes to the capacity or changes in operation of refinery process units. The Division considers that the modifications to the flare were appropriately addressed at separate modifications.

There were two modifications related to the Plant 2 WWTS and the later application superseded the initial application. The end result of the modifications is that emissions from the Plant 2 WWTS are permitted below the PSD/NANSR significant level.

There are two applications related to the rail rack. One application was to revise the emission calculation methodology for loading LPG into railcars (June 14, 2018) and the other to cease loading gasoline at the rail rack (received January 30, 2019). Although permitted emissions from the rail rack were increased with the June 14, 2018 modification, the allowable throughput for the rail rack decreases with these modifications and permitted emissions are below the significance level.

The remaining modifications address individual emission units, none of the modifications appear to be related to or dependent upon each other or upon other applications. 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 (requested) emissions from all of the modifications covered in this permit revision can be found starting on page 157 of this document.

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 Plant 2 (East Plant) Operating Permit with the source's requested modifications. These changes are as follows:

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- Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the previous permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).
- The facility contact was revised.

Section I – General Activities and Summary

- The language in Conditions 1.1 (one sentence) and 1.2 have been combined and the entire descriptive language is designated as Condition 1.1. In addition additional descriptive language was added to the permit.
- The citation for the definition of 8-hour ozone control area in Condition 1.2 was revised and a sentence was added indicating the 8-hr ozone control area has been classified as a serious non-attainment area.
- Removed construction permit numbers 95AD1073-2 and 12AD032-2 from the list in Condition 1.4, since no equipment identified in this permit was covered under those construction permits. Construction permits 09AD0961, 09AD1422 and 09AD1423 were added to the list in Condition 1.4 since these permits have been incorporated into the Title V permit. (Note that Condition 1.4 is renumbered to 1.3, due to combining Conditions 1.1 and 1.2.)
- Condition 1.5 was revised to remove Section IV, Condition 3.d as a state-only

requirement and added Section IV, Condition 30 (as noted) as a state only requirement. (Note that Condition 1.5 is renumbered to 1.4, due to combining Conditions 1.1 and 1.2.)

General Condition 3.d is no longer a state-only requirement since EPA approved these provisions into Colorado's SIP effective October 6, 2008. Portions of General Condition 30 are state-only in certain areas (new nonattainment areas for either the 1-hr or 8-hr ozone standard).

- Added a statement to Condition 1.6 indicating that either electronic or hard copy records are acceptable. (Note that Condition 1.6 is renumbered to 1.5, due to combining Conditions 1.1 and 1.2.)
- Revised the reg citations for the definitions of "net emissions increase" and "significant" in Conditions 3.1 and 3.2. These citations were revised due to revisions to Reg 3.
- Revised the major stationary source threshold for NANSR in Condition 3.1 to 50 tons/yr year. The threshold was lowered when the area was re-classified as a serious non-attainment area.
- The following changes were made to the table in Condition 5.1:
  - Changed the second column title to "AIRS pt No." since that is more appropriate.
  - Added a column for "startup date" and included available information in this column. The startup date for most of the equipment is based on the information provided in the December 1999 Title V permit application.
  - Removed the column labeled "pollution control device" since most of the emission units are not equipped with add-on pollution control devices. Information in this column was in general moved to the description section, with the following exceptions:
    - Leak detection and repair programs (LDAR), all components with the potential to leak are subject to LDAR at this facility, so this was not included in the description. This is consistent with the Plant 1/3 permit.
    - Designed and operated to minimize emissions, this applies to most of the tanks, so this was not included in the description. This is consistent with the Plant 1/3 permit.
  - Removed the Gas Plant (P007) from the table. There is not a section in Section II for the gas plant. The gas plant has no vents to emit pollutants and is primarily a source of VOC emissions from leaking components. It is addressed in Section II.18 for fugitive VOC equipment leaks subject to permit limits and will be included in the section in this table.
  - Removed the Polymerization Unit (P006). The polymerization unit has been included in the insignificant activity list in Appendix A.
  - Revised the description of Tank T028 (group G tank) to indicate the tank stores ethanol.

- Included the cold cleaner solvent degreasers and industrial solvent cleaning operations.
- Added language to the description of the FCCU reactor-regenerator (P004) to indicate when the third stage separator was installed, that it operates in full burn mode and uses palladium combustion promoters.

Section II – General

General

- Minor language and format changes were made to a number of permit conditions (both in the table and text) in order to more clearly indicate the monitoring or underlying requirement.
- In general permit conditions requiring emission calculations and/or recording throughputs specify that records shall be retained and made available to the Division upon request. In general much of this language has been removed since the general conditions require that records of all required monitoring and support information be retained for 5 years (general conditions 22.c and d), therefore, it is not necessary to explicitly state that records must be retained for all required monitoring.
- For conditions related to calculating emissions for purposes of APEN reporting or monitoring compliance with annual limits, revisions were made to include equations or describe methods to calculate emissions.
- There are several conditions where the permit requires the source to calculate emissions monthly and keep a rolling twelve month total to monitor compliance with the annual emission limitations. However, the permit condition also includes a requirement to calculate emissions annually for purposes of APEN reporting and fees. It is not necessary to conduct a separate annual calculation of emissions for purposes of APEN reporting. The twelve month rolling totals of emissions is sufficient. Calendar year annual emissions are used in APEN reporting, this can be determined from the rolling twelve month totals. Therefore the paragraph relating to the annual emission calculation has been removed. In addition, annually has been removed from the table under the column labeled "monitoring interval".
- For many of the sources that are not subject to emission limitations the permit requires that annual emissions be calculated for purposes of APEN reporting and payment of fees and Regulation No.3, Part A, Section II is cited. The citation has been removed. The requirement to calculate emissions annually reflects periodic monitoring for sources that are subject to APEN reporting requirements but not emission limitations, thus it isn't really a reflection of the requirement to submit revised APENs (which is addressed in Regulation No. 3, Part A, Section II). The Division has typically not included the citation for this type of condition in other Title V permits, thus it has been removed.

Process Heaters and Boilers

- Added language to clarify that fuel use limits, in units of Btu, are based on the higher heating value.

Facility Wide SO_2 limits (0.3 lb/bbl)

The SO_2 requirements in both Reg 1 and Reg 6, Part B are numerically the same standard. The Regulation No. 6, Part B requirement is a state-only requirement. The averaging time is specific for the Reg 1 limitation (the standard is 0.3 lbs/barrel/day), while the averaging time for the Reg 6, Part B standard is not specified. Generally the Reg 6, Part B requirements for SO_2 (e.g. Section II and IV) are essentially the same numerically as the Reg 1, Section VI.B SO_2 requirements for new sources, although in general the averaging times are unspecified for the Reg 6, Part B requirements. The Reg 6, Part B requirements incorporate the NSPS general provisions, which include performance test requirements. The performance test requirements in the NSPS general provisions, specify that the test will consist of three test runs, but the duration is not specified (defers to specific subpart). Therefore, there is no clear indication in the regulation as to how compliance with the Reg 6, Part B limit shall be monitored. In practice the Division has required that the source estimate daily SO_2 emissions and then divide daily emissions by the daily average of barrels processed for the month (Reg 1) or calendar year (Reg 6, Part B). Therefore, in practice, the Reg 6, Part B limit is less stringent than the Reg 1 limit (longer averaging time for daily barrels), so the Reg 6, Part B limit will be streamlined out in favor of the Reg 1 limit. Reg 6, Part B will be identified in Section III.3 of the permit as a streamlined condition.

Based on the above analysis, the following revisions were made to the permit:

- Removed Condition 22.1 (Reg 6, Part B SO_2) from Section I, Condition 1.5.
- The references to the Reg 6, Part B SO_2 requirements (Condition 22.1) were removed from the tables and text for the individual emission units in various parts of Section II.
- Section II, Condition 22.1 was removed (this includes the NSPS general provisions language included in this condition).
- The Reg 6, Part B SO_2 limitation (Section IV.C.2) was included in Section III.3 of the permit (permit shield for streamlined conditions)

Regulation No. 6, Part B, Section II – Particulate Matter Standards and General Provisions

Many of the heaters are subject to the Regulation No. 6, Part B, Section II requirements for particulate matter (lb/MMBtu standards and opacity), as well as the NSPS general provisions (on a state-only basis). Given that the limitations are similar, a streamlining analysis was done to see if any requirements could be streamlined in favor of more stringent requirements. The streamlining analysis is as follows:

Opacity

Many of the heaters are subject to the Regulation No. 1 opacity standards and the Regulation No. 6, Part B opacity requirement. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% opacity requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other <u>at all times</u>, all applicable opacity requirements are included in the operating permit. See the attached grid (page 164) for a clarified view on the opacity requirements and their relative stringency.

PM

Many of the heaters are subject to the Regulation No. 1 and No. 6, Part B PM standards. The PM requirements in both Reg 1 and Reg 6, Part B are the same standard. The Regulation No. 6, Part B requirement is a state-only requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, unless indicated otherwise in the specific subpart, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "…it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B PM requirements do not apply during periods of startup, shutdown and malfunction. Therefore, the Regulation No. 1 PM requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirement will be streamlined out of the permit.

NSPS general provisions

Many of the heaters and boilers are subject to the NSPS general provisions (40 CFR Part 60) on a federal and state basis (the units are subject to 40 CFR Part 60 Subpart J) and on a state-only basis (the units are subject to Reg 6, Part B, Section II and the NSPS general provisions are adopted by reference in Reg 6, Part B, Section I.A). Therefore, the Division will streamline the state-only NSPS general provisions out of the permit in favor of the state and federal NSPS general provisions.

Based on the above analysis, the following revisions were made to the permit:

- Removed Condition 20.2 (Reg 6, Part B PM) from Section I, Condition 1.5.
- The references to the Reg 6, Part B particulate matter requirements (Condition 20.2) were removed from the tables and text for the individual emission units.
- Section II, Condition 20.2 was removed (this includes the NSPS general provisions language included in this condition).
- Revised Section II, Condition 36 to remove the language regarding Reg 6, Part B and state-only requirements was removed from Condition 36.
- The Reg 6, Part B PM limitations (Section II.C.2) and the general provisions (Section I.B) were included in Section III.3 of the permit (permit shield for streamlined conditions)

Tanks

- For tanks, the permit specifies that the most recent version of EPA TANKS be used to calculate emissions but allows the source as an alternate to use AP-42. The Division considers that the permit should only include one means to calculate emissions and initially revised the permit to require use of EPA TANKS as this is the method the source is currently using and is consistent with the with the Plants 1 and 3 permit (96OPAD120). Based on comments from the source (received on May 11, 2020), the Division revised the permit to allow the source to use TankESP to estimate emissions from tanks that are not subject to permit limits. Tanks without permit limits are included in Sections II.12 (Group B tanks), II.13 (Group C Tanks), II.14 (Group D Tanks), II.16 (Group F Tanks) and II.17 (Group G Tanks) and Tanks T012 and T038 in Section II.15 (Group E Tanks).
- The paragraph regarding updated versions of EPA TANKS and time delays has been removed, as this paragraph is no longer relevant.

Regulation No. 7 Citation Changes

As discussed previously, the AQCC adopted revisions to Colorado Regulation No. 7 on December 19, 2019 (effective February 14, 2020) and these revisions included reorganizing these requirements into various parts. This means that various sections are renumbered and assigned to a part (e.g. Part B) of the regulation. Therefore Regulation No. t citations throughout the permit were revised.

Appendix H – SO_2 Emissions Calculation Methodology

The provisions of Appendix H – SO_2 Emissions Calculation Methodology have been incorporated into the relevant locations in Section II of the permit. The Division considers that including the SO_2 emission calculation method in the relevant sections of the permit will make it easier for the source, inspector and/or others to follow to determine applicable requirements.

<u>Section II.1 – Crude Unit</u>

- The AP-42 emission factors listed in Condition 1.1 were converted to units of lb/MMBtu by dividing by 1020 Btu/scf, since the fuel consumption limit is in units of Btu. The NO_X emission factor for the crude unit, which was from the manufacturer, was also converted to lb/MMBtu by dividing by 1020 Btu/scf.

- Condition 1.6 (equipment leaks, NSPS GGG and MACT CC) applies to equipment leaks, which are also subject to other leak detection and repair requirements, as well as APEN reporting requirements. Therefore, the language in this condition was revised to refer to “new” Condition 19 for fugitive VOC equipment leaks without permitted emission limits.
- Added “new” Condition 1.9 for the Boiler MACT requirements (40 CFR Part 63 Subpart DDDDD).
- Added “new” Condition 1.10 for the Reg 7 combustion process adjustment requirements in Section XVI.D.

<u>Section II.2 – FCCU</u>

- Removed the process weight rate particulate matter emission limitations (Condition 2.4). Since these requirements are based on a tons/yr processing rate, it appears that they were not intended to apply to equipment processing a liquid feed. The Division may have considered that these requirements applied primarily because the FCCU is a source of PM emissions and at the time of initial Title V permit issuance it was not subject to other PM emission limitations. However, the FCCU is currently subject to the NSPS Subpart J PM limitations.
- Condition 2.6 (equipment leaks, MACT CC) applies to equipment leaks, which are also subject to other leak detection and repair requirements, as well as APEN reporting requirements. Therefore, the language in this condition was revised to refer to “new” Condition 19 for fugitive VOC equipment leaks without permitted emission limits.
- Added “new” Condition 2.21 for the Reg 7 combustion process adjustment requirements in Section XVI.D.

<u>Section II.3 – Naphtha Hydrotreater/Reformer</u>

- The summary table was split into 2 tables to provide more clarity with respect to requirements. One table covers the heaters and the other table covers reformer reactors and fugitive sources.
- The AP-42 emission factors listed in Condition 3.1 were converted to units of lb/MMBtu by dividing by 1020 Btu/scf, since the fuel consumption limit is in units of Btu.
- The NO_X emission limit in Condition 3.1 was corrected to 62.4 tons/yr. The most recent underlying construction permit (12AD032-4, FA w/mod issued November 19, 1996), included a NO_X limit of 62.4 tons/yr however, the Title V permit inadvertently included a NO_X limit of 63.4 tons/yr.
- Condition 3.6 (equipment leaks, MACT CC) applies to equipment leaks, which are also subject to other leak detection and repair requirements, as well as APEN reporting requirements. Therefore, the language in this condition was revised to refer to “new” Condition 19 for fugitive VOC equipment leaks without permitted emission limits.

- Added "new" Condition 3.10 for the Boiler MACT requirements (40 CFR Part 63 Subpart DDDDD).
- Added "new" Condition 3.11 for the Reg 7 combustion process adjustment requirements in Section XVI.D.

Section II.4 – Polymerization Unit

Other than VOC emissions from leaking piping components, the polymerization unit is a source of PM/PM_{10} emissions from catalyst loading/unloading and reactor blowdowns. VOC emissions from leaking piping components are not subject to permitted emission limits and are reported on an APEN for "grandfathered" equipment leaks. Section II.35 of the current permit (last revised June 15, 2009) addresses emission calculations for "grandfathered" equipment leaks.

A review of past inspection reports indicate that PM/PM_{10} emissions from catalyst loading/unloading and reactor blowdowns are below the APEN de minimis level (2 tons/yr) and thus are APEN exempt.

Therefore, since PM/PM_{10} emissions are below the APEN de minimis level and since VOC emissions from equipment leaks are addressed in another section of the permit, the polymerization unit has been removed from Section II of the permit and is included in the insignificant activity list. This is consistent with the way the polymerization unit has been addressed in the Plants 1/3 permit (96OPAD120).

Note that the Plant 2 cooling tower will be addressed in Section II.4 of the permit.

Section II.5 – Sulfur Recovery Plant

- Minor wording changes were made to various conditions and some changes were made to the order and format of requirements.
- The PM, PM_{10}, NO_X, VOC and CO emission factors in Condition 5.1 were all revised to units of lb/MMBtu since the gas input limit is in units of MMBtu. These are all AP-42 emission factors (Section 1.4) and were converted by dividing a heat content of 1020 Btu/scf per footnote a in Tables 1.4-1 and 1.4-2.
- The PM requirements in Reg 1, Section III.B.2.a (incinerator requirements) were included in the permit. These Reg 1 requirements are also included in the P1/3 permit (96OPAD120) for the P1/3 tail gas incinerator.

  The Common Provisions Regulation defines an incinerator as "any equipment, device, or contrivance used for the destruction of solids, liquids or gaseous wastes by burning, other than devices commonly called wigwam waste burners used exclusively to burn wood wastes." According to this definition, the tail gas incinerator is considered an incinerator. Therefore, the tail gas incinerator is subject to the requirements for incinerators.

  In addition to the Reg 1 incinerator requirements, the requirements in Reg 6, Part B, Section VII apply, for incinerators constructed or modified after January 30, 1979. The December 1999 revised initial Title V permit application indicates that the SRU and tail gas unit commenced operation sometime prior to January 1982. The initial approval construction permit for the construction permit was issued on February 1, 1972 thus it appears that the tail gas incinerator is subject to the Reg 6, Part B requirements. Specifically the incinerator is subject to the 20% opacity requirements in Reg 6, Part B, Section VII.C. The permit already includes a state-only 20% opacity requirement for the tail gas.

The Reg 6, Part B, Section VII requirements include particulate matter standards and specific requirements for monitoring and test methods. However, the Division's permit section (PS) memo PS 99-2, dated May 6, 1999, indicates that since these particulate matter standards are based on the charging rate, which is specified in tons/yr, the Division considers that these standards were not intended to apply to flares that were only burning waste gases, since a tons/yr charge rate is not practical for that type of incinerator. Since the particulate matter standards do not apply, the Division considers that the monitoring and testing requirement also do not apply.

- Added language to the SO_2 limit (1.2 vol %) in Condition 5.8 (claus plant operation) to indicate that data from all valid hours that gases are routed to the sulfur recovery unit incinerator, including periods of startup, shutdown and malfunction, shall be used to assess compliance with the limit.
- Revised the language in Condition 5.9 (PSD monitoring requirements) to state that periods when the CEMS is not operating shall be reported as monitor downtime. The current permit (last revised June 15, 2009) indicates that when the CEMS is down emissions shall be determined per Appendix H, but Appendix H just includes procedures to calculate emissions using the CEMS.
- Added language to Condition 5.11 (NSPS J requirements) to clarify that the sulfur recovery unit claus plant is not subject to the sulfur recovery unit requirements in NSPS J and that combustion of tail gas (which comes from the sulfur recovery unit claus plant) in the sulfur recovery unit incinerator is not subject to the fuel gas combustion device requirements in NSPS J.
- Added a "new" Condition 5.11 to require that emissions from the sulfur pit either be eliminated or routed to the tail gas incinerator (this is requirement in the CD).

Section II.7 – Crude Unloading/Gasoline Tank Truck Loading

The gasoline tank truck "flare" is enclosed, so as defined in 40 CFR Part 60 Subpart XX and Part 63 Subpart R (requirements for bulk gasoline terminals), it is not a flare. The definition of flare in 40 CFR Part 63 Subpart CC (requirements for petroleum refineries), is slightly different than the definitions in Subparts XX and R, so the source initially presumed that the truck rack combustor would be considered a "flare". The source requested an applicability determination from EPA, as to whether the truck dock "flare" is in fact a flare. In an April 17, 2017 response, EPA indicated that the truck rack combustor is not flare as defined in 40 CFR Part 63 Subpart CC. Thus the truck rack combustor is not subject to the flare requirements in 40 CFR Part 60, Subpart XX and Part 63 Subparts R and CC. The truck rack combustor is referred to a "flare", so references to the unit throughout the permit will be revised to indicate it is a "combustor", not a "flare."

- Minor wording changes were made to various conditions and some changes were made to the order and format of requirements.

- Added additional language to Condition 7.2 (NSPS J) to more appropriately reflect the requirements in the EPA-approved AMP.
- Revised the RACT requirements in Conditions 7.4 and 7.5. The statement in Condition 7.4 regarding the flare complying with the requirements in Condition 60.18 was removed, as these requirements no longer apply (the combustor is not a flare). Condition 7.4 was revised to indicate that Reg 7, Section VI.D.2.a applies to the truck rack. Condition 7.5 was revised to indicate that the requirements in Reg 7, Section VII.B apply to the crude rack in lieu of Section VI.A.1 (Section VII.B refers to VI.A).
- Included the temperature monitoring language in Condition 7.4 as a separate, “new” Condition.
- Added a “new” requirement to monitor and record the quantity of pilot and supplemental fuel burned in the combustor.
- Removed Condition 7.9 (NSPS flare requirements, §60.18) since it does not apply.
- Revised the opacity requirement in Condition 7.8 to reflect the 20%./30% requirements in Reg 1, Section II.A.1 and 4. The current permit (last revised June 15, 2009) includes the opacity requirement in Reg 1, Section II.A.5 for flares which does not apply. Frequency of monitoring visible emissions shall be daily, which is consistent with the monitoring required for the Plants 1/3 loading racks in that permit (96OPAD120).
- Added a “new” requirement to conduct subsequent performance tests every five years to verify compliance with the MACT CC loading rack limit and reset the operating parameter (temperature).

<u>Section II.8 – Refinery Flare</u>

- Minor wording changes were made to various conditions and some changes were made to the order and format of requirements.
- The RACT requirements listed for the refinery flare (Condition 8.5) references the requirements in Regulation No. 7, Section VIII.B.6, which is the control device requirements but it should also reference Section VIII.B.3 (route process relief valves to flare). This is consistent with the RACT requirements for the flares in the Plants 1 and 3 permit (96OPAD120). Therefore the RACT requirement (Condition 8.5) was revised to include both Sections VIII.B.3 and 6. In addition, the second sentence in this condition was removed since the same sentence is noted in Condition 27.6 (includes the RACT requirements in Section VIII.B.6).
- Condition 8.7 (leaks from pump seals shall be routed to flare) is not included in the summary table, so the summary table was revised to include this requirement.
- Condition 8.6 (NSPS GGG) applies to equipment leaks, which are also subject to other leak detection and repair requirements, as well as APEN reporting requirements. Therefore, the language in this condition was revised to refer to “new” Condition 19 for fugitive VOC equipment leaks without permitted emission limits.
- Added a requirement for hours of operation which is necessary to determine the flow

rate from the pilot gases.

Section II.9 – LPG Storage Truck and Rail Facility

- Minor wording changes were made to various conditions and some changes were made to the order and format of requirements.
- Added additional language to Condition 9.2 (NSPS J) to more appropriately reflect the requirements in the EPA-approved AMP.
- Added a “new” separate condition for fugitive sources to refer to the APEN reporting and leak detection and repair requirements to “new” Condition 19. The source requested a VOC emission limit for equipment leaks associated with LPG loading at the rail rack, the rail rack flare and the LPG truck rack. However, any VOC emissions from loading petroleum products at the rail rack are unpermitted, thus the new condition will address those.
- Revised the RACT requirements in Condition 9.5. The statement in Condition 9.5 regarding the flare complying with the requirements in Condition 60.18 was removed, as this is stated in Condition 27 (Reg 7, Section VIII requirements). In addition, Condition 9.5 was revised to indicate that Reg 7, Section VIII.B, applies in lieu of just VIII.B.6.
- Expanded the information provided in the table for the flare requirements (Condition 9.9).

Section II.10 – Wastewater Treatment System

- Removed the throughput limit for the Middle API in Condition 10.6 and the requirement to record the actual quantities of water treated. Permitted emissions for the majority of the Plant 2 WWTS (upper, middle and lower APIs, API lift stations and API sumps) were included in the permit. The emission limitations were based on inlet VOC concentrations and exhaust flow through carbon canisters. Therefore a throughput limit was not necessary for the emission limitation. In addition, since flow through the Plant 2 wastewater treatment system can vary and be beyond the control of the plant (includes storm water) throughput limits can be problematic; therefore throughput limits were not included. This is consistent with the permitting for the Plant 1 WWTS in that permit (96OPAD120). The Division considers that sufficient monitoring of waste streams is provided for in the BWON requirements.

Section II.12 – Group B Tanks

- The language in Condition 12.1 (emission calculations) was revised to specify that emissions be based on the average (or numerically greater RVP) of the materials stored over the annual period.
- Noted in Condition 12.2 that the tanks are Group 1 tanks under MACT CC.
- Reformatted Condition 12.3 (Reg 7 RACT requirements).
- Revised the wording in Condition 12.4 to specify that annual throughput shall be monitored and recorded and that records of the vapor pressures of the stored materials be maintained.

Section II.13 – Group C Tanks

- The language in Condition 13.1 (emission calculations) was revised to specify that emissions be based on the average (or numerically greater RVP) of the materials stored over the annual period.
- Noted in Condition 13.2 that the tanks are Group 2 tanks under MACT CC.
- Included Reg 7, Section VI.A.1 as an applicable requirement to Condition 13.3 (Reg 7 RACT requirements). Tanks storing exempt materials as noted in Reg 7, Section VI.B.1.a are only exempt from the requirements in Sections VI.B.2 and 3, Section VI.A.1 still applies. Also added language to Condition 13.3 to require that records be retained to verify that only the exempt materials listed in Section VI.B.1.a are stored in these tanks.
- Revised the wording in Condition 13.4 to specify that annual throughput shall be monitored and recorded and that records of the vapor pressures of the stored materials be maintained.

Section II.14 – Group D Tanks

- The language in Condition 14.1 (emission calculations) was revised to specify that emissions be based on the average (or numerically greater RVP) of the materials stored over the annual period.
- Noted in Condition 14.2 that the tanks are Group 2 tanks under MACT CC.
- Included the Reg 7 RACT requirements in one Condition (Condition 14.3). The Reg 7, Section VI.A.1 requirements were included as an applicable requirement. Added language to Condition 14.3 to require that records be retained to verify that only the materials with a true vapor pressure less than or equal to 0.65 psia (at 20º C) or an RVP of 1.3 psia are stored in the tank.
- Revised the wording in Condition 14.5 to specify that annual throughput shall be monitored and recorded and that records of the vapor pressures of the stored materials be maintained.

Section II.15 – Group E Tanks

- The construction permit (88AD298-2) for Tank T47 was revised on February 3, 2006 and this revision is not reflected in the Title V permit. Therefore, the emission and throughput limits for Tank T47 were revised to reflect the February 3, 2006 construction permit.
- Added conditions to calculate emissions and record throughput annually for Tanks T012 and T038 as these tanks are not subject to emission or throughput limitations.
- Section II, Condition 15.3 was revised to indicate that all tanks are subject to the requirements in Reg 7, Section VI.A.1 and that tank T012 is subject to the requirements in Reg 7, Section VII.B and C. In addition, RACT conditions (Conditions 15.2 through 15. 7) were included under one permit condition (Condition 15.2). Added language to require that records be kept of tank contents for those tanks (T012, T046, T062 and T079) exempt from Reg 7 RACT requirements

because of contents.

- Condition 15.8 was revised to indicated that Tank T046 is not subject to the requirements in NSPS Kb (tank stores materials with a maximum true vapor pressure less than 0.5 psia and is exempt per 60.1110b(b)).
- The throughput limit for Tank T046 is included in the summary table but not in the text of the Title V permit, therefore, this is being corrected.
- In order to be consistent with the Plant 1/3 Title V permit (96OPAD120), the throughput limits will all be included in units of barrels. Therefore, the limits for Tanks T006, T026, T047 and T053 were converted to barrels.
- The relevant true or reid vapor pressure has been included in the description of allowable throughputs. In addition, in order to be more consistent, the language in the summary table regarding allowable throughputs just includes the primary material (e.g. gasoline) and the text contains the full language (e.g. gasoline and/or materials with a RVP of 15 psia or less)

<u>Section II.16 – Group F Tanks</u>

- The language in Condition 16.1 (emission calculations) was revised to specify that emissions be based on the average (or numerically greater RVP) of the materials stored over the annual period.
- Noted in Condition 16.2 that the tanks are Group 1 tanks under MACT CC.
- Reformatted Condition 16.3 (Reg 7 RACT requirements).
- Revised the wording in Condition 16.4 to specify that annual throughput shall be monitored and recorded and that records of the vapor pressures of the stored materials be maintained.

<u>Section II.17 – Group G Tanks</u>

- The language in Condition 17.1 (emission calculations) was revised to specify that emissions be based on the average (or numerically greater RVP) of the materials stored over the annual period.
- Noted in Condition 17.2 that tank T025 is a Group 1 tank and the others are Group 2 tanks under MACT CC.
- Reformatted Condition 17.3 (Reg 7 RACT requirements). Added language to indicate that Tank T028 is subject to requirements in Reg 7, Section III.B.
- Revised the wording in Condition 17.4 to specify that annual throughput shall be monitored and recorded and that records of the vapor pressures of the stored materials be maintained.

<u>“New” Section II.19 – Fugitive VOC Equipment Leak Emissions without Permit Limits</u>

Note that in the current permit (last revised June 15, 2009), Section II.19 includes opacity limits.

- This section was added to address fugitive VOCs from equipment leaks that are not subject to permit limits.

Section II.19 – Opacity Limits

These requirements were moved to "new" Section II.20, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.20 includes PM requirements for fuel burning equipment.

- Revised Conditions 19.1, 19.2 and 19.3 to reflect actual language in Reg 1.
- Based on EPA's response to a petition on another Title V operating permit, minor language changes were made to Condition 19.5.1 (monitoring for fuel burning equipment) to clarify that only gaseous fuel is permitted to be used as fuel and included a requirement to retain records that only gaseous fuel is burned.
- Where appropriate, monitoring language for the equipment has been modified to be consistent with the language in the Plants 1/3 permit (96OPAD120).
- Removed the language for the cooling tower and the polymerization unit loading and unloading. The polymerization unit was removed from Section II of the permit and opacity monitoring for the cooling tower is included in the cooling tower section ("new" Section II.4).
- Created a separate condition for the truck loading dock enclosed combustor, since it does not meet the definition of a flare.
- Added language to the opacity monitoring condition for the P2 flare to address the new MACT CC requirements for flares (once these apply, the P2 flare is no longer subject to 60.18 or 63.11(b)).
- Revised the opacity monitoring language for the railcar dock flare to address periods when the flare visibility monitoring requirements indicate non-compliance with the flare visible emission requirements.

Section II.20 – PM Limits – Fuel Burning Equipment

- Based on EPA's response to a petition on another Title V operating permit, minor language changes were made to Condition 20.1 (monitoring for fuel burning equipment) to clarify that only gaseous fuel is permitted to be used as fuel and included a requirement to retain records that only gaseous fuel is burned.

Section II.21 - PM Limits – Manufacturing Processes

- This condition (the Reg 1 process weight rate PM limits) was removed from the permit. Upon further review, since the process weight rate limits are determined based on the processing rate, in tons/hr, that such limits were not intended to apply to manufacturing processes that process liquid feed. The PM requirements for fuel burning equipment were moved to this section.

"New" Section II.22 – Solvent Usage - Cold Cleaner Solvent Degreasers and Industrial Solvent Cleaning Operations

Note that in the current permit, (last revised June 15, 2009), section II.22 includes SO_2

requirements.

The insignificant activity list in Appendix A indicates that there are three (3) degreasers for parts cleaning. Cold cleaner solvent degreasers are subject to requirements in Colorado Regulation No. 7, Section X. Although emissions from the solvent degreasers are below the APEN de minimis level and therefore exempt from both APEN reporting and construction permit requirements, under the “catch-all” provisions in Regulation No. 3, Part C, Section II.E (2nd paragraph) the solvent degreasers cannot be considered insignificant activities because they are subject to specific requirements in Regulation No. 7. Since the solvent degreasers cannot be considered insignificant activities, they have been included in this Section II.22 as significant emission units.

The applicable requirements from Regulation No. 7 for these units are as follows:

- Transfer and storage of waste solvent and used solvent (Reg 7, Sections X.A.3 and 4)
- Solvent Cold Cleaner Requirements (Reg 7, Section X.B)
  - Control Equipment - covers, drainage, labeling and spray apparatus requirements (Reg 7, Section X.B.1)
  - Operating Requirements (Reg 7, Section X.B.2)

As discussed previously, revisions to Colorado Regulation No. 7 were adopted on November 17, 2016 (effective January 14, 2017) and included EPA’s CTG for industrial solvent cleaning operations. These requirements apply to facilities with actual, uncontrolled VOC emissions from solvent cleaning operations at or above 3 tons on a calendar year basis. The Division considers that these requirements may apply to the facility in some years. Therefore, the requirements in Reg 7, Section X.E. were included in the permit.

Section II.22 – SO_2 Requirements

This section was removed and the requirements that were included in this section were addressed as follows:

- As discussed previously, Condition 22.1 (Reg. 6, Part B SO_2 limit) was removed and is included in the permit shield for streamlined conditions (Section III.3).
- Conditions 22.2 (Reg 1 SO_2 limit) and 22.3 (facility wide SO_2 ton/yr limit) are included in “new” Section II.23 (facility wide requirements).
- Condition 22.4 (rely on Appendix H for approved methods to monitor compliance with the SO_2 limits) has been removed. The provisions in Appendix H have been included in various parts of Section II to stipulate how SO_2 emissions are to be monitored.
- Conditions 22.5.1 and 22.5.2 (NSPS J fuel gas combustion device SO_2 limit and monitoring requirements) are included in “new” Section II.31 for NSPS Subpart J requirements.
- The requirements in Conditions 22.5.3 (compliance options for refinery flare to meet

NSPS J), 22.5.4 (submittal of compliance plan for refinery flare to meet NSPS J), 22.5.5 (conduct a flare performance test) and 22.5.6 (exemption from NSPS J for process upset gases, relief valve leakage or other emergency malfunction) were removed for the following reasons.

The source was complying with the NSPS J requirements through the use of the H_2S CMS, a compliance plan had been submitted and the performance test completed. The requirements for the compliance plan (22.5.4 and 22.5.5) and performance test were removed. The refinery flare triggered the NSPS Ja requirements, which include the same H_2S limit and H_2S CMS, as well as additional monitoring requirements. The NSPS Ja requirements are as or more stringent than the NSPS J requirements thus the NSPS J requirements were streamlined and so Conditions 22.5.3 and 22.5.6 can be removed.

<u>“New” Section II.23 – Facility Wide Requirements</u>

Note that in the current permit (last revised June 15, 2009), Section II.23 includes the requirements in Reg 7, Section III.

- This section was created to address facility wide requirements, such as the Reg 1 SO_2 limit and the facility wide SO_2 (ton/yr limit).

<u>Section II.23 – Reg 7, Section III Requirements (RACT for storage and transfer of VOC, general requirements)</u>

These requirements were moved to “new” Section II.24, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.24 included the requirements in Reg 7, Section IV.

- Revised the second sentence in Condition 23.1 to indicate that all storage tanks are subject to these requirements.
- The monitoring requirements for Condition 23.1 were revised to indicate that all tanks must be monitored semi-annually. The source is currently monitoring all tanks semi-annually and has indicated that they would accept a semi-annual monitoring requirement for all tanks. The semi-annual monitoring requirement is consistent with the requirements in the P1/3 Title V permit.

<u>Section II.25 – Reg 7, Section VI Requirements (RACT for storage and transport of petroleum liquids)</u>

These requirements were moved to “new” Section II.26, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.26 includes the requirements in Reg 7, Section VII.

- Removed the paragraph indicating the source will conduct annual inspections from Condition 25.1. Compliance with this condition will be monitored via leak detection requirements specified in other applicable requirements. This is consistent with the Plant 1/3 Title V permit (96OPAD120) which does not include an annual inspection requirement.

- Added language indicating which tanks are subject to the requirements in Condition 25.1 (Reg 7, Section VI.A.1)
- Added Tank T024 to the list of tanks subject to the requirements in Reg 7, Section VI.B.2.a in Condition 25.2.1.
- Removed the sentence in Condition 25.2.3 indicating that a copy of the complete regulation is attached (it will not be) and also removed the note indicating that this condition continues to apply for areas designated as attainment/maintenance (the area is non-attainment).
- Added the Reg 7 citations for Conditions 25.3.2 through 25.3.4.
- The loading racks are subject to more stringent emission limitations under 40 CFR Part 63 Subpart CC (10 mg/l) than the Reg 7 requirements in Section VI.C.2.b.(vii) (80 mg/l). 40 CFR Part 63 Subpart CC stipulates that loading racks meet the requirements in 40 CFR Part 63 Subpart R, which specifies requirement for control devices. In a January 30, 2019 application, the source revised their permit to cease loading of gasoline at the rail rack, thus the requirements in Reg 7, Section VI.C.2 no longer apply to the rail rack. As indicated previously, the truck rack vapor combustor does not meet the definition of a flare in MACT CC or R, therefore, the language in Conditions 25.3.2 and 25.3.3 regarding the requirements in 60.18 have been removed. Language has been added to indicate that absent credible evident to the contrary, compliance with Conditions 25.3.2 through 25.3.4 are met if the truck rack vapor combustor meets the temperature monitoring requirements (required by MACT CC via MACT R) and the truck rack meets the requirements in MACT CC (which refers to MACT R).

  Once the MACT CC requirements for flares apply (January 30, 2019), flares that are subject to MACT CC no longer have to comply with 60.18 or 63.11(b), so language was added to indicate that flares that meet the MACT CC requirements comply with the requirements in Conditions 25.3.2 through 25.3.4.
- To be consistent with the language in the Plant 1/3 permit (96OPAD120), the statement in Condition 25.4.1 indicating that an inspection will be performed while loading was removed.
- The requirements for terminals (Condition 25.3) and for transport vehicles – rail cars (Condition 25.4) were expanded to include more of the Reg 7 requirements. Note that the language includes revisions made to Reg 7 on December 19, 2019 (effective February 14, 2020).
- To be consistent with the Plant 1/3 permit (96OPAD120), the requirements for tank trucks in Reg 7, Section VI.D.2.a were included.

<u>Section II.26 – Reg 7, Section VII Requirements (RACT for crude oil)</u>

These requirements were moved to "new" Section II.27, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section

II.27 includes the requirements in Reg 7, Section VIII.

- Added Tank T012 to the list of tanks subject to the crude oil requirements in Reg 7, Section VII.
- Removed the statement in Condition 26.1 indicating that the permittee is subject to all applicable requirements of Section VII and that Section VII is federally and state-enforceable. The statement is considered unnecessary, so it has been removed.
- The language is this condition was revised to reflect the language in the regulation.

Section II.27 – Reg 7, Section VIII Requirements (RACT for petroleum refineries)

These requirements were moved to "new" Section II.28, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.28 includes the requirements in Reg 7, Section XV.

- In general, all substantive conditions were assigned numbers.
- Changes were made to the summary table to properly reflect the requirements and the monitoring method.
- Added language indicating that in the absence of credible evidence to the contrary, compliance with the provisions in Conditions 27.3 and 27.6 and 27.7, are presumed provided that the flare requirements are met. This is consistent with the monitoring included in the Plants 1/3 permit (96OPAD120).

  Once the MACT CC requirements for flares apply (January 30, 2019), flares that are subject to MACT CC no longer have to comply with 60.18 or 63.11(b), so language was added to indicate that flares that meet the MACT CC requirements comply with the requirements in Conditions 27.3 and 27.6 and 27.7.
- Added language to Condition 27.5 indicating that compliance with this condition would be monitored by inspection during a monthly walk-through. This is consistent with the monitoring requirements in the Plants 1/3 permit (96OPAD120).
- The statements starting with "in lieu of." in Conditions 27.6 and 27.7 were removed.
- Added the requirements in Colorado Regulation No. 7, Section VIII.C.2.c.
- Included the monitoring provisions in Colorado Regulation No. 7, Section VIII.C.4.a.

Section II.28 – Regulation No. 7, Section XV Requirements (RACT for VOC Leaks from Gasoline Terminals, Bulk Plants and Dispensing Facilities)

These requirements were moved to "new" Section II.29, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.29 includes the NSPS Kb requirements.

- In general, all substantive conditions were assigned numbers. Revisions were made to reflect the December 19, 2019 revisions to Regulation No. 7 (effective February 14, 2020).

Section II.29 – NSPS Kb

These requirements were moved to "new" Section II.33, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.33 includes the 40 CFR Part 63 UUU requirements.

- Added a statement to the beginning of this section, indicating which version of the rule is included and that the permittee is subject to the most recent versions of the requirements.
- The list of tanks applicable to the NSPS Kb requirements was revised to indicate that Tank T046 is not subject to these requirements (it stores materials with a maximum true vapor pressure less than 0.5 psia per 60.110b(b)).
- Revisions were made to include more information regarding the requirements that apply and to indicate which requirements the various tanks are subject to.
- Removed Condition 29.6 regarding the NSPS general conditions. The summary tables for the individual emission units will note that the source is also subject to the NSPS general provisions.

Section II.30 – NSPS GGG

These requirements were moved to "new" Section II.36, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.36 include the NSPS General Provisions.

- Added a statement to the beginning of this section, indicating which version of the rule is included and that the permittee is subject to the most recent versions of the requirements.
- The headers in this condition were revised to reflect the actual section titles in the rules
- Included the requirements in 60.592(c) and the exceptions in 60.593. Note that the exception in 60.593(e) was not included as it does not apply (60.593(e) applies to equipment located on the Alaskan Northern Slope).
- Removed Condition 30.3 regarding the NSPS general conditions. The summary tables for the individual emission units will note that the source is also subject to the NSPS general provision

"New" Section II.31 – NSPS J

Note that in the current permit (last revised June 15, 2009), Section II.31 includes the requirements in NSPS QQQ.

- The NSPS J requirements were included in this section.

Section II.31 – NSPS QQQ

These requirements were moved to "new" Section II.38, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.38 includes the BWON requirements.

- Added a statement to the beginning of this section, indicating which version of the rule is included and that the permittee is subject to the most recent versions of the requirements. The statement after Condition 31.22 that indicates that the source is subject to the most recent requirements and that the requirements are state and federally enforceable was removed.
- Corrected Condition 31.21 to read as indicated in 60.697(a), as this requirement cannot be revised. A statement was added to indicate that records are to be kept for 5 years as specified in General Condition 22.b & c.
- Removed Condition 31.23 regarding the NSPS general conditions. The summary tables for the individual emission units will note that the source is also subject to the NSPS general provisions.

"New" Section II.34 – NSPS VV

Note that in the current permit (last revised June 15, 2009), Section II.34 includes the Production Limit.

- The requirements in NSPS GGG reference sections of NSPS VV, thus the requirements in VV were included in this new section.

  Note that 60.482-1(g) was not included since that paragraph has been stayed until further notice.

Section II.36 – NSPS General Provisions

These requirements were moved to "new" Section II.30, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009). Note that in the current permit (last revised June 15, 2009), Section II.30 includes the NSPS GGG requirements.

- All conditions except for Conditions 36.1, 36.5 and 36.6 were removed. Except for Condition 36.7, the conditions that were removed are included in "new" Section II.46 for CEMS and COMS.

Section II.37 – Flare Requirements

These requirements were moved to "new" Section II.43, the below discussion addresses the requirements as they appear in the current Title V permit (last revised June 15, 2009).

- Added language to Condition 37.2 to indicate the methods used to ensure a flame is present.
- Condition 37.3 was revised to list the net heating value requirements.

- Removed the second sentence in Condition 37.7 to be consistent with the language in the Plants 1 and 3 permit (96OPAD120).
- The visible emission monitoring language in Condition 37.9 was revised to be more consistent with the language and requirements for flares in the Plants 1 and 3 permit (96OPAD120). To that end frequency of conducting visible emissions observations was revised to daily (when the flares are in operation), increasing the length of observations from 5 minutes to 6 minutes and adding additional language to clarify the requirements.

Section II.39 – Emission Factors

- This condition provides information on emission factors. Since this condition doesn't include any applicable requirements, the Division considers that this condition is not necessary and it was removed.

  Note that the BWON requirements have been included in this section.

Section II.40 – Maximum Achievable Control Technology

- This condition notes that EPA finalized MACT standards for organic liquid distribution (non gasoline) and industrial, commercial and institutional boilers and process heaters and notes that if the source is subject to these requirements the permit will be modified using the appropriate procedures to include these requirements. This condition has been removed.

  The requirements for industrial, commercial and institutional boilers and process heaters (40 CFR Part 63 Subpart DDDDD) are included in "new" Section II.42 and the organic liquid distribution requirements (40 CFR Part 63 Subpart EEEE) do not apply thus they are not included in the permit.

"New" Section II.44 – Fuel Monitoring

- A general fuel monitoring requirement was added to new Section II, Condition 44. The language in this condition is consistent with the language that will be included in the Suncor Plants 1 and 3 permit (96OPAD120). In the specific equipment sections in Section II, individual conditions related to fuel consumption refer to this Condition 44 for fuel monitoring.

  The language clarifies that the gross (higher) heating value of the fuel shall be used in emission calculations and to determine heat input (fuel use) for fired equipment.

"New" Section II.45 – Continuous Emission Monitoring and Continuous Opacity Monitoring System Requirements

- General requirements for CEMS and COMS were included in this section.

"New" Section II.48 – Reg 7, Section XVI.D Requirements (RACT for combustion process adjustment)

- The combustion process adjustment requirements and associated recordkeeping requirements in Reg 7, Section XVI.D.6 and XVI.D.7.f were included in this section, except as discussed below. Note that in the relevant equipment specific sections, conditions have been added to refer to this condition.

Section XVI.D.7.f.(i)(F) was not included as the process heaters only burn gaseous fuel.

Section III – Permit Shield

- The following changes were made to the permit shield for non-applicable requirements (Section III.1):
  - As discussed previously, the permit shield for non-applicable requirements was revised to reflect the source's September 1, 2016 submittal, with some exceptions. See the discussion in Section III.1.25 of this document.
- The following changes were made to the permit shield for streamlined conditions (Section III.3):
  - Updated permit condition numbers in the 1st column of the table.
  - The facility wide SO_2 limit of 0.7 lb/bbl/day (state-only limit) was removed from the permit shield for streamlined conditions. Reg 1 was revised to revert to the SIP limit for new refineries (previously approved language in Reg 1 for new refineries), therefore, this requirement is no longer included in Reg 1 and should not be included in the permit shield for streamlined conditions.

Section IV – General Conditions

- A version date was added.
- The paragraph in Condition 3.d indicating that the requirements are state-only has been removed, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.
- The title for Condition 6 was changed from "Emission Standards for Asbestos" to "Emission Controls for Asbestos" and in the text the phrase "emission standards for asbestos" was changed to "asbestos control".
- Revised General Condition 12 to include requirements in Reg 3, Part D.
- Corrected the citation in Condition 18 (changed from "CCR 1001-17" to "CCR 1001-19").
- Revised the language in Condition 22.e to reference Reg 3, Part A, Section II.A and to indicate that an APEN shall be filed once per year for control equipment changes at condensate storage tanks subject to Reg 7, Part D, Section I (previously Reg 7 Section XII).
- Added major stationary source monitoring, recordkeeping and reporting requirements in "new" Condition 24. Conditions that follow are renumbered.
- Condition 29 (VOC) was revised primarily to add the provisions in Reg 7, Section III.C as paragraph e although other minor language and format changes were made. In addition, Condition 29 (VOC) was revised to reflect the December 19, 2019 Reg 7 revisions (correct citations) and to note in the introductory paragraph that portions are state-only in certain areas (new nonattainment areas for either the 1-hr or 8-hr ozone standard).

Appendices

- The following changes were made to the insignificant activity list in Appendix A.
  - Language was added to indicate those insignificant activity categories for which records should be available to verify insignificant activity status.
  - The insignificant activity "categories" were shortened and revised as necessary, the appropriate regulatory citation was added and the insignificant activities were grouped under their respective category.
  - The polymerization unit (P006) was moved from Section II to the insignificant activity list.
  - Ethanol unloading at the truck and railcar dock were included in the insignificant activity list (VOC emissions below 1 ton/yr).
  - At the request of the Division, the source submitted a revised list of insignificant activities on September 22, 2016 and these were included in the permit. See the discussion in Section III.1.25 of this document.
- The following changes were made to the tables in Appendices B and C:
  - Revisions were made to reflect the emission units identified in the table in Section I, Condition 5.1. Of specific note, the Group C tanks and some fugitive emission source groupings were not included in these tables in the current permit (revised June 15, 2009).
  - Removed the polymerization unit, since it is not included in Appendix A as an insignificant activity.
  - Added facility wide requirements.
  - Added cold cleaner solvent degreasers and industrial solvent cleaning operations.
- The Reg 3 citation for the Responsible Official on the certifications in Appendices B and C were revised (the version date was also changed).
- Revised Appendix D to add a version date, correct EPA information, clarify permit mods sent to EPA and replace "Jim King" with "Title V Unit Supervisor".
- Cleared the information from the table in Appendix F.

Suncor Plant 2 (East Plant) – Potential to Emit

Emission Unit	AIRs Pt No.	Method (footnote #)	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Crude Unit								
Crude Heater	206	1	4.99	4.99	17.77	55.85	55.19	3.6
Vacuum Heater	295	1	1.36	1.36	6.13	10.18	5.43	0.73
FCCU								
Preheater	205	1	1.9	1.9	7	23.2	21.4	1.4
Regenerator	217	1	24.1	24.1	30.8	53.1	67.3	13
Naphtha Hydrotreater and Reformer								
Heaters 1, 2 & 3	208	1	5.4	5.4	26	62.4	28.2	3.9
Sulfur Recovery Plant								
Claus Plant, Amine Unit, SWS routed to TG incinerator	220	1	0.07	0.07	271	50.95	0.80	0.05
Utilities								
Boilers 504 & 505	309	1	8.3	8.3	12.7	36.4	33.1	4.5
Cooling Tower	304	1	4.8	4.8				23.1
Crude Unloading & Gasoline Truck Tank Loading Docks								
Tuck loading docks w/flare*	204	1	0.30	0.30	0.02	3.7	16.9	17.2
Truck loading dock fugitives*								0.6
North (old) crude unloading**	290	1						9.4
South (new) crude unloading**	293	1						
Refinery Flare	279	1	1.84	1.84	18.3	16.8	76.4	84.8
LPG Storage, LPG Truck Loading and Railcar Loading w/flare								
Rail rack flare	284	1	0.13	0.13	0.002	1.10	5.00	37.8
LPG Truck rack	319	1	1					0.9
Wastewater Treatment System	283	1						4.95
Tank T29	245	1						1.71
Group B Tanks								
T010	226	2						4.69
T027	242	2						7.21
T030	246	2						0.05
Group C Tanks								
T008	224	2						0.32
T009	225	2						0.1
T043	258	2						0.12
T045	260	2						0.06
T048	261	2						0.08
T049	262	2						0.1
T057	270	2						0.77
Group D Tanks								
T039	254	2						0.06
Group E Tanks								
T006	223	1						16.7
T011	227	1						4.26
T012	228	2						0.06
T020	234	1						0.96
T026	240	1						6.83

Emission Unit	AIRs Pt No.	Method (footnote #)	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
T038	253	2						1.87
T046	281	1						0.56
T047	282	1						6.81
T053	266	1						3.77
T058	271	1						4.65
T062	274	1						0.13
T079	306	1						2.1
Group F Tanks								
T035	250	2						4.98
T036	251	2						3.16
T044	259	2						2.41
T052	265	2						1.03
T054	267	2						6.88
Group G Tanks								
T025	239	2						0.78
T028	243	2						0.28
T037	252	2						0.88
Fugitive VOC Emission Sources								
Plant Wide - No Emission Limits	289	2						17.5
Gas Plant Fugitives	280	1						24.5
Piping Mod (SEP project) Fugitives*	297	1						5.21
Second Stage of Crude Oil Desalting Project Fugitives*								2.82
Tank T079 Installation Fugitives	308	1						0.61
Boilers B504 and B505 Tie-In Fugitives	310	1						2.8
Fugitives Identified in 2014 COC	314	1						9.55
MPV Project Fugitives	316	1						2.55
P2 Flare RSR Project Fugitives	317	1						0.16
LPG loading at Rail Rack, rail rack Flare and LPG Truck Rack Fugitives	320	1						0.75
Miscellaneous Sources								
Thermal Oxidizer for Tank Cleaning	315	1	0.15	0.15		2.73	1.57	17.2
Total			**53.34**	**53.34**	**389.73**	**266.41**	**311.29**	**373.95**

Emissions from the security center emergency generator, emergency air compressors and solvent cold cleaners not included since emissions from these are below the APEN de minimis level.

*Emissions from these sources have the same AIRS id and are included on the same CP but with separate emission limits.

**This is a combined VOC emission limit for these sources.

1 Emissions based on permit limits and/or requested emissions. If no permit limits on certain pollutants, emissions are based on throughput limits and appropriate emission factors.

2 Actual emissions multiplied by 1.2.

Suncor Plant 2 (East Plant) – Actual Emissions

Emission Unit	AIRs Pt No.	Data Year	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Crude Unit								
Crude Heater	206	2014	3.35	3.35	0.95	37.48	37.04	2.42
Vacuum Heater	295	2014	0.63	0.63	0.13	4.7	2.51	0.34
FCCU								
Preheater	205	2014	0.49	0.49	0.14	9.89	5.45	0.36
Regenerator	217	2015	17.42	17.42	13.62	25.64	6.14	10.08
Naphtha Hydrotreater and Reformer								
Heaters 1, 2 & 3	208	2014	3.71	3.71	1.02	37.37	19.93	2.69
Sulfur Recovery Plant								
Claus Plant, Amine Unit, SWS routed to TG incinerator	220	2015	0.03	0.03	23.2	0.34	0.32	0.02
Utilities								
Boilers 504 & 505	309	2013	4.17	4.17	1.09	21.94	1.55	3.35
Cooling Tower*	304	2014	4.12	4.12				0.88
Crude Unloading & Gasoline Truck Tank Loading Docks								
Tuck loading docks w/flare	204	2014				0.43	2.33	0.11
North (old) crude unloading	290	2014						0.44
South (new) crude unloading	293	2012						3
Refinery Flare	279	2014			0.87	9.92	53.98	9.25
LPG Storage, LPG Truck Loading and Railcar Loading w/flare								
Rail rack flare	284	2018	0.08	0.08		0.86	3.02	24.16
LPG Truck rack	319	2018						0.62
Wastewater Treatment System	283	PTE						4.95
Tank T29	245	PTE						1.71
Group B Tanks								
T010	226	2014						3.91
T011	227	2014						4.34
T027	242	2014						6.01
T030	246	2011						0.04
Group C Tanks								
T008	224	2014						0.27
T009	225	2014						0.08
T043	258	2014						0.1
T045	260	2014						0.05
T048	261	2014						0.07
T049	262	2014						0.08
T057	270	2014						0.64
Group D Tanks								
T039	254	2014						0.05
Group E Tanks								
T006	223	2012						3.23
T012	228	2014						0.05
T020	234	2014						0.04

Emission Unit	AIRs Pt No.	Data Year	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
T026	240	2012						2.06
T038	253	2014						1.56
T046	281	2014						0.01
T047	282	2014						1.54
T053	266	2014						1.96
T058	271	2017						0
T062	274	2014						0.06
T079	306	2013						2.1
Group F Tanks								
T035	250	2011						4.15
T036	251	2013						2.63
T044	259	2013						2.01
T052	265	2013						0.86
T054	267	2011						5.73
Group G Tanks								
T025	239	2014						0.65
T028	243	2014						0.23
T037	252	2014						0.73
Fugitive VOC Emission Sources								
Plant Wide - No Emission Limits	289	2011						14.58
Gas Plant Fugitives	280	2015						0.45
Piping Mod (SEP project) Fugitives**	297**	2012						0.18
Second Stage of Crude Oil Desalting Project Fugitives**								
Tank T079 Installation Fugitives	308	2013						0.61
Boilers B504 and B505 Tie-In Fugitives	310	2013						0.21
Fugitives Identified in 2014 COC	314	2014						0.44
MPV Project Fugitives	316	PTE						2.55
P2 Flare RSR Project Fugitives	317	PTE						0.16
LPG loading at Rail Rack, rail rack Flare and LPG Truck Rack Fugitives	320	2018						0.11
Miscellaneous Sources								
Thermal Oxidizer for Tank Cleaning	315	PTE	0.04	0.04		0.71	0.41	5.0
Total			**34.04**	**34.04**	**41.02**	**149.28**	**132.68**	**133.91**

*For cooling tower, $PM_{2.5}$ actual emissions = 0.08 tpy

**Emissions from these fugitive sources have the same AIRS id and are included on the same CP but with separate emission limits.

Cooling Tower $PM_{2.5}$ Information

Eric A. Anderson, M.S., P.E.

Consulting Engineer

From a Mississippi permit approval:

- Cooling Towers – The drift emissions from the cooling towers are limited to the particulate associated with dissolved solids in liquid droplets that become entrained in the air stream exiting the cooling tower. The particle size distribution is dependent on several factors including the design of the cooling tower, the drift eliminators, and the concentration of dissolved solids in the recirculating water (e.g., higher concentrations of dissolved solids may result in fewer particles below 2.5 microns aerodynamic diameter). Based on the Reisman and Frisbie method, "Calculating Realistic PM_{10} Emissions from Cooling Towers" (Reisman and Frisbie, 2002), $PM_{2.5}$ emissions would be less than 2% of the PM_{10} emissions at the assumed TDS concentration. This ratio would hold despite variance in circulation rates or expected TDS concentrations of the cooling tower. Accordingly, this represents a reliable statistical relationship over the operating range of the cooling towers. Therefore, 2% of the PM_{10} represents a reasonable and conservative proxy and surrogate for $PM_{2.5}$ from the cooling towers.

Pre-Construction Review and Preliminary Determination of Approval for Mississippi Power Company, Kemper IGCC Facility Facility No. 1380-00017, Technical Review by Krystal Rudolph; Air Quality Analysis By Bruce Ferguson, December 17, 2009

Stationary Sources Program PS Memo 10-01

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 NO_2 and SO_2 NAAQS

The Division is establishing this guidance for use by minor stationary sources of nitrogen dioxide (NO_2) and sulfur dioxide (SO_2) in evaluating whether modeling is necessary for permitting purposes to determine whether a permit applicant's emissions will comply with the new 1-hour NO_2 and/or the new 1-hour SO_2 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 NO_X and SO_2 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 NO_2 and SO_2 standards. EPA concludes and states that an ambient air quality impact analysis is not necessary for PSD sources with projected NO_2 or SO_2 emissions rates below the SER. (Wood Memoranda at p.11 and p.4)

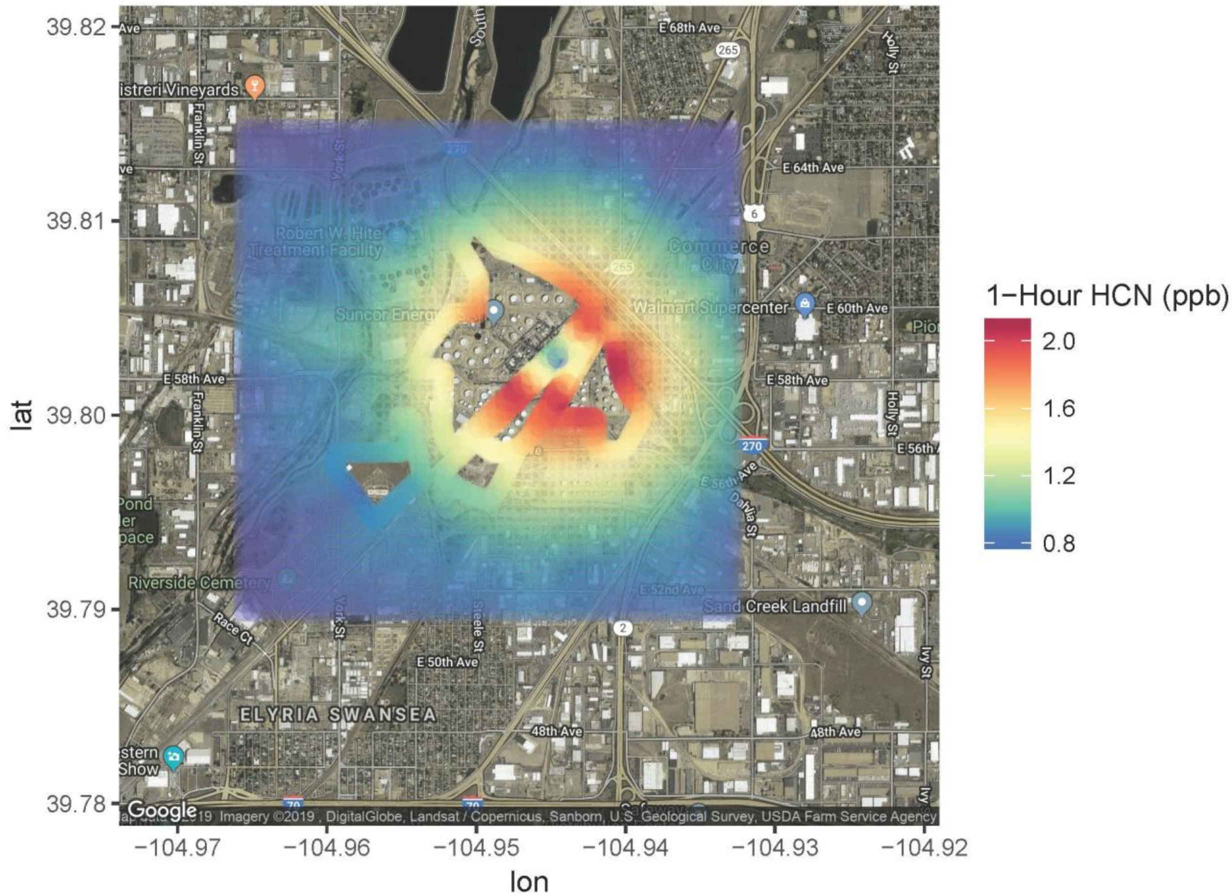
[1] See June 28, 2010, Anna Marie Wood, Acting Director, Air Quality Policy Division, Office of Air Quality Planning and Standards Memorandum "General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour NO_2 Significant Impact Level" and August 23, 2010 Memorandum "General Guidance for Implementing the 1-hour SO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour SO_2 Significant Impact Level" ("Wood Memoranda").

The Division has evaluated EPA's rationale for establishing NO_2 and SO_2 SERs for modeling the 1-hour NO_2 and SO_2 standards. The Wood Memoranda guidance set forth EPA's reasoning that its SER for SO_2 (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 NO_2 and SO_2 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 NO_x and SO_2 emissions with respect to the 1-hour NO_2 and SO_2 standards, and thus ambient air quality impact analyses are not necessary for either NO_2 or SO_2 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 NO_X and SO_2 to the 1-hour NO_2 and 1-hour SO_2 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.

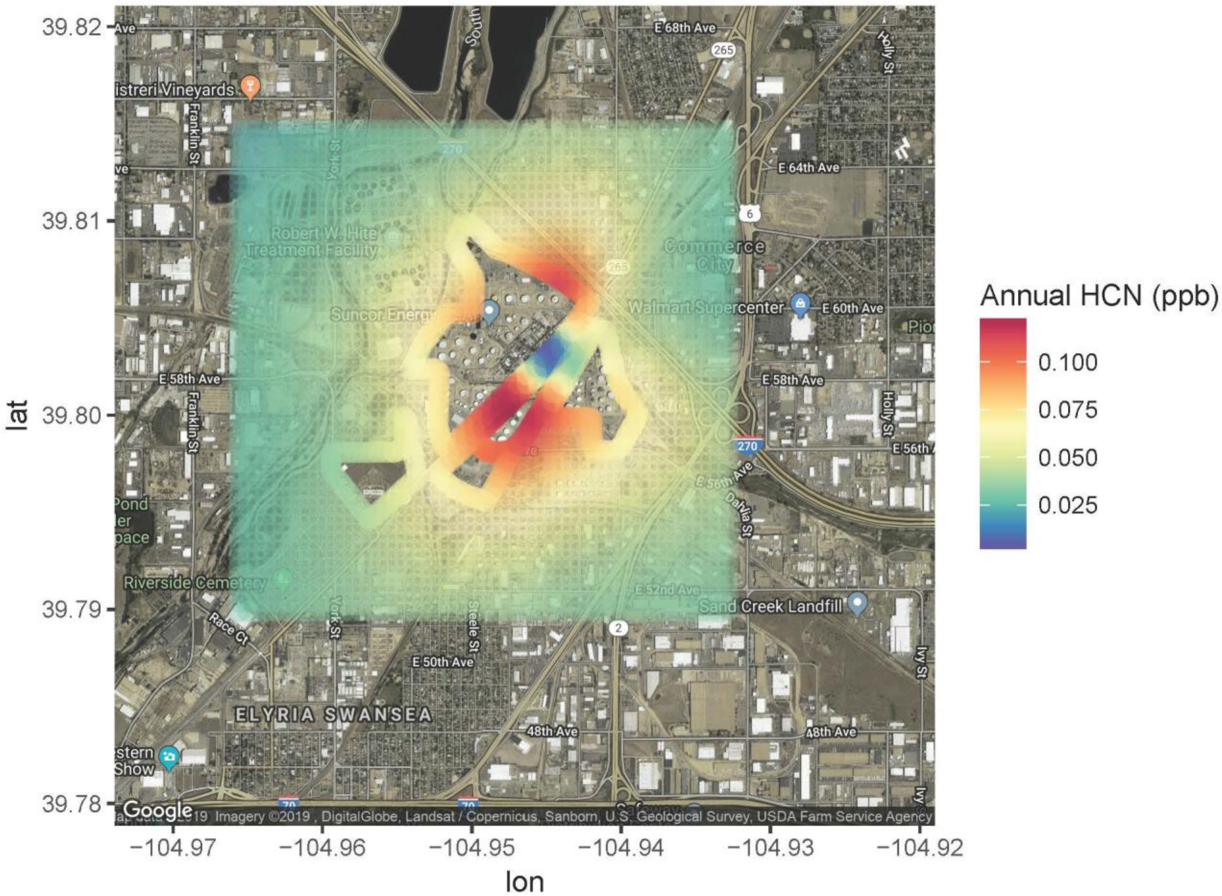
Hydrogen Cyanide (HCN) Modeling Results

1-hour basis



Hydrogen Cyanide (HCN) Modeling Results

annual basis



Change in Permitted (Requested) Emissions Associated with Modifications/Submittals Processed with this Permit Revision

Modification	Permitted (Requested) Emissions Increase (tons/yr)						Comments
	$PM/PM_{10}/PM_{2.5}$[1]	SO_2	NO_X	VOC	CO	HCN	
March 10, 2009 (source description corrections)							No change in emissions with this mod.
March 31, 2009 (NO_X limit for FCCU)							No change in annual (tons/yr) emissions.
July 30, 2009 (crude unloading dock)				5.5			
December 30, 2009 (Tank T024) April 27, 2018 (Cancel APEN for Tank T024)				-1.9			The December 30, 2009 application requested an increase in the throughput limit for T024 but the April 27, 2018 submittal indicated that Tank T024 had been permanently removed from service and asked that the tank be removed from the permit. The change in emissions reflects the removal of the tank at the current permit limits (6/15/09 revised permit).
January 4, 2010 (main plant flare emission calculation methodology)	1.9	-167.4	-103.3	30.79	67.33		Requested emissions and throughput were adjusted to reflect a 365 day year and a lb-mole volume of 385.3 scf. In addition, the change in emissions is with respect to the underlying construction permit (CP) limits (issued 11/8/06) which had not been incorporated into the T5 permit. Note that the CP did not include limits for PM and PM_{10}.
May 14, 2010 (incorporate emergency generator CP)							No change in emissions. The engine is now CP and APEN exempt, so it does not have emission limits.

Modification	Permitted (Requested) Emissions Increase (tons/yr)						Comments
	$PM/PM_{10}/PM_{2.5}$[1]	SO_2	NO_X	VOC	CO	HCN	
May 14, 2010 (crude furnace)	2.07	0.47	23.09	1.49	22.82		Note that the modification was to incorporate provisions from a revision to the underlying CP that had not previously been reflected in the T5 permit.
November 1, 2010 (incorporate FCCU CP)							The FCCU was exempt from emission limits prior to the CP. The CP went through the appropriate Reg 3, Part B permitting process, including public comment (PC). The Division does not consider this to be an increase in permitted emissions, since the FCCU was not previously subject to permit limits and the CP went through PC.
July 27, 2011 (remove tanks T031, T055 and T056)							These tanks were required to be removed per the CP for the new boilers (09AD1422). Note that the tanks were not subject to annual emission limits, so there was no change to permitted emissions.
September 16, 2011 (mixed butanes project)							No change in emissions. No changes to the permit were necessary for this project. Projected emission changes are changes to "actual" emissions, not permitted and VOC emissions from new piping components (0.74 ton/yr) were below the APEN de minimis level.
September 28, 2011 (address Reg 7 requirements for terminals)							No change in emissions with this mod.
December 19, 2011 (NO_X limit for FCCU)							No change in annual (tons/yr) emissions.

Modification	Permitted (Requested) Emissions Increase (tons/yr)						Comments
	$PM/PM_{10}/PM_{2.5}$[1]	SO_2	NO_X	VOC	CO	HCN	
March 21, 2012 (tank T029)				1.71			Note that VOC emissions from new piping components (0.16 tpy) were less than the APEN de minimis level, so no permit limit was provided for them. The change in emissions is from Tank T029
May 25, 2012 (Plant 2 wastewater treatment system)							The May 8, 2013 modification superseded this one. Therefore, the change in permitted emissions for the P2 WWTS is addressed under the May 8, 2013 modification.
October 11, 2012 (incorporate CP for new boilers)	3.7	-5.3	-15.8	-2.8	-26.6		The change in emissions shown is the difference between permitted emissions for the new boilers and permitted emissions from the existing boilers.
May 8, 2013 (install controls on Plant 2 APIs)				0.15			
November 29, 2013, August 8, 2014 and February 9, July 17 and October 10, 2018 (install, remove, install, install and remove emergency air compressor engine)							No change in emissions. With the February 9, 2018 application an emergency air compressor was installed. No emission limits were included since at 500 hrs/yr of operation, emissions from this engine are below the APEN de minimis level. Applications to install emergency air compressors were submitted on November 29, 2013 and July 17, 2018 but those applications were cancelled on August 8, 2014 and October 10, 2018 and the engines removed.
June 17, 2014 (change responsible official)							No change in emissions.
August 4, 2014 (FCCU SO_2 limits)							No change in annual (tons/yr) emissions.

Modification	Permitted (Requested) Emissions Increase (tons/yr)						Comments
	$PM/PM_{10}/PM_{2.5}$[1]	SO_2	NO_X	VOC	CO	HCN	
January 14, 2015 (apply NSPS Ja to main flare)							No change in emissions.
April 15, 2015 (tank T062)				-3.63			
June 10, 2015 (revise VOC emission limits for cooling towers)[2]	4.8			23.1			The cooling tower is listed in the current permit (last revised June 15, 2009) but was not previously subject to emissions limits.
October 28, 2015 (Tank degassing TO)	0.15	3.77E-03	2.73	17.2	1.57		Tank degassing was previously conducted under portable CPs issued to contractors. Note that since PM, PM_{10}, $PM_{2.5}$, SO_2, CO and NO_X are below the APEN de minimis level, limits for these pollutants were not included in the permit.
October 28, 2015 (address fugitive VOC emissions from unpermitted components)				9.55			
April 20, 2016 (include sulfur recovery plant consent decree SO2 limit)		-73					
November 22, 2016 (HCN limit for FCCU) and December 3, 2019 (cancel application to request HCN limit)							HCN was not previously permitted, but the source requested a permit limit in the November 22, 2016 application. In the December 3, 2019 submittal, the source requested that the application for the HCN limit be cancelled. In that submittal the source noted that they were doing additional testing to determine a more robust HCN emissions factor/limit. Therefore, it is anticipated that at some point in the future, an application will be submitted to include an HCN emission limit.

Modification	Permitted (Requested) Emissions Increase (tons/yr)						Comments
	$PM/PM_{10}/PM_{2.5}$[1]	SO_2	NO_X	VOC	CO	HCN	
December 20, 2016 (add RO's designated rep)							No change in emissions.
February 10, 2017 (Miscellaneous Process Vent (MPV) Modification)	-0.3	13.6	-2.7	41.6	-27.7		This includes fugitive VOC emissions from new piping components as well as changes in emissions from the P2 flare. The change in permitted (requested) emissions for the P2 flare is based on requested for this application minus requested for the January 4, 2010 application. These increases include the emission factor change for the P2 flare. For T5 minor modification applicability, the MPV mod and emission factor change were viewed separately.
July 10, 2017 (Plant 2 Flare RSR Project)	0.24	0.1	2.1	10.66	9.4		This includes fugitive VOC emissions from new piping components as well as changes in emissions from the P2 flare. The change in permitted (requested) emissions for the P2 flare is based on requested for this application minus requested for the February 10, 2017 application.
July 31, 2017 (include temperature and O2 indicators for SRU)							No change in emissions
December 4, 2017 (Tank T26)				2.25			

Modification	Permitted (Requested) Emissions Increase (tons/yr)						Comments
	$PM/PM_{10}/PM_{2.5}$[1]	SO_2	NO_X	VOC	CO	HCN	
June 14, 2018 (Revise emission limits and calculation method for LPG Rail Rack Loading)	-0.87	-0.998	-12.7	11.15	-69.9		This includes the requested emission limits for LPG truck loading and fugitives from LPG loading at the rail rack, rail rack flare and LPG truck rack. This is existing equipment that did not previously have emission limits. Note that since requested emissions of PM, PM_{10}, $PM_{2.5}$ and SO_2 were below the APEN de miminis level, limits for these pollutants were not included in the permit.
December 27, 2018 (FCCU Cold Resid Project)							No change in emissions. No changes to the permit were necessary for this project. Projected emission changes are changes to "actual" emissions, not permitted and VOCs from new piping components (0.74 tpy) were less than APEN de minimis.
January 8, 2019 (Tank T058)				4.65			This tank was previously grandfathered from minor source permitting requirements. The APEN submitted with the application indicated 0 emissions for 2017.
January 30, 2019 (P2 Rail Rack Flare RSR Project)							The change in permitted emissions associated with this project are addressed above under the June 14, 2018 modification to change the emission calculation methodology for the rail rack.

Modification	Permitted (Requested) Emissions Increase (tons/yr)						Comments
	$PM/PM_{10}/PM_{2.5}$[1]	SO_2	NO_X	VOC	CO	HCN	
October 22, 2019 (P2 Truck Rack Vapor Combustion Unit Emission Calculation Methodology)	0.3	0.02	0.4	-6.9	-0.8		The current permit (revised June 15, 2009) does not include permit limits for PM, PM_{10}, $PM_{2.5}$ and SO_2. Requested PM, PM_{10}, $PM_{2.5}$ and SO_2 emissions are below APEN de minimis level, so limits were not included in the permit those pollutants.
February 19, 2020 (Convert Tank T011 from an IFR to an EFR)				-6.37			Tank T011 is grandfathered in the current permit (last revised June 15, 2009). The change in permitted emissions is based on the difference between the tank as an IFR (10.63 tpy) and an EFR (4.26 tpy) at the requested throughput.
October 19, 2020 (revise PM, PM_{10}, NO_X, VOC and CO emission limits for SRU)	-0.33	0	-4.25	-0.15	0.2		The change in permitted emissions for CO, VOC and PM/PM_{10} is based on the difference between requested emissions and CP 12AD032-3, issued January 5, 1998. **The source also requested that the H_2S limit be revised, so there is a 3 tpy reduction in permitted H_2S emissions as well.**
Total	11.66	-232.50	-110.43	138.05	-23.68	0.00	

[1]For the most part, PM= PM_{10} = $PM_{2.5}$. However, for the cooling tower (June 10, 2015 modification), PM = PM_{10} and $PM_{2.5}$ is much lower (0.1 tpy).
[2]For the cooling towers, there was also an additional information submittal on February 13, 2014 that addressed permitted8emissions from this unit.

Opacity Streamlining Grid

Reqmt Source	Normal	Start-up	Shutdown	Malfunction	Fire Building	Cleaning of Fire Boxes	Soot Blowing	Process Modifications	Adjustment of Control Equipment
Reg 1 Sections II.A.1 & 4	20%	30% with one 6 minute interval in excess of 30% per hour	20%	20 %	30% with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour	30 % with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour
Reg 6, Part B, Section II.C.3 **- State Only**	20%	No standard[1]	No standard[1]	No standard[1]	**20%**	**20%**	**20%**	**20%**	**20%**

[1]Although the opacity standards are not applicable during start-up, shutdown and malfunction 40 CFR § 60.7(c) (2) requires the source to report each period of excess emissions that occurs during startups, shutdowns, and malfunctions, the nature of the malfunction and the corrective action taken or preventative measures adopted.

* Shaded regions are the most stringent **Federal** requirements

** Values in bold are the most stringent **State-only** requirements however **federal** requirements cannot be streamlined out of the permit due to more stringent **state-only** requirements