Pennsylvania
Department of
Environmental Protection
SOUTHWEST REGIONAL OFFICE – AIR QUALITY PROGRAM

TO Air Quality Permit File PA-04-00740D

FROM Alexander Sandy/AS
Air Quality Engineering Specialist
Air Quality Program

THROUGH Sheri L. Guerrieri, P.E./slg
Environmental Engineer Manager
Air Quality Program

Mark R. Gorog, P.E./MRG
Regional Manager
Air Quality Program

DATE January 30, 2026

RE Plan Approval Application
Shell Chemical Appalachia LLC
Shell Polymers Monaca Site
Potter and Center Townships, Beaver County
APS 1122267; Auth 1500641; PF 775836

BACKGROUND

On September 13, 2024, the Department of Environmental Protection (Department) received a plan approval application from Shell Chemical Appalachia, LLC (Shell) proposing the Wastewater Treatment Plant (WWTP) Permanent Controls Project, Ethylene Maximum Achievable Control Technology (EMACT) Project, as well as Plan Approval Reconciliations for the current plan approval at the existing ethylene and polyethylene production facility known as the Shell Polymers Monaca (SPM) Site located in Potter and Center Townships, Beaver County. This site is located on the southern bank of the Ohio River approximately 2.5 miles southwest of the town of Monaca.

The Department authorized the construction and temporary operation of SPM under PA-04-00740A issued on June 18, 2015, and construction commenced on February 10, 2016. Both PA-04-00740B for the installation and temporary operation of sulfur hexafluoride (SF_6)-insulated high-voltage equipment and PA-04-00740C for as-built changes at SPM were subsequently issued on February 18, 2021. The startup date of SPM's ethylene manufacturing line was September 24, 2022, and the startup dates for the three (3) polyethylene manufacturing units were October 1, 2022, November 1, 2022, and February 23, 2024. Shell has proposed the following projects at SPM in this application:

- *WWTP Permanent Controls Project*: Shell is proposing to implement the WWTP Permanent Controls Project to install permanent equipment in the primary treatment section of the WWTP at SPM to improve the oils, grease, and VOC removal efficiency of the primary treatment section of SPM's WWTP.

- *EMACT Project*: Shell is proposing what is referred to in this application as the "Ethylene Maximum Achievable Control Technology (EMACT) Project" to comply with the revised requirements of 40 Code of Federal Regulations (CFR), Part 63, Subpart YY for pressure-assisted multi-point flares. The increased minimum net heating value of flare combustion zone gas (NHV_{CZ}) requirement for pressure-assisted multi-point flares is applicable to the High Pressure (HP) Ground Flare #1 and HP Ground Flare #2; hereinafter referred to as Totally Enclosed Ground Flare (TEGF) A and TEGF B as described in more detail later in this memo.

- *Plan Approval Reconciliations*: After commissioning of SPM's operations and completing a review of the facility's as-built equipment and operations with the source inventory, potential to emit calculations, and conditions included in or referenced by PA-04-00740A, PA-04-00740B, and PA-04-00740C, Shell is proposing to reconcile specific plan approval source descriptions, potential to emit calculations, and plan approval conditions.

The following is an updated list of air contamination sources and air cleaning devices at SPM, including the reconciliations detailed in this plan approval application. Source IDs and Source Names are shown in italic font. Additional description from Section C, Condition #030 of PA-04-00740C follows the Source Name. Changes are indicated by bold font and/or strikethrough.

- *Source ID 031 – 037: Ethane Cracking Furnace #1 – #7*: Seven (7) tail gas- and natural gas-fired ethane cracking furnaces, 620 MMBtu/hr heat input rating each; equipped with low-NO_X burners and controlled by selective catalytic reduction (SCR).

- *Source ID 101 – 103: Combustion Turbine/Duct Burner Unit #1 – #3*: Three (3) General Electric, Frame 6B, natural gas-fired combustion turbines, 41.5 MW**e** (481.4 MMBtu/hr heat input rating) each, including natural gas- ~~or tail gas-~~fired duct burners, 234 MMBtu/hr heat input rating each; controlled by SCR and oxidation catalysts.

- *Source ID 104: Cogeneration Plant Cooling Tower*: One (1) ~~cogen cooling tower~~ **Cogeneration Plant Cooling Tower**, 6 cell counter-flow mechanical draft, ~~4.443~~ **7.2** MMgal/hr water flow capacity; controlled by drift eliminators.

- *Source ID 105: Diesel-Fired Emergency Generator Engines (2)*: Two (2) diesel-fired generator engines, 67 bhp and 103 bhp rating.

- *Source ID 106: Fire Pump Engines (2)*: Two (2) diesel-fired fire pump engines, 488 bhp rating each.

- *Source ID 107: Natural Gas-Fired Emergency Generator Engines (~~3~~ **2**)*: ~~Three (3)~~ **Two (2)** natural gas-fired emergency generator engines, 50 bh~~p, 113 bhp,~~ and 158 bhp rating.

- *Source ID 201: Ethylene Manufacturing Line*: One (1) ethylene manufacturing line, ~~1,500,000~~ **1,763,000** metric tons/yr; compressor seal vents and startup/shutdown/maintenance/upsets controlled by the ~~high-pressure header system (~~HP **Flare** System).

- *Source ID 202: Polyethylene Manufacturing Line*: Two (2) gas phase polyethylene manufacturing lines, ~~550,000~~ **605,000** metric tons/yr each; VOC emission points controlled by the ~~low-pressure header~~

~~system (LP System)~~ **Continuous Vent Thermal Oxidizer (CVTO), Multi-Point Ground Flare (MPGF),** or HP **Flare** System**;** PM emission points controlled by filters.

- One (1) slurry technology polyethylene manufacturing line, ~~500,000~~ **550,000** metric tons/yr; VOC emission points controlled by the ~~LP System~~ **CVTO, MPGF,** or HP **Flare** System**;** PM emission points controlled by filters. [Separate bullet in PA-04-00740C, Section C, Condition #030, but conditions included with Source ID 202].

- *Source ID 203: Process Cooling Tower*: 26 cell counter-flow mechanical draft, 17.8 MMgal/hr water flow capacity; controlled by drift eliminators.

- *Source ID 204: ~~Low Pressure (LP)~~* ***CVTO*** *Header System*; One (1) ~~LP System~~ **CVTO Header System receiving vent gas from Source IDs 202, 303, 403, 404, and 407;** routed to the ~~LP incinerator~~ **CVTO**, ~~10 tons/hr~~ **200 MMBtu/hr** capacity~~, with backup multipoint ground flare (MPGF), 74 metric tons/hr total capacity~~.

- ***Source ID 207: MPGF CVTO Trip Header***[1]; One (1) low pressure header system receiving vent gas from Source ID 204, routed to the MPGF, 186 MMBtu/hr capacity.

- ***Source ID 208: MPGF Ethylene Tank Header***[1]; One (1) low pressure header system receiving vent gas from Source ID 411, routed to the MPGF, 1,152 MMBtu/hr capacity.

- ***Source ID 209: MPGF PE Units 1/2 Episodic Vent Header***[1]; One (1) low pressure header system receiving vent gas from Source ID 202, routed to the MPGF, 860 MMBtu/hr capacity.

- *Source ID 205: High Pressure (HP) Header System*: One (1) HP Header System ~~1,800 metric tons/hr capacity~~, routed to two (2) ~~HP~~ **totally** enclosed ground flares ~~150 metric tons/hr capacity each,~~ with **a** backup emergency elevated flare, ~~1,500 metric tons/hr~~ 1**3,257 MMBtu/hr total** capacity.

- *Source ID 206: Spent Caustic Vent Header System*; controlled by the SCTO.

- *Source ID 301: Polyethylene Pellet Material Storage/Handling/Loadout*: Polyethylene pellet blending, handling, storage, and loadout; controlled by fabric filters.

- *Source ID 302: Liquid Loadout (Recovered Oil)*: Liquid load**ing** ~~out~~, ~~coke residue/tar and~~ recovered oil; controlled by vapor capture and routing **to a carbon adsorption system** ~~back to the process or Spent Caustic Vent Incinerator~~, and low-leak couplings.

- *Source ID 303: Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline**, PE3 Heavies**)*: Liquid load**ing** ~~out~~, pyrolysis fuel oil, light gasoline**, and PE3 heavies**; controlled by vapor capture and routing to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header**, and low-leak couplings.

- *Source ID 304: Liquid Loadout (C3+, Butene, Isopentane, Isobutane, ~~C3+~~* ***C3*** *Ref)*: Liquid load**ing** ~~out~~, C3+, **and liquid unloading** butene, isopentane, isobutane, and *~~C3+~~* ***C3*** refrigerant; controlled by

[1] MPGF CVTO Trip Header, MPGF PE Units 1/2 Episodic Vent Header, and MPGF Ethylene Tank Header are not new sources, rather a clarification of the header systems at SPM.

pressurized transfer with vapor balance and low-leak couplings.

- *Source ID 305: Liquid Loadout (~~Coke Residue/Tar~~ **Blended Pitch**)*: Liquid load**ing** ~~out~~, ~~coke residue/tar~~ **blended pitch** ~~and recovered oil~~; controlled by vapor capture and routing back to the process or ~~Spent Caustic Vent incinerator~~ **HP Header System**, and low-leak couplings.

- *Source ID 401: Storage Tanks (Recovered Oil, Equalization Wastewater)*: One (1) 23,775-gallon recovered oil and two (2) equalization wastewater storage tanks, 521,211-gallon capacity and 877,051-gallon capacity each; controlled by internal floating roofs (IFRs) and vapor capture routed to the ~~Spent Caustic Vent incinerator~~ **SCTO**, ~~10.7~~ **11.07** MMBtu/hr.

- *Source ID 402: Storage Tank (Spent Caustic)*: One (1) spent caustic storage tank, 345,273-gallon capacity; controlled by IFR and vapor capture routed to the ~~Spent Caustic Vent~~ ~~incinerator~~ **SCTO**, ~~10.7~~ **11.07** MMBtu/hr.

- *Source ID 403: Storage Tanks (Light Gasoline)*: One (1) light gasoline storage tank, ~~85,856~~ **152,000**-gallon capacity; controlled by IFR and vapor capture routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header**.

- *Source ID 404: Storage Tanks (Hexene)*: **Two (2)** hexene storage tanks, ~~607,596~~ **802,000**-gallon capacity each; controlled by IFRs and vapor capture routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header**.

- *Source ID 405: Storage Tanks (Misc Pressurized~~/Refrigerated~~)*
    - One (1) pressurized spherical vessel for ethylene storage, 1,912,077-gallon capacity.
    - Two (2) pressurized spherical vessels for C3+ storage, 607,596-gallon capacity each.
    - One (1) pressurized horizontal vessel for C3 refrigerant storage, 79,252-gallon capacity.
    - One (1) pressurized spherical vessel for butene storage, 317,006-gallon capacity.
    - Two (2) pressurized horizontal vessels for isopentane storage, 158,503-gallon capacity each.
    - One (1) pressurized horizontal vessel for isobutane storage, 52,834-gallon capacity.
    - One (1) pressurized horizontal vessel for PE3 heavies storage, 52,834-gallon capacity.
    - One (1) pressurized horizontal vessel for dimethyl disulfide storage, 8,189-gallon capacity.
    - One (1) pressurized horizontal vessel for wash oil storage, 33,343-gallon capacity.

- *Source ID 406: Storage Tanks (Diesel Fuel > 150 Gallons)*: **500 to** 1,849 ~~to 18,000~~-gallon capacities; ~~controlled by carbon canisters~~.

- *Source ID 407: Storage Tanks (Pyrolysis Fuel Oil)*: Two (2) pyrolysis fuel oil storage tanks; ~~85,856~~ **127,000**-gallon capacity **each**; controlled by vapor capture routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header**.

- *Source ID 408: Storage Tanks (Diesel Fuel < 150 Gallons)*: 133 to 140-gallon capacities.

- *Source ID 409: Methanol Storage Vessels and Associated Components*: Pressurized methanol storage vessels (36,000-gallon, 6,450-gallon, and 67,200-gallon capacities) and associated components; controlled by the HP **Flare** System.

- ***Source ID 411: Refrigerated Ethylene Storage Tank*[2]: 7,925,160-gallon capacity; controlled by vapor capture routed to the MPGF Ethylene Tank Header.**

- *Source ID 501: Equipment Components:* Miscellaneous components in gas, light liquid, and heavy liquid service; controlled by leak detection and repair (LDAR).

- *Source ID 502: Wastewater Treatment Plant* ***(Secondary and Tertiary Treatment)***: Wastewater treatment equipment that carries out the secondary and tertiary treatment of process wastewater and potentially contaminated stormwater.

- *Source ID 503: Plant Roadways*: Plant roadways; controlled by paving and a road dust control plan including sweeping and watering (as necessary).

- ***Source ID 505: WWTP (Primary Treatment)***: Wastewater treatment equipment that carries out the primary treatment of process wastewater and potentially contaminated stormwater; controlled by vapor capture and routing to the SCTO.

Shell's most recent PTE submission shows PTE results that are below major source thresholds for HAP. SPM has been major for HAPs since the initial plan approval was issued. Despite this HAP PTE decrease, Shell desires to retain major source status for SPM. 40 CFR 63.1(c)(6) generally provides that a major HAP source may reduce its PTE and become a HAP area source. However, the source remains subject to major source requirements until it is "reclassified" per 40 CFR 63.1(c)(6)(i)(A). Reclassification occurs when an area source permit is issued for the source. Accordingly, to accommodate Shell's request, SPM will not be reclassified as a HAP area source in PA-04-00740D, and SPM will continue to be subject to major source HAP requirements, including the applicable provisions of 40 CFR Part 63.

Process Description Summary

For a detailed description of the manufacturing process to convert ethane into ethylene, which is then converted into low density polyethylene and high-density polyethylene (HDPE) pellets that are shipped offsite to plastic product manufacturing facilities, as well as a detailed description of the air contamination sources and air cleaning devices at SPM, see Section 2.0 of the September 13, 2024, application for PA-04-00740D[3]. A brief process description summary is provided directly below.

SPM is comprised of an ethylene manufacturing unit, three (3) polyethylene manufacturing units, three (3) cogeneration units (Cogen Units), and ancillary equipment. These integrated manufacturing, utility, and support facilities and operations are currently authorized under PA-04-00740A, PA-04-00740B, and PA-04-00740C. SPM's ethylene manufacturing unit includes seven (7) ethane cracking furnaces that thermally "crack" ethane to produce ethylene. The ethane cracking reaction is accomplished by heating ethane to very high temperatures in the ethane cracking furnaces. "Tail gas" is one of the byproducts of the ethane cracking process, and the tail gas produced at SPM contains mostly hydrogen and methane. The tail gas is collected and primarily used to fuel the ethane cracking furnaces.

[2] Source ID 411 is the existing refrigerated ethylene storage tank that was previously included as part of Source ID 405.
[3] See Plan Approval Application, Shell Polymers Monaca, Shell Chemical Appalachia, LLC, Beaver County, September 13, 2024 ("Application") Section 2.0, pages 2-1 – 2-14.

SPM's polyethylene manufacturing unit includes two (2) gas phase polyethylene manufacturing units and one (1) liquid phase slurry polyethylene manufacturing unit at SPM. Each unit is fed ethylene produced by the ethylene manufacturing unit. Both polyethylene manufacturing processes employ catalysts but use different equipment and operating parameters to produce different grades of polyethylene. Each polyethylene manufacturing unit has its own polyethylene pellet handling system prior to pellet blending. Common pellet storage, railcar loading, and truck loading equipment and operations follow the pellet blending operation.

Each of the three (3) Cogen Units includes a natural gas-fired combustion turbine that is coupled with duct burners and a dedicated heat recovery steam generator (HRSG). The Cogen Units supply electricity and steam to SPM and any excess electricity produced by the units is sold to the local electric utility grid.

SPM's ancillary equipment includes two (2) diesel-fired emergency generator engines, two (2) natural gas-fired emergency generator engines, two (2) diesel-fired firewater pump engines, two (2) cooling water towers, atmospheric storage tanks, pressurized storage tanks, and a wastewater treatment plant.
The Standard Industrial Classification codes applicable to SPM are the following:

- 2821 – Plastics Materials, Synthetic Resins, and Nonvulcanizable Elastomers
- 2869 – Industrial Organic Chemicals, Not Elsewhere Classified
- 4911 – Electric Services.

The North American Industry Classification System codes applicable to SPM are the following:

- 221112 – Fossil Fuel Electric Power Generation
- 325110 – Petrochemical Manufacturing
- 325211 – Plastics Material and Resin Manufacturing.

Permit History

The original plan approval application for SPM was submitted in May 2014. A revised application was received in February 2015 to incorporate previously submitted updates and additional information to support the application. The approval for construction of SPM was subject to Prevention of Significant Deterioration (PSD) review for nitrogen dioxide (NO_2), carbon monoxide (CO), particulate matter (PM), PM with an aerodynamic diameter less than or equal to 10 micrometers (PM_{10}), and carbon dioxide equivalent (CO_2e); and, Nonattainment New Source Review (NNSR) for nitrogen oxides (NOx), volatile organic compounds (VOC), and PM with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) based on the ozone and $PM_{2.5}$ nonattainment status of Beaver County. The Plan Approval (PA-04-00740A) was issued by the Department on June 18, 2015, authorizing the construction of SPM. Construction of SPM commenced on February 10, 2016, within 18 months of issuance of PA-04-00740A.

On April 11, 2016, Shell submitted an application to modify PA-04-00740A to incorporate NOx, VOC, and $PM_{2.5}$ ERCs, as required by Section C, Conditions #037 and #038 of PA-04-00740A. Supplemental requests were submitted on April 27, 2016 and May 10, 2016, seeking approval from the Department and U.S. Environmental Protection Agency (EPA) for interprecursor offset trading between NOx and VOC that would allow Shell to use NOx ERCs to partially satisfy VOC offsetting requirements. The submittals were updated on August 15, 2016. On September 14, 2016, the Department sent a letter of summary evaluation, approval, and request to EPA's Region 3. EPA Region 3 granted a case-by-case approval on October 17, 2016, and modification to PA-04-00740A was subsequently issued by the Department on December 30, 2016, to incorporate the ERCs.

On November 5, 2019, the Department received a commencement of operation notification from Shell for the operation of SF_6 insulated high voltage equipment. The SF_6 insulated high voltage equipment was installed without authorization; therefore, Shell entered into a Consent Order and Agreement (COA) with the Department on November 11, 2019, requiring a submittal of a plan approval application for the SF_6 insulated high voltage equipment. The plan approval application (PA-04-00740B) was received on December 18, 2019. Although the SF_6 insulated high voltage equipment was not included in the original plan approval, it was part of the original design of the facility; therefore, the installation was considered as the beginning of the period of temporary operation of the facility in accordance with PA-04-00740A, Section B, Condition #003. The effective date of commencement of operation coincided with the date that the COA was executed on November 11, 2019, and the expiration date of PA-04-00740A was modified to April 28, 2020 (up to 180 days from commencing operation).

On February 14, 2020, the Department received a plan approval application (PA-04-00740C) addressing the differences between the "as-built" facility and the original design reflected in plan approval PA-04-00740A. The as-built changes included equipment additions, removal and downsizing of permitted equipment, and increases and decreases in the design capacities of various equipment. The application included a control technology analysis for equipment additions that were in a class or category not previously evaluated and an update to the air quality impacts analysis and inhalation risk assessment originally completed in support of PA-04-00740A to incorporate the changes. PA-04-00740C authorizing the as-built changes was issued by Department on February 18, 2021, concurrent with the issuance of PA-04-00740B for the SF_6-insulated high-voltage equipment.

PA-04-00740A, B, and C were most recently extended on October 14, 2025, for an additional 180 days, expiring on April 28, 2026.

On February 22, 2024, the Department sent a letter to Shell requesting the submittal of an initial Title V operating permit (TVOP) application within 120 days. On June 19, 2024, Shell submitted the initial TVOP application for SPM in accordance with the Pennsylvania Air Pollution Control Act and 25 Pa. Code § 127.505(a). The TVOP application is being reviewed separately from this plan approval.

RFDs

Below is a summary of the request for determination (RFD) authorizations at SPM since the issuance of PA-04-00740C on February 18, 2021[4]:

<u>RFD 8799</u>: On October 27, 2020, the Department determined that the installation of two (2) 572-gallon aboveground diesel storage tanks without carbon cannisters is a source of minor significance and is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44 in the Department's Air Quality Permit Exemptions (275-2101-003, July 1, 2021) established under 25 Pa. Code § 127.14(d).

[4] RFD 8799 is included in this list as it is referenced in this memo.

RFD-04-00740L: On September 15, 2021, the Department determined that extending the temporary operation of three (3) 617 bhp diesel-powered air compressors and one (1) 800-gallon diesel storage tank is a source of minor significance and is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44.

RFD 9604: On March 10, 2022, the Department determined that additional operating time for the initial refractory dry out and furnace warming prior to the initial startup of the seven (7) Ethane Cracking Furnaces is a source of minor significance and is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44.

RFD 9633: On April 8, 2022, the Department determined that conducting Cogen Units Island Mode Testing is a source of minor significance and is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44.

RFD 9697: On April 5, 2022, the Department determined that the temporary operation of a 29.3 MMBtu/hr natural gas-fired boiler to supply steam during the Cogen outage and allow for ongoing commissioning activities to continue in the ethane cracking unit area is a source of minor significance and is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44.

RFD 9720: On May 6, 2022, the Department determined that the temporary operation of two (2) 200 kW diesel generators, one (1) 35.9 bhp diesel engine, and two (2) 800-gallon diesel storage tanks is a source of minor significance and is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44.

RFD 10119[5]: On April 10, 2023, the Department determined that the temporary operation of wastewater treatment equipment is a source of minor significance and is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44.

RFD 10196: On April 13, 2023, the Department determined that repairs of the HP Elevated Flare (C205C) liquid seal drum V-59003 is a source of minor significance and is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44.

RFD 10277: On August 9, 2023, the Department determined that the temporary operation of a WEMCO 84 Depurator (DAF) and an Enviro-Cell (EC-15) Induced Air Flotation (IAF) unit for wastewater treatment is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44.

RFD 10540: On March 28, 2024, the Department determined that the continued operation of the WEMCO 84 Depurator (DAF) and EC-15 IAF unit for wastewater treatment is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44. The temporary system was approved contingent that the system will be replaced with a permanent system after approval under a plan approval. The WWTP Permanent Controls Project being evaluated as part of this plan approval proposes the installation of permanent wastewater treatment equipment to replace the temporary equipment approved by this RFD.

RFD-04-00740N: On April 4, 2024, the Department determined that the repairs of the High Pressure (HP)

[5] The Department's determination for RFD 10119 states the exemption is for a WEMCO 84 Depurator (DAF) and an Enviro-Cell (EC-15) Induced Air Flotation (IAF) unit; however, the RFD application was for a WEMCO 120x Depurator (DAF).

Header System's two Totally Enclosed Ground Flares (TEGFs), permitted under Source ID C205A and Source ID C205B, respectively, in Plan Approval 04-00740C, is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44. The RFD determination letter noted the following:

- The TEGF repairs include upgrades of burner floor steel, replacement of damaged burner tips, repair of hot spots on the enclosure, installation of ceramic fiber modules on the lower 41 feet of the enclosure, adjustment of the flare control system programing to include multiple staging ramp curves, and change of the drilling hole patterns on select burner tips consistent with Attachment B to the RFD application: TEGF Final Repair Report
- That the TEGFs are classified as pressure-assisted multi-point flares and as such must have two pilots per stage in accordance with 40 CFR Part 63 Subpart YY § 63.1103(e)(4)(vii)(D)
- That six (6) additional pilots per TEGF will be installed and will be kept lit in order to maximize TEGF reliability so they are available if needed
- The planned repairs to each TEGF will not exceed fifty percent of the fixed capital cost that would be required to construct a comparable entirely new TEGF

Due to repeated visible emissions from the TEGFs, Shell has proposed a new condition in this plan approval related to flare stage sequencing, which is discussed further in the *Plan Approval Condition Reconciliations* section of this memo.

<u>RFD 10890</u>: On November 14, 2024, the Department determined that the physical changes to the existing MPGF control device (Source ID C204B), which is part of the existing low pressure (LP) header system (Source ID 204) at SPM, is exempt from plan approval requirements per 25 Pa Code § 127.14(a)(8) listed as No. 44. Physical changes to the MPGF CVTO Trip Header authorized under the RFD include replacing the existing shear pin valve with a new safety relief valve; adding a supplemental natural gas line, valve, and flowmeter to the MPGF; and adding process controls to prevent trips of the CVTO.

This Plan Approval

This plan approval application for the WWTP Permanent Controls Project, EMACT Project, and Plan Approval Reconciliations was received on September 13, 2024. On September 30, 2024, the Department's Air Quality Modeling and Risk Assessment Section determined the PSD air quality analyses and inhalation risk assessment portions of Shell's plan approval application are administratively complete. On October 3, 2024, files relevant to Shell's PSD air quality analyses and inhalation risk assessment to support its application for Plan Approval 04-00740D were sent to the EPA. On October 10, 2024, the plan approval application was determined to be administratively complete pursuant to 25 Pa. Code § 127.12d, meaning that it contains information, maps, fees, and other documents requested in the plan approval application regardless of whether the information, maps, and documents would be sufficient to justify the issuance of a plan approval. The plan approval application and administrative completeness determination were sent to the EPA and the Federal Land Managers (FLMs) of the National Park Service (NPS) and the Forest Service (FS) on October 10 and 11, 2024.

On September 6, 2024, Landau Associates, on behalf of Shell, submitted a Request for Applicability of Class I Area Modeling Analysis to the FLMs with information regarding the results of the Q/d screening analysis completed for SPM's potential impacts on federally protected Class I areas. On September 17, 2024, Alexia Prosperi of the FS notified the Department and applicant that "…Based on your calculations, the Shell Polymers

Monaca projects screen out of the need to do a Class I area analysis for FS lands…" On October 9, 2024, Andrea Stacy of the NPS notified the Department and applicant that "…based on the Q/d assessment, this facility screens out of AQRV analysis for Shenandoah NP…" The Department will provide the EPA and FLM's with the draft plan approval and the Department's review at the appropriate time in accordance with the Memorandum of Understanding (MOU) amongst the Department, EPA, and the FLMs.

On December 20, 2024, the Department's Air Quality Modeling and Risk Assessment Section sent a letter to Shell with technical review comments on Shell's PSD air quality analyses and inhalation risk assessment. Shell provided a response to the letter on March 25, 2025. On May 29, 2025, Shell submitted updated PSD Air Quality Analyses and Inhalation Risk Assessment reports and associated modeling files and figures. On July 7, 2025, the Department's Air Quality Modeling and Risk Assessment Section provided additional comments on the PSD air quality analysis and the modeling portion of the inhalation risk assessment. On July 14, the Department's Air Quality Modeling and Risk Assessment Section provided additional comments on the inhalation risk assessment. The applicant provided a revised PSD air quality analysis and inhalation risk assessment on September 5, 2025. On October 14, 2025, the applicant submitted a revised inhalation risk assessment to the Department to update the emission rates evaluated in the acute non-cancer risk assessment portion.

On December 24, 2024, the Department's Southwest Regional Office sent a technical deficiency letter to Shell with technical review comments on Shell's plan approval application. On January 23, 2025, the Department received an initial response to numbers 6 – 16 in the technical deficiency letter, stating that "Shell will provide updates weekly to communicate the status of completed responses to the remaining requests. These weekly updates will also provide DEP with an updated schedule as the development of the responses progresses." The second response was received on February 7, 2025, related to the WWTP (Secondary and Tertiary Treatment), Source ID 502, the third response was received on February 28, 2025, related to the CVTO, Source ID C204A, and SCTO, Source ID C206, the fourth response was received on March 7, 2025, related to the MPGF, Source ID C204B, and the HP flares, Source IDs C205A, B, and C: TEGF A, TEGF B, and HP Elevated Flare, and the fifth response was received on April 11, 2025, related to facility-wide potential to emit (PTE), best available control technology (BACT), best available technology (BAT), and NNSR, including lowest achievable emission rate (LAER), emissions offsets, and alternatives analysis.

On June 3, 2025, Shell submitted a revised Appendix B to the original September 13, 2024, application which details PTE calculations for all air contamination sources and air cleaning devices and the changes made since the original submittal. Based on technical discussions with the Department, additional technical information was provided by the applicant on July 21, July 23, July 24, September 23, October 1, October 15, 2025, October 27, 2025, and December 17, 2025. Revised PTE calculations, Appendix B, were included with the revised modeling on September 5, 2025.

The following table shows the proposed potential to emit, total change in emissions from the previous plan approval, the proposed PTE and change in emissions due to the Plan Approval Reconciliations and WWTP Permanent Controls Project (the "original" facility, excluding the EMACT Project), and the increase due to the EMACT Project compared to the NNSR Major Facility/Significant and PSD Significant Thresholds.

Table 1: Proposed Potential to Emit Summary and PSD/NNSR Thresholds

Description	CO	NOx	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO_2e
	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy
Proposed Facility-Wide PTE[a]	**1,214.35**	**455.13**	**78.41**	**184.02**	**178.15**	**27.24**	**509.99**	**2,566,563**
PA-04-00740C PTE[b]	983.7	328.5	74.3	168.9	163.7	22.4	516.2	2,304,499
Total Change in PTE[c]	230.65	126.63	4.11	15.12	14.45	4.84	-6.21	262,064
Proposed PTE, Excluding EMACT Project	**864.98**	**378.49**	**76.31**	**175.62**	**169.75**	**25.58**	**503.91**	**2,468,325**
Plan Approval Reconciliations/ WWTP Change in PTE	-118.72	49.99	2.01	6.72	6.05	3.18	-12.29	163,826
NNSR Major Facility and PSD Major Source Thresholds	100 (PSD)	100 (NNSR/PSD)	100 (PSD)	100 (PSD)	100 (NNSR)	100 (NNSR)	50 (NNSR)	-
NNSR Major Facility/Significant and PSD Significant Thresholds for Modification	100 (PSD)	40 (NNSR/PSD)	25 (PSD)	15 (PSD)	10 (NNSR)	100 (NNSR)	40 (NNSR)	75,000 (PSD)
EMACT Project Increase	**349.37**	**76.64**	2.10	8.40	8.40	1.66	6.08	**98,238**
NNSR Major Facility/Significant and PSD Significant Thresholds	100 (PSD)	40 (NNSR/PSD)	25 (PSD)	15 (PSD)	10 (PSD)	100 (NNSR)	40 (NNSR)	75,000 (PSD)
ERCs Required for EMACT Project	-	89	-	-	-	-	0	-
ERCs Required for Plan Approval Reconciliations/WWTP	-	58	-	-	7	-	0	-

[a] Proposed Facility-Wide PTE is as submitted by the applicant on September 5, 2025, with the exception of PM_{10} and $PM_{2.5}$, which account for the Department's LAER and BACT determination for the SCTO, and VOC, which accounts for the revised Liquid Loadout (Recovered Oil) PTE calculation submitted by the applicant on October 27, 2025.
[b] PA-04-00740C PTE is from PA-04-00740C, Section C, Condition #005.
[c] Total change in PTE is the difference of Proposed Facility-Wide PTE and PA-04-00740C PTE.

This plan approval review includes:

- NNSR Analysis including LAER, emissions offsets, and alternatives analysis for the Plan Approval Reconciliations and WWTP Permanent Controls Project, and separately for the EMACT Project.
- PSD Analysis including BACT and air dispersion modeling for the Plan Approval Reconciliations and WWTP Permanent Controls Project, and separately for the EMACT Project.
- Inhalation Risk Assessment as required by PA-04-00740C, Condition # 035.

WWTP Permanent Controls Project

SPM is currently using temporary equipment including a WEMCO 84 Depurator and an Environ-Cell EC-15 hydraulic induced nitrogen flotation (INF) device, which were approved for temporary operation by the Department via eRFD 10277 on August 9, 2023. The purpose of the temporary equipment is to achieve improvements in oils, grease, and VOC removal capabilities in the primary treatment section of the facility's WWTP. On March 28, 2024, the Department authorized continued operation of the temporary system via eRFD 10540 until approval of a permanent system is granted under a plan approval; hence the inclusion of the WWTP

Permanent Controls Project in this plan approval application.

After conducting evaluations of SPM's wastewater characteristics and WWTP design and operations, Shell is now proposing to implement the "WWTP Permanent Controls Project" to install permanent equipment in the primary treatment section of the WWTP to improve that section's oils, grease, and VOC removal capabilities, which is designed to result in an improvement in the overall wastewater treatment performance of the WWTP. Specifically, Shell has proposed to install the following permanent wastewater treatment vessels in the primary treatment section of SPM's WWTP under this plan approval:

- Settlement Drum(s): One or more drums that will receive wastewater and provide for three-phase gravity separation of the wastewater's main constituents (i.e., gravity separation of the oil, water, and sludge contained in the inlet wastewater). The oil phase will be routed to the new Float/Sludge Drum and then to the existing Recovered Oil Storage Tank or recycled back to the Settlement Drum(s). The water phase will be routed to further treatment. The sludge material will be transferred to a truck to be transported offsite or routed to the existing Recovered Oil Storage Tank.

- Two (2) Dissolved Nitrogen Flotation (DNF) Units (DNF Unit #1 and DNF Unit #2): DNF Unit #1 will primarily be used to remove oils, grease, and solids from wastewater. DNF is a variation of dissolved air flotation (DAF) that replaces air with nitrogen. This process is useful for applications where preventing explosions or controlling hydrocarbon emissions is important, as nitrogen is an inert gas. In DNF, nitrogen gas is dissolved in the wastewater under pressure. When this pressure is released, the dissolved nitrogen forms tiny bubbles that attach to suspended solids, oils, and other contaminants, floating them to the surface for removal. Proper nitrogen pressure ensures the formation of appropriately sized bubbles and efficient adhesion to the contaminants, maximizing the removal rate.

  The effluent from DNF Unit #1 will be routed to the new Steam Stripper. The float and sludge from DNF Unit #1 will be routed to the new Float/Sludge Drum. DNF Unit #2 will typically receive effluent from the two existing Flow Equalization and Oil Removal (FEOR) Tanks, but it will also serve as a spare to DNF Unit #1. When receiving effluent from the FEOR Tanks, the effluent from DNF #2 will be routed to the existing Biotreater Aeration Tanks. Alternatively, when DNF #2 is used in place of DNF #1, the effluent from DNF Unit #2 will be routed to the Steam Stripper. The float and sludge from DNF Unit #2 will be routed to the Float/Sludge Drum. The design capacity of each DNF unit is 250 m^3/hr.

- Float/Sludge Drum: The drum will receive float and sludge from DNF Unit #1 and DNF Unit #2 and oils from the Settlement Drum(s) and new Steam Stripper. The material collected in the drum will be transferred to the existing Recovered Oil Storage Tank or routed to the Settlement Drum(s).

- Steam Stripper, including a reflux drum: The Steam Stripper will use low-pressure steam as the stripping media. The Steam Stripper overhead will be routed through a condenser. The overhead condenser after the steam stripper serves to cool and condense the vapor stream, primarily composed of water and volatile contaminants, back into a liquid state. This condensed liquid is then returned to the stripper column as reflux, enhancing separation efficiency by increasing the concentration of volatile components at the top of the column, promoting better separation of contaminants from the wastewater. Any condensed hydrocarbons collected in the reflux drum will be routed to the Float/Sludge Drum which is controlled by the SCTO. The effluent from the Steam Stripper will be routed to the existing FEOR Tanks (Source ID 401), which are also controlled by the SCTO.

Shell refers to the vessels detailed above (Settlement Drum(s), DNF Unit #1, DNF Unit #2, Float/Sludge Drum, and Steam Stripper) as the "new Wastewater Treatment Vessels." According to the application, Shell also plans to install heat exchangers, small vessels (e.g., knockout vessel), chemical additive containers, and ancillary equipment such as piping, pumps, valves, and analyzers as part of the WWTP Permanent Controls Project to connect and support the operation of the new Wastewater Treatment Vessels. Shell intends to continue to utilize the temporary equipment approved under RFDs until the permanent system is approved and successfully commissioned. The temporary equipment will subsequently be removed.

The new Wastewater Treatment Vessels will treat VOC- and organic HAP-containing wastewater using a combination of gravity settlement/phase separation, dissolved nitrogen flotation, and steam stripping mechanisms. Therefore, the new Wastewater Treatment Vessels will have the potential to emit VOC and organic HAPs because some of the VOC and organic HAPs contained in the wastewater will either volatilize or be stripped from the wastewater during the referenced treatment processes. To minimize the new Wastewater Treatment Vessels' VOC and organic HAP emissions, Shell proposes to collect the vent streams from each of the vessels in a closed vent system and route the vent streams to SPM's Spent Caustic Vent Incinerator for combustion. Note that Shell has requested to rename the Spent Caustic Vent Incinerator (Source ID C206) as the "Spent Caustic Thermal Oxidizer (SCTO)" or "SCTO." This is discussed in more detail under Plan Approval Source Description Reconciliations section of this memo.

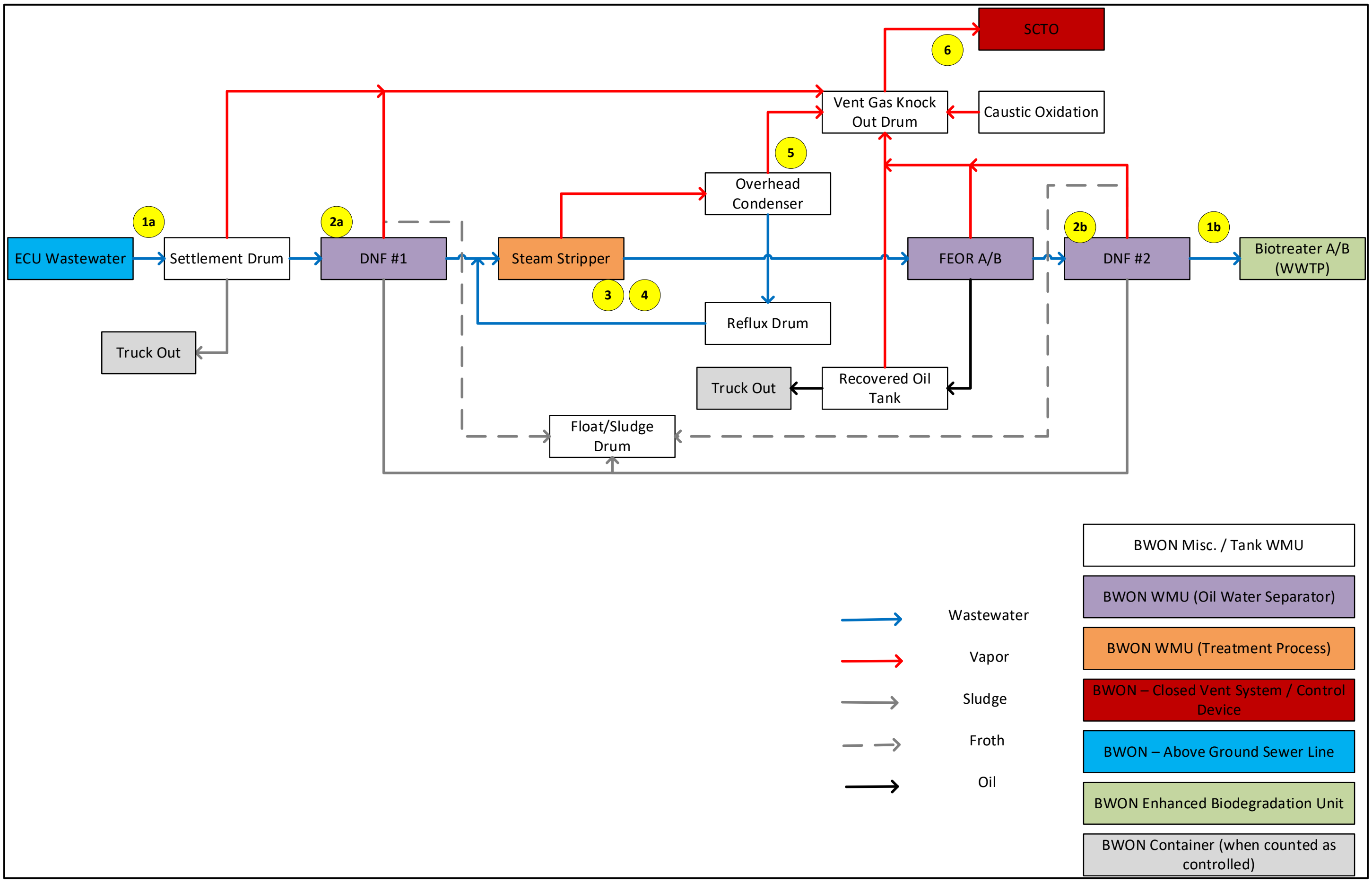
The BAT and LAER analyses for the WWTP are discussed in the Regulatory Analysis section of this memo. The following is a list of WWTP equipment that currently vents to, and will vent to, a closed vent system that routes collected vent streams to the SCTO:

- Two (2) Flow Equalization and Oil Removal (FEOR) Tanks
- Recovered Oil Storage Tank
- Settlement Drum (*proposed equipment that will vent to a closed vent system that will be routed to the SCTO*)
- Two (2) Dissolved Nitrogen Flotation (DNF) Units (*proposed equipment that will vent to a closed vent system that will be routed to the SCTO*)
- Float/Sludge Drum (*proposed equipment that will vent to a closed vent system that will be routed to the SCTO*)
- Steam Stripper and associated Reflux Drum (*proposed equipment that will vent to a closed vent system that will be routed to the SCTO*)

According to the applicant, there is no component in the WWTP prior to the Biotreater that is uncontrolled. The two (2) Induced Nitrogen Flotation (INF) vessels that are temporarily being used vent to the SCTO. These vessels will be removed after the successful commissioning of the WWTP Permanent Controls Project. Note that the Spent Caustic Storage Tank and the Spent Caustic Oxidation Unit vent to a closed vent system that routes collected vent streams to the SCTO as well.

The process flow diagram shown below illustrates how the new Wastewater Treatment Vessels are proposed to be incorporated into the WWTP with this plan approval. The numbered sections of the diagram indicate key areas for monitoring to ensure the new Wastewater Treatment Vessels are operating correctly to maximize the VOC/HAP removal efficiency (e.g. 1a (settlement drum inlet) or 1b (outlet of DNF #2) for inlet/outlet concentrations). As shown in the figure, vapors from this portion of the WWTP will be routed to the SCTO for control. The section labeled Biotreater A/B (WWTP) consists of the biotreater aeration tanks, secondary clarifiers, and further handling until discharge. Emission points from that section are uncontrolled and the potential to emit has been calculated using Toxchem, which is discussed in the Emissions and Controls section of this memo.

Figure 1: WWTP Process Flow Diagram



The Wastewater Treatment Plant does not currently have source specific plan approval conditions in PA-04-00740C, Section D, Source ID 502. Per PA-04-00740C, Section C, Condition #045, "The site is subject to limited requirements of 40 CFR Part 61 Subpart FF – National Emission Standard for Benzene Waste Operations." Section C also requires Shell to comply with the applicable requirements of 40 CFR §§ 61.342, 61.354, 61.355, 61.356, and 61.357 of Subpart FF.

The Department proposes to include requirements under 25 Pa. Code § 127.12b for the new Wastewater Treatment Vessels. The proposed conditions will be included in the plan approval under a new source, **Source ID 505: Wastewater Treatment Plant (Primary Treatment)**, which will include the Settlement and Float/Sludge Drums, DNF Units, and Steam Stripper and be considered the primary section for wastewater treatment. As previously noted, the existing source, Source ID 502: WWTP (Secondary and Tertiary Treatment) is the existing wastewater treatment equipment that carries out the secondary and tertiary treatment of process wastewater and potentially contaminated stormwater.

The proposed requirements are to ensure each component is operating properly and plan approval conditions will be included to require monitoring of specific operational parameters at certain frequencies. Rather than setting specific operating limits (e.g. minimum temperature, pressure of nitrogen, etc.) as plan approval conditions, the Department proposes to require Shell to develop a WWTP Control Plan to memorialize these values. The WWTP Control Plan will be required to include target operating ranges for the equipment with procedures and timeframes to correct instances when the system is not operating as designed. The following conditions in italicized font are proposed to be included in this plan approval for the WWTP (Primary Treatment), Source ID 505. The full list of proposed conditions is included at the end of this memo.

Testing Requirements

The numerical designations reference the locations identified in the WWTP Process Flow Diagram in Figure 1.

1a & 1b Concentration Monitoring

- *Within 180 days of the startup of the WWTP Permanent Controls Project and monthly thereafter, or an alternative schedule approved by the Department, the Owner/Operator shall conduct sampling and testing at the settlement drum inlet to determine the wastewater stream* speciated *HAP concentrations, including, but not limited to, 1,3-Butadiene, benzene, toluene, ethylbenzene, xylene, styrene, naphthalene, dibutyl phthalate, chloroform, acenaphthene, acenaphthylene, fluorene, anthracene, phenanthrene, fluoranthene, and pyrene. The report shall be submitted to the Department no later than 30 days from the date of completion of sampling and testing. The report shall include the following* [25 Pa. Code § 127.12b]*.:*

    a. *Wastewater lab results and testing method used;*
    b. *Location the sample is taken;*
    c. *Wastewater flow rate;*

- *The Owner/Operator shall sample the inlet and outlet of the WWTP at the settlement drum inlet and DNF #2 outlet for concentration of benzene, toluene, ethylbenzene, and xylene (BTEX) and styrene at a minimum of once per calendar week. Sample analyses shall be conducted by methods and techniques acceptable to the Department* [25 Pa. Code § 127.12b].

- *The Owner/Operator shall sample the inlet and outlet of the WWTP at the settlement drum inlet and DNF #2 outlet for concentration of Total Organic Compounds (TOC) at a minimum of once per calendar week to monitor for operational efficiency of the WWTP's primary treatment system. Sample analyses shall be conducted by methods and techniques acceptable to the Department* [25 Pa. Code § 127.12b].

- *The Owner/Operator shall sample the inlet and outlet of the WWTP at the settlement drum inlet and DNF #2 outlet for concentration of Oil and Grease (O&G), as referenced in 40 CFR Part 401, at least once per calendar week to monitor for O&G removal efficiency of the WWTP's primary treatment system. Sample analyses shall be conducted by methods and techniques acceptable to the Department* [25 Pa. Code § 127.12b].

According to the applicant, when the sampled concentrations are out of range, work practice procedures would include escalating troubleshooting to engineering and/or manufacturer support, and take action to minimize impacts, including but not limited to recirculating wastewater between the FEORs and DNF#2 and minimize flow to the downstream WWTP equipment (bio-treaters).

Monitoring Requirements

2a & 2b – DNF Nitrogen Pressure Monitoring

- *The Owner/Operator shall monitor the pressure of nitrogen once per calendar day into the primary DNF. The minimum nitrogen pressure target shall be set within 60 days of initial operation* [25 Pa. Code §127.12b].

As described in the WWTP Permanent Controls Project overview, DNF #1 will typically act as the primary DNF, and the effluent will be routed to the Steam Stripper. Alternatively, DNF #2 may be used in place of DNF #1 as a "spare."

3 – Steam Stripper Temperature Monitoring

- *The Owner/Operator shall monitor the temperature of the steam stripper bottoms each operating day. The specific location of the thermocouple shall be determined within 60 days of initial operation* [25 Pa. Code §127.12b].

According to the applicant, the steam stripper bottoms temperature should typically be greater than 115°C on a calendar-day average during steam stripper operations, or as documented by an engineering assessment of the as-built steam stripper.

3 – Steam Stripper Steam Monitoring

- *The Owner/Operator shall monitor the steam stripper inlet steam-to-water ratio on an hourly average when the steam stripper is in operation* [25 Pa. Code § 127.12b].

- *The Owner/Operator shall monitor the total steam supplied to the steam stripper on an hourly average when the steam stripper is in operation* [25 Pa. Code § 127.12b].

- *The Owner/Operator shall monitor the steam pressure supplied to the steam stripper on an hourly average when the steam stripper is in operation* [25 Pa. Code § 127.12b].

It is the Department's understanding that the steam to water ratio is important for maintaining optimal stripping efficiency while monitoring the total steam supplied ensures enough stripping capacity for the removal of contaminants while not supplying excessive steam which may lead to operational issues and increased cost without significant benefit. Maintaining the pressure of the steam is also important for stripping efficiency as it directly influences the operating temperature of the stripper, which impacts the effectiveness, while too low of pressure may lead to incomplete stripping. Stable steam pressure will also ensure consistent operation. According to the applicant, the steam stripper inlet steam-to-water ratio should typically be greater than 3%, or as documented by an engineering assessment of the as-built steam stripper.

5 – Steam Stripper Overhead Condenser Temperature Monitoring

- *The Owner/Operator shall monitor the temperature at the outlet of the steam stripper overhead condenser on an hourly average when the condenser is in operation* [25 Pa. Code § 127.12b].

According to the applicant, the temperature at the outlet of the condenser should typically be between 25°C and 55°C or as documented by an engineering assessment of the condenser.

6 – SCTO Monitoring

The following requirement will be included in the proposed plan approval under Source ID 206, Spent Caustic Vent Header System to ensure the SCTO is operating properly due to the additional load from the WWTP:

- *The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the vent gas header to the SCTO at a minimum of once every 15 minutes* [25 Pa. Code § 127.12b].

- *The Owner/Operator shall maintain records of the flow rate in the vent gas header to the SCTO on a daily basi*s [25 Pa. Code § 127.12b].

The installation and operation of the flow rate monitoring system will be completed when the WWTP Permanent Controls Project is completed. The SCTO vent gas header is existing equipment, and the flow rate monitoring system will be installed with the new primary treatment equipment.

Section D, Source ID 206, Condition # 006 of the plan approval requires monitoring of the SCTO in accordance with 40 CFR § 63.985(c) of 40 CFR Part 63 Subpart SS. Operating parameter monitoring shall include combustion temperature at a minimum.

Per 40 CFR § 63.985(c)(i) "The owner or operator shall submit with the Notification of Compliance Status, a monitoring plan containing the information specified in § 63.999(b)(2)(i) and (ii) to identify the parameters that will be monitored to assure proper operation of the control device." The information specified in 40 CFR § 63.999(b)(2)(i) and (ii) includes a description of the parameter or parameters to be monitored and the operating range for each parameter.

In accordance with 40 CFR § 63.999(b)(2)(i), the parameter monitored at SPM is the combustion zone temperature, and the criteria for selection is the manufacturer's design guarantee basis and performance testing. The monitoring frequency is continuous. Compliance with emission limitations and VOC destruction efficiency will be re-verified through performance testing during maximum routine operating conditions with the new Wastewater Treatment Vessels, as included and updated in Section D, under Source ID 206, as Conditions #004 and #005 of the proposed plan approval.

While monitoring the heating value of a gas stream in a flare vent gas header is common because the gas stream heating value serves as a surrogate for combustion temperature measurements since a flare does not have a combustion chamber to install temperature monitoring equipment; monitoring the gas stream heating value in a thermal oxidizer vent gas header is not necessary because the thermal oxidizer combustion chamber temperature can be measured directly. Additionally, in the case of the SCTO, most of the heating value is derived from the fuel gas (natural gas) routed to the burners. As previously stated, compliance with the emission limitations and VOC destruction efficiency will be re-verified through performance testing.

Work Practice Requirements

Per 40 CFR § 61.343(a)(1), the owner or operator is required to install, operate, and maintain a fixed-roof and closed vent system that routes all organic vapors vented from the tanks to a control device. This includes the proposed settlement drum and float/sludge drum that will vent to a closed vent system to the SCTO.

As previously discussed, the Department proposes to require the development of a written WWTP Control Plan that will exist outside of the plan approval. The intention of the control plan is to include procedures for operating the WWTP's primary treatment system and corrective actions to be taken when the equipment is operating outside the design parameters. The WWTP Control Plan will be required to be submitted after commencing operation of the WWTP Permanent Controls Project. The WWTP Control Plan is expected to be updated upon obtaining operational data or any changes to the design of the WWTP's primary treatment system. Procedures in the WWTP Control Plan are expected to include items such as the following:

- If a target TOC concentration at the outlet of the DNF#2 is not able to be met within the timeframe specified in the WWTP Control Plan, the owner or operator shall increase sampling of the DNF#2 outlet for TOC to once each calendar day and implement corrective procedures as detailed in the WWTP Control Plan.

- If the minimum nitrogen pressure into the primary DNF specified in the WWTP Control Plan is not met during the daily inspection of the pressure, the owner or operator shall implement procedures specified in the WWTP Control Plan.

- If the steam stripper bottoms temperature is not above the minimum specified temperature in the WWTP Control Plan, troubleshooting must commence, and steam temperature restored above minimum specified temperature within 1 business day after a calendar-day average is calculated below target. If the temperature cannot be restored within that business day, the owner or operator shall implement procedures specified in the WWTP Control Plan.

- If the hourly-average steam stripper inlet steam-to-water ratio is below the target specified in the WWTP Control Plan, troubleshooting must commence, and the ratio restored above the minimum specified level within 1 business day. If the ratio cannot be restored within that business day, the owner or operator shall implement the procedures in WWTP Control Plan.

- If the condenser outlet temperature is outside the specified range in the WWTP Control Plan for greater than one hour, troubleshooting must commence, and the temperature restored within the range within 1 business day. If the temperature cannot be restored within that business day, the owner or operator shall implement the procedures in the WWTP Control Plan.

The existing Wastewater Treatment Plant (Secondary and Tertiary Treatment), Source ID 502, is included in PA-04-00740C Section E, G05: NESHAP Part 63 Subpart YY, G06: NESHAP Part 63 Subpart XX, G07: NSPS Part 60 Subpart VVa, and G09: NESHAP Part 63 Subpart FFFF (partial).

Note that the current plan approval also includes Source ID 401, Storage Tanks (Recovered Oil, Equalization Wastewater). This includes the existing FEOR A/B tanks and recovered oil storage tank shown in Figure 1. The plan approval includes Work Practice Requirements for the tanks to be equipped with an IFR and for vapors to be routed to the SCTO.

EMACT Project

"On July 6, 2020, the U.S. Environmental Protection Agency (EPA or the Agency) finalized the residual risk and technology review (RTR) conducted for the Ethylene Production source category, which is part of the Generic Maximum Achievable Control Technology Standards National Emission Standards for Hazardous Air Pollutants (NESHAP). NESHAP and associated regulated industrial source categories that are the subject of this action include 40 CFR part 63, subparts XX and YY for ethylene production."[6]

The MACT standards for the Ethylene Production source category (herein called the EMACT standards) are contained in the Generic Maximum Achievable Control Technology (GMACT) NESHAP, which also includes MACT standards for several other source categories. The EMACT standards were promulgated on July 12, 2002, and codified at 40 CFR Part 63, Subparts XX and YY. As promulgated in 2002, and further amended, the EMACT standards regulate hazardous air pollutant (HAP) emissions from ethylene production units located at major sources.

SPM is classified as a *major source*[7] of HAPs and SPM's ethylene manufacturing unit is an *ethylene production unit*[8], as the term is defined in 40 CFR Part 63 Subpart YY. Therefore, SPM's ethylene manufacturing unit and relevant associated emission points represent an ethylene production affected source, subject to 40 CFR Part 63 Subpart YY. TEGF A and TEGF B (formerly known as HP Ground Flare #1 and #2) receive vent streams from equipment that is part of the ethylene production unit affected source at SPM. As a result, the TEGF A and TEGF B are *pressure-assisted multipoint flares*[9] subject to applicable 40 CFR Part 63 Subpart YY control device requirements. 40 CFR Part 63 Subpart YY requires subject pressure-assisted multi-point flares that use cross lighting on a stage of burners to be equipped with two pilots per stage and one of the pilots to be lit and capable of igniting all regulated material that is routed to that stage of burners.

---

[6] https://www.federalregister.gov/documents/2024/04/04/2024-05906/national-emission-standards-for-hazardous-air-pollutants-ethylene-production-miscellaneous-organic

[7] *Major source* – means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this Sentence [40 CFR Part 63, Subpart A].

[8] *Ethylene production or production unit* – means a chemical manufacturing process unit in which ethylene and/or propylene are produced by separation from petroleum refining process streams or by subjecting hydrocarbons to high temperatures in the presence of steam. The ethylene production unit includes the separation of ethylene and/or propylene from associated streams such as a C4 product, pyrolysis gasoline, and pyrolysis fuel oil. Ethylene production does not include the manufacture of SOCMI chemicals such as the production of butadiene from the C4 stream and aromatics from pyrolysis gasoline (40 CFR Part 63, Subpart YY).

[9] *Pressure-assisted multi-point flare* – means a flare system consisting of multiple flare burners in staged arrays whereby the vent stream pressure is used to promote mixing and smokeless operation at the flare burner tips. Pressure-assisted multipoint flares are designed for smokeless operation at velocities up to Mach = 1 conditions (i.e., sonic conditions), can be elevated or at ground level, and typically use cross-lighting for flame propagation to combust any flare vent gases sent to a particular stage of flare burners [40 CFR Part 63, Subpart YY].

On April 4, 2024, the Department authorized RFD-04-00740N which, in part, approved the installation of additional pilots in the flares to comply with 40 CFR Part 63 Subpart YY. SPM has completed the installation such that as of June of 2024, there are two pilots on each stage of burners for both TEGF A and TEGF B. Per 40 CFR 63.1102(c), "All ethylene production affected sources that commenced construction or reconstruction on or before October 9, 2019, must be in compliance with the requirements listed in paragraphs (c)(1) through (13) of this section upon initial startup or July 6, 2023, whichever is later…"

Paragraph (c)(8) of 40 CFR § 63.1102 references the flare requirements specified in § 63.1103(e)(4). Per § 63.1103(e)(4), "Beginning no later than the compliance dates specified in § 63.1102(c), if a steam-assisted, air-assisted, non-assisted, or pressure-assisted multi-point flare is used as a control device for an emission point subject to the requirements in Table 7 to this section, then the owner or operator must meet the applicable requirements for flares as specified in §§ 63.670 and 63.671 of subpart CC…." 40 CFR Part 63 Subpart CC, or the Refinery MACT, was originally finalized in August 1995 and was significantly updated based upon the Petroleum Refinery Sector Risk and Technology Review (RTR),[10] finalized on December 1, 2015. Subsequent technical corrections and clarifications were finalized on February 4, 2020, and April 4, 2024.
Prior to July 6, 2023, the TEGF A and TEGF B were required to comply with both of the following flare vent gas minimum heating value limitations:

- 40 CFR Part 63 Subpart YY required the flare vent gas combusted at the flares to have a net heating value of 200 Btu/scf or greater to comply with the flare control device requirements referenced by the subpart; and
- PA-04-00740A and PA-04-00740C BACT/LAER conditions require the flare vent gas combusted at the flares to have an NHV_{CZ} of 500 Btu/scf or greater.

To ensure compliance with these two different requirements, the effective flare vent gas minimum heating value limitation for the TEGF A and TEGF B had been maintained at the higher value of 500 Btu/scf or greater.

As of July 6, 2023, 40 CFR Part 63 Subpart YY requires the flare vent gas combusted at the TEGF A and TEGF B to have an NHV_{CZ} of 800 Btu/scf or greater due to the "pressure-assisted multi-point flare" design of the flares. The 800 Btu/scf NHV_{CZ} for pressure-assisted flares is designed to ensure stable and efficient combustion in these types of flares. This higher heating value (compared to unassisted flares) helps prevent flameouts and promotes complete combustion.

In the proposed amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP): Generic Maximum Achievable Control Technology Standards for the Ethylene Production source category,[11] the EPA states in Section IV.A.1.G. Pressure-Assisted Multi-Point Flares that:

> "In reviewing the initial MPGF AMEL requests by Dow Chemical and ExxonMobil (80 FR 8023-8030[12], February 13, 2015), the Agency noted two general conclusions from the test data supporting the AMEL requests that were consistent with 1985 studies conducted by the EPA on

[10] https://www.epa.gov/stationary-sources-air-pollution/petroleum-refinery-sector-rule-risk-and-technology-review-and-new
[11] https://www.federalregister.gov/documents/2019/10/09/2019-19875/national-emission-standards-for-hazardous-air-pollutants-generic-maximum-achievable-control
[12] Pohl, J. and N. Soelberg. 1985. *Evaluation of the efficiency of industrial flares: Flare head design and gas composition.* EPA-600/2-85-106. Prepared for U.S. EPA Office of Air Quality Planning and Standards.

> pressure-assisted flares. The first general conclusion was that "flare head design can influence the flame stability curve." The second general conclusion was that "stable flare flames and high (>98-99%) combustion and destruction efficiencies are attained when flares are operated within operating envelopes specific to each flare burner and gas mixture tested. Operation beyond the edge of the operating envelope can result in rapid flame de-stabilization and a decrease in combustion and destruction efficiencies. … Thus, we selected a minimum NHVcz of 800 Btu/scf to ensure the MPGF is operated within the proper envelope to produce a stable flame and achieve high destruction efficiencies at least equivalent to those as the underlying Ethylene Production MACT standards…"
>
> "Furthermore, in reviewing the site-specific AMEL standards that facilities are complying with for MPGF,[13] we believe that if these same site-specific standards are applied to all MPGF at ethylene production facilities, owners or operators would demonstrate at least equivalent emissions reductions as the underlying Ethylene Production MACT standards as well as demonstrate at least equivalent reductions with the operational and monitoring requirements we are proposing for more traditional, elevated flare tips. Therefore, we are proposing that owners or operators of MPGF: (1) Maintain an NHVcz ≥ 800 Btu/scf; (2) continuously monitor the NHVcz and flare vent gas flow rate; (3) continuously monitor for the presence of a pilot flame, and if cross-lighting is used on a particular stage of burners, then continuously monitor to ensure that the stage has a minimum of two pilots per stage that will ignite all flare vent gases sent to that stage; (4) operate the MPGF with no visible emissions (except for 5 minutes during any 2 consecutive hours); (5) maintain a distance of no greater than 6 feet between any two burners in series on a stage of burners that use cross-lighting; and (6) monitor to ensure staging valves for each stage of the MPGF operate properly so that the flare will control vent gases within the proper flow and pressure ranges based on the flare manufacturer's recommendations."

Note that EPA's mention of MPGF is regarding pressure-assisted multi-point ground flares, not Source ID 204B in the plan approval. Source ID 204B is air assisted, not pressure-assisted, and different requirements apply. The high destruction efficiencies that is at least equivalent to those in the underlying Ethylene Production MACT standards is 98%.

To ensure compliance with new requirements, the effective flare vent gas minimum heating value for the TEGF A and TEGF B is now maintained at 800 Btu/scf or greater. To achieve compliance with the minimum NHVcz level of 800 Btu/scf that is required by 40 CFR Part 63 Subpart YY (through 40 CFR Part 63 Subpart CC at 40 CFR 63.670(e)(2)), increased amounts of flare supplemental gas (natural gas and tail gas) at the TEGF A and TEGF B are necessary. Combusting additional flare supplemental gas at the TEGF A and TEGF B results in increased combustion pollutant emissions from the two flares. Therefore, the EMACT Project represents a change in the method of operation of the TEGF A and TEGF B for New Source Review (NSR) purposes and results in a significant increase in emissions which is discussed in more detail in the *Regulatory Analysis* section of this memo, particularly related to PSD and NNSR.

The figure below depicts the HP Flare System and the major connections and monitoring equipment. To monitor the net heating value, the EMACT (via 40 CFR Part 63 Subpart CC) requires the use of a monitoring (e.g. gas chromatograph) or sampling system to analyze the composition of the vent gas and determine the net heating

[13] 80 FR 52426, August 31, 2015; 81 FR 23480, April 21, 2016; and 82 FR 27822, June 19, 2017.

value of the vent gas stream (NHV_{vg}) based on the concentration and individual net heating value of each compound in the vent gas OR the use of a calorimeter to directly measure the NHV_{vg} [40 CFR § 63.670(j)]. NHV_{cz} is then calculated using equations in 40 CFR Part 63 Subpart CC. These equations consider the contribution of the vent gas, pilot gas, and any assist gas (like air or steam) to the overall heating value of the combustion zone. Accurately measuring the flow rates and compositions of all contributing gas streams is critical.

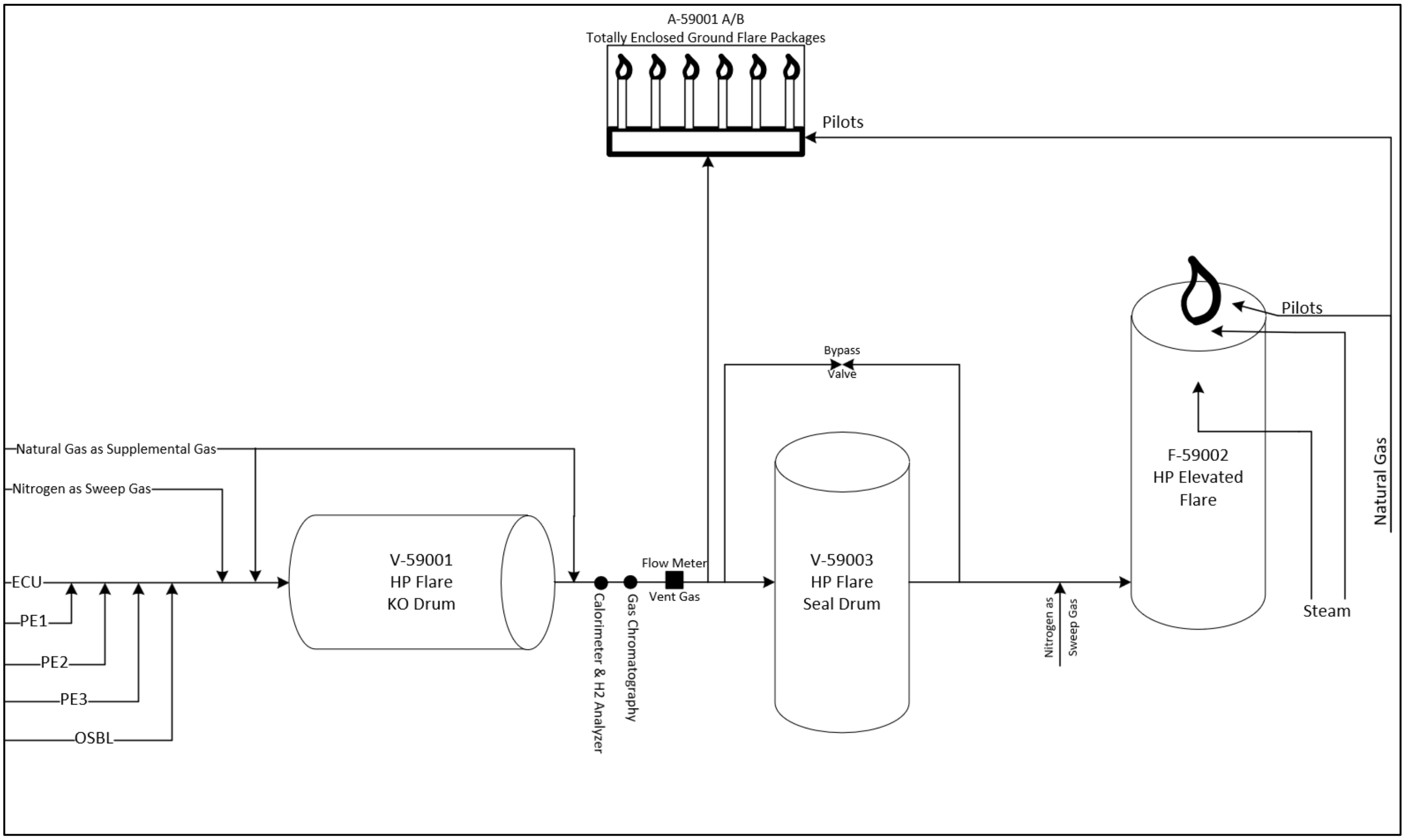
SPM operates both a calorimeter and gas chromatograph (GC) such that the calorimeter can quickly calculate net heating value while the GC can be used to identify specific constituents in the vent gas. According to the applicant, the GC is no longer used for NHV_{cz} compliance but is maintained as a backup monitoring system for this parameter. Among other components measured like carbon dioxide, water, and nitrogen, the GC measures individual hydrocarbon compounds up to hexene. Heavier hydrocarbons are then grouped as C6+ and C7+. Shell is required to continuously monitor (at least every 15 minutes) the VOC and GHG content in the flare vent gas for VOC and GHG emission calculation purposes.

As shown in the figure below, the GC and calorimeter are located after the HP Flare System knockout drum prior to the flow meter and combustion in the flare(s). The requirements for the location of the net heating value calorimeter, as well as other calibration and quality control requirements for the continuous parameter monitoring system (CPMS), are detailed in Table 13 of 40 CFR Part 63 Subpart CC.

Per 40 CFR § 63.671(1), "Except for CPMS installed for pilot flame monitoring, all monitoring equipment must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart."

Per 40 CFR § 63.670(d)(3), "Pressure-assisted flares are not subject to the flare tip velocity limits in either paragraph (d)(1) or (2) of this section. In lieu of the flare tip velocity limits, beginning on April 4, 2024, the owner or operator of a pressure-assisted flare must install and operate pressure monitor(s) on the main flare header, as well as a valve position indicator monitoring system for each staging valve to ensure that the flare operates within the proper range of conditions as specified by the manufacturer. The pressure monitor must meet the requirements in table 13 of this subpart."

Figure 2: HP Flare System Process Flow Diagram



The CPMS for the TEGF A and TEGF B includes monitors for vent gas flow, temperature, and pressure, valve position switches for stages, pressure for header, a calorimeter with hydrogen analyzer,[14] a GC, pilot thermocouples, and a video camera.

According to the applicant, the TEGF A and TEGF B achieved compliance with applicable 40 CFR Part 63 Subpart YY pressure-assisted multi-point flare requirements by the deadline of July 6, 2023, *except* for the following:

- The TEGF A and TEGF B achieved compliance with the requirement to operate with an NHV_{CZ} at or above 800 Btu/scf on February 6, 2024.
- The TEGF A achieved compliance with the requirement to have at least two pilots on each stage of burners on June 19, 2024.
- The TEGF A achieved compliance with the requirement to have a thermocouple or other equivalent device to detect the presence of pilot flame(s) on each stage of burners on June 19, 2024.
- The TEGF B achieved compliance with the requirement to have at least two pilots on each stage of burners on June 28, 2024.

[14] Per 40 CFR § 63.670(j)(4), if the owner or operator uses a calorimeter for net heating value monitoring, the owner or operator may, at their discretion, install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the flare vent gas. This can be used in the net heating value calculation.

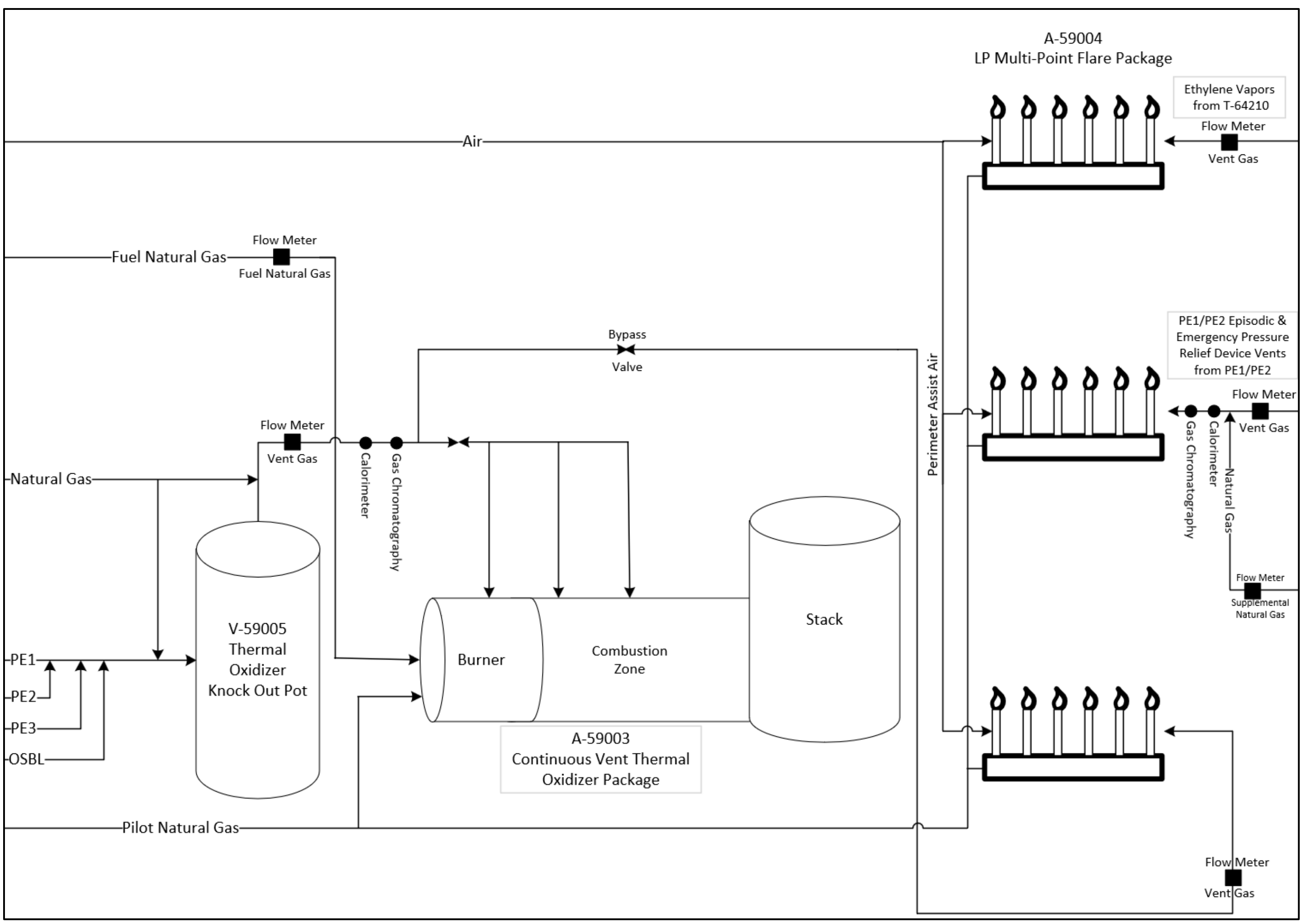
- The TEGF B achieved compliance with the requirement to have a thermocouple or other equivalent device to detect the presence of pilot flame(s) on each stage of burners on June 28, 2024.

Although not part of the EMACT Project in terms of this plan approval, the MPGF is also subject to 40 CFR Subpart YY. The MPGF (Source ID C207) is part of the low-pressure header control system and is subject to similar, albeit different, flare requirements by reference in 40 CFR Part 63 Subpart CC.

The CVTO (Source ID C204A) is the primary control device for the low-pressure system. The CVTO is not a flare and therefore not subject to the flare requirements of 40 CFR Part 63 Subpart CC. The plan approval does however include site-specific monitoring requirements for the CVTO.

The MPGF controls vent streams from three (3) different low pressure header systems: the MPGF CVTO Trip Header, MPGF PE Units 1/2 Episodic Vent Header, and MPGF Ethylene Tank Header. This is a distinction being made in this plan approval compared to PA-04-00740C. The figure below shows the process flow diagram of the low-pressure system.

Figure 3: Low-Pressure System Process Flow Diagram



As shown in the figure above, CPMS for the low-pressure system also includes a calorimeter and GC, the calorimeter being used for compliance with the NHV_{CZ} requirement, as with the HP system. The MPGF is perimeter air-assisted, not pressure-assisted like the TEGF A and TEGF B and therefore does not have to meet the minimum NHV_{CZ} level of 800 Btu/scf. The applicable minimum NHVcz requirement for all flares other than pressure-assisted flares is 270 Btu/scf in 40 CFR Part 63 Subpart CC (40 CFR 63.670(e)(1)).

Note that PA-04-00740C includes a higher minimum NHVcz of 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes. The 270 Btu/scf limit is on a 15-minute basis compared to the 500 Btu/scf limit, which is on a three-hour average basis, calculated every 15 minutes. Shell demonstrates compliance with both the 270 Btu/scf, 15-minute-basis limit and 500 Btu/scf, three-hour average-basis limit, which are not directly comparable due to the averaging period difference between the two limitations.

By design, differences to the CPMS for the MPGF compared to TEGF A/B is that it does not include monitors for pressure to the header or valve position switches for the stages but does include monitors for vent gas flow, temperature, and pressure, as well as a calorimeter, a GC, pilot thermocouples, and a video camera. The MPGF also includes a perimeter air assist fan speed monitor for air flow correlation. According to the application, continuously monitoring fan speed or power and using fan curves is the method used for continuously monitoring assist air flow rates at the MPGF. Like the TEGF A and TEGF B, the MPGF previously used the GC for monitoring heat content but will use the calorimeter going forward, with the GC providing supplemental information including VOC content required by the plan approval.

Plan Approval Source Name Reconciliations

Shell has proposed changes to the source names/descriptions of several of the air contamination sources and air cleaning devices included in the plan approval. The proposed changes are in line with SPM's configurations, operations, and Shell's own source descriptions. The following table summarizes the proposed changes and reason for the change:

Table 2: Proposed Plan Approval Source Description Reconciliations

Source ID	Current Source Name	Proposed Source Name	Reason for Reconciliation
107	Natural Gas-Fired Emergency Generator Engines (3)	Natural Gas-Fired Emergency Generator Engines (2)	To accurately reflect the number of natural gas-fired emergency generator engines installed at SPM.
204	Low Pressure (LP) Header System	CVTO Header System	The plan approval currently indicates SPM is equipped with one integrated LP header system that connects to the CVTO and MPGF. However, that is not the case. There is one header system that connects to the CVTO, which Shell has requested

Source ID	Current Source Name	Proposed Source Name	Reason for Reconciliation
207	* Included as part of Source ID 204	**MPGF CVTO Trip Header**	to be referenced in the plan approval as the CVTO Header System. The CVTO Header System is also connected to an MPGF header, which receives vent streams from the CVTO Header System when the CVTO is unavailable. Shell proposes that this MPGF header is referenced as the MPGF CVTO Trip Header in the plan approval. Additionally, there is a header that is used to periodically route vent streams from Polyethylene (PE) Units 1 and 2 to the MPGF for combustion. Shell proposes that this MPGF header is referenced as the MPGF PE Units 1/2 Episodic Vent Header in the plan approval. Lastly, there is a header that is used to route intermittent vent streams from the Refrigerated Ethylene Storage Tank and ethylene gas recovery system to the MPGF for combustion. Shell proposes that this MPGF header is referenced as the MPGF Ethylene Tank Header in the plan approval.
208	* Included as part of Source ID 204	**MPGF Ethylene Tank Header**	
209	* Included as part of Source ID 204	**MPGF PE Units 1/2 Episodic Vent Header**	
C204	LP System	N/A	The CVTO and MPGF will be associated with specific headers, which eliminates the need to include this source in the plan approval.
C204A	LP Incinerator	CVTO	To match the description SPM uses for this control device.
C204B	LP Multipoint Ground Flare (MPGF)	N/A	Not to be included in PA-04-00740D. The MPGF will be represented by three (3) separate Source IDs: C207, C208, and C209.
C205	HP System	HP Flare System	To match the description SPM uses for the equipment representing this source.
C205A	HP Ground Flare #1	TEGF A	To match the description SPM uses for this control device.
C205B	HP Ground Flare #2	TEGF B	To match the description SPM uses for this control device.
C206	Spent Caustic Vent Incinerator	SCTO	To match the description SPM uses for this control device

Source ID	Current Source Name	Proposed Source Name	Reason for Reconciliation
C207	N/A	**MPGF CVTO Trip**	The MPGF is a single Zeeco Model No. AFDS-6/24 / AFTA-8/18 multi-point, perimeter air-assisted ground flare. However, as described above, the MPGF controls vent streams from three (3) distinct headers which are subject to different regulations and have different requirements. Source IDs 204, 207, 208, and 209 will be used for conditions specific to the headers, while C204, C207, C208, C209 will be used for mapping purposes to appropriate source IDs such as 202, 411, etc.
C208	N/A	**MPGF Ethylene Tank**	
C209	N/A	**MPGF PE Units 1/2 Episodic Vent**	
303	Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline)	Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, PE3 Heavies)	Shell originally planned to blend PE3 heavies into light gasoline. However, PE3 heavies are loaded separately from light gasoline into railcars at SPM, and the vapors generated during the loading of PE3 heavies into railcars are collected and routed through a closed system to the CVTO or MPGF, the same as originally planned when the PE3 heavies were to be blended into light gasoline. Therefore, Shell proposes to separately identify PE3 heavies in the source's description.
304	Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3+ Ref)	Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)	To correctly identify the refrigerant material included in the description as C_3 refrigerant rather than C_{3+} refrigerant.
305	Liquid Loadout (Coke Residue/Tar)	Liquid Loadout (Blended Pitch)	To match the description SPM uses for this material.
411	* Included as part of Source ID 405, Storage Tanks (Misc Pressurized/Refrigerated)	**Refrigerated Ethylene Storage Tank**	Since the Refrigerated Ethylene Storage Tank vents to the MPGF Ethylene Tank Header and has different requirements than the pressurized storage tanks, a new source is proposed for the existing Refrigerated Ethylene Storage Tank.
502	Wastewater Treatment Plant	Wastewater Treatment Plant (Secondary & Tertiary Treatment)	To distinguish the existing WWTP from the proposed Wastewater Treatment Vessels.
505	N/A	**Wastewater Treatment Plant (Primary Treatment)**	New source for the proposed Wastewater Treatment Vessels as part of the WWTP Permanent Controls Project.

Potential to Emit Calculation Reconciliations

The proposed potential to emit calculation reconciliations are described in the *Emissions and Controls* section of this memo. The proposed changes are described in Section 1.7 of Shell's September 13, 2024, application, with the potential to emit calculations included in Appendix B. The PTE of certain air contamination sources and air cleaning devices was revised in Shell's 2nd, 3rd, and 4th responses to the Department's December 24, 2024, deficiency letter. The revised facility-wide PTE was included in Shell's 5th response on April 11, 2025, and a revised Appendix B was provided on June 3, 2025. Appendix B was again revised and included with the September 5, 2025, revised modeling and risk assessment.

Plan Approval Condition Reconciliations

Proposed plan approval condition revisions are at the end of this memo. Revisions proposed by the applicant represent corrections, as-built changes, or updates to monitoring, record keeping, or reporting requirements. The condition numbers reference the conditions in PA-04-00740C. Additional new conditions proposed by the Department are also included at the end of this memo. Condition changes which require more explanation are discussed directly below.

Section C – Site Level Plan Approval Requirements

The Department proposes to update the malfunction notification requirement consistent with all plan approvals to require the owner or operator to contact their local emergency organization as well as the Department to report malfunctions that pose an imminent danger to the community.

The Department recognizes that the potential does exist for unforeseen events or malfunctions that may result in an emergency situation at an industrial site of this scale. Department field staff perform facility-wide compliance inspections and complaint response on a periodic and as-needed basis; however, Shell will in almost all cases be in position as the first identifier of any problems occurring at the facility whether related to air quality or otherwise. Responses to any problems or events at the facility which pose an immediate threat to the public would be coordinated between Shell and local emergency services such as the Center and Potter Townships and Beaver County Emergency Management Agencies as well as the Department's Environmental Emergency Response Team and the Pennsylvania Emergency Management Agency (PEMA) as necessary.

The Department's Environmental Emergency Response Team is responsible for protecting public health and the environment by responding to and mitigating the effects of environmental emergencies. This includes spills, releases of hazardous materials, fires, and other incidents that threaten the environment or public safety. The program has emergency response team members available to respond on-site whenever there is an immediate threat to the public health, safety, or the environment. The team provides a 24-hour emergency response hotline,[15] with on-call duty officers in each regional office and emergency response team members available to respond to emergencies and incidents within DEP's range of experience. An environmental emergency is a situation requiring an immediate response.

Pennsylvania's Emergency Management Services Code, found in Title 35 of the Pennsylvania Consolidated Statutes, establishes the framework for disaster preparedness, response, and recovery within the

[15] https://www.pa.gov/services/dep/report-an-environmental-emergency-to-the-department-of-environmental-protection1

Commonwealth. It outlines the responsibilities of the Governor, PEMA, and local political subdivisions in managing emergencies and disasters. Title 35 directs and authorizes every political subdivision (i.e. county, city, borough, and townships) to have an emergency management program.

PEMA plays a central role in coordinating emergency response and recovery efforts across the state. PEMA focuses on helping communities and individuals before, during, and after emergencies, including natural disasters, acts of terrorism, and other human-made disasters. This is achieved by assisting counties with emergency operations, providing incident command technical assistance, and managing a state-level multi-agency coordination system.

The Beaver County Emergency Management Coordinator (EMC) operates out of an Emergency Operations Center (EOC) at the Emergency Services Center in Ambridge, PA.[16] The EOC is activated in times of disaster and staffed by trained, mostly volunteer personnel, from throughout Beaver County representing various disciplines. Potter Township is served by the Center Township Police Department for its police services. For general emergency management and coordination, the Beaver County Emergency Services is the primary agency, encompassing both 911 dispatch and emergency management functions for both Potter and Center Townships.

Section B Condition #012 of the plan approval requires Shell to meet the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68: Chemical Accident Prevention Provisions, Federal Chemical Safety Information, and Site Security and Fuels Regulatory Relief Act. This includes the development and implementation of an accidental release program and Risk Management Plan (RMP) as applicable under those statutes and regulations. Shell submitted their RMP to the EPA on April 6, 2022, establishing the anniversary date of April 6, 2027. Per the EPA's April 25, 2022, completeness review notification letter for Shell's RMP, Shell's RMP must be updated and submitted on or before the anniversary date as required by 40 CFR § 68.190.

Specific to air quality, the Department's Air Quality Monitoring Division (Division) oversees the monitoring of air quality throughout the state to ensure compliance with federal and state standards and protect public health. The Division collects current and maintains historical data on air pollution, conducts investigative sampling to determine the nature and extent of pollutants, initiates emergency control programs, and develops new sampling and analysis techniques.[17] The Division operates the Commonwealth of Pennsylvania Air Monitoring System (COPAMS), which continuously monitors pollutants and weather conditions at various locations. This data is used to assess air quality, identify pollution episodes, and inform public awareness.

Section D – Source Level Plan Approval Requirements

Source ID 204: CVTO Header System (previously Low Pressure (LP) Header System)

The plan approval currently represents the low-pressure header system as one integrated system that connects to the CVTO and MPGF for control, which does not accurately reflect the header systems. There is one header system that connects to the CVTO, which Shell has requested to be referenced in the plan approval as the CVTO Header System. The CVTO Header System is also connected to an MPGF header, which receives vent streams from the CVTO Header System when the CVTO is unavailable for backup control by the MPGF. Shell

[16] https://www.beavercountypa.gov/departments/emergency-services/ema-(emergency-management)
[17] https://www.pa.gov/agencies/dep/programs-and-services/air/air-quality-monitoring-division

has requested to identify this MPGF header as the MPGF CVTO Trip Header in the plan approval. The CVTO Header System vent gas may also be routed to the MPGF CVTO Trip Header during abnormal CVTO system operating conditions, such as high CVTO Header System pressure, high CVTO temperature, high CVTO combustion zone temperature, and low CVTO combustion air pressure. According to the applicant, the MPGF CVTO Trip Header is normally not in use.

Additionally, there is a header that is used to periodically route vent streams from PE Units 1 and 2 to the MPGF for combustion. Shell has proposed to identify this MPGF header as the MPGF PE Units 1/2 Episodic Vent Header in the plan approval. Lastly, there is a header that is used to route intermittent vent streams from the Refrigerated Ethylene Storage Tank and ethylene gas recovery system to the MPGF for combustion. Shell has proposed to identify this MPGF header as the MPGF Ethylene Tank Header in the plan approval.

<u>Conditions # 004, 008, 009, 010, 011, 012, 016, 017, 018, and 019</u>: Each of these referenced conditions are relevant to the MPGF. According to the application, "Shell proposes to remove the condition[s]…because the MPGF is connected to the MPGF CVTO Trip Header, MPGF PE Units 1/2 Episodic Vent Header, and MPGF Ethylene Tank Header, not the CVTO Header System. However, Shell expects DEP to include applicable MPGF requirements in plan approval conditions assigned to the MPGF CVTO Trip Header, MPGF PE Units 1/2 Episodic Vent Header, and MPGF Ethylene Tank Header."

MPGF conditions will be removed from the CVTO Header System requirements as requested and included, as applicable, under the following new Source IDs:

- New Source ID 207: MPGF CVTO Trip Header, which receives the same vent streams from the CVTO Header System when the CVTO is unavailable.

- New Source ID 208: MPGF Ethylene Tank Header, which receives vent streams from Source ID 411: Refrigerated Ethylene Storage Tank. The refrigerated ethylene storage tank was previously included with Source ID 405: Storage Tanks (Misc Pressurized/Refrigerated) which will be renamed in this plan approval as Source ID 405: Storage Tanks (Misc Pressurized) since the refrigerated ethylene storage tank will be its own source.

- New Source ID 209: MPGF PE Units 1/2 Episodic Vent Header, which receives vent streams from Source ID 202: Polyethylene Manufacturing Line.

Shell has documented the monitoring, testing, reporting, record keeping, and work practice requirements applicable to the MPGF CVTO Trip Header, MPGF PE Units 1/2 Episodic Vent Header, and MPGF Ethylene Tank Header in Appendix A of the application. The proposed MPGF header conditions are included at the end of this memo.

State Implementation Plan Revision; Concerning Reasonably Available Control Technology Determinations for the 2015 Ozone National Ambient Air Quality Standards[18]

Per 55 Pa.B. 7040, published on Saturday, October 4, 2025:

[18] https://www.pacodeandbulletin.gov/Display/pabull?file=/secure/pabulletin/data/vol55/55-40/1362.html

The Department of Environmental Protection (Department) has made a preliminary determination that the owners and operators of the permitted facilities listed in the following table are implementing control measures to meet the Federal Clean Air Act (CAA) Reasonably Available Control Technology (RACT) requirements under the 2015 8-hour ozone National Ambient Air Quality Standards (NAAQS) for sources of volatile organic compound (VOC) emissions, for which the United States Environmental Protection Agency (EPA) has issued a Control Techniques Guideline (CTG). The Department has determined that the permits for these facilities contain conditions that are consistent with or more stringent than the EPA's CTG EPA-450/3-83-008, 1983/11 for Control of Volatile Organic Compound Emissions from Manufacture of High-Density Polyethylene, Polypropylene and Polystyrene Resins.

County	*Permit Number*	*Facility Name*
Luzerne	40-00083	MULTI PLASTICS EXTRUSIONS, INC./HAZLETON
Bucks	09-00015	ROHM & HAAS CO./BRISTOL
Beaver	**04-00740**	**SHELL CHEMICAL APPALACHIA**

The Department performed an independent RACT analysis taking into consideration the EPA's CTG and other additional information and has concluded that the provisions and requirements of these permits meet RACT requirements for the control of VOC emissions from the subject sources. These provisions and requirements are intended to address the Commonwealth's RACT obligations under section 184 of the CAA (42 U.S.C. § 7511c) for the 1997, 2008 and 2015 8-hour ozone NAAQS. The Department is further proposing to certify these conditions as RACT to meet the CTG RACT certification requirements for the 2015 ozone NAAQS. This State Implementation Plan (SIP) revision will be submitted to the EPA to meet the Commonwealth's CTG RACT requirements and CTG RACT certification obligations under the Federal CAA.

As a result, PA-04-00740C, Source ID 204, Conditions #003 – 004 and #006 – 019 are in the process of being made part of the SIP under the CTG 37 SIP action and will be federally enforceable as they are currently written, regardless of any changes made in this plan approval.

The same holds true for PA-04-00740C, Source ID 205, Conditions #002 – 015.

Section D – Source Level Plan Approval Requirements

Source ID 205: High Pressure (HP) Header System

On April 25, 2025, during planned Ethane Cracking Unit startup activities that required venting to the HP Flare System, visible emissions were observed at the TEGF A and B. According to the malfunction report submitted by Shell on May 23, 2025, the Root Cause of the malfunction identified that some burner tips on stages 8 and 9 of TEGF A and B did not have flames anchored to the burners. Stage 10 eventually had all burner flames anchored but experienced the same problem when the stage came online. When the flame does not anchor to the burner, vent gas combusts higher in the chamber yielding visible emissions due to improper mixing. Shell has identified that changing the TEGF stage firing sequence (the order in which stages open) will mitigate the combustion air limitations of the stages caused by flare draft to resolve flame anchoring issues. The stage sequence will be adjusted such that the stages will open from the center of the flares and work evenly outwards to optimize available combustion air, which is pulled in from the outside perimeter of the flares.

In addition to internal Management of Change (MOC) revisions to modify the staging sequence, Shell has proposed that the plan approval includes a condition for the flare stage sequencing to be in accordance with manufacturer's recommendations. Changes to the stage sequencing are separate from the repairs that were noted in the August 30, 2023, TEGF Repair Report and RFD-04-00740N which was approved on April 4, 2024.

Section D – Source Level Plan Approval Requirements

Source ID 206: Spent Caustic Vent Header System

Condition # 001: Shell has proposed that the SCTO's combustion pollutant emission limitations be on a lb/hr basis rather than a lb/MMBtu basis to avoid firing rate intensity biases that are associated with a lb/MMBtu limitation. Specifically, operations at low firing rates may result in lb/MMBtu ratios that are biased high because of the lower firing rate divisor value even though lb/hr emission rates are well below authorized amounts. The proposed changes to the condition are based on the LAER/BACT/BAT lb/MMBtu limits established in PA-04-00740A multiplied by the short-term maximum capacity of the SCTO of 11.07 MMBtu/hr.

Emissions from the ~~Spent Caustic Vent incinerator~~ SCTO shall not exceed the following:

a. NOx - ~~0.068 lb/MMBtu~~ ***0.75 lb/hr***
b. CO ~~- 0.0824 lb/MMBtu~~ ***0.91 lb/hr***
c. PM_{10} - ~~0.0075 lb/MMBtu~~ ***0.13 lb/hr****
d. $PM_{2.5}$ - ~~0.0075 lb/MMBtu~~ ***0.13 lb/hr****
* See below

The SCTO is required to meet the LAER/BACT/BAT requirements, including the representative emission limits established, which are on a lb/MMBtu basis. LAER, BACT, and BAT were reevaluated in this plan approval application and the corresponding emission limits proposed by Shell are on a lb/MMBtu basis, consistent with PA-04-00740A and review of the RBLC database. Taking the proposed short-term limits on a lb/MMBtu basis and converting them to a mass-based limit would represent a change in LAER/BACT/BAT which has not been sufficiently justified in this submittal. Furthermore, a properly designed and operated thermal oxidizer should be capable of meeting the manufacture guaranteed emissions rates or BACT/LAER limits on a lb/MMBtu basis across the entire operating range, not just at certain firing rates. As such, the SCTO emission limits will remain on a lb/MMBtu basis and reflect the newly proposed LAER limit of 0.06 lb/MMBtu NOx.

Emissions from the ~~Spent Caustic Vent incinerator~~ ***SCTO*** *shall not exceed the following:*

a. NOx - ~~0.068 lb/MMBtu~~ ***0.06 lb/MMBtu***
b. CO - 0.0824 lb/MMBtu
c. PM_{10} - 0.0075 lb/MMBtu
d. $PM_{2.5}$ - 0.0075 lb/MMBtu

PM

The current PM_{10} and $PM_{2.5}$ limits are based upon emission factors from AP-42, Table 1.4-2 (filterable + condensable). The limits are also equivalent to the guaranteed emission rates by the manufacturer, John Zink. The manufacturer guarantee for the SCTO for this facility was most recently provided in Shell's February 28, 2025, response to the Department. In the application for PA-04-00740D, Shell has proposed to add H_2SO_4 to PM_{10} and $PM_{2.5}$ based on the SO_3-to-SO_2 emission factor ratio in AP-42, Table 1.3-1 for fuel oil combustion in boilers > 100 MMBtu/hr, to account for potential sulfur in the vent stream combusted by the SCTO. This raises the previous lb/MMBtu rate from 0.0075 to 0.012 lb/MMBtu and the corresponding proposed limit of 0.13 lb/hr (0.012 lb/MMBtu x 11.07 MMBtu/hr = 0.13 lb/hr).

The Department has determined that Shell has not provided sufficient supporting information to raise the PM_{10} and $PM_{2.5}$ emission limits to account for potential sulfur in the vent stream. Furthermore, Shell has proposed PM_{10} and $PM_{2.5}$ LAER and BACT limits on a lb/MMBtu basis, not a lb/hr basis.

The initial performance test of the SCTO conducted on May 23, 2024, resulted in non-compliant total PM_{10} and $PM_{2.5}$ emissions at an average of 0.0110 lb/MMBtu compared to the current limit of 0.0075 lb/MMBtu. Note that the test results were below Shell's proposed limit of 0.13 lb/hr. However, the Department has determined the proposed limit to be inappropriate, and the test exceeds the current limit and the Department's proposed limit.

Re-testing for PM was performed on September 21-21, 2024. For the re-test, the test run lengths were extended to approximately four hours to ensure that a larger sample volume and a more representative measurable mass of PM was collected. On February 27, 2025, the Department's Source Testing Section determined re-test results are acceptable for determining compliance under conditions like those during testing. Average total PM (filterable PM + condensable PM) emissions to demonstrate compliance with the PM_{10} and $PM_{2.5}$ emission limits during the test were 0.00187 lb/MMBtu or 0.0162 lb/hr.

NOx

The initial performance test of the SCTO conducted on May 23, 2024, also resulted in non-compliant NOx emissions at a rate of 0.087 lb/MMBtu compared to the current limit of 0.068 lb/MMBtu. The results are also above the proposed limit on a lb/hr basis of 0.75 lb/hr (0.087 lb/MMBtu/hr x 11.07 MMBtu/hr = 0.96 lb/hr). The September 17-18, 2024, re-test included PM_{10} and $PM_{2.5}$ only. As such, Shell does not have compliant NOx test results for the SCTO.

In response to the NOx exceedance, efforts by Shell to reduce the NOx emissions from the SCTO have included: replacing the burner tips, installation of a knockout drum, reducing the operating temperature, and adjustments to the air-to-fuel ratio, but little or no NOx improvement was achieved. Shell is exploring other options in the interim while securing a new vendor to upgrade or replace the SCTO burners and has proposed a new LAER limit of 0.06 lb NOx/MMBtu.

Testing of the SCTO will be required once modifications are made to the SCTO burners to demonstrate compliance with the plan approval limits. Testing will also be required once the WWTP Permanent

Controls Project is complete to demonstrate compliance with the VOC destruction efficiency and additional load from the new Wastewater Treatment Vessels.

Condition # 003: Shell has proposed to raise the VOC percentage destruction efficiency indicated for the SCTO in the condition to more accurately represent the VOC percentage destruction efficiency that has been demonstrated by the SCTO.

> *The ~~Spent Caustic Vent incinerator~~ **SCTO** shall be operated to reduce collected VOC emissions by a minimum of 99**.9**%.*

Performance testing on the SCTO destruction efficiency (DE) was conducted per the PA-04-00740C requirements on May 23, 2024. The performance test indicated greater than 99.9% destruction efficiency. Subsequent testing and monitoring will be required to demonstrate compliance with the increased destruction efficiency requirement.

Condition #004: As discussed above, Shell plans to modify or replace the LNBs currently installed in the SCTO, due to the previous NOx exceedance and to meet the more stringent NOx LAER limit of 0.06 lb/MMBtu. The Department proposes to include the following revised testing condition to demonstrate compliance with the new limit:

> *The Owner/Operator shall perform NOx, CO, PM_{10}, $PM_{2.5}$, and Benzene emission testing upon the ~~Spent Caustic Vent incinerator~~ **SCTO** according to the requirements of 25 Pa. Code Chapter 139. ~~Initial p~~**P**erformance testing is required within 180 days of ~~startup~~ **modification or replacement of the burners** of the ~~Spent Caustic Vent incinerator~~ **SCTO** or on an alternative schedule as approved by the Department. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension to the ~~initial and subsequent~~ performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified. EPA Reference Method performance testing shall be conducted for the ~~initial and subsequent~~ performance tests.*

Condition #005: As a result of the WWTP Permanent Controls Project, the SCTO will control additional vent streams from the WWTP. The Department proposes to include the following revised testing condition to demonstrate compliance with the VOC destruction efficiency once the permanent WWTP is operational:

> *The Owner/Operator shall perform VOC destruction efficiency testing upon the ~~Spent Caustic Vent incinerator~~ **SCTO** in accordance with 40 CFR §63.985(b)(1)(ii). ~~Initial p~~**P**erformance testing is required within 180 days of startup of the ~~Spent Caustic Vent incinerator~~ **WWTP Permanent Controls Project equipment** or on an alternative schedule as approved by the Department. Subsequent performance testing is required at a minimum of once every 5 years thereafter. Extension of the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified.*

Condition # 006: Shell has proposed to raise the required minimum VOC percentage destruction efficiency for the SCTO to more accurately represent the VOC percentage destruction efficiency that has been demonstrated by the SCTO.

*Monitoring for compliance with the 99.**9**% destruction efficiency requirement for the ~~Spent Caustic Vent incinerator~~ **SCTO** shall be performed in accordance with 40 CFR § 63.985(c). Operating parameter monitoring shall include combustion temperature at a minimum.*

Condition # 007: Shell has proposed to raise the required minimum VOC percentage destruction efficiency for the SCTO to more accurately represent the VOC percentage destruction efficiency that has been demonstrated by the SCTO.

*The ~~Spent Caustic Vent incinerator~~ **SCTO** shall, at all times that vapors are being collected, be operated at or above the minimum temperature at which at least 99.**9**% destruction efficiency is guaranteed by the manufacturer or demonstrated during performance testing.*

Section D – Source Level Plan Approval Requirements

Source ID 405: Storage Tanks (Misc Pressurized~~/Refrigerated~~)

As part of Shell's response to the Department's deficiency letter dated December 24, 2024, Shell proposed to identify the refrigerated ethylene storage tank that was previously included with Source ID 405 as a stand-alone source, Source ID 411.

Section D – Source Level Plan Approval Requirements

Source ID 411: Refrigerated Ethylene Storage Tank

Since the Refrigerated Ethylene Storage Tank vents to the MPGF Ethylene Tank Header and has different requirements than the pressurized storage tanks that are included with Source ID 405, a new source is proposed for the Refrigerated Ethylene Storage Tank. Shell has proposed that the applicable 40 CFR Part 60 Subpart Kb requirements for the Refrigerated Ethylene Storage Tank be included in the plan approval because the storage tank is a fixed roof storage vessel affected facility under the subpart that vents to a closed vent system and control device (MPGF Ethylene Tank Header and MPGF) to comply with the subpart. The proposed plan approval will include the applicable requirements of 40 CFR Part 60 Subpart Kb.

Section E – Source Group Plan Approval Restrictions

Group Name: G01 – Ethane Cracking Furnaces

Source ID: 031: Ethane Cracking Furnace #1
Source ID: 032: Ethane Cracking Furnace #2
Source ID: 033: Ethane Cracking Furnace #3
Source ID: 034: Ethane Cracking Furnace #4
Source ID: 035: Ethane Cracking Furnace #5
Source ID: 036: Ethane Cracking Furnace #6
Source ID: 037: Ethane Cracking Furnace #7

Condition # 005: Shell has proposed that the condition be revised as indicated below, similar to the existing requirements for CO and NOx. The CO and NOx conditions, #004 and #007, limit *all furnaces combined* to the

12-month rolling period limit. For PM_{10} and $PM_{2.5}$, the current condition limits *each* furnace to 12.4 tons in any consecutive 12-month period. The PM_{10} and $PM_{2.5}$ limit of 12.4 tons is based on the PTE across all operating modes (normal operation, decoking, feed in, feed out, hot steam standby, startup, and shutdown). Both the total PM_{10} and $PM_{2.5}$ PTE from the seven furnaces is 86.8 tons per year.

According to the applicant, the flexibility of a 12-month rolling limit for furnaces combined allows for better furnace utilization based on when furnaces require decoking or other operating modes. If a single furnace does not decoke in a given month, the furnace may need to operate at reduced rates to stay below the limit of 12.4 tons (decoking emissions are lower on a tpy basis: decoking has a higher emissions factor of 0.01 lb/MMBtu compared to 0.005 lb/MMBtu during normal operation, but has a lower hourly heat input of 180 MMBtu/hr compared to 620 MMBtu/hr during normal operation).

> *PM_{10} and $PM_{2.5}$ emissions, respectively, from ~~each of~~ the ethane cracking furnaces shall not exceed the following:*
>
> - *3.10 lb/hr **from each furnace**, excluding periods of decoking.*
> - *1.86 lb/hr **from each furnace** during periods of decoking.*
> - *~~12.4~~ **86.8** tons **from all furnaces combined** in any consecutive 12-month period.*

For modeling considerations related to the proposed change, the 24-hour PM_{10} model considered the max emission rate for all furnaces of 3.10 lb/hr, which is equal to design heat input of 620 MMBTU/hr times the PM_{10} emission factor of 0.005 lb/MMBTU. There is no annual PM_{10} standard. For $PM_{2.5}$ 24-hour and annual NAAQS, the EMACT Project modeled under the Significant Impact Levels (SILs) so no additional modeling was required, and the Plan Approval Reconciliations and WWTP Permanent Controls Project did not propose any changes to the furnaces that would affect the original analysis. A more detailed summary of the Department's review of the air quality analyses is included later in this memo.

<u>Condition # 006</u>: Shell has proposed that the condition be revised as indicated below to specify the averaging period basis to demonstrate compliance with the ammonia slip emission limitation for the ethane cracking furnaces.

> *NH_3 emissions from each of the ethane cracking furnaces shall not exceed 10 ppmvd at 3% O_2 **on a daily average**.*

This proposed revision is to specify the averaging time. The current monitoring condition for ammonia slip, Condition # 014, which is also proposed to be revised, requires monitoring at a minimum of once each day with provisions to be reduced to weekly. Shell has proposed to continuously monitor for ammonia slip via in-situ tunable diode laser (TDL) as discussed below.

<u>Condition # 008</u>: Shell has proposed that certain ethane cracking furnace defined operating modes be revised as indicated below.

> *Hot Steam Standby*

Shell has proposed that "below 50% of the maximum allowable firing rate" be removed from the "hot steam standby" definition because none of the ethane cracking furnace short-term emission limitations included in the plan approval are dependent on a firing rate below 50%, and this firing rate reference is not necessary to distinguish the "hot steam standby" mode of operation from the remaining ethane cracking furnace modes of operation defined in the plan approval. This is in consideration of the remaining operating criteria and references used to define "hot steam standby" and the operating criteria used to define the remaining ethane cracking furnace modes of operation in the plan approval.

The ethane cracking furnaces typically operate at a firing rate less than 50% of their maximum allowable firing rate (620 MMBtu/hr) during hot steam standby, but there is the potential for a furnace to operate above 310 MMBtu/hr (50% of 620 MMBtu/hr) when the hydrocarbon feed to the furnace must be suddenly removed and the rate of reduction in fuel to the furnace lags behind such that the furnace's firing rate is temporarily above 310 MMBtu/hr while the hydrocarbon feed to the furnace is zero and the furnace's COT is greater than or equal to 750°C. The only ethane cracking furnace pollutant subject to a specific emission limitation during hot steam standby is NOx (6.20 lb/hr NOx), and furnace firing rate is not a variable used to calculate NOx emission rates during hot steam standby because the furnaces are equipped with NOx CEMS that measure NOx directly rather than relying on furnace firing rate and a NOx emission factor during hot steam standby to calculate NOx emission rates.

The proposed change does not result in any increases in ethane cracking furnace allowable emission rates in association with this revision. The proposed revision is to better align actual hot steam standby operating conditions that may occur with the plan approval hot steam standby definition and already defined allowable emissions for the hot steam standby mode of operation.

Feed In, Normal, and Feed Out

The proposed revisions to these operating mode definitions are to allow a lower ethane cracking furnace minimum turndown hydrocarbon feed rate of 29 metric tons per hour. According to the applicant, this feed rate is within the original design capabilities of the furnaces and has been identified and demonstrated through engineering study, simulation, and trial run without requiring any new equipment or physical changes to existing equipment. The ethane cracking furnaces can sustain stable operation at a hydrocarbon feed rate of 29 metric tons per hour, and this lower normal operation threshold for the furnaces will provide a wider range of balanced operations between SPM's ethylene manufacturing unit and polyethylene manufacturing units, which in turn will support efforts to minimize the flaring that occurs when the ethylene manufacturing unit must be shut down due to material balance misalignments between the ethylene manufacturing unit and polyethylene manufacturing units.

The proposed change does not result in any increases in ethane cracking furnace allowable emission rates in association with this revision. Specifically, for NOx, the ethane cracking furnaces will be subject to the more stringent 1-hour 0.015 lb NOx/MMBtu and 12-month rolling average 0.010 lb NOx/MMBtu emission limitations during the proposed lower operating rate normal operations rather than the 6.2 lb/hr allowable NOx emission rate that would apply during feed in and feed out operations at this lower operating rate.

The Owner/Operator may only operate an ethane cracking furnace in a defined operating mode. Operating modes of the ethane cracking furnaces are defined as follows:

- *Startup – Beginning when fuel is introduced to the furnace and ending when the SCR catalyst bed* *reaches its stable operating temperature. Stable operating temperature is achieved when the furnace coil outlet temperature (COT) reaches 750°C.*

- *Hot Steam Standby – When the furnace COT is greater than or equal to 750°C, ~~below 50% of the maximum allowable firing rate,~~ no hydrocarbon feed is being charged to the furnace, and* ***the furnace is*** *not operating in decoking, startup, or shutdown mode.*
- *Feed In – Beginning when hydrocarbon feed is introduced to the furnace and ending when the hydrocarbon feed reaches ~~43~~* ***29*** *metric tons per hour.*
- *Normal – When the furnace is at or above a hydrocarbon feed rate of ~~43~~* ***29*** *metric tons per hour.*
- *Feed Out – Beginning when the furnace drops below a hydrocarbon feed rate of ~~43~~* ***29*** *metric tons per hour and ending when hydrocarbon feed is isolated from the furnace.*
- *Shutdown – Beginning when the SCR catalyst bed drops below its stable operating temperature and ending upon removing all fuel from the furnace. Stable operating temperature is lost when the furnace COT drops below 750°C.*
- *Decoking – Beginning when air is introduced to the furnace for the purpose of decoking and ending when decoking air is removed.*

Note that on November 14, 2023, the Department sent Shell a determination on how to treat circumstances when the ethane cracking furnaces are heated only by pilots and there is no hydrocarbon feed ("Pilots Only Operation") for purposes of continuous emission monitor (CEM) emission coding. The Department determined that Pilots Only Operation is already covered by the Plan Approval. Per Section E, Group G01, Condition # 008, Pilots Only operation meets the existing definitions of both Startup and Shutdown because the furnace coil operating temperature is below the stable operating temperature of 750 degrees C. There is no hydrocarbon feed being introduced to the ethane cracking furnaces during Pilots Only Operation, so it does not meet the definition of Normal Operation. As such, the emission limitations applicable to Pilots Only Operation are included in Section E, Group G01, Conditions # 004 and # 007 for CO and NOx, respectively, on a lb/hr basis during startup/shutdown and with the 12-month total.

<u>Condition # 010</u>: Shell has proposed that the condition be revised as indicated below to provide firing rate flexibility during the startup of an ethane cracking furnace. The plan approval defines "startup" as detailed above. The proposed condition revision will allow an ethane cracking furnace to operate in compliance in a scenario where the furnace's firing rate exceeds 25% of the maximum allowable firing rate of the furnace, or 155 MMBtu/hr, but the furnace's COT has not yet reached 750°C, the end point defined for a startup, provided the furnace's NOx emission rate does not exceed 6.2 lb/hr, which is the allowable NOx emission rate for a furnace during long-term normal operations. Shell is not proposing any increases in ethane cracking furnace allowable emission rates in association with this revision. The proposed 6.2 lb/hr allowable NOx emission rate for an ethane cracking furnace when it is operating above 25% of its maximum allowable firing rate during a startup is significantly lower than the 31.1 lb/hr allowable NOx emission rate that would otherwise apply during the startup.

> *A startup for each furnace shall not exceed 24 hours and shall not exceed 25% of the maximum allowable firing rate, except during startups requiring refractory dry out which is limited to 72 hours at 25% or less of the maximum allowable firing rate.* ***The 25% maximum allowable firing rate limitation does not apply at times during a startup when a furnace's NOx emissions are 6.2 lb/hr or less.***

<u>Condition # 013</u>: The plan approval includes the following condition requiring continuous NOx monitoring for the ethane cracking furnaces. The Department is currently working on a plan for the determination of heat input

for the ethane cracking furnaces due to an issue with one of the two previously approved fuel density analyzers which led to a miscalculation of the heat input and therefore, emission data. Shell has proposed the use of the gas chromatograph (GC) for determination of heat input in place of the unreliable results obtained from Density Analyzer B; however, the GC has not been certified by the Department to meet the quality assurance and quality control requirements (QA/QC), including daily calibration, of a certified monitoring system. The Department proposes to retain the existing condition as it allows flexibility on the final method to determine heat input through the rigorous certification process for the continuous monitoring system by the Department's CEMS Section.

> *The Owner/Operator shall install and operate NOx continuous monitoring systems to monitor NOx emissions from each ethane cracking furnace in accordance with 25 Pa. Code § 123.51.*

Condition # 014: Shell has proposed that the condition's existing language be replaced with language to document the ammonia slip monitoring methodology that is being used on the ethane cracking furnaces, as approved by the Department. The current plan approval condition related to ammonia slip from the ethane cracking furnaces comes from 30 Tex. Admin. Code § 117.8130 - Ammonia Monitoring, and is as follows:

> *The Owner/Operator shall monitor for ammonia slip from each ethane cracking furnace in accordance with any one of the following methods:*
>
> *a. Mass balance. Ammonia emissions are calculated as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NOx upstream and downstream of the control device that injects urea or ammonia into the exhaust stream. The ammonia emissions must be calculated using the following equation:*
>
> NH_3 *@ 3% O2 = [(a/b * 10^6) - c] * d*
>
> *Where:*
>
> *a = ammonia injection rate (in pounds per hour (lb/hr))/17 pound per pound-mole (lb/lb-mol);*
> *b = dry exhaust flow rate (lb/hr)/29 lb/lb-mol;*
> *c = change in measured NOx concentration across catalyst (ppmv at reference oxygen); and*
> *d = correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack testing for ammonia during the initial demonstration of compliance required by this Plan Approval.*
>
> *b. Oxidation of ammonia to nitric oxide (NO). Convert ammonia to NO using a molybdenum oxidizer and measure ammonia slip by difference using a NO analyzer. The NO analyzer must be quality assured in accordance with the manufacturer's specifications and with a quarterly cylinder gas audit with a 10 ppmv reference sample of ammonia passed through the probe and confirming monitor response to within ± 2.0 ppmv for the furnaces.*
>
> *c. Stain tubes. Measure ammonia using a sorbent or stain tube device specific for ammonia measurement in the 5.0 to 10.0 ppmv range for the furnaces. Every effort must be made to sample near the normal highest ammonia injection rate.*
>
> *d. Other methods as approved by the Department.*

Ammonia slip monitoring shall be conducted at a minimum of once each day for each source for the first 60 days of operation. Monitoring may subsequently be reduced to a minimum of once each week for each source if operating procedures have been developed to prevent excess amounts of ammonia from being introduced in the control device and when operation of the control device has been proven successful with regard to controlling ammonia slip. Daily monitoring must resume when the catalyst is within 30 days of its useful life expectancy.

The current plan approval condition requires ammonia slip monitoring of each ethane cracking furnace by any one of multiple methods including "Other methods as approved by the Department." In a letter dated February 14, 2018, from the Department to Shell, *Alternative Measurement Method for Ammonia Slip for Ethane Cracking Furnaces and Cogeneration Units*, the Department determined that the in-situ tunable diode laser (TDL) method is acceptable and allowed for in accordance with the plan approval condition. At the request of the applicant, the following condition is proposed to replace the condition above:

The Owner/Operator shall continuously monitor for ammonia slip from each ethane cracking furnace via in-situ tunable diode laser (TDL), or equivalent monitor, as approved by the Department.

Condition # 015: Shell has proposed that the condition be revised as indicated below because only the inlet temperature of the catalyst bed in the SCR system is used as a setpoint reference for the SCR system's operations, not the outlet temperature of the catalyst bed. Therefore, it is not necessary to continuously monitor and record the outlet temperature of the catalyst bed in the SCR system. Similarly, the plan approval does not currently require the outlet temperature of the Cogeneration Unit SCR systems to be monitored.

The Owner/Operator shall continuously monitor and record the catalyst bed inlet ~~and outlet~~ temperature for each SCR system.

Section E – Source Group Plan Approval Restrictions

Group Name: G02 – Cogeneration Units

Source ID: 101: Combustion Turbine/Duct Burner Unit #1
Source ID: 102: Combustion Turbine/Duct Burner Unit #2
Source ID: 103: Combustion Turbine/Duct Burner Unit #3

Condition # 001: Shell has proposed that the condition be revised as indicated below to acknowledge a scenario that can occur when the combustion turbines at SPM are being shut down, which is not properly captured in the shutdown definition currently included in the condition. The combustion turbines at SPM must be transitioned out of low NOx firing mode while they are being shut down. During this shutdown process, the transition out of low NOx firing mode can occur prior to the SCR catalyst dropping below its design operating temperature. In this scenario, even though the SCR catalyst is at or above its design operating temperature, the Cogeneration Unit may not be able to comply with the 2 parts per million by volume on a dry basis (ppmvd) @ 15% oxygen emission limitation that would otherwise apply because the NOx concentrations at the inlet of the SCR catalyst would be higher than normal due to the combustion turbine having transitioned out of low NOx mode to complete the shutdown process. Shell is not proposing any increases in Cogeneration Unit allowable emission rates in association with this revision, just the threshold for the start of a shutdown event. The same duration and emission limitations will apply to each Cogeneration Unit shutdown event.

On September 25, 2024, the Department received a letter from Shell requesting to increase the SCR catalyst bed design operating temperature for the cogeneration units from 218° C to 316° C. The design operating temperature is incorporated in the Combustion Turbine/Duct Burner Units' (Cogen Units) continuous emissions monitoring system (CEMS) data acquisition system (DAS) and CEMS QA/QC manual. There have been numerous identified NOx exceedances that occurred during unit startup and shutdown due to the defined SCR design operating temperature of 218° C. On November 8, 2024, the Department approved the increase of the design operating temperature from 218° C to 316° C based upon information provided by the SCR vendor.

The Department also proposed to revise the definition of startup and shutdown for the Cogeneration Units in PA-04-00740D. The current condition references the design operating temperature but does not specify the value. Based upon the information provided by the SCR vendor regarding the design operating temperature and the information in this application regarding low NOx firing mode during shutdown, the Department proposes the following condition, which is consistent with conditions basing combustion turbine shutdown on the turbine transitioning out of low NOx mode that have been included for similar units in recent plan approvals (e.g. Tenaska Pennsylvania Partners, LLC PA-65-00990C and CPV Fairview, LLC PA-11-00536A) and that base:

NOx emissions from the combustion turbines with duct burners shall not exceed the following:

- *2 ppmvd @ 15% O2 from each turbine/duct burner on a 1-hour average, excluding periods of defined startup or shutdown.*
- *113 lb/hr from each turbine/duct burner during periods of startup or shutdown.*
- *70.4 tons from all turbines and duct burners combined in any consecutive 12-month period.*

For purposes of determining compliance with these NOx limits, startup is defined as beginning when fuel is introduced into the turbine and ending when the SCR catalyst bed reaches its design operating temperature ***of* 316° C**.

For purposes of determining compliance with these NOx limits, shutdown is defined as beginning when the ~~SCR catalyst bed drops below its design operating temperature~~ ***combustion turbine is transitioned out of low NOx firing mode*** *and ending upon removing all fuel from the turbine.* ***Each shutdown event shall not exceed 30 minutes in duration.***

For purposes of determining compliance with these NOx limits, low NOx firing mode is defined as a lean premixed mode where air and fuel are mixed before entering the turbine combustor (versus the diffusion mode where fuel and air are injected into the combustor separately).

Regarding the method of compliance with the above defined operating modes, the GE Frame 6B gas combustion turbines at SPM operate in accordance with automated control logic determined by the manufacturer. This is the GE Mark VIe distributed control system (DCS) and it dictates the firing mode of the turbine and whether it operates in premix steady state (dry low NOx or DLN mode) or other (non-DLN) firing configuration such as primary burners only or lean-lean firing normally experienced during low-load, startup, or shutdown. Transition out of premix steady state is dictated by many monitored inputs to the DCS but is ultimately indicated as a single digital output from the DCS for the firing mode. This indicator will be connected to the CEMS PLC and incorporated into the CEMS operating mode logic such that if fuel is greater than zero and the indicator transitions out of premix steady state, the CEMS minute data will be coded as shutdown until fuel reaches zero.

Condition # 003: Similarly, Shell has requested to revise the definition of shutdown related to CO emissions. Shell has proposed to revise the condition as indicated below so that the same shutdown definition is used to evaluate applicable short-term CO and NOx emission limitations for the Cogeneration Units. Shell is not proposing any increases in Cogeneration Unit allowable emission rates in association with this revision, just the threshold for the start of a shutdown event. The same duration and emission limitations will apply to each Cogeneration Unit shutdown event.

CO emissions from the combustion turbines with duct burners shall not exceed the following:

- *2 ppmvd @ 15% O2 from each turbine/duct burner on a 1-hour average, excluding periods of defined startup or shutdown.*
- *276 lb/hr from each turbine/duct burner during periods of startup or shutdown.*
- *45.0 tons from all turbines and duct burners combined in any consecutive 12-month period.*

For purposes of determining compliance with these CO limits, startup is defined as beginning upon commencement of ignition and ending when the combustion turbine reaches 55% of its baseload operating level.

For purposes of determining compliance with these CO limits, shutdown is defined as beginning when the combustion turbine ~~drops below 55% of its baseload operating level and ending when fuel is cut to this unit~~ ***is transitioned out of low NOx firing mode and ending upon removing all fuel from the turbine****. Each shutdown event shall not exceed 30 minutes in duration.*

For purposes of determining compliance with these CO limits, low NOx firing mode is defined as a lean premixed mode where air and fuel are mixed before entering the turbine combustor (versus the diffusion mode where fuel and air are injected into the combustor separately).

Condition # 008: Shell has proposed that the condition be revised as indicated below to document the averaging period basis to demonstrate compliance with the ammonia slip emission limitation for the Cogeneration Units.

NH_3 emissions from each of the combustion turbines with duct burners shall not exceed 5 ppmvd at 15% O_2 **on a daily average**.

This proposed revision is to specify the averaging time. The current monitoring condition for ammonia slip, Condition # 016, which is also proposed to be revised, requires monitoring at a minimum of once each day with provisions to be reduced to weekly. Shell has proposed to continuously monitor for ammonia slip via in-situ TDL as discussed below.

Condition # 016: Shell has proposed to replace the condition's existing language with language to properly document the ammonia slip monitoring methodology that is being used on the Cogeneration Units, as approved by the Department. The following condition is proposed by the Department:

The Owner/Operator shall continuously monitor for ammonia slip from each combustion turbine with duct burner via in-situ tunable diode laser (TDL), or equivalent monitor, as approved by the Department.

Similar to the ethane cracking furnace requirement, the current plan approval condition requires ammonia slip monitoring of each combustion turbine with duct burner by any one of multiple methods including "Other methods as approved by the Department." In a letter dated February 14, 2018, from the Department to Shell, *Alternative Measurement Method for Ammonia Slip for Ethane Cracking Furnaces and Cogeneration Units*, the Department determined that the TDL method is acceptable and allowed for in accordance with the plan approval condition.

Conditions # 027 and 035: Shell has proposed that the conditions be revised as indicated below because the three lean premix gas-fired stationary combustion turbines are now subject to 40 CFR Part 63 Subpart YYYY emission limitation, operating limitation, monitoring, testing, reporting, recordkeeping, and work practice requirements since the removal of the stay of the subpart's standards for new lean premix gas-fired stationary combustion turbines on March 9, 2022.

> *~~The Owner/Operator of lean premix stationary combustion turbines is only required to comply with the initial notification requirements of 40 CFR Part 63 Subpart YYYY as specified in 40 CFR §63.6095.~~*
>
> *~~The three combustion turbines are subject to limited requirements of 40 CFR Part 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.~~*

The previously included limited requirements will be removed as requested and the applicable 40 CFR Part 63 Subpart YYYY emission limitation, operating limitation, monitoring, testing, reporting, record keeping, and work practice requirements will be included in the plan approval for the three lean premix gas-fired stationary combustion turbines. The requirements will be included in a new group, G14 – NESHAP Part 63 Subpart YYYY.

Section E – Source Group Plan Approval Restrictions

Group Name: G10 – Liquid Loadout

Source ID 302: Liquid Loadout (Recovered Oil)
Source ID 303: Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, PE3 Heavies)
Source ID 304: Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)
Source ID 305: Liquid Loadout (Blended Pitch)

Condition # 002: Shell has proposed that the condition be revised as indicated below to clarify that the specific material transfer activities referenced in the condition represent the "loading" of materials into trucks and railcars to be transported offsite.

> *The Owner/Operator shall monitor for pressure relief valve releases during liquid load~~out~~**ing** operations. Records of any pressure relief event shall be maintained onsite and include the following details at a minimum:*
>
> *a. Date and time of the pressure relief event;*
> *b. Name and title of the observer;*

c. Duration of the event;
d. Estimated emission rate during the event; and,
e. Corrective action taken as a result of the event.

Condition # 006: PA-04-00740C includes a condition requiring liquid loadout hoses to be equipped with a specific manufacturer's low-leak couplings (or equivalent). According to this application, railcar loading rack loading arms at SPM are designed and installed with TODO Dry Break couplings. The plan approval condition currently requires OPW® Drylock™ couplings (or equivalent). These are low emissions couplings as they make a full closed connection before beginning product transfer. Then, a spring actuated piston acts to stop the flow completely before the hose is disconnected after product transfer is complete. Product is retained within the hose and railcar tank connection point. This function is integrated into the coupling design and there is no additional procedural step to accomplish this. The 2-inch TODO coupling has a documented disconnect volume of 0.35 mL/disconnect.

The Department is not aware of any specific industry-consensus design standard or certification to qualify a loading hose coupling as low-leak. However, TODO® DryBreak and OPW® Drylock™ couplings both independently make this claim in their design statements for separately registered and trademarked couplings. The TODO Dry Break low-leak couplings used at SPM include observable design elements such as a two-step and interlocking feature that ensures a complete locking connection is made between the coupling and fitting before the valve can be opened for material transferred (which is then reversed prior to disconnection). The design includes a flat or matching interface between the coupling and fitting to minimize the amount of material which may be lost upon disconnection to "virtually zero" or "very low" per the respective manufacturer design documentation.

Pre-transfer leak checks are performed on hoses and fittings by pressuring with nitrogen and checking for leaks. Leak checks are performed with a bubble test due to using nitrogen as the test medium. Any leaks detected are repaired prior to introducing hydrocarbons into a transfer hose.

The Department proposes to revise the condition as follows to remove the specific coupling manufacturer and to require leak checks prior to any transfer:

- *Liquid loadout hoses shall be equipped with ~~OPW's Drylok™ Dry Disconnect Coupling (or equivalent)~~ low-leak couplings* ***designed to close off the loading hose at the coupling prior to disconnect and operated in accordance with the manufacturer's specifications*** [25 Pa. Code § 127.12b].

- ***Pre-transfer leak checks shall be performed on hoses and fittings by pressuring with nitrogen. Any leaks detected shall be repaired prior to introducing hydrocarbons into a transfer hose* [25 Pa. Code § 127.12b].**

Source IDs 302, 303, and 305 are required to capture and route vapors displaced during loadout to a closed system to be controlled or routed back to the process; while Source 304 liquids are required to be loaded out with vapor balance to pressurized storage tanks capable of maintaining working pressures sufficient at all times to prevent vapor or gas loss to the atmosphere and with no venting during loading operations. Additionally, per G05: NESHAP Part 63 Subpart YY, Condition # 003, Shell is required to comply with the applicable requirements for transfer racks as specified in Table 7(e)(1) to 40 CFR § 63.1103(e)."

Per 40 CFR § 63.1103(e)(2), *Transfer rack* means the collection of loading arms and loading hoses at a single loading rack that is used to fill tank trucks and/or railcars with organic HAP. Transfer rack includes the associated pumps, meters, shutoff valves, relief valves, and other piping and valves. Transfer rack does not include racks, arms, or hoses that contain organic HAP only as impurities; or racks, arms, or hoses that vapor balance during all loading operations.

Closed vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device. A closed vent system does not include the vapor collection system that is part of any tank truck or railcar or the loading arm or hose that is used for vapor return. For transfer racks, the closed vent system begins at, and includes, the first block valve on the downstream side of the loading arm or hose used to convey displaced vapors.

Vapor balancing system means a piping system that is designed to collect organic HAP vapors displaced from tank trucks or railcars during loading; and to route the collected organic HAP vapors to the storage vessel from which the liquid being loaded originated, or to compress collected organic HAP vapors and commingle with the raw feed of a production process unit.

Per Table 7(e)(1) to 40 CFR § 63.1103(e), if you own or operate a transfer rack (as defined in paragraph (e)(2) of this section), and if (1) Materials loaded have a true vapor pressure of total organic HAP ≥3.4 kilopascals and ≥76 cubic meters per day (averaged over any consecutive 30-day period) of HAP-containing material is loaded, then you must:

(i) Reduce emissions of organic HAP by 98 weight-percent; or reduce organic HAP or TOC to a concentration of 20 parts per million by volume on a dry basis corrected to 3-percent oxygen; whichever is less stringent, by venting emissions through a closed vent system to any combination of control devices as specified in § 63.1105 and meet the requirements specified in paragraph (e)(9) of this section.; or

(ii) Install process piping designed to collect the HAP-containing vapors displaced from tank trucks or railcars during loading and to route it to a process, a fuel gas system, or a vapor balance system, as specified in § 63.1105 and meet the requirements specified in paragraph (e)(9) of this section, for startup, shutdown, and malfunction referenced provisions.

<u>Section H – Miscellaneous</u>

The following information will be revised in the Miscellaneous section because the proposed potential to emit calculation revisions result in SPM no longer having the potential to emit 10 tpy or more of n-hexane or greater than 25 tpy of all HAPs combined.

This is a major Title V facility for NOx, CO, PM_{10}, $PM_{2.5}$, VOC, ~~Hexane, Total HAP~~, and CO_2e and as such, actual emissions may equal or exceed the following in any consecutive 12-month period.

100.0 tons of NOx (NITROGEN OXIDES)

100.0 tons of CO (CARBON MONOXIDE)
100.0 tons of PM-10 (PARTICULATE MATTER < 10 MICRONS)
100.0 tons of PM-2.5 (PARTICULATE MATTER < 2.5 MICRONS)
50.0 tons of VOC (VOLATILE ORGANIC COMPOUNDS)
~~10.0 tons of HEXANE~~
~~25.0 tons of ALL HAP COMBINED (HAZARDOUS AIR POLLUTANT)~~

This is a natural minor facility with respect to SOx and as such, actual emissions cannot equal or exceed the following in any consecutive 12-month period:

100.0 tons of SOx (SULFUR OXIDES)

REGULATORY ANALYSIS

This section addresses the applicability and requirements of Pennsylvania and Federal air quality regulations due to the proposed changes at the facility.

25 Pa. Code § 127.1 – New air contamination sources shall control emissions to the maximum extent, consistent with BAT as determined by the Department as of the date of issuance of the plan approval for the new source. Pursuant to 25 Pa. Code § 127.12(a)(5), a plan approval applicant must show that emissions from each new emission source will be the minimum attainable through the use of BAT. Per 25 Pa. Code § 121.1, BAT is defined as follows:

> *Best available technology*—Equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available.

In the application for PA-04-00740D, Shell provided a BAT analysis for the new Wastewater Treatment Vessels that are proposed to be installed as part of the WWTP Permanent Controls Project. In response to the Department's December 24, 2024, deficiency letter, Shell provided a revised BAT analysis on April 11, 2025, for the following existing sources:

- Ethane cracking furnaces (Source IDs 031-037) for SO_2 and ammonia
- Combustion turbines/duct burner units (Source IDs 101-103) for HAPs
- CVTO (Source ID C204A) for SO_2 and H_2SO_4
- MPGF (Source ID C204B) for SO_2
- TEGF A, TEGF B, and the HP Elevated Flare (Source IDs C205A, C205B, C205C) for SO_2, H_2SO_4, and HAPs
- SCTO (Source ID C206) for SO_2 and H_2SO_4
- WWTP (Secondary and Tertiary Treatment) (Source ID 502) for HAPs.

The revised BAT analysis is included as Attachment 6 of the April 11, 2025, response. BAT was not re-evaluated for pollutants in which the PTE is proposed to decrease or if the proposed increase is insignificant and would not affect the technical and economic feasibility analyses that were previously completed in support of the previous BAT determination. BAT is summarized in the BACT/LAER/BAT section of this memo.

Per **25 Pa. Code § 127.11**, a person may not cause or permit the construction or modification of an air contamination source, the reactivation of an air contamination source after the source has been out of operation or production for 1 year or more, or the installation of an air cleaning device on an air contamination source, unless the construction, modification, reactivation or installation has been approved by the Department. Approval by the Department for the proposed projects is being sought through this plan approval.

This plan approval application has been submitted by Shell for review and consideration of three projects: WWTP Permanent Controls Project, EMACT Project, and Plan Approval Reconciliations. Plan approval application forms have been included for the following:

- Each combustion unit and process for which a potential to emit calculation reconciliation is proposed;
- Each combustion unit and process that would experience a physical change or change in the method of operation due to the WWTP Permanent Controls Project (i.e., WWTP) or EMACT Project (i.e., TEGF A and TEGF B);
- Each process that is proposed to be separately identified in the plan approval (i.e., MPGF CVTO Trip Header, MPGF PE Units 1/2 Episodic Vent Header, and MPGF Ethylene Tank Header); and
- Each process that is proposed to have an additional material specifically identified in the plan approval (i.e., Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, PE3 Heavies)).

<u>New Source Review (NSR)</u>

New source review is applicable to the construction of certain new stationary sources and specific physical and operational changes at certain existing stationary sources. The proposed WWTP Permanent Controls Project is considered a physical change and the proposed EMACT Project is considered a change in the method of operation, as discussed in more detail below. Due to the nature of the proposed projects, they do not qualify for minor NSR permitting and are subject to the more stringent requirements of NNSR and PSD.

Shell has evaluated NSR applicability for the Plan Approval Reconciliations, WWTP Permanent Controls Project, and EMACT Project. Specifically, Shell has retrospectively evaluated the Plan Approval Reconciliations and WWTP Permanent Controls Project together as part of the initial construction of SPM for the following reasons: the relatively close timing between the Plan Approval Reconciliations and WWTP Permanent Controls Project and the recently completed initial construction of the facility; the Plan Approval Reconciliations represent as-built changes to the facility's initial construction plan approvals; and the WWTP Permanent Controls Project represents needed improvements to the initial construction of the facility's WWTP.

Shell has evaluated the EMACT Project separately from the Plan Approval Reconciliations, WWTP Permanent Controls Project, and initial construction of SPM because the EMACT Project is a regulatory driven project that could not have been anticipated and is being implemented at the facility to comply with newly effective federal regulatory requirements that now apply to ethylene production units.

In summary, for NSR purposes, this plan approval consists of the following projects:

- Re-evaluation of a major facility due to the Plan Approval Reconciliations which includes the WWTP Permanent Controls Project as part of a major facility; and
- Evaluation of the EMACT Project as an increase in emissions at an existing major facility.

SPM's location in Beaver County is currently designated as marginal nonattainment for ozone (NOx and VOC), nonattainment for SO_2 and lead, and attainment or unclassifiable/attainment for CO, NO_2, PM_{10}, and $PM_{2.5}$. The change in designation for $PM_{2.5}$ from nonattainment to attainment became effective on October 2, 2015. Therefore, Shell evaluated the EMACT Project under the Department's NNSR regulations (25 Pa. Code §§ 127.201 to 127.218) for ozone (NOx and VOC), SO_2, and lead. Shell evaluated the EMACT Project under the Department's PSD regulations (25 Pa. Code §§ 127.81 to 127.83) for CO, NO_2 (NOx), PM_{10}, $PM_{2.5}$, and all other regulated PSD pollutants.

The Plan Approval Reconciliations and WWTP Permanent Controls Project were evaluated together and based on the attainment status of the area at the time of original permitting. The attainment status designations for SPM's location contemporaneous with the Department's issuance of PA-04-00740A, which authorized the initial construction of SPM, are the relevant designations for the retrospective NSR applicability analysis performed for the Plan Approval Reconciliations and WWTP Permanent Controls Project. Although Beaver County is currently designated as attainment for $PM_{2.5}$, the county was designated as nonattainment for $PM_{2.5}$ when the Department issued PA-04-00740A to Shell. The remaining currently effective attainment status designations for SPM's location are unchanged from the attainment status designations that were in effect when the Department issued PA-04-00740A. Therefore, Shell evaluated the Plan Approval Reconciliations and WWTP Permanent Controls Project under the Department's NNSR regulations (25 Pa. Code §§ 127.201 to 127.218) for ozone (NOx and VOC), $PM_{2.5}$, SO_2, and lead. Shell evaluated the Plan Approval Reconciliations and WWTP Permanent Controls Project under to the Department's PSD regulations (25 Pa. Code §§ 127.81 to 127.83) for CO, NO_2 (NOx), PM_{10}, and all other regulated PSD pollutants.

Nonattainment New Source Review (NNSR)

On May 19, 2007, PA DEP adopted revised New Source Review regulations in 25 Pa. Code Chapter 127 Subchapter E. Per 25 Pa. Code § 127.201(a), "a person may not cause or permit the construction or modification of an air contamination facility in a nonattainment area… unless the Department… has determined that the requirements of this subchapter have been met." Per 25 Pa. Code § 127.203(a), "This subchapter applies to the construction of a new major facility…"

25 Pa. Code § 127.201(c) specifies that "The NSR requirements of this subchapter also apply to a facility located in an attainment area for ozone and within an ozone transport region that emits or has the potential to emit at least 50 tpy of VOC or 100 tpy of NOx. A facility within either an unclassifiable/attainment area for ozone or within a marginal or incomplete data nonattainment area for ozone or within a basic nonattainment area and located within an ozone transport region will be considered a major facility and shall be subject to the requirements applicable to a major facility located in a moderate nonattainment area."

In accordance with the definition of *Major facility* under 25 Pa. Code §121.1, this facility is major if the potential to emit exceeds 100 tons of $PM_{2.5}$, 100 tons of NOx, 50 tons of VOC, 100 tons of SO_2, or 100 tons of lead per year.

25 Pa. Code § 127.201(g)(1) specifies that "Beginning January 1, 2011, or an earlier date established by the Administrator of the EPA, condensable PM shall be accounted for in applicability determinations and for $PM_{2.5}$ and PM-10 emission limitations established in a plan approval or operating permit issued under this chapter." Per 25 Pa. Code § 127.202(a), "The special permit requirements in this subchapter apply to an owner or operator of a facility to which a plan approval will be issued by the Department after May 19, 2007, except for $PM_{2.5}$, which will apply after September 3, 2011."

Two central requirements that must be addressed through NNSR are LAER and emissions offsets. Additionally, an alternatives analysis must be performed.

NNSR – Plan Approval Reconciliations and WWTP Permanent Controls Project

The Plan Approval Reconciliations and WWTP Permanent Controls Project together as part of the initial SPM construction for NSR applicability purposes have been retrospectively evaluated. The initial construction of SPM required NNSR permitting for ozone (NOx and VOC) and $PM_{2.5}$ because SPM was estimated to have the potential to emit NOx, VOC, and $PM_{2.5}$ above the applicable NNSR major facility thresholds of 100 tpy, 50 tpy, and 100 tpy, respectively. Table 2 below summarizes the NNSR applicability for the Plan Approval Reconciliations and WWTP Permanent Controls Project retrospectively.

Table 3: Plan Approval Reconciliations and WWTP Permanent Controls Project NNSR Applicability Summary

Pollutant	Proposed Facility-Wide PTE Including Plan Approval Reconciliations and WWTP Permanent Controls Project (tpy)[19]	NNSR Major Facility Threshold (tpy)	Proposed Plan Approval NNSR Applicability (Yes/No)
NOx	378.49	100	Yes
$PM_{2.5}$	169.75	100	Yes
SO_2	25.58	100	No
VOC	503.91	50	Yes
Lead	0.01	100	No

As indicated in the table, the Plan Approval Reconciliations and WWTP Permanent Controls Project, as part of the initial SPM construction, are subject to NNSR under 25 Pa Code Chapter 127, Subchapter E. Per the September 13, 2024, application, "As indicated in the table [referring to the Plan Approval Reconciliations and WWTP Permanent Controls Project NNSR Applicability Summary shown above], the Plan Approval Reconciliations and WWTP Permanent Controls Project will not retrospectively cause the initial construction of SPM to require NNSR permitting under Chapter 127, Subchapter E *for any additional NNSR pollutants* [emphasis added, namely lead] relative to the NNSR applicability determinations that were made contemporaneous with DEP's authorization of the initial construction of SPM. However, as discussed in more detail later in Section 4.0, LAER is applicable to the new Wastewater Treatment Vessels that will be installed as

[19] The proposed facility-wide potential to emit in the table does not include the potential to emit increases that are proposed to occur at the TEGF A and TEGF B due to the EMACT Project. The proposed facility-wide PTE in the table represents the PTE as submitted by the applicant on September 5, 2025, with the exception of PM_{10} and $PM_{2.5}$, which account for the Department's LAER and BACT determination for the SCTO, and VOC, which accounts for the revised Liquid Loadout (Recovered Oil) PTE calculation submitted by the applicant on October 27, 2025

part of the WWTP Permanent Controls Project. As such, Shell completed a VOC LAER analysis for the new Wastewater Treatment Vessels, which is documented in Section 4.0. Additionally, the alternatives analysis for the Plan Approval Reconciliations and WWTP Permanent Controls Project pursuant to 25 Pa. Code § 127.205(5) is addressed later in Section 7.0. Lastly, as presented immediately below, Shell has reevaluated the NNSR offsetting requirements for the initial construction of SPM due to the proposed changes to SPM's facility-wide NNSR pollutant potential to emit rates that are a result of the Plan Approval Reconciliations and WWTP Permanent Controls Project…"

The original project exceeded the major source thresholds and was subject to NNSR, and the original project retrospectively including the Plan Approval Reconciliations and WWTP Permanent Controls Project exceeds the major source thresholds and is subject to NNSR. Per 25 Pa. Code § 127.205(1), "A new or modified facility subject to this subchapter shall comply with LAER…" The new facility-wide PTE including the Plan Approval Reconciliations and WWTP Permanent Controls Project does not change the NNSR applicability of the original project. This plan approval is being handled using the NNSR requirements that were in effect at the time of the original permitting of PA-04-00740A. Shell exceeded the NNSR major source threshold for NOx, VOC, and $PM_{2.5}$ in PA-04-00740A. Shell is therefore subject to LAER requirements for NOx, VOC, and $PM_{2.5}$. In response to the Department's December 24, 2024, deficiency letter, Shell reevaluated the Plan Approval Reconciliations to determine if they potentially require revised LAER analyses for emissions units that were constructed as part of the initial construction of SPM. Shell provided a revised LAER analysis on April 11, 2025, for the following sources and pollutants:

- Cogeneration Plant Cooling Tower (Source ID 104) for $PM_{2.5}$
- CVTO (Source ID C204A) for NOx, VOC, and $PM_{2.5}$
- MPGF (Source ID C204B) for NOx, VOC, and $PM_{2.5}$
- TEGF A, TEGF B, and HP Elevated Flare (Source IDs C205A, C205B, and C205C) for NOx and $PM_{2.5}$
- SCTO (Source ID C206) for NOx and $PM_{2.5}$
- Polyethylene Pellet Material Storage/Handling/Loadout (Source ID 301) for VOC
- WWTP (Source ID 502) for VOC

LAER was not re-evaluated for pollutants in which the PTE is proposed to decrease. The revised LAER analysis is included as Attachment 2 of the April 11, 2025, response. LAER is summarized in the BACT/LAER/BAT section of this memo.

<u>NNSR Offsetting Requirements – Plan Approval Reconciliations and WWTP Permanent Controls Project</u>

Per 25 Pa. Code § 127.205(4), the Department may issue a plan approval for the construction of a new major facility when the facility offsets its potential to emit with ERCs in accordance with 25 Pa. Code §§ 127.206 and 127.210. With the initial construction of SPM, Shell offset the facility's NOx, $PM_{2.5}$, and VOC potential to emit rates in accordance with applicable offsetting requirements under Chapter 127, Subchapter E. Shell has reevaluated the NOx, $PM_{2.5}$, and VOC offsetting requirements for SPM's initial construction due to the proposed changes to SPM's facility-wide PTE. The table below identifies the additional offsets required as a result.

Table 4: Plan Approval Reconciliations and WWTP Permanent Controls Project Required ERC Summary

Pollutant	Facility-Wide PTE Including Plan Approval Reconciliations and WWTP Permanent Controls Project (tpy)	PA-04-00740C Facility-Wide PTE[a] (tpy)	Facility-Wide PTE Increase (tpy)	25 Pa. Code 127.210(a) Offset Ratio	Additional Offsets Required (tpy)
NOx	378.49	328.5	49.99	1.15:1	58
$PM_{2.5}$	169.75	163.7	6.05	1:1	7
VOC	503.91	516.2	-12.29	Flue - 1.15:1 Fugitive - 1.3:1	N/A

[a] PA-04-00740C facility-wide PTE from Section C, Condition # 005.

As indicated in the table above, additional NOx and $PM_{2.5}$ offsets are required for the initial construction of SPM due to the Plan Approval Reconciliations and WWTP Permanent Controls Project. Sufficient VOC offsets have already been acquired and incorporated into PA-04-00740A and PA-04-00640C for use at this facility. No additional VOC offsets are required due to these changes since the VOC PTE decreases.

Note that the Department is currently facing sanctions from the EPA in accordance with the publication in the Federal Register shown below. Emission offsets for ozone precursors would be required for new or modified sources at a ratio of 2:1 when effective on March 16, 2026, potentially affecting the number of offsets required at SPM. The plan approval will be updated accordingly at the time of issuance to reflect the offset ratios in effect at that time.

40 CFR Part 52 [EPA–R03–OAR–2019–0562; FRL–11960– 02–R3] Air Plan Approval and Disapproval; Pennsylvania; Reasonably Available Control Technology (RACT) for Volatile Organic Compounds (VOC) Under the 2008 Ozone National Ambient Air Quality Standards (NAAQS)[20]

Federal Register / Vol. 89, No. 159, Friday August 16, 2024 – Per Section IV. Final Action, "EPA is amending our prior full approval of PADEP's August 13, 2018 SIP submittals to a partial approval and partial disapproval."

"In finalizing the disapproval, a sanctions clock under CAA section 179 begins. If EPA has not fully approved a revised plan within 18 months after this final disapproval, emission offset sanctions for new or modified sources will begin."

The following table is an excerpt from EPA's Status of Active Sanctions Clocks under the Clean Air Act.[21] The table shows the status of sanction "countdown" clocks that have been started and have not yet been officially terminated. The Date of Sanction columns indicate the date sanctions would apply if they have not been stayed or deferred. The "Sanction Clock Stayed or Deferred" column indicates whether EPA has taken an action to stay the relevant sanction after it had started to apply; and/or whether EPA has taken an action to "defer" one or both sanctions that had not yet applied.

[20] https://www.govinfo.gov/content/pkg/FR-2024-08-16/pdf/2024-18162.pdf
[21] https://www.epa.gov/air-quality-implementation-plans/status-active-sanctions-clocks-under-clean-air-act

Table 5: Status of Active Sanction Clocks under the Clean Air Act as of November 30, 2025

State	Area	Required Element(s)	Effective Date and Type of Finding	Date of New Source Review 2:1 Offset Sanctions	Date of Highway Sanctions	Sanction Clock Stayed of Deferred
PA	Nonattainment Areas Statewide for applicable NAAQS	2008 Ozone CTG RACT	9/16/2024 Disapproval	3/16/2026	9/16/2026	No

NOx ERCs – Plan Approval Reconciliations and WWTP Permanent Controls Project

Shell has secured 184 tpy NOx ERCs from Northern Star Generation LLC. As part of Shell's April 11, 2025, response to the Department, Shell has proposed to use a portion of these NOx ERCs from Northern Star Generation to satisfy the 58 tpy NOx offset requirement for the Plan Approval Reconciliations/WWTP Permanent Controls Project. The secured ERCs have been verified to be contained within the Department's ERC registry system and have therefore been properly generated and certified by the Department. Transfer of these ERCs to Shell has been approved by the Department and separately documented through an ERC transfer letter on June 4, 2025.

$PM_{2.5}$ ERCs – Plan Approval Reconciliations and WWTP Permanent Controls Project

In the September 13, 2024, application for PA-04-00740D, Shell proposed to use ERCs acquired from AES Beaver Valley, LLC. The Department approved the transfer of a total of 319 tpy of NOx and 19 tpy of $PM_{2.5}$ ERCs from AES Beaver Valley, LLC to Shell in a letter dated October 25, 2024. The expiration date of the ERCs from AES Beaver Valley, LLC was June 30, 2025.

As part of Shell's April 11, 2025, response to the Department, Shell notes that they have separately requested the Department to confirm the creditable status of 31.03 tpy of $PM_{2.5}$ ERCs that were requested to be transferred from INDSPEC Chemical Corporation to Shell. Shell has proposed to instead use 7 tpy of these 31.03 tpy of $PM_{2.5}$ ERCs from INDSPEC Chemical Corporation to satisfy the $PM_{2.5}$ offset requirements for the Plan Approval Reconciliations and WWTP Permanent Controls Project rather than the $PM_{2.5}$ ERCs acquired from AES Beaver Valley. Transfer of these ERCs to Shell has been approved by the Department and separately documented through an ERC transfer letter on June 4, 2025.

Table 6: Proposed ERCs for Usage by Shell

Generating Facility	Location	Type	Quantity (tpy)	Expiration Date
Northern Star Generation LLC	Cambria Co., PA	NOx	184	6/19/2029
INDSPEC Chemical Corporation	Butler Co., PA	$PM_{2.5}$	31.03	9/11/2027

Potential ERC Reduction

Pursuant to 25 Pa. Code § 127.206(c), "ERCs shall be proportionally reduced prior to use in a plan approval in an amount equal to the reductions that the generating facility is or would have been required to make in order to comply with new requirements promulgated by the Department or the EPA, which apply to the generating facility after the ERCs were created."

Northern Star Generation LLC – Cambria Cogeneration

During the Department's review to determine if the ERCs generated by Northern Star Generation LLC from the shutdown of boilers 1 and 2 are creditable in accordance with 25 Pa. Code § 127.207, the NOx ERCs were proportionally reduced to account for the presumptive Reasonably Available Control Technology (RACT) II limit of 0.16 lb/MMBtu that would have applied to the boilers. RACT III for boilers would have been equivalent to RACT II and there are no other new requirements that have been promulgated which would require potential reductions to the transferred ERCs; therefore, no reduction to these ERCs is needed.

INDSPEC Chemical Corporation

In a letter dated August 25, 2022, from the Department to INDSPEC Chemical Corporation, *Certification of Emission Reduction Credits (ERCs)*, the Department confirmed that the 31.03 tpy of $PM_{2.5}$ generated are creditable for use. Therefore, no reduction to these ERCs is needed.

ERC Expiration Date

In accordance with 25 Pa. Code § 127.206(f), "ERCs generated by the curtailment or shutdown of a facility which are not included in a plan approval and used as offsets will expire for use as offsets 10 years after the date the facility ceased emitting the ERC generating emissions…"

In accordance with 25 Pa. Code § 127.208(2), "The transferee shall secure approval to use the offsetting ERCs through a plan approval or an operating permit, which indicates the Department's approval of the ERC transfer and use. Upon the issuance of a plan approval or an operating permit, the ERCs are no longer subject to expiration under § 127.206(f) (relating to ERC general requirements) except as specified in § 127.206(g).[22]"

The portion of the acquired ERCs that are used in this plan approval for the Plan Approval Reconciliations and WWTP Permanent Controls Project will no longer be subject to expiration. The unused portion will retain their expiration dates shown in Table 6 above.

NNSR – EMACT Project

SPM currently has the potential to emit greater than 50 tpy of VOC and 100 tpy of NOx. Therefore, SPM is a major facility for VOC and NOx (i.e., ozone) for NNSR purposes under Chapter 127, Subchapter E. SPM currently has the potential to emit less than 100 tpy of SO_2 and lead, respectively; therefore, the facility is not an existing NNSR major facility for those pollutants under Chapter 127, Subchapter E. NNSR permitting

[22] The expiration date of ERCs may not extend beyond the 10-year period allowed by subsection (f), if the ERCs are included in a plan approval but are not used and are subsequently reentered in the registry [25 Pa. Code §127.206(g)].

requirements would apply to the EMACT Project in either or both of the following scenarios on a pollutant specific basis:

- If the EMACT Project is estimated to result in a significant net emissions increase of 40 tpy or greater of either NOx, VOC, or both.
- If the EMACT Project is estimated to result in an increase of 100 tpy of SO_2, lead, or both (i.e. the project is major itself for these pollutants).

The EMACT Project results in an increase of 1.66 tpy SO_2 and <0.01 tpy lead; therefore, NNSR is not triggered for these pollutants. The following table shows the increase in NOx and VOC emissions due to the EMACT Project:

Table 7: EMACT Project NNSR Applicability Summary for NOx and VOC

Pollutant	EMACT Project Emissions Increase (tpy)	EMACT Project Net Emissions Increase (tpy)[23]	NNSR Significant Increase Threshold (tpy)	NNSR Applicability (Yes/No)
NOx	76.64	76.64	40	Yes
VOC	6.08	6.08	40	No

As indicated in the table above, the EMACT Project will result in a significant net emissions increase of NOx. Accordingly, the EMACT Project will be a major modification subject to NNSR permitting requirements under 25 Pa Code Chapter 127, Subchapter E for NOx (ozone).

Note that NNSR is triggered for the EMACT Project due to the increase in NOx emissions from the additional amount of fuel combusted by the TEGF A and TEGF B to achieve the higher minimum combustion zone net heating value required by the updated EMACT. In the 2019 proposed EMACT preamble[24], EPA explains that:

> We selected a minimum NHVcz of 800 Btu/scf to ensure the MPGF is operated within the proper envelope to produce a stable flame and achieve high destruction efficiencies at least equivalent to those as the underlying Ethylene Production MACT standards. Also, given that rapid flame de-stabilization can occur when pressure-assisted multi-point flares are operated outside their proper operating envelope, ensuring there is always enough heat content in the vent gases sent to these types of flares so that flare flameouts will not occur is critically important.

Thus, the minimum NHVcz of 800 Btu/scf was selected to ensure a stable flame to consistently achieve the underlying 98% destruction efficiency of the EMACT. This requirement highlights the importance EPA has put on the proper operation of the flares used to control HAP emissions from this source category, with the tradeoff being the increase in NOx combustion emissions. It is also important to note that the revised requirements for flares in the EMACT is not to ensure additional destruction efficiency beyond the generally expected level of 98%. Again, from the 2019 preamble:

---

[23] The net emissions increase includes this project only.
[24] https://www.federalregister.gov/documents/2019/10/09/2019-19875/national-emission-standards-for-hazardous-air-pollutants-generic-maximum-achievable-control#citation-25-p54300

> For purposes of this RTR, we have determined that flares in the Ethylene Production source category are currently complying with certain design and operational requirements that are generally expected to achieve 98-percent destruction efficiencies or control. HAP emissions inventories for flares in the Ethylene Production source category are developed using engineering knowledge and, in many instances, presume this 98-percent level of control. The Agency is unaware of any data that suggest that flares used as controls in the Ethylene Production source category are consistently over-controlling HAP emissions beyond 98-percent control.

The NOx LAER analysis and alternatives analysis for the EMACT Project are discussed later in this memo. ERC requirements for the EMACT Project are discussed immediately below.

NNSR Offsetting Requirements – EMACT Project

The table below identifies the additional NOx offsets required due to the emissions increase related to the EMACT Project.

Table 8: EMACT Project NNSR Offset Requirements Summary

Pollutant	Emissions Increase (tpy)	Applicable 25 Pa. Code 127.210(a) Offset Ratio	Offsets Required (tpy)
NOx	76.64	1.15:1	89

As noted above, the Department is currently facing sanctions from the EPA in which emission offsets for ozone precursors would be required for new or modified sources at a ratio of 2:1 when effective on March 16, 2026. The plan approval will be updated accordingly at the time of issuance to reflect the offset ratios in effect at that time.

As previously discussed, the Department approved the transfer of a total of 319 tpy of NOx and 19 tpy of $PM_{2.5}$ ERCs from AES Beaver Valley, LLC to Shell in a letter dated October 25, 2024.

In the application for PA-04-00740D, Shell had requested that the use of 86.56 tpy of the 319 tpy of NOx ERCs from AES Beaver Valley, LLC be included in this plan approval. However, the ERCs from AES Beaver Valley, LLC expired on June 30, 2025. As part of Shell's April 11, 2025, response to the Department, Shell has proposed to instead use 87 tpy of the acquired NOx ERCs from Northern Star Generation LLC to satisfy the NOx offset requirements for the EMACT Project. Due to the change in PTE submitted by Shell on September 5, 2025, the required amount of NOx ERCs is 89 tpy.

Alternatives Analysis – Plan Approval Reconciliations

In accordance with 25 Pa. Code § 127.205(5), "For a new or modified facility which meets the requirements of and is subject to this subchapter, an analysis shall be conducted of alternative sites, sizes, production processes and environmental control techniques for the proposed facility, which demonstrates that the benefits of the proposed facility significantly outweigh the environmental and social costs imposed within this Commonwealth as a result of its location, construction or modification."

In accordance with the alternatives analysis requirements summarized above for the construction of a new major facility such as SPM, Shell contemporaneously completed an alternatives analysis for the initial construction of SPM. Shell has retrospectively evaluated the Plan Approval Reconciliations as part of the initial SPM construction for NNSR applicability purposes. For the reasons discussed below, the alternatives analysis Shell completed for the initial construction of SPM pursuant to 25 Pa. Code § 127.205(5) is applicable to the Plan Approval Reconciliations due to the as built and corrective nature of the reconciliations.

Alternative Sites

The purpose of the Plan Approval Reconciliations is to ensure that the source inventory, potential to emit calculations, and conditions included in or referenced by PA-04-00740B and PA-04-00740C for the initial construction of SPM more closely match the as-built equipment and operations at SPM. As such, it is not applicable to evaluate alternative sites for the Plan Approval Reconciliations. However, the alternative sites analysis included in the alternatives analysis that Shell completed contemporaneously with the proposed initial construction of SPM demonstrated the net benefits of SPM's location.

Alternative Sizes

The Plan Approval Reconciliations do not propose the installation of new equipment at SPM, and these reconciliations do not propose changes to the sizes of existing equipment at SPM. Instead, the Plan Approval Reconciliations will align plan approval information with the existing equipment and operations already installed and operating at SPM. As such, there are no alternative sizes to consider for the Plan Approval Reconciliations. However, the alternative sizes analysis included in the alternatives analysis that Shell completed contemporaneously with the proposed initial construction of SPM demonstrated the net benefits of SPM's size.

Alternative Production Processes

The Plan Approval Reconciliations do not propose the installation of any new production processes at SPM, and these reconciliations do not propose physical changes to existing production processes at SPM. Therefore, there are no alternative production processes to evaluate for the Plan Approval Reconciliations. However, the alternative production processes analysis included in the alternatives analysis that Shell completed contemporaneously with the proposed initial construction of SPM demonstrated the net benefits of SPM's production processes.

Alternative Environmental Control Techniques

The Plan Approval Reconciliations do not include the installation of new equipment at SPM, including environmental control equipment. Instead, the Plan Approval Reconciliations propose to improve the representations (e.g., hydrocarbon destruction efficiencies, vent gas characteristics) for certain emission control devices based on as-built design and operating data. As a result, there are no alternative environmental control techniques to consider for the Plan Approval Reconciliations. However, the alternative environmental control techniques analysis included in the alternatives analysis that Shell completed contemporaneously with the proposed initial construction of SPM demonstrated the net benefits of SPM's environmental control techniques.

Alternatives Analysis –WWTP Permanent Controls Project

Shell completed the below alternatives analysis for the WWTP Permanent Controls Project pursuant to 25 Pa. Code §127.205(5) to specifically address the new equipment and emission sources that are proposed to be installed at SPM in association with the project, but that have been retrospectively evaluated as part of the initial construction of SPM for NSR applicability purposes.

Alternative Sites

The WWTP Permanent Controls Project is being implemented at SPM to improve the oils, grease, and VOC removal efficiency of the primary treatment section of SPM's existing Wastewater Treatment Plant, which will result in an improvement in the overall wastewater treatment performance of the Wastewater Treatment Plant. Based on the absence of an existing, nearby off-site wastewater treatment facility capable of processing the volume and composition of wastewater generated by SPM and the practicality issues, excessive costs, and increased risks associated with using trucks or a newly constructed pipeline to transport SPM's wastewater to a newly constructed off-site wastewater treatment facility, SPM has concluded that there is not a feasible alternative site for the WWTP Permanent Controls Project.

Alternative Sizes

The WWTP Permanent Controls Project proposes the installation of permanent wastewater treatment vessels and associated heat exchangers, small vessels (e.g., knockout vessel), chemical additive containers, and ancillary equipment such as piping, pumps, valves, and analyzers in the primary treatment section of SPM's Wastewater Treatment Plant to improve its operations, and a key design requirement to achieve these performance improvements is to properly size all the proposed new equipment. As such, Shell will appropriately size the WWTP Permanent Controls Project's equipment in accordance with established engineering principles to achieve the project's targeted Wastewater Treatment Plant performance improvements, making the consideration of alternative sizes for this equipment for 25 Pa. Code § 127.205(5) alternatives analysis purposes not applicable.

Alternative Production Processes

The WWTP Permanent Controls Project addresses the more effective design and operation of SPM's Wastewater Treatment Plant, which is an existing wastewater treatment process, not a production process. The WWTP Permanent Controls Project does not propose the installation of any new production processes at SPM, and the project does not propose changes to existing production processes at SPM. Therefore, there are no alternative production processes to evaluate for the WWTP Permanent Controls Project.

Alternative Environmental Control Techniques

The permanent wastewater treatment vessels that are proposed to be installed with the WWTP Permanent Controls Project will vent to a closed vent system that will route collected vent streams to SPM's SCTO. As documented for the WWTP Permanent Controls Project, the SCTO represents lowest achievable emission rate technology for the VOC emissions from the project's new permanent wastewater treatment vessels. As a result, Shell has concluded that there are no better environmental control techniques to use on the WWTP Permanent

Controls Project's new permanent wastewater treatment vessels. Other control techniques evaluated are discussed in the BACT/LAER/BAT section of this memo.

Alternatives Analysis – EMACT Project

SPM is an existing major facility for NOx for NNSR applicability purposes for the EMACT Project, and the EMACT Project is a major modification subject to NNSR permitting for NOx under 25 Pa. Code Chapter 127, Subchapter E. Therefore, Shell completed the below alternatives analysis for the EMACT Project pursuant to 25 Pa. Code § 127.205(5).

Alternative Sites

The EMACT Project is being implemented at SPM because the TEGF A and TEGF B must comply with newly applicable federal requirements, which EPA promulgated to ensure improved combustion efficiency of VOC and organic HAPs routed to flares with the same design features as the TEGF A and TEGF B. Therefore, Shell must implement the EMACT Project at SPM, eliminating the option to perform the project at a site other than SPM while also ensuring compliance with a federally mandated requirement applicable to the TEGF A and TEGF B at SPM.

Alternative Sizes

The EMACT Project is a change in the method of operation of the existing TEGF A and TEGF B, which were appropriately sized in association with the initial design and construction of SPM for the safe and effective combustion of specific VOC- and organic HAP-containing vent streams, to meet federal regulatory requirements that were promulgated to reduce VOC and organic HAP emissions across the country from similarly designed flares. The EMACT Project does not propose the installation of any new operations at SPM, and the project does not propose changes to the sizes of the TEGF A, TEGF B, or other existing operations at SPM. As such, there are no alternative sizes to consider for the EMACT Project.

Alternative Production Processes

The EMACT Project addresses the more effective operation of the TEGF A and TEGF B, which are emission control devices, not production processes. The EMACT Project does not propose the installation of any new production processes at SPM, and the project does not propose changes to existing production processes at SPM. Therefore, there are no alternative production processes to evaluate for the EMACT Project.

Alternative Environmental Control Techniques

The TEGF A and TEGF B are existing emission control devices at SPM. The EMACT Project will ensure that the TEGF A and TEGF B effectively combust VOC and organic HAPs to minimize VOC and organic HAP emissions to the atmosphere. Additionally, as documented for the EMACT Project, the TEGF A and TEGF B will be designed and operated in accordance with BACT and LAER requirements that will minimize emissions from the two flares. In summary, the EMACT Project itself represents the implementation of federally mandated environmental control techniques on the TEGF A and TEGF B, and the EMACT Project's PSD and NNSR permitting requirements result in the application of BACT and LAER, respectively, on the TEGF A and TEGF B for specific pollutants. As a result, Shell has concluded that there are no better environmental control techniques to use on the TEGF A and TEGF B in association with the EMACT Project.

The Department has reviewed Shell's analyses of alternative sites, sizes, production processes, and environmental control techniques as part of this plan approval application. Alternative environmental control techniques are primarily considered in the regulatory analysis section of the application (specifically, BACT, LAER, and BAT) and detailed in the BACT/LAER/BAT section of this memo. The alternative analyses provided are considered acceptable by the Department and meet the requirements of 25 Pa. Code § 127.205(5).

Prevention of Significant Deterioration (PSD)

Per 40 CFR § 52.21(a)(2)(i) and § 52.21(a)(2)(ii), any project at a new major stationary source (as defined in paragraph (b)(1) of this section) or the major modification of any existing major stationary source in an area designated as attainment or unclassifiable under the federal Clean Air Act must comply with the applicable requirements of 40 CFR § 52.21, *Prevention of Significant Deterioration of Air Quality (PSD).* A major stationary source is defined as either:

(a) A source in one of the 28 source categories identified in 40 CFR 52.21 that has a potential to emit 100 tons or more per year of any regulated NSR pollutant;
(b) Any other stationary source that has the potential to emit 250 tons or more per year of a regulated NSR pollutant; or
(c) Any physical change which would constitute a major stationary source by itself.

On May 31, 1980, PA DEP adopted PSD requirements promulgated by the EPA under the Clean Air Act. These requirements have been adopted in their entirety and incorporated by reference in 25 Pa. Code Chapter 127 Subchapter D. Two main requirements of a PSD analysis include BACT and an air quality analysis.

The primary activity at SPM is the production of ethylene and polyethylene using reaction and separation operations, which falls under the "chemical process plants" source category, one of the 28 source categories listed at 40 CFR 52.21(b)(1)(i)(a). As a result, the PSD "major stationary source" threshold applicable to SPM is 100 tpy of any regulated non-GHG NSR pollutant.

PSD Applicability – Plan Approval Reconciliations and WWTP Permanent Controls Project

Shell has retrospectively evaluated the Plan Approval Reconciliations and WWTP Permanent Controls Project together as part of the initial SPM construction for NSR applicability purposes. The initial construction of SPM required PSD permitting for CO, NOx (NO_2), PM (filterable only), PM_{10}, and GHGs because SPM was estimated to have the potential to emit one or more regulated non-GHG PSD pollutants above the applicable PSD major source threshold of 100 tpy, and the potentials to emit of CO, NOx, PM (filterable only), PM_{10}, and GHGs were estimated to be above the applicable PSD significant thresholds of 100 tpy, 40 tpy, 25 tpy, 15 tpy, and 75,000 tpy, respectively. The initial construction of SPM did not require PSD permitting for sulfuric acid mist because SPM was estimated to have a sulfuric acid mist potential to emit below the pollutant's PSD significant threshold of 7 tpy. These PSD applicability determinations were documented in the review memo dated April 1, 2015, for PA-04-00740A issued on June 18, 2015, authorizing the initial construction of SPM. The table below shows SPM's proposed facility-wide potential to emit rates of applicable PSD pollutants after the incorporation of the Plan Approval Reconciliations and WWTP Permanent Controls Project to relevant PSD significant thresholds.

Table 9: Plan Approval Reconciliations and WWTP Permanent Controls Project Retrospective PSD Applicability Summary

Pollutant	Proposed Facility-Wide PTE Including Plan Approval Reconciliations and WWTP Permanent Controls Project (tpy)[25]	PSD Significant Threshold[a] (tpy)	Subject to PSD Review (Yes/No)
CO	864.98	100	Yes
NOx	378.49	40	Yes
PM (filterable)	76.31	25	Yes
PM_{10}	175.62	15	Yes
Sulfuric Acid Mist	1.24	7	No
GHGs, as CO_2e	2,468,325	75,000	Yes

[a] Significant increase thresholds are included because once a facility is subject to PSD for any pollutant, it may be subject for any other pollutant which exceeds the significant increase threshold.

Shell has updated the most recent air quality analysis that was completed for the initial construction of SPM due to the emissions unit-specific and facility-wide CO, NOx, and PM_{10} potential to emit rate changes that are being proposed because of the Plan Approval Reconciliations and WWTP Permanent Controls Project. On December 20, 2025, the Department's Air Quality Modeling and Risk Assessment Section sent Shell a technical review comment letter on the PSD Air Quality Analyses and Inhalation Risk Assessment. Shell provided revised analyses on May 29, 2025. Additional revisions were received by the Department on September 5, 2025, and October 14, 2025. A summary of the Department's review of the air quality analyses is included later in this memo.

In the September 13, 2024, application for this plan approval, Shell concluded that the Plan Approval Reconciliations and WWTP Permanent Controls Project do not require a BACT analysis because they will not retrospectively cause the initial construction of SPM to require PSD permitting under 25 Pa. Code §127.83 for any additional regulated PSD pollutants relative to the PSD applicability determinations that were made contemporaneous with the Department's authorization of the initial construction of SPM. The original project exceeded the PSD major source thresholds and was subject to PSD, and the original project retrospectively including the Plan Approval Reconciliations and WWTP Permanent Controls Project exceed the PSD major source thresholds and is subject to PSD. The Plan Approval Reconciliations and WWTP Permanent Controls Project does not change the PSD applicability of the original project. This portion of the plan approval is being handled using the PSD requirements that were in effect at the time of the original permitting of PA-04-00740A. Shell exceeded the PSD major source threshold for NO_2, CO, PM, PM_{10}, CO_2e in PA-04-00740A. Shell is therefore subject to BACT requirements for NO_2, CO, PM, PM_{10}, and CO_2e. In response to the Department's December 24, 2024, deficiency letter, Shell has evaluated the Plan Approval Reconciliations to determine if they potentially require revised BACT analyses for emissions units that were constructed as part of the initial construction of SPM. Shell provided a revised BACT analysis on April 11, 2025, for the following sources and pollutants:

[25] The proposed facility-wide potential to emit rates in the table do not include the potential to emit rate increases that are proposed to occur at the TEGF A and TEGF B due to the EMACT Project.

- Ethane Cracking Furnaces (Source IDs 031-037) for GHGs
- Cogeneration Plant Cooling Tower (Source ID 104) for PM (filterable only) and PM_{10}
- CVTO (Source ID 204A) for CO, NOx, PM (filterable only), PM_{10}, and GHGs
- MPGF (Source ID 204B) for CO, NOx, PM (filterable only), PM10, and GHGs
- TEGF A, TEGF B, and HP Elevated Flare (Source IDs C205A, C205B, and C205C) for CO, NOx, PM (filterable only), PM_{10}, and GHGs
- SCTO (Source ID C206) for CO, NOx, PM_{10}, and GHGs
- Equipment Components (Source ID 501) for CO.

The revised BACT analysis was included as Attachment 7 of the April 11, 2025, response. BACT was not re-evaluated for pollutants in which the PTE is proposed to decrease or if the proposed increase is insignificant and would not affect the technical and economic feasibility analyses that were previously completed in support of the previous BACT determination.

PSD Applicability – EMACT Project

SPM currently has the potential to emit greater than 100 tpy of CO, NOx, PM_{10}, $PM_{2.5}$, and VOC, respectively, which means the facility is an existing PSD major stationary source under 40 CFR § 52.21. Because SPM is currently a PSD major stationary source, PSD permitting requirements would apply to the EMACT Project if the project were estimated to represent a “major modification” (i.e., if the EMACT Project were estimated to result in a significant net emissions increase of one or more regulated non-GHG NSR pollutants). The table below shows the EMACT Project emissions increase compared to the relevant PSD significant thresholds.

Table 10: EMACT Project PSD Applicability Summary

Pollutant	EMACT Project Emissions Increase (tpy)	Project Net Emissions Increase (tpy)	PSD Significant Increase Threshold (tpy)	Subject to PSD Review (Yes/No)
CO	349.37	349.37	100	Yes
NOx	76.64	76.64	40	Yes
PM (filterable)	2.10	2.10	25	No
PM_{10}	8.40	8.40	15	No
$PM_{2.5}$	8.40	8.40	10	Yes[26]
Sulfuric Acid Mist	0.08	0.08	7	No
GHGs, as, CO_2e	98,238	98,238	75,000	Yes

As indicated in the table above, the EMACT Project will result in a significant net emissions increase of CO, NOx, and GHGs. Additionally, although the EMACT Project will not result in a significant net emissions increase in direct $PM_{2.5}$ emissions, the project is subject to PSD review for $PM_{2.5}$ because it will result in a significant net emissions increase in NOx, which is a precursor to $PM_{2.5}$. Accordingly, the EMACT Project will

[26] Although the EMACT Project was not estimated to cause a significant net emissions increase in direct $PM_{2.5}$ emissions, the project is subject to PSD review for $PM_{2.5}$ because it was estimated to cause a significant net emissions increase in NOx, which is a precursor to $PM_{2.5}$.

be a major modification subject to PSD permitting requirements under 40 CFR § 52.21 for CO, NOx (NO_2), $PM_{2.5}$, and GHGs. In response to the Department's December 20, 2024, technical review comment letter on the PSD Air Quality Analyses and Inhalation Risk Assessment, Shell provided revised analyses on May 29, 2025. The summary of the Department's review of the air quality analyses for the EMACT Project is discussed later in this memo. The BACT requirements are discussed directly below.

BACT/LAER/BAT

Control technology analyses for new equipment additions have been addressed in this application (new Wastewater Treatment Vessels due to the WWTP Permanent Controls Project) as well as for the TEGF A and B due to the EMACT Project resulting in a significant emissions increase. Revised control technology analyses have also been conducted for existing equipment in which potential emissions increases are proposed to occur as a result of the Plan Approval Reconciliations covered by this plan approval application. These revised analyses are documented in Shell's April 11, 2025, response, as discussed above.

The applicant has conducted a BACT analysis following a 5 step "top-down" analysis which has been recommended by EPA for traditional attainment pollutants as well as the new GHG pollutants.[27] The steps of this analysis are summarized as follows:

1. Identify all available control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining control technologies by effectiveness.
4. Evaluate the most effective controls and document results.
5. Select BACT.

The applicant has conducted a LAER analysis following a 3-step analysis summarized as follows:

1. Identify existing permit limits and SIP limits.
2. Identify existing permit limits and SIP limits that have been achieved in practice.
3. Identify LAER based on the most stringent limit that has been achieved in practice.

Per Shell's April 11, 2025, response to the Department's technical deficiency letter:

> To make the LAER determinations in this submittal, Shell first identified NNSR permit, PSD permit, and SIP limits for the same class or category of source as the particular source subject to LAER. Shell primarily relied upon a review of the EPA's reasonably available control technology (RACT)/BACT/LAER Clearinghouse (RBLC) database, South Coast Air Quality Management District (SCAQMD) BACT Guidelines, Bay Area Air Quality Management District (BAAQMD) BACT/Best Available Control Technology for Toxics (TBACT) Workbook, and California and Texas RACT requirements to identify potential LAER limits for a specific class or category of source. Next, these limits were evaluated to confirm which of them have been achieved in practice. A limit was deemed to have been achieved in practice when testing or continuous monitoring has successfully demonstrated compliance with the limit over

[27] U.S. Environmental Protection Agency, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, p. 17.

its associated averaging period. Lastly, LAER was proposed for the source based on the most stringent limit that has been achieved in practice by the same class or category of source.

This approach will satisfy the definition of LAER under 25 Pa. Code § 121.1. Per 25 Pa. Code § 127.205(1), "A new or modified facility subject to this subchapter shall comply with LAER…" In accordance with 25 Pa. Code § 121.1, LAER is defined as:

(i) The rate of emissions based on the following, whichever is more stringent:
  (A) The most stringent emission limitation which is contained in the implementation plan of a state for the class or category of source unless the owner or operator of the proposed source demonstrates that the limitations are not achievable.
  (B) The most stringent emission limitation which is achieved in practice by the class or category of source.
(ii) The application of the term may not allow a new or proposed modified source to emit a pollutant in excess of the amount allowable under an applicable new source standard of performance.

BACT and LAER must also be at least as stringent as any NSPS that is applicable to a particular source. LAER for NOx is considered to be at least as stringent as BACT for NO_2.

Although not required, Shell used the same "top-down" process typically used to perform a PSD BACT analysis to make the BAT determinations in this submittal. The following is a summary of the BACT/LAER/BAT determinations and their respective emission limits made by the Department, taking into consideration available control technologies, other recent plan approvals, limitations achieved in practice, the RBLC, and additional resources identified above.

For Shell's revised control technologies analyses for LAER, BAT, and BACT, see Attachments 2, 6, and 7 of the April 11, 2025, response, respectively.

<u>Ethane Cracking Furnaces</u>

The Department has determined that BACT, LAER, and BAT remain the same for the ethane cracking furnaces, as established in the review of PA-04-00740A. Because the furnace's CO_2e potential to emit is proposed to increase by 7,555 tpy each due to a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnaces, BACT for GHGs has been re-evaluated. The ethane cracking furnaces are currently subject to the following GHG BACT requirements.

- The GHG emissions from the ethane cracking furnaces shall not exceed 1,048,670 tons of CO_2e from all furnaces combined in any consecutive 12-month period.
- The exhaust gas temperature from each of the ethane cracking furnace stacks shall not exceed 350°F on a monthly 12-month rolling average, excluding periods of startup, shutdown, hot steam standby, or decoking.
- Each ethane cracking furnace shall undergo a tune-up at a minimum of once every 5 years.

Potentially available GHG emission control technologies identified for the ethane cracking furnaces are low-carbon fuels, energy efficient design, good combustion practices, and carbon capture and storage (CCS). All identified options have been determined to be technically feasible and low-carbon fuels, energy efficient design, and good combustion practices are already employed.

CCS as potential BACT for control of GHGs had been evaluated by the applicant in the application for PA-04-00740A on a larger scale for all the large combustion sources (ethane cracking furnaces and combustion turbines) combined. At that time, CCS had been deemed economically infeasible for the project. In the April 11, 2025, response to the Department, Shell provided an evaluation of CCS considering a post-combustion capture system that would treat the combustion exhaust gases generated by all seven ethane cracking furnaces, as well as the combustion exhaust gases from the CVTO and SCTO. The combustion turbines were not included in the analysis since BACT was not reevaluated for the turbines in this application.

While CCS is being considered as a method for reducing emissions, its feasibility in the context of BACT depends on technical, economic, and environmental implications. Other factors include the availability of storage capacity and infrastructure, the additional energy requirements to construct and operate a CO_2 capture system and transportation pipeline, potentially producing additional emissions, scalability, and the potential for leakage raises concerns about its overall effectiveness and practicality. Ongoing improvements in CCS technology and increasing availability of infrastructure are expected to increase its feasibility and cost-effectiveness in the future. Shell's analysis of CCS, including the cost analysis approach used, can be found on pages 1-27 through 1-32 of the April 11, 2025, response. Additional cost information can be found in Attachment 7-2 of the response. Shell concludes that the considerable costs, as well as the additional energy requirements to install and operate a CO_2 capture system and transportation pipeline suggest unacceptable economic and energy impacts.

After review of Shell's analysis, CCS has been deemed by the Department to be economically infeasible as part of the changes to this facility. It has been determined that combusting low-carbon fuels, incorporating energy efficient design features, and operating in accordance with good combustion practices represent BACT for the GHG emissions from the existing ethane cracking furnaces.

This plan approval will maintain a facility-wide CO_2e limit in addition to CO2e limits placed on the facility's large combustion sources, including the ethane cracking furnaces. EPA states that "since the environmental concern with GHGs is with their cumulative impact in the environment, metrics should focus on longer-term averages (*e.g.*, 30- or 365-day rolling average) rather than short-term average (*e.g.*, 3- or 24-hour rolling average)."[28] The limit has been established as a 12-month rolling average consistent with the long-term average recommendation and with the fuel usage data already required by a plan approval condition. Fugitive GHG emissions are included in the facility-wide CO_2e limitation because this facility belongs to one of the 28 source categories for which fugitive emissions are included for determining a major stationary source and PSD applicability. Compliance with the facility-wide CO_2e limitation is demonstrated through records of operational hours, fuel usage, actual fuel gas analyses, and Department-approved emission factors and test results. Shell is required to report GHG emissions from this facility annually under 25 Pa. Code §127.12b, as part of an Annual Emission Inventory Report.

[28] U.S. Environmental Protection Agency, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, Page 46.

Combustion Turbines

The combustion turbine/duct burner unit's HAP potential to emit is proposed to increase because of the incorporation of source-specific HAP stack test results into the potential to emit calculation and a proposed reduction in the organic HAP destruction efficiency used in the potential to emit calculation for the oxidation catalyst equipped on the combustion turbine/duct burner unit. The oxidation catalyst's organic HAP destruction efficiency is proposed to be reduced from 90% to 30% for organic HAP emissions based on the catalyst manufacturer's recommendation. Calculations for organic HAP emissions were previously calculated using the guaranteed CO destruction efficiency of 90%, which is not appropriate for organic HAP reduction.

The combustion turbines are subject to 40 CFR Part 63 Subpart YYYY, and the subpart's applicable emission limitation, operating limitation, monitoring, testing, reporting, record keeping, and work practice requirements will be included in the plan approval for the three lean premix gas-fired stationary combustion turbines. In the notice of final rulemaking for 40 CFR Part 63 Subpart YYYY, EPA stated that "formaldehyde is an appropriate surrogate for the other organic HAP which are also controlled by an oxidation catalyst." It has been determined that good combustion practices and catalytic oxidation represent BAT for the combustion turbine/duct burner units' HAP emissions. Monitoring the oxidation catalyst inlet temperature will ensure its proper operation and compliance with the HCHO limit of 91 ppbvd @ 15% O_2.

Cogeneration Plant Cooling Tower

The cooling tower's $PM_{2.5}$ potential to emit is proposed to increase by 14 pounds per year because of the proposed increase in the cooling tower's potential recirculation rate. Shell has reevaluated the $PM_{2.5}$ LAER determination for the cooling tower in coordination with the PM and PM_{10} BACT determination reevaluations that have been determined to be warranted for the cooling tower. Control technologies evaluated include high efficiency drift eliminators, low cooling water TDS levels, and air-cooled heat exchangers. The use of air-cooled heat exchangers in place of water-cooled heat exchangers in the Cogen Units has been determined to be technically infeasible because air-cooled heat exchangers would not provide adequate cooling. The Department has determined that high-efficiency drift eliminators and managing cooling water TDS levels represent LAER for the Cogeneration Plant Cooling Tower's $PM_{2.5}$ emissions and BACT for the Cogeneration Plant Cooling Tower's PM and PM_{10} emissions, along with the following requirements that are currently applicable to the cooling tower:

- Equip the Cogeneration Plant Cooling Tower with drift/mist eliminators designed not to exceed 0.0005% drift loss.
- Manage the Cogeneration Plant Cooling Tower's cooling water TDS levels to ≤ 2,000 ppmw TDS on a 12-month rolling average.

Wastewater Treatment Plant

The new Wastewater Treatment Vessels and existing WWTP equipment will treat VOC and HAP-containing wastewater using a combination of gravity settlement/phase separation, dissolved nitrogen flotation, steam stripping, biotreatment, and filtration mechanisms. Therefore, the new and existing wastewater treatment equipment will have the potential to emit VOC and HAP because some of the VOC and HAP contained in the wastewater will either volatilize or be stripped from the wastewater during the referenced treatment processes.

Both the new and existing equipment have been analyzed in this review.

The new Wastewater Treatment Vessels proposed in this plan approval are the following:

- Settlement Drum(s)
- Two (2) Dissolved Nitrogen Flotation (DNF) Units
- Float/Sludge Drum
- Steam Stripper with associated Overhead Condenser and Reflux Drum

The Department has determined that LAER and BAT for the new Wastewater Treatment Vessels is venting the equipment to the SCTO for control. Additionally, the Department proposes to require that the new Wastewater Treatment Vessels be operated in accordance with good operating practices. Good operating practices include proper monitoring of the equipment to ensure it is operated to maximize VOC and HAP removal efficiency and effectiveness. Higher removal efficiency of the equipment results in less VOC and HAP that is routed to the secondary treatment portion of the Wastewater Treatment Plant, including the biotreaters and clarifiers. Specific monitoring proposed in the plan approval includes primary treatment section inlet/outlet concentration sampling, DNF nitrogen pressure monitoring, steam stripper temperature, steam-to-water ratio, total steam supplied, and pressure of the steam monitoring, steam stripper overhead condenser temperature monitoring, and additional monitoring of the SCTO. Furthermore, Shell will be required to develop and maintain a WWTP Control Plan detailing the procedures for operating and maintaining the WWTP's primary treatment system, the parameters to be monitored, standard operating ranges, and procedures and timeframes to restore the system to normal operating conditions.

The existing Wastewater Treatment Plant is comprised of the following wastewater treatment equipment:

- Two (2) Flow Equalization and Oil Removal (FEOR) Tanks, which vent to a closed vent system that routes collected vent gases to the SCTO
- One (1) Recovered Oil Storage Tank, which vents to a closed vent system that routes collected vent gases to the SCTO
- Two (2) Biotreater Aeration Tanks
- Two (2) Secondary Clarifiers
- Two (2) Biosludge Holding Tanks
- One (1) Centrifuge
- One (1) Sand Filter
- One (1) Sump (for centrate and sand filter backwash)
- One (1) Treated Effluent Sump

The wastewater received by the Wastewater Treatment Plant enters the two FEOR Tanks where oil that rises to the top of the liquid surface is skimmed off and routed to the Recovered Oil Storage Tank. The effluent from the two FEOR Tanks is routed to the two Biotreater Aeration Tanks, which represents the beginning of the Wastewater Treatment Plant's biological treatment section. The referenced biotreatment tanks and downstream Secondary Clarifiers, Biosludge Holding Tanks, Centrifuge, and Sand Filter use a combination of biotreatment, gravity settlement, filtration, and centrifugation mechanisms to treat wastewater and biosolids managed in the Wastewater Treatment Plant.

The Biotreater Aeration Tanks, Secondary Clarifiers, Biosludge Holding Tanks, Centrifuge, Sand Filter, Centrate/Sand Filter Backwash Sump, and Treated Effluent Sump emit VOC to the atmosphere because some of the VOC contained in the wastewater managed in this equipment volatilizes to the atmosphere. However, the amount of VOC contained in the wastewater entering the Biotreater Aeration Tanks is relatively low (< 2 ppmw VOC). Additionally, the biotreatment process that occurs in the Biotreater Aeration Tanks removes a portion of the VOC (organic material) contained in the wastewater by breaking it down into simpler, non-VOC compounds (e.g., water, biomass). For these reasons, the Biotreater Aeration Tanks, Secondary Clarifiers, Biosludge Holding Tanks, Centrifuge, Sand Filter, Centrate/Sand Filter Backwash Sump, and Treated Effluent Sump in the Wastewater Treatment Plant emit only a small amount of VOC. The Wastewater Treatment Plant is currently subject to the following VOC LAER requirements.

- The FEOR Tanks shall be equipped with an IFR and controlled by vapor recovery routed to the SCTO.
- The Recovered Oil Storage Tank shall be equipped with an IFR and controlled by vapor recovery routed to the SCTO.

It has been determined that equipping and maintaining an IFR on the FEOR Tanks and Recovered Oil Storage Tank that are upstream of the Biotreater Aeration Tanks and routing the vents from the FEOR Tanks and Recovered Oil Storage Tank to the SCTO that achieves a 99.9% VOC destruction efficiency represents LAER for the VOC emissions from these wastewater treatment vessels in the Wastewater Treatment Plant. During truck loading from the Settlement Drum or the Recovered Oil Storage Tank, vent gases generated will be required to be vented through a closed vent system to a carbon adsorption system designed to reduce VOC emissions by a minimum of 95%. Additionally, it has been determined that using biological treatment for secondary wastewater treatment represents LAER for the VOC emissions from wastewater treatment equipment that follows the referenced primary wastewater treatment vessels in the Wastewater Treatment Plant. This determination is equivalent to or more stringent than the limits identified during this review.

This LAER determination also represents BAT for the control of HAP from the existing WWTP. Compliance with the destruction efficiency will be verified through performance testing. The SCTO was tested on May 23, 2024, and the test report demonstrated a VOC destruction efficiency of greater than 99.99%.

Other control technologies evaluated to control VOC and HAPs emissions from the new Wastewater Treatment Vessels, FEOR Tanks, and Recovered Oil Storage Tank included catalytic oxidation, absorption, carbon adsorption, and condensation. Each option was determined to be technically feasible for these wastewater treatment vessels; however, of the available control technologies, thermal oxidation was ranked the highest and selected for this project.

SCTO

The SCTO is designed to control VOC emissions from the spent caustic oxidizer stripper, the Spent Caustic Storage Tank, the FEOR Tanks, and the Recovered Oil Storage Tank. As part of this plan approval, the SCTO will also be the permanent control of the new Wastewater Treatment Vessels. The SCTO functions as an air cleaning device primarily, but it also meets the definition of an air contamination source because the combustion of natural gas and waste gas generates products of combustion.

LAER for control of NOx, VOC, and $PM_{2.5}$; BACT for control of CO, NOx, PM_{10}, and GHGs; and BAT for control of SOx and HAP has been determined to be low NOx burners, good combustion practices, and proper operation and maintenance. Note that BAT applies to all pollutants. BAT for SOx and HAP is identified here since the more stringent control technology requirements of LAER and BACT don't apply to these pollutants.

NOx

The SCTO emits NOx due to the thermal NOx mechanism and may emit a minor amount of NOx formed by the prompt NOx mechanism. However, the SCTO is not expected to emit fuel-bound NOx because it does not combust vent gases that contain fuel-bound nitrogen compounds since SPM does not generate vent gases containing fuel-bound nitrogen compounds, and the pipeline quality natural gas fuel combusted in the SCTO does not contain fuel-bound nitrogen compounds. The SCTO is currently subject to the NOx LAER limit of 0.068 lb/MMBtu.

It has been determined that low NOx burners (LNBs) and good combustion practices represent the LAER for the SCTO's NOx emissions. Shell has proposed a NOx LAER limit of 0.06 lb/MMBtu (3-hour average) for the SCTO, which is more stringent than the NOx LAER limit that is currently applicable to the thermal oxidizer. The proposed limit is as stringent as NOx limits identified for operating thermal oxidizers that are used to control ethylene and polyethylene manufacturing unit process vents based on a review of information from sources that include EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Shell has proposed plans to modify or replace the LNBs currently installed in the SCTO to meet the more stringent NOx LAER limit of 0.06 lb/MMBtu. The plan approval will be conditioned to require the SCTO burner upgrades to be completed within 180 days of issuance of the plan approval, or other schedule as approved by the Department in writing. The plan approval will also be conditioned to require stack testing of the SCTO for NOx, CO, PM_{10}, $PM_{2.5}$, and benzene to be completed within 180 days of the SCTO burner upgrades, or on an alternative schedule as approved by the Department.

$PM_{2.5}$

$PM_{2.5}$ is emitted by the SCTO due to sulfur-containing compounds and metals that may be present in the fuel and vent gases combusted in the thermal oxidizer, as well as the incomplete combustion of fuel and vent gases in the thermal oxidizer. However, the fuel combusted in the SCTO is pipeline quality natural gas, which is comprised of easily combustible hydrocarbons and negligible amounts of sulfur-containing compounds or metals. The composite vent gas stream combusted in the SCTO, which is comprised of vent gases generated by SPM's spent caustic storage tank, spent caustic oxidation treatment operation, and Wastewater Treatment Plant-related equipment, does not contain appreciable amounts of sulfur-containing compounds that would result in the generation of noteworthy amounts of acid gases (condensable PM) when combusted. However, one of the vent gases combusted in the SCTO (the spent caustic oxidation treatment operation vent gas) may contain sulfur at a level greater than pipeline quality natural gas, which *may* result in sulfuric acid mist (condensable PM) emissions slightly greater than the amount that would occur when combusting pipeline quality natural gas or a vent gas with sulfur levels equivalent to pipeline quality natural gas. Overall, the SCTO emits $PM_{2.5}$ at low levels. The SCTO is currently subject to the $PM_{2.5}$ LAER limit of 0.0075 lb/MMBtu. This is as stringent as identified in EPA's RBLC database, SCAQMD BACT Guidelines, and BAAQMD BACT/TBACT Workbook. Specifically, Shell has identified RBLC Reference ID TX-0858 for GCGV Asset Holding LLC Complex in

Gregory, TX, with a $PM_{2.5}$ limit of 0.0075 lb/MMBtu. Shell has proposed a $PM_{2.5}$ LAER limit of 0.012 lb/MMBtu for the SCTO, which is greater than the limit indicated above, because, according to Shell's LAER analysis, the thermal oxidizer at the GCGV Asset Holding LLC Complex does not combust a vent gas that is comparable to the spent caustic oxidation treatment operation vent gas at SPM. The resulting increase in the SCTO's $PM_{2.5}$ PTE is 0.22 tpy.

As part of Shell's February 28, 2025, response to the Department, vent stream information used in the SCTO potential to emit calculation was provided in Attachment 3. According to the information related to the spent caustic oxidizer vents in Attachment 3 of the response, emissions basis assumptions/inputs are as follows: "Process engineering model calculates 1,750 kg/hr vent flow rate with the majority of the vent being water, oxygen, and carbon monoxide. The VOC portion of the vent is estimated to be 14.76 kg/hr. The main VOC constituents are benzene at 0.37 wt.%, 1,3-butadiene at 0.05 wt.%, and acetylene at 0.03 wt.%." The supporting information for the vent streams to the SCTO does not include the potential for sulfur. Without supporting information for the increased LAER limit, the Department has determined the existing limit of 0.0075 lb/MMBtu to be LAER.

The following emission limits have been determined to comply with LAER and BACT for the SCTO:

- NO_X – 0.06 lb/MMBtu (decreased from 0.068 lb/MMBtu)
- CO – 0.0824 lb/MMBtu
- PM_{10} – 0.0075 lb/MMBtu
- $PM_{2.5}$ – 0.0075 lb/MMBtu
- VOC – 99.9% destruction efficiency (increased from 99% destruction efficiency)

SO_2 and H_2SO_4

The SCTO combusts a combination of vent gases, which are generated by SPM's spent caustic storage tank, spent caustic oxidation treatment operation, and Wastewater Treatment Plant-related equipment, and pipeline quality natural gas. Except for the spent caustic oxidation treatment operation vent gas, the vent gases combusted in the SCTO are not expected to contain measurable levels of sulfur. Additionally, pipeline quality natural gas contains considerably low levels of sulfur. As a result of these vent gas and natural gas sulfur characteristics, the SCTO emits only a small amount of SO_2 and sulfuric acid mist.

SO_2 and sulfuric acid mist control technologies and techniques identified include low-sulfur vent gases, low-sulfur fuels, absorption, and absorption. Except for the spent caustic oxidation treatment operation vent gas, the vent gases combusted in the SCTO do not contain measurable amounts of sulfur; therefore, it would not be feasible to design an absorption or adsorption unit to reduce the sulfur content prior to combustion in the SCTO. The Department has determined that combusting low-sulfur vent gases and low-sulfur fuels represents BAT for the SO_2 and sulfuric acid mist emissions from the SCTO.

<u>Recovered Oil Truck Loadout</u>

In the application for this plan approval, Shell requested that the requirement to control emissions from the recovered oil truck loadout be removed since this operation at SPM is both a low vapor pressure and low throughput organic liquid loading operation. However, the original VOC LAER analysis submitted in the

February 2015 application by Shell for PA-04-00740A proposed a closed vent vapor capture system and routing to the SCTO for control, which is included as a requirement in PA-04-00740A/C, Source ID 302 Liquid Loadout (Recovered Oil), Condition #001.

As documented in the review memo for PA-04-00740A, dated April 1, 2015, "**Low Vapor Pressure (< 0.5 psia) Liquid Loadout (coke residue/tar, recovered oil)** LAER for control of VOC, and BAT for control of HAP has been determined to be work practice standards of submerged loading with vapor capture and low-leak disconnect couplings, and routing to the process or spent caustic vent incinerator. There is no NSPS limit or 25 Pa. Code Chapter 129 Standard applicable to the loadout of these low vapor pressure organic liquids. A minimum VOC control efficiency of 99% is required through the application of LAER in this case."

Shell has acknowledged that the recovered oil truck loadout has not been designed and built based on the original LAER determination. On October 27, 2025, a revised LAER analysis was provided. Based on the review, the control option that has been applied to the same class or category of source and that has been achieved in practice is the use of submerged filling combined with dedicated service transport vehicles.

However, Shell has proposed control of recovered oil loadout by a carbon adsorption system consistent with the design and work practice, monitoring, and recordkeeping standards set forth in 40 CFR Part 61 Subpart FF (BWON) for treatment of waste in a container. The proposed conditions are included at the end of this memo. Shell has proposed that vent gases generated by loading recovered oil into transport vehicles shall be vented through a closed vent system to a carbon adsorption system designed to reduce VOC emissions by a minimum of 95%.

Uncontrolled PTE from the recovered oil truck loading is 0.10 tpy VOC. Although 99% control was originally proposed, the PTE did not previously account for control. The previous calculations also assumed the HAP fraction of VOC is 100%. The revised PTE calculations in this plan approval with the proposed 95% control and revised HAP fraction of VOC based on site-specific data results in a decrease in HAP PTE.

Table 11: Recovered Oil Truck Loadout Emission Comparison

Pollutant	PA-C PTE	PA-C PTE*	PA-D
	tpy	tpy	tpy
Uncontrolled VOC	0.10	0.10	0.10
Control Efficiency	99%	99%	95%
Controlled VOC	0.10	0.001	0.005
HAP Fraction	100%	100%	0.20%
HAP	0.10	0.001	1.04E-05

* PTE accounting for previously proposed 99% control efficiency.

After review, the previously established LAER for the recovered oil truck loadout has not been achieved in practice at SPM or other facilities for liquid loadout with low vapor pressure less than 0.5 psia. The proposed control efficiency of 95% is equivalent to or more stringent than any limits found in EPA's RBLC database for the same class or category of source. This plan approval will also include work practice, monitoring, and recordkeeping requirements including carbon breakthrough monitoring and/or replacement.

TEGF A and B

The TEGF A and TEGF B function as air cleaning devices primarily but also meet the definition of an air contamination source because the pilot burner and combustion of organic vapors will generate products of combustion. LAER for control of NOx, VOC, and $PM_{2.5}$; BACT for control of CO, NOx, PM_{10}, $PM_{2.5}$, and GHGs; and BAT for control of SO_X and HAP has been determined to be good combustion practices (i.e., flare designed and operated in accordance with 40 CFR Part 63 Subparts CC/YY flare control device design, operating, and monitoring requirements) and proper operation and maintenance including operating in accordance with an approved flare minimization plan (FMP). Good combustion practices will include maximizing the complete combustion of VOC waste gas streams and minimizing the products of incomplete combustion. Good combustion practice requirements in 40 CFR Part 63 Subpart CC includes design requirements (e.g. multiple pilots for redundancy, reliability, and continuous ignition), minimum flare combustion zone gas heating value requirements (800 Btu/scf for ensuring destruction efficiency), and monitoring requirements for the flares. Shell has also proposed an additional work practice requirement for flare stage sequencing in accordance with manufacturer's recommendations to promote complete combustion and reduce the likelihood of incomplete combustion and visible emissions. These control device requirements of the EMACT have been designed to produce a stable flame capable of continuously meeting the underlying destruction efficiency of 98%. Proper design and operation of the flares is critical for achieving the destruction efficiency and significantly impacts the facility-wide emissions. At a DRE of 98%, the flares reduce VOC by over 11,000 tpy compared to the approximately 77 tpy of NOx that results from combusting a sufficient amount of supplemental gas to maintain the net heating value in the combustion zone of the flares at 800 Btu/scf.

The FMP and associated work practices that are currently in PA-04-00740C include the following conditions under Section D for both Source ID 204, Low Pressure (LP) Header System and Source ID 205, High Pressure (HP) Header System:

> The Owner/Operator shall minimize flaring resulting from startups, shutdowns, and unforeseeable events by operating at all times in accordance with an approved flare minimization plan. The plan shall include the following:
>
> a. Procedures for operating and maintaining the HP and LP Systems during periods of process unit startup, shutdown, and unforeseeable events.
> b. A program of corrective action for malfunctioning process equipment.
> c. Procedures to minimize discharges either directly to the atmosphere or to the HP and LP Systems during the planned and unplanned startup or shutdown or process unit and air pollution control equipment.
> d. Procedures for conducting root cause analyses.
> e. Procedures for taking identified corrective actions.
> f. The baseline flow to the HP and LP Systems determined in accordance with the provisions of 40 CFR §60.103a(a)(4).
>
> The Owner/Operator shall conduct a root cause analysis within 45 days after any startup, shutdown and unforeseeable flaring event. Flaring event shall be defined as an event that exceeds the baseline by 500,000 scf within a 24 hour period. The analysis shall address the following:
>
> a. The date and time that the flaring event started and ended.

b. The total quantity of gas flared during each event.
c. An estimate of the quantity of VOC that was emitted and the calculations used to determine the quantities.
d. The steps taken to limit the duration of the flaring event of the quantity of emissions associated with the event.
e. A detailed analysis that sets forth the root cause and all significant contributing causes of the flaring event to the extent determinable.
f. An ~~analyses~~ analysis of the measures that are available to reduce the likelihood of a recurrence of a flaring event resulting from the same root cause or significant contributing causes in the future.
g. A demonstration that the actions taken during the flaring event are consistent with the procedures specified in the flare minimization plan.
h. In response to a flaring event, the Owner/Operator shall implement, as expeditiously as practicable, such interim and/or long-term corrective actions as are consistent with good engineering practice to minimize the likelihood of a recurrence of the root cause and all significant contributing causes of that flaring event.
i. If any items required to be addressed in this analysis are still under investigation 45 days after the flaring event, the Owner/Operator shall include a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Condition shall be completed.

Additionally, per 40 CFR § 63.1103(e)(4), the owner or operator must meet the applicable requirements for flares as specified in §§ 63.670 and 63.671 of subpart CC. Among other stipulations, per 40 CFR § 63.1103(e)(4):

(v) Substitute “ethylene production unit” for each occurrence of “petroleum refinery.”
(vi) Each occurrence of “refinery” does not apply.

In accordance with the applicable emergency flaring provisions of 40 CFR 63.670(o), “The owner or operator of a flare that has the potential to operate above its smokeless capacity under any circumstance shall comply with the provisions in paragraphs (o)(1) through (7) of this section.”

(1) Develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases. The flare management plan must include the information described in paragraphs (o)(1)(i) through (vii) of this section.

(i) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(ii) Flare minimization assessment – discussed further below

(iii) A description of each affected flare containing the information in paragraphs (o)(1)(iii)(A) through (G) of this section.

(A) A general description of the flare, including whether it is a ground flare or elevated (including height), the type of assist system (*e.g.,* air, steam, pressure, non-assisted), whether the flare is used on a routine basis or if it is only used during periods of startup, shutdown or emergency release, and whether the flare is equipped with a flare gas recovery system.

(B) The smokeless capacity of the flare based on a 15-minute block average and design conditions. *Note:* A single value must be provided for the smokeless capacity of the flare.

(C) The maximum vent gas flow rate (hydraulic load capacity).

(D) The maximum supplemental gas flow rate.

(E) For flares that receive assist steam, the minimum total steam rate and the maximum total steam rate.

(F) For flares that receive assist air, an indication of whether the fan/blower is single speed, multi-fixed speed (*e.g.*, high, medium, and low speeds), or variable speeds. For fans/blowers with fixed speeds, provide the estimated assist air flow rate at each fixed speed. For variable speeds, provide the design fan curve (*e.g.,* air flow rate as a function of power input).

(G) Simple process flow diagram showing the locations of the flare following components of the flare: Flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iv) Description and simple process flow diagram showing all gas lines (including flare waste gas, purge or sweep gas (as applicable), supplemental gas) that are associated with the flare. For purge, sweep, supplemental gas, identify the type of gas used. Designate which lines are exempt from composition or net heating value monitoring and why (*e.g.*, natural gas, gas streams that have been demonstrated to have consistent composition, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor. Designate the pressure relief devices that are vented to the flare.

(v) For each flow rate, gas composition, net heating value or hydrogen concentration monitor identified in paragraph (o)(1)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For each pressure relief device vented to the flare identified in paragraph (o)(1)(iv) of this section, provide a detailed description of each pressure release device, including type of relief device (rupture disc, valve type) diameter of the relief device opening, set pressure of the relief device and listing of the prevention measures implemented. This information may be maintained in an electronic database on-site and does not need to be submitted as part of the flare management plan unless requested to do so by the Administrator.

(vii) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(2) Paragraph (2) is related to the submittal of the flare management plan and not included here. Additionally, 40 CFR 63.1103(e)(4)(ii) and (iii) detail differences in the submittal requirements.

(3) The owner or operator of a flare subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each flow event that contains regulated material and that meets either the criteria in paragraph (o)(3)(i) or (ii) of this section.

(i) The vent gas flow rate exceeds the smokeless capacity of the flare based on a 15-minute block average and visible emissions are present from the flare for more than 5 minutes during any 2 consecutive hours during the release event.

(ii) Not applicable per 40 CFR 63.1103(e)(4)(iv).

(4) A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a flare flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (o)(4)(i) through (v) of this section.

(5) Each owner or operator of a flare required to conduct a root cause analysis and corrective action analysis as specified in paragraphs (o)(3) and (4) of this section shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in paragraphs (o)(5)(i) through (iii) of this section.

(i) All corrective action(s) must be implemented within 45 days of the event for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that no corrective action should be implemented, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the event.

(ii) For corrective actions that cannot be fully implemented within 45 days following the event for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(iii) No later than 45 days following the event for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(6) The owner or operator shall determine the total number of events for which a root cause and

corrective action analyses was required during the calendar year for each affected flare separately for events meeting the criteria in paragraph (o)(3)(i) of this section and those meeting the criteria in paragraph (o)(3)(ii) of this section. For the purpose of this requirement, a single root cause analysis conducted for an event that met both of the criteria in paragraphs (o)(3)(i) and (ii) of this section would be counted as an event under each of the separate criteria counts for that flare. Additionally, if a single root cause analysis was conducted for an event that caused multiple flares to meet the criteria in paragraph (o)(3)(i) or (ii) of this section, that event would count as an event for each of the flares for each criteria in paragraph (o)(3) of this section that was met during that event. Prior to June 3, 2024, the owner or operator shall also determine the total number of events for which a root cause and correct action analyses was required and the analyses concluded that the root cause was a force majeure event, as defined in this subpart.

(7) The following events would be a violation of this emergency flaring work practice standard.

(i) Any flow event for which a root cause analysis was required and the root cause was determined to be operator error or poor maintenance.

During the review of the BACT, LAER, and BAT analyses, the Department determined the analyses did not evaluate other available control alternatives related to flaring such as flare gas recovery (FGR) and reducing waste gas generation through a waste gas minimization plan (WGMP) for control of VOC and GHGs. FGR and waste gas minimization have also been shown to reduce flaring combustion emissions of NOx, CO, PM, PM_{10}, $PM_{2.5}$, HAPs, and GHGs due to the reduced amount of waste gas combusted by flaring.

The Department is aware that EPA's Air Enforcement Division has negotiated ethylene plant settlements through Consent Decrees from 2013 to 2022 that each required FGR be installed at most of the existing ethylene plants in the United States. Each settlement also includes the need for a WGMP.

Waste gas minimization addresses all sources of waste gases across the entire plant, not just streams sent to the flare and requires in-depth root cause analysis to understand why waste is generated in the first place and implementing corrective actions to prevent recurrence. Other waste gas minimization strategies may include optimizing operating conditions such as operating the cracking furnaces and downstream separation sections under optimal conditions to maximize production and minimize off-spec products, reducing the need for venting and flaring.

Waste Gas Minimization

Each of the Consent Decrees requires that the Defendant submit an initial WGMP that includes five main components and to then subsequently update the plan.

a. Waste Gas Characterization and Mapping.
    i. Volumetric (in scfm) and mass (in pounds) flow rate
    ii. Baseload Waste Gas Flow Rates
    iii. Identification of Constituent Gases
    iv. Waste Gas Mapping
b. Reductions Previously Realized – Not relevant since SPM is a new facility.
c. Planned Reductions – According to Shell, any reductions are provided in updates to the FMP.

d. Taking a Covered Flare Permanently Out of Service – Not relevant to SPM currently.
e. Prevention Measures
    i. Flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including Startup and Shutdown. The evaluation must include a review of flaring that has occurred during these activities, and must consider the feasibility of performing these activities without flaring.
    ii. Flaring that may reasonably be expected to occur due to issues of gas quantity and quality. The evaluation must include a general audit of the FGRS' capacity for each Covered Flare and the storage capacity available for excess Waste Gas – Not relevant unless flare gas recovery is required
    iii. Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation of Prevention Measures must consider the adequacy of existing maintenance schedules and protocols for such equipment. A failure is "recurrent" if it occurs more than twice during any five-year period as a result of the same cause.

Some of the components of the WGMP in the Consent Decrees overlap with the requirements that are already included in SPM's FMP required by PA-04-00740A/C and the flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases required by 40 CFR Part 63 Subparts YY/CC in 40 CFR 63.670(o). Conceptually, waste gas minimization is a broader, facility-wide strategy focused on preventing the generation of waste gases in the first place and finding alternative uses for them, while an FMP is a more specific subset dealing only with reducing the volume of gases sent to the flare. The applicant asserts that no further conditions in the Plan Approval are needed to ensure waste gas minimization is being conducted at SPM.

In each of the referenced Consent Decrees, Waste Gas Mapping is required to identify the source(s) of waste gas entering each Covered Flare. Waste Gas Mapping can be done using instrumentation, isotopic tracing, acoustic monitoring, and/or engineering estimates for all sources entering a flare header (e.g. pump seal purges, sample station purges, compressor seal nitrogen purges, relief valve leakage, and other sources under normal operations).

For purposes of waste gas mapping, a main header is defined as the last pipe segment prior to the flare knock out drum. Process unit headers are defined as pipes from inside the battery limits of each process unit that connect to the main header. For process unit headers that are greater than or equal to six (6) inches in diameter, flow ("Q") must be identified and quantified if it is technically feasible to do so. In addition, all sources feeding each process unit header must be identified and listed in a table, but not necessarily individually quantified. For process unit headers that are less than six (6) inches in diameter, sources must be identified, but they do not need to be quantified.

Regarding Waste Gas Characterization and Mapping, Shell has provided the following:

- Volumetric (in scfm) and mass (in pounds) flow rate – SPM has highly instrumented flare systems that include equipment that continuously measure and record flow rates to the flares along with extensive reporting requirements that already achieve this element.
- Baseload waste gas flow rates – There are requirements in the FMP that is already required by the plan approval to identify baseline flows in accordance with NSPS Subpart Ja.

- Identification of Constituent Gases – Requirements in the FMP and flare requirements in the EMACT (40 CFR Part 63 Subpart YY) and MON (40 CFR Part 63 Subpart FFFF). SPM has GCs on the flares (except the MPGF Ethylene Tank Header because of its consistent composition).
- Waste Gas Mapping – Requirements in FMP for listing of all units, ancillary equipment, etc. that are connected to each flare. Requirements for PFDs showing all gas lines connected to the flare including sub headers.

After review, the concepts of waste gas minimization required by the Consent Decrees are generally covered by the requirements already in place for flare minimization through the plan approval conditions and 40 CFR 63.670(o) of Subpart CC which is required by reference in the plan approval through 40 CFR Part 63 Subpart YY for the TEGF A, TEGF B, HP Elevated Flare, and MPGF (MPGF CVTO Trip Header) and through 40 CFR Part 63 Subpart FFFF for the MPGF (MPGF CVTO Trip Header and MPGF PE Units 1/2 Episodic Vent Header). Per 40 CFR 63.670(o)(2)(ii), the owner or operator must comply with the plan as submitted and the plan should be updated periodically to account for changes in the operation of the flare.

The Department proposes to modify the flare minimization plan condition in the plan approval as follows:

c. Procedures to minimize discharges either directly to the atmosphere or to the [**Flare]** during the planned and unplanned startup or shutdown of process unit and air pollution control equipment, **including an evaluation of flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including startup and shutdown, that considers the feasibility of performing these activities without flaring.**

The Department proposes to modify the preventative measures currently required in the root cause analysis condition as follows:

f. An analysis of the measures that are available to reduce the likelihood of a recurrence of a flaring event resulting from the same root cause or significant contributing causes in the future. **The evaluation of prevention measures must consider the adequacy of existing maintenance schedules and protocols for equipment contributing to the flaring event.**

Flare Gas Recovery (FGR)

In the original application for plan approval for SPM, issued under PA-04-00740A, FGR for use as fuel had been ruled out as technically infeasible because the recovered gases would have different combustion characteristics than the low carbon fuels that the furnaces and turbines will be designed to combust. Similarly, FGR for use as process feedstock has been ruled out as technically infeasible because recovered gases would be relatively impure compared to the on-site manufactured ethylene and imported co-monomers used in the polyethylene manufacturing process. Analysis of FGR was not included in the application for PA-04-00740D or in the revised BACT/LAER/BAT submitted on April 11, 2025.

Per 40 CFR 63.670(o)(1)(ii) which is required under 40 CFR Part 63 Subpart YY, the flare management plan must include:

> An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized or prevented during periods of startup,

> shutdown, or emergency releases. The flare minimization assessment must (at a minimum) consider the items in paragraphs (o)(1)(ii)(A) through (C) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.
>
> (A) Modification in startup and shutdown procedures to reduce the quantity of process gas discharge to the flare.
> (B) Implementation of prevention measures listed for pressure relief devices in § 63.648(j)(3)(ii)(A) through (E) for each pressure relief device that can discharge to the flare.
> (C) **Installation of a flare gas recovery system** or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit. [emphasis added]

Shell is required by the FMP requirements of PA-04-00740A/C to determine the baseline flow to the HP and LP Systems in accordance with the provisions of 40 CFR §60.103a(a)(4) of NSPS Subpart Ja. Per 40 CFR §60.103a(a)(4), the baseline flow to the flare must be determined after implementing the minimization assessment in paragraph (a)(2) of this section. Per 40 CFR 60.103a(a)(2), the flare management plan must include:

> An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. The flare minimization assessment must (at a minimum) consider the items in paragraphs (a)(2)(i) through (iv) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.
>
> (i) Elimination of process gas discharge to the flare through process operating changes or gas recovery at the source.
> (ii) Reduction of the volume of process gas to the flare through process operating changes.
> (iii) **Installation of a flare gas recovery system** or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit. [emphasis added]
> (iv) Minimization of sweep gas flow rates and, for flares with water seals, purge gas flow rates.

On October 15, 2025, the applicant provided the following information via email:

> SPM's FMMP is being updated in 2025 to account for changes included in the plan approval application. This includes designation of the TEGFs as multi-stage pressure-assisted flares consistent with EMACT, addition of new calorimeters and gas chromatographs, addition of

steam controls pressure and temperature transmitters, updated flaring event baselines, and updated historical flaring event preventative measures or reductions. This will also include the recently separately submitted flare gas recovery (FGR) analysis and updates to address flare minimization as part of SPM's design and which satisfies a flare minimization assessment as described in 40 CFR 63.103a(a)(2).

(i) Process gas discharges to the flare systems have been eliminated from SPM's ECU and PE Units in design by the respective manufacturers or technology licensors Linde, Univation, or Ineos. Design is consistent with achieving the most efficient ethylene and polyethylene production process at the time of facility design prior to construction. Design considerations included both the operating process and gas recovery consistent with good engineering practices.

(ii) Process gas discharge volumes to the flare systems have been provided as part of the initial design by the respective manufacturers or technology licensors Linde, Univation, or Ineos. Process gas volumes are inherent to the design of the facility. Startup and shutdown procedures are executed at minimum ECU rates which also minimize volumes of vent gas flow rates.

(iii) Process gas is already recovered and reused within ECU and PE as part of the inherent design of SPM as a new facility by the manufacturers and technology licensors. Examples include both ECU's off-spec ethylene sphere and the ethylene tank boil off gas compressor system. An updated FGR analysis for any remaining vent streams has been completed and is being incorporated into the updated FMMP.

(iv) Sweep gas flow rates were reevaluated prior to submittal of PA-04-00740C application to be set at the minimum values. Minimum values are those necessary to prevent air infiltration and maintain design and engineering practice velocities in each flare lateral or header. Either nitrogen or natural gas can be used, and SPM uses natural gas to offset baseline vent gas nitrogen and maintain NHVcz minimums for each flare. Additionally, further sweep gas reductions would have limited material impact as supplemental gas is required for all flare header baseline flows to maintain NHVcz minimums due to the presence of nitrogen. Purge gas downstream of the HPEF liquid seal drum is nitrogen and maintained at a constant flow rate necessary to prevent air ingress into the HPEF between the seal drum and the tip. Nitrogen is used as an inert gas and there is no normal flaring or combustion at the HPEF other than the constant natural gas pilots.

At the request of the Department, Shell provided a re-evaluation of FGR on September 23, 2025. Additional supporting information was requested by the Department on November 3, 2025, and provided by Shell on December 8, 2025.

Shell's response dated December 8, 2025, discusses the challenges of implementing FGR systems at SPM and Shell's position that it is technically infeasible. The Department's review of the RBLC and other resources has not identified the requirement for FGR at ethylene and/or polyethylene plants as a result of a control technology analysis. As Shell explains in their response, there are practical differences at SPM compared to other plants producing ethylene and/or polyethylene due to the design and location of the plant, the combustion sources available, and the characteristics of the waste gas that impact the feasibility of FGR at SPM. The Department is not aware of any information to dispute the position that FGR is not now technically feasible at SPM.

The flare minimization and management plan required by 40 CFR 63.670(o) and the plan approval is designed for the owner or operator to continue to evaluate minimization strategies and is required to be updated periodically per 40 CFR 63.670(o)(2)(ii) and the plan approval.

CVTO

LAER for control of NOx, VOC, and $PM_{2.5}$; BACT for control of CO, NOx, PM_{10}, and GHGs; and BAT for control of SOx and HAP has been determined to be low NOx burners, good combustion practices, and proper operation and maintenance. Note that BAT applies to all pollutants. BAT for SOx and HAP is identified here since the more stringent control technology requirements of LAER and BACT don’t apply to these pollutants. The following emission limits have been determined to comply with LAER and BACT for the CVTO:

- NOx – 0.06 lb/MMBtu (decreased from 0.068 lb/MMBtu)
- CO – 0.0824 lb/MMBtu
- PM_{10} – 0.0075 lb/MMBtu
- $PM_{2.5}$ – 0.0075 lb/MMBtu
- VOC – 99.9% destruction efficiency

Shell has proposed a NOx LAER limit of 0.06 lb/MMBtu (3-hour average) for the CVTO, which is more stringent than the NOx LAER limit that is currently applicable to the thermal oxidizer. The proposed emission limits are also found to be equivalent to or more stringent than NOx limits found in EPA’s RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements. The performance test of the CVTO conducted on May 21, 2024, demonstrated compliance with the proposed NOx LAER limit of 0.06 lb/MMBtu (3-hour average) by the CVTO as the unit is currently designed.

Shell has proposed to reference the CVTO’s combustion pollutant emission limitations on a lb/hr basis rather than a lb/MMBtu basis to avoid firing rate intensity biases that are associated with a lb/MMBtu limitation. Specifically, operations at low firing rates may result in lb/MMBtu ratios that are biased high because of the lower firing rate divisor value even though lb/hr emission rates are well below authorized amounts. The proposed changes to the condition are based on the LAER/BACT/BAT lb/MMBtu limits established in PA-04-00740A multiplied by the short-term maximum capacity of the CVTO.

The CVTO is required to meet the LAER/BACT/BAT requirements, including the representative emission limits established which are on a lb/MMBtu basis. LAER, BACT, and BAT were reevaluated in this plan approval application and the corresponding emission limits proposed by Shell are on a lb/MMBtu basis, consistent with PA-04-00740A and review of the RBLC database. Taking the proposed short-term limits on a lb/MMBtu basis and converting them to a mass-based limit would represent a change in LAER/BACT/BAT which has not been sufficiently justified in this submittal. Furthermore, a properly designed and operated thermal oxidizer should be capable of meeting the manufacture guaranteed emissions rate or BACT/LAER limit on a lb/MMBtu basis across the entire operating range, not just at certain firing rates. As such, the CVTO emission limits will remain on a lb/MMBtu basis and reflect the newly proposed LAER limit of 0.06 lb/MMBtu NOx.

Polyethylene Pellet Material Storage/Handling/Loadout

The Polyethylene Pellet Material Storage/Handling/Loadout emission source represents polyethylene pellet blending, transport, storage, and loadout operations at SPM that vent to the atmosphere, typically after passing through a PM filtration device. VOC is emitted from these operations due to the diffusion of VOC from the polyethylene pellets to the atmosphere during the handling and storing of the pellets. However, the residual VOC content of the polyethylene pellets handled and stored in the referenced operations is low, which results in relatively low VOC emissions to the atmosphere from the operations.

SPM has two gas phase polyethylene manufacturing units (PE Units 1 and 2) and one liquid phase slurry polyethylene manufacturing unit (PE Unit 3). For PE Units 1 and 2, the Polyethylene Pellet Material Storage/Handling/Loadout emission source covers the equipment and activities after the product purge bin through the loading of polyethylene pellets into trucks and railcars. For PE Unit 3, the Polyethylene Pellet Material Storage/Handling/Loadout emission source covers the equipment and activities after the degasser through the loading of polyethylene pellets into trucks and railcars.

The Polyethylene Pellet Material Storage/Handling/Loadout emission source is currently subject to the following VOC LAER requirement:

- The polyethylene residual VOC content shall not exceed 50 ppmw on a monthly average for each polyethylene manufacturing line.

  *As measured downstream of the product purge bin in the gas phase technology polyethylene manufacturing line and downstream of and including the degasser at the slurry polyethylene manufacturing line

Upon review of EPA's RBLC database, a VOC emission limit of 35.08 lb VOC emitted per MMlb of polyethylene produced has been identified that has been achieved in practice. LAER has been determined to be minimizing the residual amount of VOC contained in and emitted from polyethylene pellets that are handled by and stored in uncontrolled equipment and operations. Shell has proposed the following LAER limit based on the RLBC findings:

- The difference in the polyethylene residual VOC content between the following locations in PE Units 1 and 2 shall not exceed 35.08 ppmw on a monthly average: the polyethylene residual VOC content as measured downstream of the product purge bin in PE Units 1 and 2 and the polyethylene residual VOC content as measured for PE pellets being loaded out from final storage to trucks or railcars. If residual VOC is not measured for PE pellets being loaded out, then it shall be assumed to be zero for purposes of this compliance calculation.

- The difference in the polyethylene residual VOC content between the following locations in PE Unit 3 shall not exceed 35.08 ppmw on a monthly average: the polyethylene residual VOC content as measured downstream of the degasser in PE Unit 3 and the polyethylene residual VOC content as measured for PE pellets being loaded out from final storage to trucks or railcars. If residual VOC is not measured for PE pellets being loaded out, then it shall be assumed to be zero for purposes of this compliance calculation.

PTE and actual emissions from this source are currently calculated assuming 100% of the VOC contained in the pellets is emitted. Compliance is based on measuring the VOC content no less than once per calendar month downstream of the product purge bin in each gas phase technology polyethylene manufacturing line (PE Units 1 and 2) or downstream of the degasser in the slurry polyethylene manufacturing line (PE Unit 3).

Source ID 301, *Polyethylene Pellet Material Storage/Handling/Loadout*, is subject to 40 CFR Part 60 Subpart DDD, and Shell complies with this subpart by maintaining records of and reporting any changes in process operations that increase the VOC weight percent of the individual streams covered by Source ID 301.

Federal Air Quality Regulations

This section is limited to newly appliable standards or changes to the applicability due to the changes proposed in this plan approval.

40 CFR Part 60: New Source Performance Standards

40 CFR Part 60 Subpart A – General Provisions applies to this facility. Per 40 CFR §60.1(a), "Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility."

Subpart A – Source ID 207: MPGF CVTO Trip Header

The general control device and work practice requirements for flares in Subpart A no longer apply to the MPGF CVTO Trip Header. As provided in 40 CFR 63.1100(g)(7) in the EMACT (40 CFR Part 63 Subpart YY) and 40 CFR 63.2535(m)(1) in the MON (40 CFR Part 63 Subpart FFFF), the MPGF CVTO Trip Header is only required to comply with the revised flare control device requirements in the EMACT as of July 6, 2023, and the MON as of August 12, 2023.

The national emission standards for hazardous air pollutants (NESHAP) for the miscellaneous organic chemical (MON) manufacturing industry established emission limits and work practice standards for new and existing miscellaneous organic chemical manufacturing process units, wastewater treatment and conveyance systems, transfer operations, and associated ancillary equipment and implemented section 112(d) of the Clean Air Act (CAA) by requiring all subject major sources to meet HAP emission standards to reflect application of the maximum achievable control technology (MACT).

Subpart A – Source ID 208: MPGF Ethylene Tank Header

The General Provisions of 40 CFR 60 Subpart A apply to the MPGF Ethylene Tank Header. As referenced in NSPS Subpart Kb, the general control device and work practice requirements in the General Provisions are applicable to the MPGF Ethylene Tank Header as outlined in Table 8b of Shell's January 23, 2025, response to the Department.

Subpart A – Source ID 209: MPGF PE Units 1/2 Episodic Vent Header

The General control device and work practice requirements for flares in Subpart A no longer apply to the MPGF PE Units 1/2 Episodic Vent Header. As provided in 40 CFR 63.2535(m)(1) in the MON, the MPGF PE Units 1/2 Episodic Vent Header is only required to comply with the revised flare control device requirements in the MON (40 CFR Part 63 Subpart FFFF) as of August 12, 2023.

NSPS from 40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, and On or Before October 4, 2023, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984, and on or before October 4, 2023.

Subpart Kb – Source ID 208: MPGF Ethylene Tank Header

40 CFR Part 60 Subpart Kb applies to the existing MPGF Ethylene Tank Header. The MPGF Ethylene Tank Header controls vapors from the Refrigerated Ethylene Storage Tank which is an affected facility under NSPS Subpart Kb. NSPS Subpart Kb requires the tank to be equipped with a closed vent system and control device. Applicable requirements include 40 CFR 60.112b(b), 60.112b(b)(1), 60.112b(a)(3), 60.112b(a)(3)(i), and 60.112b(a)(3)(ii). See "Table 8b" of Shell's January 23, 2025, response to the Department and the applicability of Subpart Kb for Source ID 411: Refrigerated Ethylene Storage Tank.

Subpart Kb – Source ID 404: Storage Tanks (Hexene)

40 CFR Part 60 Subpart Kb applies to the existing Hexene Storage Tanks. Since the Hexene Storage Tanks do not qualify as storage tanks under 40 CFR Part 63, Subpart FFFF (MON), they cannot be assigned to the PE Units. Therefore, the MON/40 CFR 60 Subpart Kb overlap provisions are not applicable to the Hexene Storage Tanks; therefore, the Hexene Storage Tanks are subject to applicable provisions of 40 CFR 60 Subpart Kb. The 40 CFR 60 Subpart Kb requirements currently included for the Hexene Storage Tanks in the PA-04-00740C will be included in PA-04-00740D.

Subpart Kb – Source ID 411: Refrigerated Ethylene Storage Tank

40 CFR Part 60 Subpart Kb applies to the existing 7,925,160-gallon (30,000 m^3) capacity ethylene storage tank, which is proposed to be identified in the plan approval as Source ID 411: Refrigerated Ethylene Storage Tank. The Refrigerated Ethylene Storage Tank was previously included as part of Source ID 405: (Misc Pressurized/Refrigerated) and the applicable requirements of this subpart were not included in the previous plan approvals. The applicable 40 CFR Part 60 Subpart Kb requirements for the existing Refrigerated Ethylene Storage Tank will be included in the proposed plan approval because the storage tank is a fixed roof storage vessel affected facility under the subpart that vents to a closed vent system and control device (MPGF Ethylene Tank Header and MPGF) to comply with the subpart.

Below is a summary of the 40 CFR Part 60, Subpart Kb requirements that are applicable to the Refrigerated Ethylene Storage Tank.

- Equip with a closed vent system and control device. Design the closed vent system to collect all VOC vapors and gases discharged from the storage vessel and operate with no detectable emissions [40 CFR 60.112b(b)(1) and 60.112b(a)(3)(i)].

- VOC reduction: A closed vent system and control device designed and operated to reduce inlet VOC emissions by 95 percent or greater. Meet the requirements specified in the general control device requirements, 40 CFR 60.18(c) through (f) [40 CFR 60.112b(b)(1) and 60.112b(a)(3)(ii)].

- Closed vent system (no detectable emissions): Total VOC less than 500 ppm above background as indicated by instrument readings and visual inspections, as determined in 40 CFR 60 Subpart VV, 40 CFR 60.485(c) [40 CFR 60.112b(b)(1) and 60.112b(a)(3)(i)].

- Equipment/operational data recordkeeping by electronic or hard copy at the approved frequency. Keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. Keep copies of all records for the life of the source as specified by 40 CFR 60.116b(a) [40 CFR 60.116b(b)].

Subpart Kb – Source ID 505: Wastewater Treatment Plant (Primary Treatment)

40 CFR Part 60 Subpart Kb will not apply to the new Wastewater Treatment Vessels. The new Wastewater Treatment Vessels will not be subject to 40 CFR Part 60 Subpart Kb because they will be "process tanks[29]" rather than "storage vessels" under the subpart since they will be used to perform wastewater treatment unit operations or serve as a surge control vessel in the WWTP.

NSPS from 40 CFR Part 60 Subpart Kc – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 2023, does not apply. There are no storage vessels at SPM that have been constructed, reconstructed, or modified after October 4, 2023.

NSPS from 40 CFR Part 60 Subpart DDD – Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry applies to affected facilities involved in the manufacture of polypropylene, polyethylene, polystyrene, or poly (ethylene terephthalate) as defined in § 60.561 of this subpart.

Subpart DDD: Source ID 207: MPGF CVTO Trip Header

The MPGF CVTO Trip Header has no applicable requirements under 40 CFR Part 60 Subpart DDD (Polymers Manufacturing – NSPS Subpart DDD). The MPGF CVTO Trip Header controls equipment subject to both the MON and NSPS Subpart DDD. As provided in 40 CFR §63.2535(h) of the MON, miscellaneous chemical manufacturing process units (MCPU) which are subject to the provisions in NSPS Subpart DDD and the MON may elect to apply the MON to all such equipment in the MCPU. Additionally, if an MCPU subject to the

[29] *Process tank* means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

provisions of the MON has equipment to which the MON does not apply but which is subject to a standard in NSPS Subpart DDD, then the MCPU may elect to comply with the requirements for Group 1 process vents in the MON for such equipment. SPM has elected to comply with the MON for all equipment in the MCPU subject to both the MON and NSPS Subpart DDD. SPM has further chosen to comply with the Group 1 process vent provisions of the MON for all equipment in the MCPU which is not subject to the MON but is subject to NSPS Subpart DDD. This constitutes compliance with NSPS Subpart DDD.

Subpart DDD: Source ID 209: MPGF PE Units 1/2 Episodic Vent Header

The MPGF PE Units 1/2 Episodic Vent Header has no applicable requirements under NSPS Subpart DDD. The MPGF PE Units 1/2 Episodic Vent Header controls equipment subject to both the MON and NSPS Subpart DDD. As provided in 40 CFR §63.2535(h) of the MON, MCPU which are subject to the provisions in NSPS Subpart DDD and the MON may elect to apply the MON to all such equipment in the MCPU.

Additionally, if an MCPU subject to the provisions of the MON has equipment to which the MON does not apply but which is subject to a standard in NSPS DDD, then the MCPU may elect to comply with the requirements for Group 1 process vents in the MON for such equipment. SPM has elected to comply with the MON for all equipment in the MCPU subject to both the MON and NSPS Subpart DDD. SPM has further chosen to comply with the Group 1 process vent provisions of the MON for all equipment in the MCPU which is not subject to the MON but is subject to NSPS DDD. This constitutes compliance with NSPS Subpart DDD.

40 CFR Part 61: National Emission Standards for Hazardous Air Pollutants

40 CFR Part 61 Subpart A – General Provisions. The general provisions in 40 CFR Part 61 Subpart A are applicable to stationary sources with facilities subject to any standard promulgated under 40 CFR Part 61. In general, 40 CFR Part 61 Subpart A provisions specify performance testing, performance evaluation (monitoring systems), notification, recordkeeping, reporting, and control device requirements for affected facilities. SPM is required to comply with these NESHAP general provisions as they apply to the facility's emission sources that are subject to 40 CFR Part 61 standards.

40 CFR Part 61 Subpart FF – National Emission Standard for Benzene Waste Operations or the BWON (Benzene Waste Operations NESHAP) rule, applies to the proposed wastewater treatment vessels at SPM. Per 40 CFR § 61.340, the provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke byproduct recovery plants, and petroleum refineries, as well as owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by such facilities.

A key concept of the BWON rule is a facility's total annual benzene (TAB) quantity, which is calculated for specific waste streams at a facility to determine the BWON rule requirements that are applicable to the facility. A facility's TAB quantity is calculated by summing together the annual benzene quantity for each waste stream at the facility, except for wastes generated by remediation activities conducted at the facility, that has a flow-weighted annual average water content greater than 10% or that is mixed with water, or other wastes, at any time and the resulting mixture has an annual average water content greater than 10%.

SPM is a "chemical manufacturing plant" that has a TAB quantity greater than 10 Megagrams per year (Mg/yr), and the new Wastewater Treatment Vessels will be subject to the BWON rule because they will manage or treat benzene-containing waste streams. However, Shell proposes to use the overlap provisions in 40 CFR Part 63 Subpart YY at 40 CFR 63.1100(g)(6)(ii) that states compliance with 40 CFR 63.1103(e) of 40 CFR Part 63 Subpart YY constitutes compliance with the BWON rule for waste streams that are subject to both the requirements of the BWON rule and 40 CFR Part 63 Subpart YY.

40 CFR Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories

40 CFR Part 63, Subpart A – General Provisions. The general provisions in 40 CFR Part 63 Subpart A are applicable to stationary sources with facilities subject to any standard promulgated under 40 CFR Part 63. SPM is required to comply with these NESHAP general provisions as they apply to the facility's emission sources that are subject to 40 CFR Part 63 standards.

<u>Subpart A – Source ID 207: MPGF CVTO Trip Header</u>

As noted above, the general control device and work practice requirements for flares in Subpart A of 40 CFR Part 60 <u>no longer apply</u> to the MPGF CVTO Trip Header. For the same reasons, the general control device and work practice requirements for flares in Subpart A of 40 CFR Part 63 <u>no longer apply</u> to the MPGF CVTO Trip Header.

<u>Subpart A – Source ID 209: MPGF PE Units 1/2 Episodic Vent Header</u>

As noted above, the general control device and work practice requirements for flares in Subpart A of 40 CFR Part 60 <u>no longer apply</u> to the MPGF PE Units 1/2 Episodic Vent Header. For the same reasons, the general control device and work practice requirements for flares in Subpart A of 40 CFR Part 63 <u>no longer apply</u> to the MPGF PE Units 1/2 Episodic Vent Header.

40 CFR Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (Refinery MACT) applies to petroleum refining process units and to related emissions points that are specified in paragraphs (c)(1) through (9) of this section that are located at a plant site and that meet the criteria in paragraphs (a)(1) and (2) of this section [40 CFR §63.640]. The Refinery MACT is not directly applicable as SPM is not a petroleum refinery. However, the Refinery MACT applies by reference to the MPGF, TEGF A, TEGF B, and HP Elevated Flare and includes monitoring, recordkeeping, work practice, and reporting requirements that are applicable to these flares. A flare is generally recognized as achieving and demonstrating good combustion practice operations when following the design, operating, and monitoring requirements specified in 40 CFR Part 63 Subpart CC. Subpart CC is specifically referenced and required to be met by 40 CFR Part 63 Subparts YY and FFFF, with minor revisions.

<u>Subpart CC – Source IDs C205A and 205B: TEGF A and B</u>

The Refinery MACT (Subpart CC) <u>applies by reference</u> to the TEGF A and TEGF B. The TEGF A and B are subject to 40 CFR Part 63 Subpart YY, and the Refinery MACT flare control device and flare monitoring system requirements are incorporated by reference into Subpart YY. The requirements for TEGF A and TEGF B are outlined in Attachment 1 "Table 7" of Shell's January 23, 2025, deficiency letter response. Requirements include:

- Visible emissions limitations per 40 CFR 63.670(c);

- Combustion zone operating limits (NHVcz at or above 800 Btu/scf) per 40 CFR 63.670(e)(2);
- Visible emission monitoring by observation and video surveillance per 40 CFR 63.670(h);
- Flare vent gas pressure, temperature, flow rate, and mass flow monitoring per 40 CFR 63.670(i);
- Vent gas composition and net heating value monitoring per 40 CFR 63.670(j);
- Calculation methods for determining combustion zone net heating value per 40 CFR 63.670(l) and (m);
- Flare management plan, root cause analysis, and corrective actions per 40 CFR 63.670(o); and
- Continuous parameter monitoring system (CPMS) per 40 CFR 63.671(a) – (d).

Subpart CC – Source ID 205C: HP Elevated Flare

The Refinery MACT (Subpart CC) applies by reference to the HP Elevated Flare. The HP Elevated Flare is subject to the 40 CFR Part 63 Subpart YY, and the Refinery MACT flare control device and flare monitoring system requirements are incorporated by reference into Subpart YY. Requirements include:

- Pilot flame presence per 40 CFR 63.670(b);
- Visible emissions limitations per 40 CFR 63.670(c);
- Flare tip velocity less than 60 feet per second per 40 CFR 63.670(d);
- Combustion zone operating limits (NHVcz at or above 270 Btu/scf) per 40 CFR 63.670(e)(1);
- Pilot flame monitoring per 40 CFR 63.670(g);
- Visible emission monitoring by observation and video surveillance per 40 CFR 63.670(h);
- Flare vent gas pressure, temperature, flow rate, mass flow, and steam assist monitoring per 40 CFR 63.670(i);
- Vent gas composition and net heating value monitoring per 40 CFR 63.670(j);
- Calculation methods for cumulative flow rates and determining compliance with Vtip operating limits per 40 CFR 63.670(k);
- Calculation methods for determining combustion zone net heating value per 40 CFR 63.670(l), (m), and (n);
- Flare management plan, root cause analysis, and corrective actions per 40 CFR 63.670(o); and
- CPMS per 40 CFR 63.671(a) – (d).

Subpart CC – Source ID 207: MPGF CVTO Trip Header

The Refinery MACT (Subpart CC) applies by reference to the MPGF CVTO Trip Header. The Refinery MACT flare control device and flare monitoring system requirements are incorporated by reference into the EMACT (Subpart YY) and MON (Subpart FFFF). The requirements are outlined in Attachment 2 “Table 8a” of Shell’s January 23, 2025, deficiency letter response. Requirements include:

- Pilot flame presence per 40 CFR 63.670(b);
- Visible emissions limitations per 40 CFR 63.670(c);
- Flare tip velocity of less than 60 feet per second per 40 CFR 63.670(d);
- Combustion zone operating limits (NHVcz at or above 270 Btu/scf) per 40 CFR 63.670(e)(1);
- Dilution operating limits for flares with perimeter assist air per 40 CFR 63.670(f);
- Pilot flame monitoring per 40 CFR 63.670(g);
- Visible emission monitoring by observation and video surveillance per 40 CFR 63.670(h);

- Flare vent gas pressure, temperature, flow rate, mass flow, and fan speed or power monitoring per 40 CFR 63.670(i);
- Vent gas composition and net heating value monitoring per 40 CFR 63.670(j);
- Calculation methods for cumulative flow rates and determining compliance with Vtip operating limits per 40 CFR 63.670(k);
- Calculation methods for determining combustion zone net heating value per 40 CFR 63.670(l), (m), and (n);
- Flare management plan, root cause analysis, and corrective actions per 40 CFR 63.670(o); and
- CPMS per 40 CFR 63.671(a) – (d).

Source ID 207 will be included in G05: NESHAP Part 63 Subpart YY. Per Section E, Group G05, Condition # 021, "The Owner/Operator shall comply with the applicable flare requirements of 40 CFR Part 63 Subpart CC as specified in 40 CFR §63.1103(e)(4)."

Source ID 207 will also be included in G09: NESHAP Part 63 Subpart FFFF. This plan approval will include the following condition for G09: NESHAP Part 63 Subpart FFFF: The Owner/Operator shall comply with the applicable flare requirements of 40 CFR Part 63 Subpart CC as specified in 40 CFR §63.2450(e).

Subpart CC – Source ID 209: MPGF PE Units 1/2 Episodic Vent Header

The Refinery MACT (Subpart CC) applies by reference to the MPGF PE Units 1/2 Episodic Vent Header. The Refinery MACT flare control device and flare monitoring system requirements are incorporated by reference into the MON (Subpart FFFF). The requirements are outlined in Attachment 4 "Table 8c" of Shell's January 23, 2025, deficiency letter response, with applicability designations and additional compliance remarks. The applicable requirements are the same as for the MPGF CVTO Trip Header above.

Source ID 209 will be included in G09: NESHAP Part 63 Subpart FFFF. This plan approval will include the following condition for G09: NESHAP Part 63 Subpart FFFF: The Owner/Operator shall comply with the applicable flare requirements of 40 CFR Part 63 Subpart CC as specified in 40 CFR §63.2450(e).

40 CFR Part 63 Subpart SS – National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process includes requirements for closed vent systems, control devices and routing of air emissions to a fuel gas system or process. These provisions apply when another subpart references the use of this subpart for such air emission control. These air emission standards are placed here for administrative convenience and only apply to those owners and operators of facilities subject to a referencing subpart.

Subpart SS – Source ID 207: MPGF CVTO Trip Header

40 CFR Part 63 Subpart SS no longer applies to the MPGF CVTO Trip Header. The MPGF CVTO Trip header is only required to comply with the revised flare control device requirements in the EMACT as of July 6, 2023, and the MON as of August 12, 2023.

Subpart SS – Source ID 209: MPGF PE Units 1/2 Episodic Vent Header

40 CFR Part 63 Subpart SS no longer applies to the MPGF Units 1/2 Episodic Vent Header. The MPGF PE Units 1/2 Episodic Vent Header is only required to comply with the revised flare control device requirements in the MON as of August 12, 2023.

Note that 40 CFR 63 Subpart SS closed vent system requirements under 40 CFR 63.983 still apply to the closed vent systems leading to the flare control devices. The closed vent system is effectively included with either Source ID 201 for EMACT vent streams or Source ID 202 for MON vent streams. The applicable 40 CFR 63.983 closed vent system requirements citation is included under Group G08: NESHAP Part 63 Subpart SS.

40 CFR Part 63 Subpart XX – National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations applies to the heat exchange systems and wastewater treatment vessels at this facility. This subpart applies to each heat exchange system and *waste stream*[30] that is part of an ethylene production affected source subject to 40 CFR Part 63 Subpart YY. SPM includes an ethylene production affected source subject to 40 CFR Part 63 Subpart YY. Therefore, all the heat exchange systems and waste streams that are associated with SPM's ethylene production unit are subject to 40 CFR Part 63 Subpart XX.

As noted under 40 CFR Part 61 Subpart FF, SPM has a TAB quantity greater than 10 Mg/yr. Therefore, in accordance with 40 CFR 63.1095(b)(2) in 40 CFR Part 63 Subpart XX, SPM must manage and treat benzene-containing waste streams generated by an ethylene production unit onsite pursuant to any of the options in 40 CFR 61.342(c)(1) through (e) in the BWON rule to comply with 40 CFR Part 63 Subpart XX. SPM uses the 6 BQ option outlined in 40 CFR 61.342(e) to comply with the BWON rule and 40 CFR Part 63 Subpart XX.

Per 40 CFR §61.342(e) of the BWON, "As an alternative to the requirements specified in paragraph (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and
(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:

    (i) The benzene quantity for the wastes described in paragraph (e)(2) of this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in § 61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in § 61.355(k). The provisions of

[30] *Waste stream* means the waste generated by a particular process unit, product tank, or waste management unit. The characteristics of the waste stream (e.g., flow rate, HAP concentration, water content) are determined at the point of waste generation. Examples of a waste stream include process wastewater, product tank drawdown, sludge and slop oil removed from waste management units, and landfill leachate. (40 CFR Part 63, Subpart YY).

paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.

(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with § 61.355(k)."

The new Wastewater Treatment Vessels will be subject to 40 CFR Part 63 Subpart XX because they will manage or treat benzene-containing waste streams generated by an ethylene production unit at SPM. As such, the new Wastewater Treatment Vessels will comply with 40 CFR Part 63 Subpart XX by complying with BWON rule emission control requirements to ensure SPM maintains compliance with the BWON rule's 6 BQ compliance option. Specifically, SPM will use a closed vent system to collect and route the new Wastewater Treatment Vessels' vent streams to an enclosed combustion device (the SCTO) that will reduce the organic content of the vent streams by 95 wt. % or greater in compliance with 40 CFR 61.349(a)(2)(i)(A).

Subpart XX – Source ID 203: Process Cooling Tower

40 CFR 63 Subpart XX applies to the Process Cooling Tower. Although the applicability has not changed as a result of the proposed changes in this plan approval, the method of compliance with the monitoring requirements is summarized here since the PTE has been revised by reducing the organic HAP fraction of any VOC leakage into the cooling tower's recirculating water. According to the applicant, the primary process streams do not contain HAP. The resulting PTE is reduced by close to 3 tpy of HAPs.

Per 40 CFR 63.1103(e) – Table 7 of 63 Subpart YY, Shell is required to comply with the requirements of 40 CFR 63 Subpart XX for controlling emissions of HAP from heat exchange systems. HAP emissions are minimized by the following monitoring, leak repair, recordkeeping, and monitoring requirements:

- Perform monitoring to identify leaks of total strippable hydrocarbons from each heat exchange system according to the procedures in 40 CFR 63.1086(e)(1) through (5). [40 CFR 63.1086(e)].
- Repair leaks to reduce the concentration or mass emissions rate to below the applicable leak action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in 40 CFR 63.1088(d). Repair must include re-monitoring at the monitoring location where the leak was identified according to the method specified in 40 CFR 63.1086(e)(3) to verify that the total strippable hydrocarbon concentration or total hydrocarbon mass emissions rate is below the applicable leak action level. Repair may also include performing the additional monitoring in 40 CFR 63.1087(d) to verify that the total strippable hydrocarbon concentration is below the applicable leak action level. Actions that can be taken to achieve repair include but are not limited to: (1) Physical modifications to the leaking heat exchanger, such as welding the leak or replacing a tube; (2) Blocking the leaking tube within the heat exchanger; (3) Changing the pressure so that water flows into the process fluid; (4) Replacing the heat exchanger or heat exchanger bundle; or (5) Isolating, bypassing, or otherwise removing the leaking heat exchanger from service until it is otherwise repaired. [40 CFR 63.1087(c)].
- If a leak is detected when monitoring a cooling tower return line according to 40 CFR 63.1086(e)(1)(i), permittee may conduct additional monitoring of each heat exchanger or group of heat exchangers associated with the heat exchange system for which the leak was detected, as provided in 40 CFR 63.1086(e)(1)(ii). If no leaks are detected when monitoring according to the requirements of 40 CFR 63.1086(e)(1)(ii), the heat exchange system is considered to have met

the repair requirements through re-monitoring of the heat exchange system, as provided in 40 CFR 63.1087(c). [40 CFR 63.1087(d)].

- Equipment/operational data recordkeeping by electronic or hard copy at the specified frequency. Keep records of the information specified in 40 CFR 63.1089(a) through (d), according to the requirements of 40 CFR 63.1109(c). [40 CFR 63.1089].
- Report any delay of repair in the semiannual report required by 40 CFR 63.1110(e). If the leak remains unrepaired, continue to report the delay of repair in semiannual reports until the leak is repaired. Include the information in 40 CFR 63.1090(f) in the semiannual report. [40 CFR 63.1090].

40 CFR Part 63 Subpart YY – National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards applies to Source IDs 031-037, 201, 203, 204, 205, 206, 207, 302, 303, 304, 305, 402, 403, 501, 502, and 505. The requirements are included in PA-04-00740C, Section E, Group G05: NESHAP Part 63 Subpart YY.

This subpart includes requirements that apply to certain "ethylene production unit" equipment located at a major source of HAPs. Specifically, the 40 CFR Part 63 Subpart YY ethylene production affected source comprises all the emission points listed below that are associated with an ethylene production unit that is located at a major source of HAP emissions:

- All storage vessels (as defined in 40 CFR 63.1101) that store liquids containing organic HAP.
- All ethylene process vents [as defined in 40 CFR 63.1103(e)(2)] from continuous unit operations.
- All transfer racks [as defined in 40 CFR 63.1103(e)(2)] that load HAP-containing material.
- Equipment (as defined in 40 CFR 63.1101) that contains or contacts organic HAP.
- All waste streams [as defined in 40 CFR 63.1103(e)(2)].
- All heat exchange systems [as defined in 40 CFR 63.1082(b)].
- All ethylene cracking furnaces and associated decoking operations.

Heat exchange systems and waste streams that are associated with an ethylene production unit subject to 40 CFR Part 63 Subpart YY must comply with applicable 40 CFR Part 63 Subpart XX requirements.

SPM includes an ethylene production affected source subject to 40 CFR Part 63 Subpart YY. Therefore, SPM must comply with applicable 40 CFR Part 63 Subpart YY storage vessel, ethylene process vent, transfer rack, equipment leak, and ethylene cracking furnace and associated decoking operations requirements. Additionally, as previously discussed, SPM must comply with applicable 40 CFR Part 63 Subpart XX heat exchange system and waste stream requirements because that subpart contains the standards for heat exchange systems and waste streams that are part of an ethylene production affected source subject to 40 CFR Part 63 Subpart YY. The new Wastewater Treatment Vessels will comply with 40 CFR Part 63 Subpart XX by complying with BWON rule emission control requirements to ensure SPM maintains compliance with the BWON rule's 6 BQ compliance option.

Subpart YY – Source IDs 031 – 037: Ethane Cracking Furnaces

40 CFR Part 63 Subpart YY (EMACT) applies to the Ethane Cracking Furnaces. Applicable requirements include decoking operation standards for ethylene cracking furnaces specified in 40 CFR 63.1103(e)(7) and ethylene cracking furnace isolation valve inspections specified in 40 CFR 63.1103(e)(8).

- During normal operations, conduct daily inspections of the firebox burners and repair all burners that are impinging on the radiant tube(s) as soon as practical, but not later than 1 calendar day after the flame impingement is found. The owner or operator may delay burner repair beyond 1 calendar day provided the repair cannot be completed during normal operations, the burner cannot be shutdown without significantly impacting the furnace heat distribution and firing rate, and action is taken to reduce flame impingement as much as possible during continued operation [40 CFR 63.1103(e)(7)(i)].
- During decoking operations, continuously monitor the temperature at the radiant tube(s) outlet when air is being introduced to ensure the coke combustion occurring inside the radiant tube(s) is not so aggressive (*i.e.,* too hot) that it damages either the radiant tube(s) or ethylene cracking furnace isolation valve(s). The owner or operator must immediately initiate procedures to reduce the temperature at the radiant tube(s) outlet once the temperature reaches a level that indicates combustion of coke inside the radiant tube(s) is too aggressive [40 CFR 63.1103(e)(7)(iii)].
- After decoking, but before returning the ethylene cracking furnace back to normal operations, verify that decoke air is no longer being added [40 CFR 63.1103(e)(7)(iv)].
- Prior to decoking operation, inspect the applicable ethylene cracking furnace isolation valve(s) to confirm that the radiant tube(s) being decoked is completely isolated from the ethylene production process so that no emissions generated from decoking operations are sent to the ethylene production process. If poor isolation is identified, then the owner or operator must rectify the isolation issue [40 CFR 63.1103(e)(8)(i)].
- Prior to returning the ethylene cracking furnace to normal operations after a decoking operation, inspect the applicable ethylene cracking furnace isolation valve(s) to confirm that the radiant tube(s) that was decoked is completely isolated from the decoking pot or furnace firebox such that no emissions are sent from the radiant tube(s) to the decoking pot or furnace firebox once the ethylene cracking furnace returns to normal operation. If poor isolation is identified, then the owner or operator must rectify the isolation issue [40 CFR 63.1103(e)(8)(ii)].

Subpart YY – Source IDs 205A and 205B: TEGF A and TEGF B

40 CFR Part 63 Subpart YY (EMACT) applies to TEGF A and TEGF B. The ethylene production category regulatory requirements in 40 CFR Part 63 Subpart YY were revised and made final on July 20, 2020. The revised rule included new requirements for flares, storage tanks, and process vents. These requirements had a final effective date of July 6, 2023.

The EMACT Project is being performed at SPM to comply with newly effective 40 CFR Part 63 Subpart YY control device requirements that are applicable to the TEGF A and TEGF B. The TEGFs control ethylene process vents from an ethylene production unit and are regulated under EMACT in 40 CFR 63.1103(e)(4). The TEGFs were re-classified to “pressure-assisted multi-point” flares in January 2024 from the original determination and permitting of the TEGFs as non-assisted flares. Regulatory changes with the re-classification include the higher NHV_{CZ} requirement of 800 Btu/scf and having at least two pilots and thermocouples on each stage of the flares. To meet these requirements, process control logic changes were made to allow an increased amount of tail gas to be routed to the TEGFs as supplemental gas to increase the heat content to meet the new NHV_{CZ} limit. Additionally, pilots and thermocouples were added to 6 of the 11 stages of each flare to meet the dual pilot and pilot flame detection monitoring requirements.

Per 40 CFR §63.1100(g)(7)(i), "Overlap of this subpart YY with other regulations for flares for the ethylene production source category – Beginning no later than the compliance dates specified in § 63.1102(c), flares that are subject to 40 CFR 60.18 or § 63.11 and used as a control device for an emission point subject to the requirements in Table 7 to § 63.1103(e) are required to comply only with § 63.1103(e)(4)." Per 40 CFR §63.1103(e)(4), "Beginning no later than the compliance dates specified in § 63.1102(c), if a steam-assisted, air-assisted, non-assisted, or pressure-assisted multi-point flare is used as a control device for an emission point subject to the requirements in Table 7 to this section, then the owner or operator must meet the applicable requirements for flares as specified in §§ 63.670 and 63.671 of subpart CC…" Per 40 CFR §63.670(e), "The owner or operator shall operate the flare to maintain the net heating value of flare combustion zone gas (NHV_{cz}) at or above the applicable limits in paragraphs (e)(1) and (2) of this section determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15-minutes."

Attachment 1 of Shell's January 23, 2025, deficiency letter response, includes "Table 7" detailing the applicability and requirements of the EMACT, along with the flare requirements of from the Refinery MACT, Subpart CC. Requirements of Subpart CC include enhanced monitoring requirements to ensure the flares are operated in a manner to achieve a destruction efficiency of 98%. Other requirements include a flare management plan to minimize flaring and root cause analysis and corrective actions per 40 CFR 63.670(o), paragraphs (o)(1) through (7).

Source ID 205 is included in G05: NESHAP Part 63 Subpart YY. Per Section E, Group G05, Condition # 021, "The Owner/Operator shall comply with the applicable flare requirements of 40 CFR Part 63 Subpart CC as specified in 40 CFR §63.1103(e)(4)."

As previously discussed, the compliance date for the EMACT requirements was July 6, 2023. Compliance with the NHV_{CZ} requirement for both TEGFs was achieved on February 6, 2024, with implementation of the process control logic changes. Compliance with the minimum two available pilots per stage and pilot flame detection monitoring requirements was achieved following completion of the TEGF repairs on June 19, 2024, for TEGF A and June 28, 2024, for TEGF B.

Subpart YY – Source ID 207: MPGF CVTO Trip Header

40 CFR Part 63 Subpart YY (EMACT) applies to the MPGF CVTO Trip Header. The MPGF CVTO Trip Header (during CVTO downtime) controls vents from storage vessels and transfer racks subject to the control standards of the EMACT. The EMACT flare control device requirements incorporate by reference the flare control device and flare monitoring system requirements in 40 CFR Part 63 Subpart CC. See Attachment 2 "Table 8a" of Shell's January 23, 2025, deficiency letter response, for a summary of the requirements of 40 CFR 63 Subparts YY, FFFF, and CC (by reference).

Note that the MPGF is not a pressure-assisted flare like the TEGF A and TEGF B. Per 40 CFR §63.670(e)(1) of Subpart CC, for all flares other than pressure-assisted flares, the owner or operator shall operate the flare to maintain the NHV_{CZ} at or above 270 Btu/scf.

PA-04-00740D will also include the minimum NHV_{cz} originally established for the MPGF of 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes. The 270 Btu/scf limit is on a 15-minute basis compared to the 500 Btu/scf limit. Shell is required to demonstrate compliance with both limits, which are not directly comparable due to the averaging period difference.

Subpart YY – Source ID 208: MPGF Ethylene Tank Header

40 CFR Part 63 Subpart YY (EMACT) does not apply to the MPGF Ethylene Tank Header. The MPGF Ethylene Tank Header controls vapors from the Refrigerated Ethylene Storage Tank which does not contain any organic HAP and is thus not an emission point requiring control as defined under the EMACT [40 CFR §63.1103(e)(1)(i)(A)].

Subpart YY – Source ID 209: MPGF PE Units 1/2 Episodic Vent Header

40 CFR Part 63 Subpart YY (EMACT) does not apply to the MPGF PE Units 1/2 Episodic Vent Header. The MPGF PE Units 1/2 Episodic Vent Header does not control any regulated sources under the EMACT and is not applicable to the control device standards in the EMACT.

40 CFR Part 63, Subpart FFFF – National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing establishes national emission standards for hazardous air pollutants for miscellaneous organic chemical (MON) manufacturing. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits, operating limits, and work practice standards.

Subpart FFFF – Source ID 207: MPGF CVTO Trip Header

40 CFR Part 63 Subpart FFFF (MON) applies to the MPGF CVTO Trip Header. The MPGF CVTO Trip Header (during CVTO downtime) controls process vents subject to the control standards of the MON. The MON flare control device requirements incorporate by reference the flare control device and flare monitoring system requirements in 40 CFR Part 63 Subpart CC. See Attachment 2"Table 8a" of Shell's January 23, 2025, deficiency letter response, with applicability designations and comments.

Subpart FFFF – Source ID 208: MPGF Ethylene Tank Header

40 CFR Part 63 Subpart FFFF (MON) does not apply to the MPGF Ethylene Tank Header. The MPGF Ethylene Tank Header controls vapors from the Refrigerated Ethylene Storage Tank, which is associated with the ethylene production unit that is an affected source under EMACT and, therefore, cannot be an affected source under the MON [40 CFR §63.2435(b)(3)].

Subpart FFFF – Source ID 209: MPGF PE Units 1/2 Episodic Vent Header

40 CFR Part 63 Subpart FFFF (MON) applies to the MPGF PE Units 1/2 Episodic Vent Header. Under 40 CFR §63.2535(h) of the MON, SPM has elected to follow the overlap provisions and subject PE Units 1 and 2 to requirements of the MON. The MPGF PE Units 1/2 Episodic Vent Header controls process vents subject to the control standards of the MON. The MON flare control device requirements incorporate by reference the flare control device and flare monitoring system requirements in 40 CFR Part 63 Subpart CC as outlined in Attachment 4 "Table 8c" of Shell's January 23, 2025, deficiency letter response.

40 CFR Part 63 Subpart EEEE – National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) establishes national emission limitations, operating limits, and work practice standards for organic HAPs emitted from organic liquids distribution (OLD) (non-gasoline) operations at major sources of HAP emissions.

Subpart EEEE – Source ID 208: MPGF Ethylene Tank Header

The MPGF Ethylene Tank Header controls vapors from the Refrigerated Ethylene Storage Tank, which is associated with the ethylene production unit that is an affected source under EMACT and, therefore, cannot be an affected source under the OLD MACT [40 CFR §63.2338(c)(1)].

EMISSIONS AND CONTROLS

After completing a review of the facility 's as-built equipment and operations, Shell has revised the potential to emit calculations for the following air contamination sources and air cleaning devices:

- Source IDs 031 – 037: Ethane Cracking Furnace #1 through Ethane Cracking Furnace #7
- Source IDs 101 – 103: Combustion Turbine/Duct Burner Unit #1 through Combustion Turbine/Duct Burner Unit #3
- Source ID 104: Cogeneration Plant Cooling Tower
- Source ID 105: Diesel-Fired Emergency Generator Engines (2)
- Source ID 106: Fire Pump Engines (2)
- Source ID 107: Natural Gas-Fired Emergency Generator Engines (2)
- Source ID 202: Polyethylene Manufacturing Lines
- Source ID 203: Process Cooling Tower
- Source ID C204A: CVTO
- Source ID C207: MPGF CVTO Trip
- Source ID C208: MPGF Ethylene Tank
- Source ID C209: MPGF PE Units 1/2 Episodic Vent
- Source ID C205A: TEGF A
- Source ID C205B: TEGF B
- Source ID C205C: HP Elevated Flare
- Source ID C206: SCTO
- Source ID 301: Polyethylene Pellet Material Storage/Handling/Loadout
- Source ID 302: Liquid Loadout (Recovered Oil)
- Source ID 304: Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)
- Source ID 501: Equipment Components
- Source ID 502: Wastewater Treatment Plant (Secondary and Tertiary Treatment)
- Source ID 503: Plant Roadways
- Source ID 504: Gas Insulated Switchgear (SF6).

The following is a summary of the proposed changes to the previously used calculation methodologies followed by the PTE for each of the above listed sources. Detailed potential to emit calculations were included in

Appendix B of the plan approval application[31]. Revised PTE with source-by-source comparison to PA-04-00740A and PA-04-0-00740C was provided in the April 11, 2025, response, and a revised Appendix B was provided on June 3, 2025, detailing all changes to the originally submitted Appendix B.

On September 5, 2025, a revised Appendix B was included with Shell's revised modeling and risk assessment submittal. Notable changes included in the September 5, 2025, Appendix B are the use of 98% control for all organic compounds routed to the MPGF, TEGF A, TEGF B, and HP Elevated Flare compared to 99% control for organic compounds containing 3 or fewer carbon atoms and 98% control for other organic compounds in the earlier version and a revised HP Header System vent stream which directs a lower amount of VOC to the TEGF A, TEGF B, and HP Elevated Flare.

<u>Source IDs 031 through 037: Ethane Cracking Furnaces #1 through #7</u>

- In this plan approval application, each of the ethane cracking furnace's potential to emit calculations have been revised by Shell so that the molecular hydrogen contained in the tail gas combusted in the furnaces during the furnaces' long-term normal operation mode is no longer estimated to result in CO and VOC emissions from the furnace.

In response to the Department's December 24, 2024, technical deficiency letter, Shell provided the following additional information regarding this proposed change on January 23, 2025:

> The heat input associated with the combustion of molecular hydrogen that is contained in the tail gas that is combusted in the ethane cracking furnaces is currently included in the furnaces' CO and VOC potential to emit calculations (e.g., 620 MMBtu/hr total furnace heat input when including the heat input associated with the combustion of molecular hydrogen that is contained in the tail gas that is combusted in the furnace x 0.035 lb CO/MMBtu x 7,509 hr/yr of long-term normal operation x (1 ton / 2,000 lb) = 81.47 tpy CO). However, molecular hydrogen does not contain carbon; therefore, molecular hydrogen does not result in CO or VOC emissions when it is combusted. As a result, the heat input associated with the combustion of molecular hydrogen that is contained in the tail gas that is combusted in the furnaces is no longer proposed to be included in the furnaces' CO and VOC potential to emit calculations (e.g., 336.2 MMBtu/hr total furnace heat input when excluding the heat input associated with the combustion of molecular hydrogen that is contained in the tail gas that is combusted in the furnace x 0.035 lb CO/MMBtu x 7,509 hr/yr of long-term normal operation x (1 ton / 2,000 lb) = 44.18 tpy CO).

- The potential to emit calculation for the ethane cracking furnaces has been revised by Shell to account for a higher percentage of natural gas in the tail gas/natural gas fuel blend combusted in each furnace. This revision impacts each furnace's sulfur dioxide (SO_2), carbon dioxide (CO_2), methane, sulfuric acid, lead, ammonia, and hazardous air pollutant (HAP) emission rates.

In response to the Department's December 24, 2024, technical deficiency letter, Shell provided the following additional information relevant to this proposed change on January 23, 2025:

> Shell proposes using an additional amount of tail gas as supplemental gas at SPM's flares. As

[31] Shell Polymers Monaca plan approval application, September 13, 2024.

such, a smaller amount of tail gas will be available to be blended into the tail gas/natural gas fuel gas stream that is combusted in the ethane cracking furnaces. Therefore, to maintain the necessary heat input to the furnaces, Shell estimated that an additional 3.76 tph of natural gas must be added to the tail gas/natural gas fuel gas stream, which resulted in the referenced increase in the percentage of heat input from CH4+NG for the fuel gas stream…

- Each ethane cracking furnace's n-hexane emission factor was updated to equal a factor derived from stack testing performed on the seven ethane cracking furnaces at SPM rather than either the n-hexane emission factor from AP-42, Section 1.4, Table 1.4-3, which has a poor "E" rating and is not representative of the furnaces, or the n-hexane factor documented by the Ventura County Air Pollution Control District, which is lower than the stack test results for the furnaces.

The table below compares the n-hexane PTE from this plan approval application, the original plan approval application (PA-04-00740A), and the PTE calculated by the Department with the referenced Ventura County Air Pollution Control District emission factor.

Table 12: Ethane Cracking Furnace n-Hexane PTE Comparison

Pollutant	PA-D[a]		PA-A[b]			Ventura County APCD[c]		
	lb/MMBtu	tpy	lb/MMscf	lb/MMBtu	tpy	lb/MMscf	lb/MMBtu	tpy
Hexane	4.07E-04	0.60	1.80	1.76E-03	2.48	1.30E-03	1.27E-06	1.88E-03

[a] Emission factor derived from stack testing; max heat input = 336.8 MMBtu/hr based on 620 MMBtu/hr and 54.3% of heat input from CH_4+NG (September 5, 2025 revised version of Appendix B of PA-D application).
[b] PA-A (and PA-C) emissions based on emission factor from AP-42, Section 1.4, Table 1.4-3; Natural gas HHV = 1,020 Btu/scf; max heat input = 320 MMBtu/hr based on 620 MMBtu/hr and 51.7% of heat input from CH_4+NG (PA-A application).
[c] Emission factor from Ventura County Air Pollution Control District AB 2588 Combustion Emission Factors document; Natural gas HHV = 1,020 Btu/scf. Tons per year (tpy) value calculated by the Department assuming the max heat input to be 336.8 MMBtu/hr based on September 5, 2025, revised version of Appendix B of PA-D application.

- Each ethane cracking furnace's sulfuric acid emission factor has been revised by Shell using the molecular weight of sulfuric acid rather than sulfur trioxide.

Shell has proposed the same change for multiple other sources as well. In response to the Department's December 24, 2024, technical deficiency letter, Shell provided the following additional information regarding this proposed change on January 23, 2025:

> The molecular weight of sulfur trioxide was incorrectly used instead of the molecular weight of sulfuric acid to calculate the mass emission rate of sulfuric acid.
>
> Shell is proposing to correctly use the molecular weight of sulfuric acid instead of the molecular weight of sulfur trioxide to calculate the mass emission rate of sulfuric acid.

- The ethane cracking furnace's methane emission factor for certain operating modes has been revised by Shell to more accurately account for the amount of molecular hydrogen contained in the tail gas combusted in the furnace.

In response to the Department's December 24, 2024, technical deficiency letter, Shell provided the following additional information regarding this proposed change on January 23, 2025:

> The amount of molecular hydrogen contained in the tail gas combusted in the ethane cracking furnaces (79 mole % molecular hydrogen) is based on material balance data for SPM's ethylene manufacturing unit. This 79 mole % molecular hydrogen content is a conservative estimate because it accounts for a slightly greater amount of methane in the tail gas than is normally observed. The furnaces' CO_2 emission factor was mistakenly referenced in the plan approval application as being reconciled to properly account for the amount of molecular hydrogen contained in the tail gas combusted in the furnaces. However, the furnaces' methane emission factor for natural gas firing modes previously reduced the natural gas combustion methane emission factor by improperly accounting for the amount of molecular hydrogen contained in the tail gas combusted in the furnaces. Shell proposed to correct the methane emission factor for natural gas firing modes to equal the natural gas combustion methane emission factor.

In the previous plan approval applications, the emission tables for particulate matter included filterable particulate matter emissions only for the ethane cracking furnaces. In response to the Department's December 24, 2024, technical deficiency letter, Shell provided the following additional information regarding condensable particulate matter emissions as well as revised PTE calculations to document the furnaces' condensable particulate matter potential to emit rates.

> SPM's ethylene manufacturing unit vendor provided PM emissions data for the ethane cracking furnaces, which Shell conservatively estimated to equal $PM_{10}/PM_{2.5}$ emissions. Shell converted the non-decoking operations PM emissions data to a 0.005 lb $PM_{10}/PM_{2.5}$/MMBtu emission factor. As an additional level of conservatism, Shell estimated this emission factor represents both filterable and condensable PM10/PM2.5. The filterable portion of the 0.005 lb $PM_{10}/PM_{2.5}$/MMBtu emission factor was estimated to equal the filterable $PM_{10}/PM_{2.5}$ emission factor of 0.00186 lb/MMBtu from AP-42, Section 1.4, Table 1.4-2. Therefore, the condensable portion of the emission factor equals 0.00314 lb/MMBtu, the difference between the 0.005 lb $PM_{10}/PM_{2.5}$/MMBtu emission factor and the 0.00186 lb $PM_{10}/PM_{2.5}$ (filterable)/MMBtu emission factor.
>
> For decoking operations, Shell converted the decoking operations PM emissions data to a 0.0103 lb $PM_{10}/PM_{2.5}$/MMBtu emission factor. Shell estimated this emission factor represents both filterable and condensable $PM_{10}/PM_{2.5}$. Because an increased amount of filterable PM may be present during decoking operations compared to non-decoking operations, the condensable portion of the 0.0103 lb $PM_{10}/PM_{2.5}$/MMBtu emission factor was set equal to the 0.00314 lb $PM_{10}/PM_{2.5}$ (condensable)/MMBtu emission factor estimated for non-decoking operations, resulting in the filterable portion of the emission factor being equal to 0.00716 lb/MMBtu, which is the difference between the 0.0103 lb $PM_{10}/PM_{2.5}$/MMBtu emission factor and the 0.00314 lb $PM_{10}/PM_{2.5}$ (condensable)/MMBtu emission factor.

The ethane cracking furnace calculations with the additional supporting information received on January 23, 2025, have been found acceptable and the PTE is shown in the table below.

Table 13: Ethane Cracking Furnaces PTE (tpy)

Furnace Operating Modes	PA-D									
	NOx	PM (Filt)	PM (Cond)	PM_{10}	$PM_{2.5}$	CO	SO2	VOC	HAPs [a]	CO_2e
Normal Operation[b]	23.28	4.34	7.3	11.64	11.64	44.25	0.57	2.40	0.73	146,262
Decoking	0.58	0.28	0.12	0.40	0.40	11.28	0.01	0.07	-	2,758
Feed In	0.05	0.01	0.01	0.02	0.02	0.12	0.005	0.01	-	389
Feed Out	0.05	0.01	0.01	0.02	0.02	0.12	0.005	0.01	-	389
Hot Steam Standby	1.56	0.12	0.2	0.31	0.31	2.19	0.09	0.12	-	7,323
Startup	0.19	0.002	0.003	0.01	0.01	0.30	0.002	0.002	-	122
Shutdown	0.19	0.002	0.003	0.01	0.01	0.30	0.002	0.002	-	122
PA-D Total (each)	**25.90**	**4.75**	**7.65**	**12.40**	**12.40**	**58.55**	**0.68**	**2.61**	**0.73**	**157,365**
PA-D Total (7 Furnaces)	**181.30**	**33.25**	**53.55**	**86.80**	**86.80**	**409.85**	**4.76**	**18.27**	**5.10**	**1,101,555**
PA-A Total[c]	181.3	34.1	N/A	86.8	86.8	670.4	3.57	32.4	18.2	1,048,670
Change	0.00	-0.85	N/A	0	0	-260.55	1.19	-14.13	-13.10	52,885

(1) Furnace operating mode parameters are estimated based on 7 furnaces with 6 in normal operation at all times.
(2) Each furnace is assumed to require decoking a maximum of 12 times per year.
(3) Each furnace is assumed to undergo one startup/shutdown cycle per year.
---
[a] Conservatively assumes continuous operation at 100% load adjusted for heat input from CH4+NG, 8,760 hours/year. Highest single HAP for PA-D is hexane at 0.60 tpy.
[b] CO and VOC Normal Operation based on heat input of 336.8 MMBtu/hr in PA-04-00740D. PA-04-00740A uses 620 MMBtu/hr for CO and VOC, resulting in the decrease for CO and VOC.
[c] Ethane cracking furnaces PTE unchanged between PA-04-00740A and PA-04-00740C. PA-A Total PTE are from the Department's review memo for PA-04-00740A dated April 1, 2015.

Source IDs 101 through 103: Combustion Turbine/Duct Burner Unit #1 through #3

- Each Cogen Unit's benzene, formaldehyde, and toluene emission factors have been updated by Shell to equal respective emission factors derived from stack testing performed on the three Cogen Units at SPM rather than the benzene, formaldehyde, and toluene emission factors from AP-42, Section 3.1, Table 3.1-3.

Table 14: Combustion Turbine/Duct Burner Individual HAP Comparison

Pollutant	AP-42	PA-04-00740C[a]	AP-42 w/30% DE[b]	PA-04-00740D
	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
Benzene	1.20E-05	1.20E-06	8.40E-06	1.57E-06
Formaldehyde	7.10E-04	7.10E-05	4.97E-04	2.30E-04
Toluene	1.30E-04	1.30E-05	9.10E-05	2.44E-04

[a] AP-42, Table 3.1-3 with 90% DE.
[b] AP-42, Table 3.1-3 with 30% DE. Shown for informational purposes. See bullet item below.

- Each Cogen Unit's potential to emit calculation was revised by Shell so that the oxidation catalyst destruction efficiency is 30% rather than 90% for organic HAP emission rates calculated using AP-42, Section 3.1, Table 3.1-3 emission factors. This lower oxidation catalyst destruction efficiency is a result of the low concentration of organic compounds in the Cogen Units' uncontrolled exhaust stream (i.e., the inlet stream to the oxidation catalyst). Control of 90% is the guaranteed destruction efficiency for CO for the oxidation catalyst and is not appropriate for organic HAPs.

According to the applicant, the oxidation catalyst manufacturer's data sheet (and other information provided to Shell) does not explicitly provide 30% or 90%, or any other control percent for the oxidation catalyst regarding VOC or organic HAPs. It does state ≥ 92% for CO conversion. For VOC, only oxidation catalyst outlet rate guarantees, and outlet expected performance with respect to VOC input design cases are provided. The oxidation catalyst is designed to meet the plan approval limitation of 1 ppmvd @ 15% O_2 for VOC, while compliance with the formaldehyde limit of 91 ppbvd @ 15% O_2 has been demonstrated through multiple performance tests.

The 30% control estimate for organic HAPs is a derived conservative control efficiency in consideration of the available data for the oxidation catalyst. VOC is taken as a surrogate for organic HAP and the 30% control efficiency is derived from Performance Case 2 (100% load @ 28.1C ambient conditions), which indicates a designed VOC inlet of 1.43 ppmvd @ 15% O_2 and guaranteed VOC outlet of 1 ppmvd @ 15% O_2 [(1.43 ppmv – 1 ppmv)/1.43 ppmv*100% = 30.07%]. The expected VOC outlet performance however is less than 1 ppmvd @ 15% O_2 and is therefore expected to be greater than 30% control efficiency for VOC, which is also expected for organic HAP. Since there is no design guarantee directly for organic HAP, this most conservative original performance case has been used for PTE purposes and for modeling inhalation risk for non-formaldehyde, non-benzene, and non-toluene organic HAPs that have not been tested directly with their own individual proposed emissions factors included in the application.

- Each Cogen Unit's sulfuric acid emission factor has been revised by Shell using the molecular weight of sulfuric acid rather than sulfur trioxide.

Calculations have been found acceptable and the PTE from the combustion turbines/duct burners is shown in the table below.

Table 15: GE Frame 6B Combustion Turbines with Duct Burners PTE (tpy)

Source	PA-D								
	NOx	**PM**	**$PM_{10/2.5}$**	**CO**	**SO2**	**VOC**	**Toluene**	**HAPs**	**CO_2e**
1 Unit	23.45	5.95	20.68	15.00	4.61	11.03	0.76	1.87	366,919
Total (3-Units)	**70.34**	**17.86**	**62.04**	**45.00**	**13.82**	**33.10**	**2.28**	**5.62**	**1,100,756**
PA-C Total	70.3	17.5	62.0	45.0	13.82	33.10	0.12	0.97	1,100,762
Change	0	0.34	0	0	0	0	2.16	4.65	-6

(1) Three combustion turbines rated at 481.4 MMBtu/hr each with three duct burners rated at 234 MMBtu/hr each.
(2) Based on normal operation expected for 8,753 hours per year; 7 hours per year combined of startup and shutdown operations.
(3) PTE for turbines/duct burners over all operational modes for 8,760 hours per year.

---

[a] PM is filterable only.
[b] PM_{10} BACT limit = $PM_{2.5}$ LAER limit = 0.0066 lb/MMBtu.
[c] Toluene is highest single HAP.

Source ID 104: Cogeneration Plant Cooling Tower

- The cooling tower's potential to emit calculation has been revised by Shell by increasing the cooling tower's cooling water recirculation rate in the calculation so that the recirculation rate more accurately represents the level required by SPM's Cogen Units.

In response to the Department's December 24, 2024, technical deficiency letter, Shell provided the following additional information regarding this proposed change:

> The proposed cooling water recirculation rate of 120,000 gallons per minute (gpm) is based on an actual measurement. A maximum recirculation rate measurement of 116,200 gpm was adjusted slightly upward to 120,000 gpm to account for variability in Cogeneration Plant operations and ambient conditions. The proposed cooling water recirculation rate is necessary to maintain Cogen Unit temperatures at appropriate levels.

Note that the previously used recirculation in the application for PA-04-00740C was 74,056 gpm. Calculations have been found acceptable and the PTE from the cogeneration plant cooling tower is shown in the table below.

Table 16: Cogeneration Plant Cooling Tower PTE

Pollutant	**PA-D**		PA-C	Change
	lb/hr	**tpy**	tpy	tpy
PM	0.6	2.63	1.62	1.01
PM_{10}	0.36	1.67	1.03	0.64
$PM_{2.5}$	0.0012	0.01	0.003	0.007

(1) Number of cells = 6; Design specification
(2) Cooling water rate = 120,000 gal/min; Maximum water flow rate
(3) Cell circulation rate = 20,000 gal/min/cell; (Cooling Water Rate)/(Number of Cells)
(4) Annual operating hours = 8,760 hours/year
(5) Drift factor = 0.0005 wt. %; Design specification, BACT limit
(6) Cooling water TDS = 2,000 ppmw; BACT/LAER limit (12-month rolling average basis)
(7) PM_{10} fraction of PM = 63.50 wt. %; See particle size distribution calculation in Appendix B
(8) $PM_{2.5}$ fraction of PM = 0.21 wt. %; See particle size distribution calculation in Appendix B

Source ID 105: Diesel-Fired Emergency Generator Engines (2)

Generator 1 – Parking Garage (103 bhp)

- The engine's CO emission factor used has been revised by Shell to equal the engine's CO BACT limit of 0.50 g/bhp-hr.
- The engine's sulfuric acid emission factor has been revised by Shell using the molecular weight of sulfuric acid rather than sulfur trioxide.

Generator 2 – Telecom Hut (67 bhp)

- The engine's CO emission factor used has been revised by Shell to equal the engine's CO BACT limit of 0.67 g/bhp-hr.

- The engine's sulfuric acid emission factor has been revised by Shell using the molecular weight of sulfuric acid rather than sulfur trioxide.

<u>Source ID 106: Fire Pump Engines (2)</u>

<u>Firewater Pump 1 and 2 (488 bhp each)</u>

- Each firewater pump engine's sulfuric acid emission factor has been revised by Shell using the molecular weight of sulfuric acid rather than sulfur trioxide.

Calculations have been found acceptable and the PTE from the diesel-fired emergency generator and fire pump engines is shown in the table below.

Table 17: Diesel-Fired Emergency Generator Engines and Fire Pump Engines PTE

Pollutant	Gen 1 – Parking Garage		Gen 2 – Telecom Hut		Fire Pump Engines (each)	
	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpy)
NO_X	0.53	0.03	0.41	0.02	2.0	0.1
CO	0.11	0.01	0.10	0.005	2.8	0.14
PM	0.01	0.001	0.03	0.002	0.16	0.01
PM_{10}	0.01	0.001	0.03	0.002	0.15	0.01
$PM_{2.5}$	0.01	0.001	0.03	0.001	0.15	0.01
SO_2	0.001	5.60E-05	0.001	3.65E-05	0.01	2.65E-04
VOC	0.01	4.54E-04	0.01	0.001	1.23	0.06
HAP	-	1.40E-04	-	9.08E-05	-	6.62E-04
H_2SO_4	5.51E-05	2.76E-06	3.58E-05	1.79E-06	2.61E-04	1.31E-05
CO_2e	118	6	77	4	559	28

(1) Annual emissions based on the plan approval limit of 100 hours of non-emergency operation per year for each engine.

<u>Source ID 107: Natural Gas-Fired Emergency Generator Engines (2)</u>

<u>Generator 3 – Lift Station (158 bhp)</u>

- The engine's CO, NOx, VOC, and CO_2 emission factors have been revised by Shell to be on a lb/bhp-hr unit basis rather than a lb/MMBtu unit basis that had been derived using a generic engine's thermal-to-mechanical energy efficiency conversion factor. The CO and CO_2 lb/bhp-hr emission factors are engine manufacturer specifications, and the NOx and VOC lb/bhp-hr emission factors equal the engine's NOx BACT limit of 2.0 g/bhp-hr and the engine's VOC LAER limit of 1.0 g/bhp-hr, respectively, converted to a lb/bhp-hr unit basis.

- The engine's sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

Generator 4 – Lift Station (50 bhp)

- The engine's CO and CO_2 emission factors have been revised by Shell to be on a lb/bhp-hr unit basis rather than a lb/MMBtu unit basis that had been derived using a generic engine's thermal-to-mechanical energy efficiency conversion factor. The CO and CO_2 lb/bhp-hr emission factors are engine manufacturer specifications.

- The engine's NOx emission factor has been revised by Shell to be on a lb/MMBtu unit basis that has been derived using a thermal-to-mechanical energy efficiency conversion factor that is specific to the engine.

- The engine's PM_{10} and $PM_{2.5}$ emission factors have been revised by Shell to equal the PM10 (filterable + condensable) and $PM_{2.5}$ (filterable + condensable) emission factors documented in AP-42, Section 3.2, Table 3.2-2 for 4-stroke lean burn engines.

- The engine's sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

Calculations have been found acceptable and the PTE from the natural gas-fired emergency generator engines is shown in the table below.

Table 18: Natural Gas-Fired Emergency Generator Engines PTE

Pollutant	Generator 3 – Lift Station (158 bhp)		Generator 4 – Lift Station (50 bhp)	
	Emission Rate (lb/hr)	Emission Rate (tpy)[a]	Emission Rate (lb/hr)	Emission Rate (tpy)[a]
NO_X	0.7	0.03	0.55	0.03
CO	0.25	0.01	2.69	0.13
PM	0.01	0.001	2.88E-05	1.44E-06
PM_{10}	0.03	0.001	0.004	1.86E-04
$PM_{2.5}$	0.03	0.001	0.004	1.86E-04
SO_2	0.001	4.17E-05	2.20E-04	1.10E-05
VOC	0.35	0.02	0.04	0.002
HAP	-	0.002	-	0.001
H_2SO_4	4.10E-05	2.05E-06	1.08E-05	5.40E-07
CO_2e	221	11	86	4

* Annual emissions based on the plan approval limit of 100 hours of non-emergency operation per year for each engine.

Source ID 202: Polyethylene Manufacturing Lines

- The emission source's potential to emit calculation has been revised by Shell by updating the hours of operation (i.e., intermittent operation versus continuous operation) and exhaust flow rate of specific filter vents (i.e., SPM-specific flow rate versus licensor estimates) to better represent the operations and design of the filtration systems.

See Appendix B of the application for the hours of operation of the individual vents from PE Units 1, 2, and 3. Consistent with the BACT/LAER requirements established in PA-04-00740A, particulate matter from specific PE Unit intermittent and continuous vents (excluding pellet dryer vents) are equipped with and controlled by fabric, sintered metal, or HEPA filters designed to achieve a particulate loading of 0.005 gr/dscf at the outlet. Consistent with PA-04-00740C, PE Unit 3 catalyst activation vents are controlled by an internal sintered metal filter, followed by knockout pot, and finally an external HEPA filter. At the request of the applicant as part of PA-04-00740C, PM (filterable) emission from the catalyst activation vents is limited to 0.002 gr/dscf as a plan approval condition. PM (filterable) emissions from each of the PE Unit pellet dryer vents shall not exceed 0.01 gr/dscf. The Table below summarizes the polyethylene manufacturing lines PTE.

Table 19: Polyethylene Manufacturing Lines PTE

Source	PA-D				
	PM	PM_{10}	$PM_{2.5}$	Hexavalent Chromium (CrVI)	
	tpy	tpy	tpy	lb/hr	tpy
PE Units 1 & 2 Process Vents	2.24	2.24	2.24	8.20E-07	3.60E-06
PE Unit 3 Process Vents	1.18	1.18	1.18	3.04E-05	1.33E-04
Railcar to Truck Talc Transfer	0.02	0.02	0.02	-	-
Total	**3.44**	**3.44**	**3.44**	**3.12E-05**	**1.37E-04**
PA-C	3.67	3.67	3.67	4.57E-05	2E-04
Change	-0.23	-0.23	-0.23	-1.45E-05	-6.3E-05

(1) Assumes $PM=PM_{10}=PM_{2.5}$.
(2) Short term and annual rates based on exhaust rates provided by vendor at normal conditions (i.e., 0°C and 1 atm) and exhaust grain loading (BACT/LAER limit) for filterable particulate at standard conditions (i.e., 20°C and 1 atm).
(3) Vendor data for the Additive Surge Bin Filter Vents, Solid Additive/Talc Feeder Filter Vents, Pellet Surge Hopper Filter Vents, and Miscellaneous Storage and Conveying Filter Vents indicated that particulate emissions from these sources are expected to be negligible/nil. However, the vents were conservatively included for potential to emit purposes and assumed to emit continuously at an exhaust grain loading of 0.005 gr/dscf. PTE is approximately 0.4 tpy PM.

Source ID 203: Process Cooling Tower

- The cooling tower's potential to emit calculation has been revised by Shell by reducing the organic HAP fraction of any VOC leak into the cooling tower's recirculating water to better represent the number of heat exchangers with the potential to leak VOC into the cooling water and the organic HAP fraction of the heat exchangers with the potential to leak VOC into the cooling water.

- The cooling tower's potential to emit calculation has been revised by Shell by assigning a worst-case organic HAP-containing material for the calculation of speciated organic HAPs due to a leaking heat exchanger.

Calculations have been found acceptable and the PTE from the process cooling tower is shown in the table below.

Table 20: Process Cooling Tower PTE

Pollutant	PA-D			PA-C		Change
	Calculation	lb/hr/cell	tpy	Calculation	tpy	tpy
PM	0.0005 wt. % Drift	0.06	**6.49**	0.0005 wt. % Drift	6.49	0
PM_{10}	63.5 wt. % of PM	0.04	**4.12**	63.5 wt. % of PM	4.12	0
$PM_{2.5}$	0.21 wt. % of PM	0.0001	**0.01**	0.21 wt. % of PM	0.013	0
VOC	0.50 lb/MMgal	0.34	**38.88**	0.50 lb/MMgal	38.88	0
HAP	2.5 wt. % of VOC	0.0085	**0.97**	10 wt. % of VOC	3.89	-2.92
1,3 Butadiene	80.17 wt. % of HAP	0.0068	**0.78**	-	-	0.78

General Notes:
(1) Number of cells = 26; Design specification
(2) Cooling water rate = 295,900 gal/min; Maximum water flowrate
(3) Cell circulation rate = 11,381 gal/min/cell; (Cooling Water Rate)/(Number of Cells)
(4) Annual operating hours = 8,760 hours/year
(5) Drift factor = 0.0005 wt. %; Design specification, BACT limit
(6) Cooling water TDS = 2,000 ppmw; BACT/LAER limit (12-month rolling average basis)

PA-04-00740D:
(7) PM_{10} fraction of PM = 63.50 wt. %; See particle size distribution calculation in Appendix B
(8) $PM_{2.5}$ fraction of PM = 0.21 wt. %; See particle size distribution calculation in Appendix B
(9) VOC emission limit = 0.50 lb/MMgal; LAER limit
(10) HAP fraction of VOC = 2.5 wt. %; Assumed value based on engineering judgement. There are few HAP-containing streams in the processes and any exchanger leaks will be repaired in a timely manner due to leak monitoring and repair requirements. If there is a HAP containing stream leak, worst case is C3+ coproduct.
(11) 1,3 Butadiene % of total HAP = 80.17 wt. %; Based on C3+ sample data. 1,3 Butadiene is highest single HAP.

Source ID C204: CVTO (previously LP Incinerator)

- The CVTO's NOx emission factor has been revised by Shell based upon the proposed LAER emission limit of 0.06 lb/MMBtu compared to the previous limit of 0.068 lb/MMBtu. Annual PTE calculations are based upon the annual average heat input of 181 MMBtu/hr and an operation time of 8,760 hours per year.

- The CVTO's potential to emit calculation has been revised by Shell to include the additional amount of supplemental fuel gas that has been estimated to be required to maintain the thermal oxidizer's temperature at a level necessary to ensure the minimum destruction efficiency required by applicable regulations and SPM's plan approval is achieved.

- The CVTO's potential to emit calculation has been revised by Shell to include updates to vent stream flow rate and composition data based on a review of SPM's operating data. Supporting vent stream data was provided by Shell on February 28, 2025.

- The CVTO's sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

- Shell has proposed to revise the CVTO's combustion product n-hexane emission factor to equal the n-hexane emission factor indicated for a flare in the Natural Gas Fired External Combustion Equipment table in the May 17, 2001, Ventura County Air Pollution Control District (VCAPCD) AB 2588 Combustion Emission Factors document rather than the n-hexane emission factor documented in AP-42, Section 1.4, Table 1.4-3 (0.029 lb/MMscf (2.84E-05 lb/MMBtu) compared to 1.8 lb/MMscf (1.76E-03 lb/MMBtu) used previously).

Table 21: n-Hexane Emission Factor Comparison

Pollutant	AP-42 [a]	VCAPCD [b]	Test Report [c]		Proposed
n-Hexane	(lb/MMBtu)	(lb/MMBtu)	ppmvd	lb/MMBtu	(lb/MMBtu)
	1.76E-03	2.84E-05	*0.260*	*1.80E-03*	2.84E-05

[a] AP-42, Section 1.4, Table 1.4-3
[b] Hexane emission factor for a flare in the Natural Gas Fired External Combustion Equipment table in the May 17, 2001, VCAPCD AB 2588 Combustion Emission Factors document
[c] Performance testing conducted on the CVTO at SPM by Alliance Technical Group on May 21, 2024 (Test report dated and submitted on July 22, 2024). *Italicized results were below the laboratory MDL; the MDL was used to calculate emissions.*
* To convert from 1b/MMscf to lb/MMBtu, divide by the heat content of natural gas of 1,020 Btu/scf. For example, 1.8 lb/MMscf/1020 Btu/scf = 1.76E-03 lb/MMBtu.

AP-42, Section 1.4 documents EPA-approved emission factors that can be used to calculate emissions from external combustion sources that combust natural gas or comparable gaseous streams (note that AP-42, Section 3.1 is mistakenly referenced in the September 13, 2024, plan approval application narrative). AP-42, Section 1.4, Table 1.4-3 includes emission factors for several individual VOCs. Propane, butane, pentane, and n-hexane are a few of those VOCs. The addition of the propane, butane, pentane, and n-hexane emission factors in AP-42, Section 1.4, Table 1.4-3 results in a sum of 8.1 lb/MMscf. However, the total VOC emission factor in AP-42, Section 1.4, Table 1.4-2 is 5.5 lb/MMscf. Therefore, the summation of the AP-42, Section 1.4 emission factors for only the four referenced VOCs exceeds the AP-42, Section 1.4 total VOC emission factor by almost 50%, indicating those emission factors are erroneous. This conclusion is supported by the better-quality rating EPA assigned to the total VOC emission factor versus the propane, butane, pentane, and n-hexane emission factors. The quality rating for the AP-42, Section 1.4, Table 1.4-2 total VOC emission factor is “C,” which indicates an “average” quality emission factor. Alternatively, the quality rating for the propane, butane, pentane, and n-hexane emission factors is “E,” which is the lowest quality rating assigned by EPA in AP-42 and indicates a “poor” quality emission factor. A contributor to this “poor” rating for the n-hexane emission factor of 1.8 lb/MMscf (or 1.76E-3 lb/MMBtu) is the fact that the emission factor was derived from only two stack tests, neither of which included three test runs of n-hexane emissions data.

As a result of the poor-quality rating assigned to the AP-42, Section 1.4, Table 1.4-3 n-hexane emission factor, Shell has revised the calculation based on the VCAPCD emission factor of 0.029 lb/MMscf (2.84E-05 lb/MMBtu) that is applicable to flares to calculate the CVTO’s n-hexane potential to emit rate that may result specifically as a combustion product from fuel and waste gas combustion in the thermal oxidizer. Note that Shell conservatively used the VCAPCD n-hexane emission factor of 2.84E-05 lb/MMBtu that is applicable to flares for the CVTO potential to emit calculation instead of the lower VCAPCD n-hexane emission factor of 1.27E-06 lb/MMBtu that is applicable to enclosed external combustion sources that have a firing rate greater than 100 MMBtu/hr, such as the CVTO.

In support of use of the VCAPCD emission factor, Shell has noted that the Bay Area Air Quality Management District (BAAQMD) stated the following in Appendix A of its August 2020 *BAAQMD Toxic Air Contaminant*

(TAC) Emission Factor Guidelines: "Since the AP-42 Chapter 1.4 hexane emission factor seemed inordinately high (33% of the total VOC factor), the Air District chose the maximum hexane emission factor from the VCAPCD data (6.18E-6 lbm/MMBTU) instead of the AP-42 Chapter 1.4 hexane factor (1.76E-3 lbm/MMBTU)." Similarly, the South Coast Air Quality Management District lists VCAPCD n-hexane emission factors as the default emission factors to use to calculate n-hexane emissions from natural gas combustion sources (e.g., boilers, heaters, and flares) for its quadrennial air toxics emissions inventory rather than the AP-42, Section 1.4, Table 1.4-3 n-hexane emission factor. The Department has determined that the use of the VCAPCD n-hexane emission factor is acceptable to calculate the CVTO's n-hexane potential to emit that may result as a combustion product from fuel and waste gas combustion in the thermal oxidizer. Note that the VCAPCD flare n-hexane emission factor is also proposed to be used for the MGPF, TEGF A, TEGF B, HP Elevated Flare, and SCTO. The CVTO's n-hexane potential to emit that may occur as a result of less than 100% destruction of n-hexane contained in the waste gas combusted in the thermal oxidizer continues to be calculated using the concentration of n-hexane estimated to be in the waste gas, which is based on process knowledge, and the CVTO's DRE for n-hexane.

The May 21, 2024, performance test conducted on the CVTO included testing of the n-hexane emissions from the CVTO that may occur as a result of two potential pathways: 1) less than 100% destruction of hexane contained in the waste gas combusted in the CVTO and 2) hexane generated as a product of combustion of waste gas and fuel gas in the CVTO. All 3 of the test runs had a result of non-detect with the results being less than the Method Detection Limit (MDL) of 0.260 ppmvd. As the performance test results were all non-detect, the test report is not representative of actual emissions from the CVTO.

- The CVTO's heat input has been updated from the preliminary designed heat input of 107 MMBtu/hr to a max short term heat input of 199.1 MMBtu/hr and annual heat input of 181 MMBtu/hr.

  According to the applicant, the basis for the CVTO heat input revision from 107 MMBtu/hr in PA-04-00740C to 181 MMBtu/hr in this plan approval is process knowledge and engineering review of design vent flow rate maximums from PE1 and PE2 High Pressure Accumulator Vents. This resulted in higher flow rates than the original basis. Additionally, PE1 and PE2 can produce multiple different grades of polyethylene. The highest hydrocarbon percentage from any grade expected to be run has been applied to the flow rates. See Shell's response to Question 17a and Attachment 1 "CVTO Potential to Emit Calculation Vent/Gas Stream Flow Rate and Composition Data" of the February 28, 2025, technical deficiency response letter for additional background information. Note that there was no physical change made to the CVTO to accommodate higher firing rates.

Organic vapors recovered from continuous polyethylene manufacturing process vents, pyrolysis fuel oil and light gasoline storage tanks and loading, and hexene storage tanks are controlled by the CVTO. Emissions were estimated based on the expected maximum vent rates to the control device, the VOC destruction efficiency of 99.9% demonstrated in the May 21, 2024, performance test, NOx LAER limitation, AP-42 Chapter 1.4 emission factors, SO3-to-SO2 emission factor ratio in AP-42, Table 1.3-1 for distillate oil combustion in boilers > 100 MMBtu/hr for H_2SO_4, VCAPCD AB 2588 Combustion Emission Factors for n-hexane, and 40 CFR Part 98 Subpart C emission factors. A worst-case operating time of 8,760 hours at an annual heat input of 181 MMBtu/hr (short term maximum heat input is 199.1 MMBtu/hr with a rated heat input of 200 MMBtu/hr). PM_{10} and $PM_{2.5}$ emissions are considered equivalent for this source due to combustion of gaseous fuel. All calculations were found to be acceptable by the Department and calculation basis data and the PTE from the CVTO are shown in the tables below.

Table 22: CVTO Calculation Basis

Flare Operating Mode	MMBtu/hr	VOC to CVTO	VOC DRE
CVTO Short-Term Max	199.1	3.86 t/hr	99.9%
CVTO Annual Average	181	3.51 t/hr	99.9%

Table 23: CVTO Potential to Emit

Pollutant	PA-D			PA-C Emission Rate (tpy)	Change (tpy)
	Emission Factor (lb/MMBtu)	Short-Term Max Emission Rate (lb/hr)	Annual Emission Rate (tpy)		
NOx	0.06	11.95	**47.57**	31.80	15.77
CO	0.0824	16.40	**65.29**	38.51	26.78
PM (Filterable)	0.0019	0.37	**1.48**	0.89	0.59
PM_{10}	0.0075	1.48	**5.91**	3.48	2.43
$PM_{2.5}$	0.0075	1.48	**5.91**	3.48	2.43
SO_2	0.0015	0.29	**1.17**	0 [a]	1.17
H_2SO_4	7.23E-05	0.01	**0.06**	0 [a]	0.06
VOC	0.0388	7.72	**30.77**	16.42	14.35
Hexane	2.84E-05 [b]	0.01	**0.02**	0.83	-0.81
HAP	-	0.03	**0.11**	0.89	-0.78
CO_2e	138.2	-	**109,579**	68,260	41,319

[a] SO_2 and H_2SO_4 PTE was assumed negligible in PC-04-00740C because minimal natural gas assist was expected to be necessary.
[b] Hexane emission factor used to calculate hexane potential to emit that may result as a combustion product from fuel and waste gas combustion in the CVTO. The hexane potential to emit that may occur as a result of less than 100% destruction of hexane contained in the waste gas combusted in the CVTO was calculated using the concentration of hexane estimated to be in the waste gas, which was based on process knowledge, and the CVTO's DRE for hexane.

Source ID C207, C208, and C209: MPGF (previously Source ID C204B: LP Multipoint Ground Flare (MPGF))

Source ID C207: MPGF CVTO Trip

- The flare's VOC potential to emit calculation originally included with the application for PA-04-00740D was based upon a destruction efficiency of 99% for organic compounds containing 3 or fewer carbon atoms, 98% for other VOC, and the VOC mass flow rate to the flare based upon operational data. Shell has revised the VOC PTE based upon 98% DRE for all VOC after discussions with the Department and which is reflected in the most recently provided calculations on September 5, 2025. This change has also been made for the TEGF A, TEGF B, and HP Elevated Flare.

- The flare's potential to emit calculation has been revised by Shell to include the additional amount of supplemental gas that has been estimated to be required to maintain the net heating value of the header's combustion zone gas at the minimum level required by SPM's plan approval.

- The flare's potential to emit calculation was revised by Shell to include updates to vent stream flow rate and composition data based on a review of SPM's operating data, including expected annual downtime of the CVTO. Supporting vent stream data was provided by Shell on March 7, 2025.

- The flare's CO emission factor was updated based upon the revised CO emission factor in Table 13.5-2 of AP-42, Section 13.5 which was revised from 0.37 to 0.31 lb/MMBtu in February 2018. The AP-42 emission factor for CO has been used for the MPGF, TEGFs, and HP Elevated Flare which are not tested units and do not include a vendor guarantee or another documented CO emissions factor.

- The flare's sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

- The flare's n-hexane emission factor was updated to equal the n-hexane emission factor indicated for a flare in the Natural Gas Fired External Combustion Equipment table in the May 17, 2001, Ventura County Air Pollution Control District AB 2588 Combustion Emission Factors document rather than the n-hexane emission factor documented in AP-42, Section 1.4, Table 1.4-3; 2.84E-05 lb/MMBtu compared to 1.76E-03 lb/MMBtu used previously.

This MPGF header receives vent streams from the CVTO Header System when the CVTO is unavailable and directs the vent streams to the MPGF for combustion. This is currently part of Source ID 204. Shell has proposed that this MPGF header be identified as the MPGF CVTO Trip Header in this plan approval under a separate Source ID 207. The CVTO Header System receives vent streams from the three polyethylene manufacturing units and specific storage tanks and loading racks at SPM. Therefore, the MPGF CVTO Trip Header will receive the same vent streams from the CVTO Header System when the CVTO is unavailable. According to the application, the MPGF CVTO Trip Header vent has a maximum heat input of 186 MMBtu/hr. Input parameters to calculate the MPGF CVTO Trip Header PTE are shown in the table below.

Table 24: MPGF CVTO Trip Header Calculation Basis

Flare Operating Mode	MMBtu/hr	VOC to MPGF	VOC DRE
MPGF CVTO Trip Header Vent Gas Short-Term Max	181.1	3.51 t/hr	98%
MPGF CVTO Trip Header Vent Gas Annual Average	6.9	0.13 t/hr	98%
MPGF CVTO Trip Header Pilots	0.46	-	-

(1) VOC mass rates are based on vendor data associated with various potential operating scenarios and actual process data.
(2) Annual average heat input based on assuming up to two weeks of CVTO trips per year.

MPGF Ethylene Tank Header

- The flare's VOC potential to emit has been calculated by Shell based upon 98% destruction efficiency and the VOC mass flow rate to the flare based upon operational data.

- The flare's potential to emit calculation were revised by Shell to include updates to vent stream flow rate and composition data based on a review of SPM's operating data. Supporting vent stream data was provided by Shell on March 7, 2025.

- The flare's CO emission factor was updated based upon the revised CO emission factor in Table 13.5-2 of AP-42, Section 13.5 which was revised from 0.37 to 0.31 lb/MMBtu in February 2018.

- The flare's sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

- The flare's n-hexane emission factor was updated to equal the n-hexane emission factor indicated for a flare in the Natural Gas Fired External Combustion Equipment table in the May 17, 2001, Ventura County Air Pollution Control District AB 2588 Combustion Emission Factors document rather than the n-hexane emission factor documented in AP-42, Section 1.4, Table 1.4-3; 2.84E-05 lb/MMBtu compared to 1.76E-3 lb/MMBtu used previously.

- The flare's potential to emit calculation has been revised by Shell to remove the Boil-Off Gas (BOG) Compressor seal's vent stream from the header's calculation because the BOG Compressor seal's vent stream was removed from the header and connected to SPM's HP header system in September of 2024.

This MPGF header is used to route intermittent vent streams from the Refrigerated Ethylene Storage Tank and associated ethylene gas recovery system to the MPGF for combustion. This header is currently part of Source ID 204. Shell has proposed that this MPGF header be identified as the MPGF Ethylene Tank Header in this plan approval under a separate Source ID 208. According to the application, the MPGF Ethylene Tank Header vent has a maximum heat input of 1,152 MMBtu/hr. Input parameters to calculate the MPGF Ethylene Tank Header PTE are shown in the table below.

Table 25: MPGF Ethylene Tank Header Calculation Basis

Flare Operating Mode	MMBtu/hr	VOC to MPGF	VOC DRE
MPGF Ethylene Tank Header Short-Term Max	27.6	0.61 t/hr	98%
MPGF Ethylene Tank Header Annual Average	1.2	0.03 t/hr	98%
MPGF Ethylene Tank Header Pilots	1.11	-	-

(1) VOC mass rates are based on vendor data associated with various potential operating scenarios and actual process data.
(2) Annual average heat input is based on 405 hours of venting above baseline rate of zero flow.

<u>MPGF PE Units 1/2 Episodic Vent Header</u>

- The flare's VOC potential to emit has been calculated by Shell based upon 98% destruction efficiency and the VOC mass flow rate to the flare based upon operational data.

- The flare's potential to emit calculation has been revised by Shell to include the additional amount of supplemental gas that has been estimated to be required to maintain the net heating value of the header's combustion zone gas at the minimum level required by SPM's plan approval.

- The flare's potential to emit calculation were revised by Shell to include updates to vent stream flow rate and composition data based on a review of SPM's operating data. Supporting vent stream data was provided by Shell on March 7, 2025.

- The flare's CO emission factor was updated based upon the revised CO emission factor in Table 13.5-2 of AP-42, Section 13.5 which was revised from 0.37 to 0.31 lb/MMBtu in February 2018.

- The flare's sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

- The flare's n-hexane emission factor was updated to equal the n-hexane emission factor indicated for a flare in the Natural Gas Fired External Combustion Equipment table in the May 17, 2001, Ventura County Air Pollution Control District AB 2588 Combustion Emission Factors document rather than the n-hexane emission factor documented in AP-42, Section 1.4, Table 1.4-3; 2.84E-05 lb/MMBtu compared to 1.76E-3 lb/MMBtu used previously.

This MPGF header is used to periodically route vent streams from PE Units 1 and 2 to the MPGF for combustion. This header is currently part of Source ID 204. Shell has proposed that this MPGF header be identified as the MPGF PE Units 1/2 Episodic Vent Header in this plan approval under a separate Source ID 209. A sweep gas stream routinely flows through the MPGF PE Units 1/2 Episodic Vent Header. According to the application, the MPGF PE Units 1/2 Episodic Vent Header vent has a maximum heat input of 860 MMBtu/hr. Input parameters to calculate the MPGF PE Units 1/2 Episodic Vent Header PTE are shown in the table below.

Table 26: MPGF PE Units 1/2 Episodic Vent Header Calculation Basis

Flare Operating Mode	MMBtu/hr	VOC to MPGF	VOC DRE
MPGF PE Units 1/2 Episodic Vent Header Short-Term Max	180	6.50 t/hr	98%
MPGF PE Units 1/2 Episodic Vent Header Annual Average	77.8	0.04 t/hr	98%
MPGF PE Units 1/2 Episodic Vent Header Pilots	0.91	-	-

(1) VOC mass rates are based on vendor data associated with various potential operating scenarios and actual process data.
(2) Annual average heat input based on assuming 1 PE Unit 1 and 1 PE Unit 2 vent recovery shutdown in a year.
(3) Annual average heat input also includes flaring events associated with reasonably anticipated maintenance events.
(4) Annual average heat input also includes supplemental gas needed to maintain a combustion zone heating value of 500 Btu/scf.

Destruction Efficiency

Shell's initial proposed MPGF destruction efficiency was based on a June 12, 2017, Zeeco, Inc. Flare Test Report that documents flare testing that was conducted to demonstrate the performance of SPM's three MPGF flare tip designs operating under simulated field conditions prior to acceptance and installation of the MPGF systems at SPM. This information was provided in Shell's March 7, 2025, response to the technical deficiency letter.

The June 12, 2017, Zeeco Flare Test Report states that the MPGF was properly designed to comply with a 99% destruction efficiency for hydrocarbon compounds containing three or fewer carbon atoms and a 98% destruction efficiency for hydrocarbon compounds containing four or more carbon atoms when combusting vent gases comparable to the vent gases routed to the MPGF CVTO Trip Header, MPGF PE Units 1/2 Episodic Vent Header, and MPGF Ethylene Tank Header.

After discussions with the Department, Shell revised the MPGF's PTE calculations based on a 98% destruction efficiency for all VOC. See the HP Flare destruction efficiency section of this memo for additional information on change in DRE. Compliance with the minimum destruction efficiency of 98% for the MPGF is assured through parametric monitoring and compliance with work practice requirements indicative of proper operation and good combustion practices.

These MPGF parametric monitoring and work practice requirements are incorporated into PA-04-00740C directly or by reference. Attachment 2 of the March 7, 2025, response summarizes the procedures that are followed to demonstrate compliance with the minimum destruction efficiency required for the MPGF.

Vent Stream

In response to the Department's December 24, 2024, deficiency letter, on March 7, 2025, Shell provided the vent stream flow rate and composition data that were used to calculate the potential to emit rates proposed for the three MPGF headers. The vent stream flow rate and composition data are included in Attachments 3, 4, and 5 of the response.

Net Heating Value

To ensure compliance with PA-04-00740C Section D, Source ID 204, Condition #019: Net heating value of the combustion zone gas at the MPGF header shall equal or exceed 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes, Shell previously used direct measurement by GC. Shell now uses direct measurement by calorimeter. For the MPGF Ethylene Tank Header, Shell intends to continue to use an engineering calculation that uses an NHV of 1,477 Btu/scf for pure ethylene per 40 CFR Part 63 Subpart CC Table 12 to calculate the net heating value of the combustion zone gas at this MPGF header.

Hexane

Shell has revised the calculation to use the VCAPCD emission factor of 0.029 lb/MMscf (2.84E-05 lb/MMBtu) that is applicable to flares to calculate the MPGF's n-hexane potential to emit rate that may result specifically as a combustion product at the flare. The Department has determined the use of the VCAPCD factor is acceptable as discussed in the CVTO section above.

The table below shows the MPGF PTE from the three headers as well as a comparison to the PTE from PA-04-00740C. Note that the MPGF headers were not previously separated. All calculations have been found acceptable by the Department.

Table 27: MPGF Potential to Emit (tpy)

Pollutant	PA-D				PA-C MPGF	Change
	MPGF CVTO Trip Header	MPGF Ethylene Tank Header	MPGF PE Units 1/2 Episodic Vent Header	PA-D MPGF Total		
NOx	2.26	0.84	23.56	**26.66**	1.76	24.90
CO	9.56	2.07	105.97	**117.60**	9.55	108.05
PM (Filterable)	0.06	0.02	0.64	**0.72**	0.05	0.67
PM_{10}	0.24	0.08	2.57	**2.89**	0.19	2.70
$PM_{2.5}$	0.24	0.08	2.57	**2.89**	0.19	2.70
SO_2	0.05	0.02	0.51	**0.57**	0.04	0.53
H_2SO_4	0.002	7.41E-04	0.02	**0.03**	0	0.03
VOC	23.54	5.00	6.27	**34.81**	0.10	34.71
Hexane	1.92E-03	2.91E-04	9.80E-03	**0.012**	0.03	-0.018
HAP	0.02	0.001	0.04	**0.06**	0.04	0.02
CO_2e	4,442	1,353	47,614	**53,409**	3,141	50,268

<u>TEGF A, TEGF B, and HP Elevated Flare</u>

Revisions to the TEGF A, TEGF B, and HP Elevated Flare calculations are summarized below, followed by PTE tables. The TEGF A and TEGF B combust vent streams from the ethylene manufacturing unit, three polyethylene manufacturing units, and specific storage tanks and transfer racks at SPM. The TEGF A and TEGF B are both pressure-assisted multi-point flares. The HP Elevated Flare is a secondary flare to the TEGF A and TEGF B; therefore, unlike the TEGF A and TEGF B, the HP Elevated Flare does not continuously receive vent streams. The HP Elevated Flare is a steam-assisted flare.

The TEGF A and B are manufactured by Zeeco and have a maximum heat input of 13,257 MMBtu/hr (HHV). The HP Elevated Flare is also manufactured by Zeeco and has a maximum heat input of 59,659 MMBtu/hr (HHV). The total annual average heat input for the TEGF A, TEGF B, and HP elevated flare is 421.7 MMBtu/hr.

<u>Source IDs C205A and C205B: TEGF A and TEGF B</u> (previously HP Ground Flare #1 and #2)

- The flares' VOC potential to emit calculation originally included with the application for PA-04-00740D was based upon a destruction efficiency of 99% for organic compounds containing 3 or fewer carbon atoms and the VOC mass flow rate to the flare based upon site-specific data. Shell has revised the VOC PTE based upon 98% DRE for all VOC after discussions with the Department and which is reflected in the most recently provided calculations on September 5, 2025. The destruction efficiency is discussed after the flare calculation parameter tables later in this section.

- The flares' potential to emit calculations have been revised by Shell to include the additional amount of supplemental gas that has been estimated to be required to maintain the net heating value of the header's combustion zone gas at the minimum level of 800 Btu/scf per required by 40 CFR Part 63 Subpart YY. The NHV_{CZ} was previously required to be maintained at or above 500 Btu/scf per PA-04-00740A and PA-04-00740C.

- The flares' potential to emit calculations have been revised by Shell to include updates to vent stream flow rate and composition data based on a review of SPM's operating data. The September 5, 2025, revised version of Appendix B of the PA-D application that was submitted to the Department includes the vent stream flow rate and composition data that were used to calculate the potential to emit rates proposed for the TEGF A, TEGF B, and HP Elevated Flare.

- The flares' CO emission factor was updated based upon the revised CO emission factor in Table 13.5-2 of AP-42, Section 13.5 which was revised from 0.37 to 0.31 lb/MMBtu in February 2018.

- The flares' sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

- The flares' n-hexane emission factor was updated to equal the n-hexane emission factor indicated for a flare in the Natural Gas Fired External Combustion Equipment table in the May 17, 2001, VCAPCD AB 2588 Combustion Emission Factors document rather than the n-hexane emission factor documented in AP-42, Section 1.4, Table 1.4-3; 2.84E-05 lb/MMBtu compared to 1.76E-03 lb/MMBtu used previously.

Source ID C205C: HP Elevated Flare

- The flare's VOC potential to emit calculation has been calculated by Shell based upon 98% destruction efficiency and the VOC mass flow rate to the flare based upon site-specific data.

- The flare's potential to emit calculation has been revised by Shell to reflect that it periodically combusts vent streams during non-emergency episodes at SPM and its annual potential to emit rates were grouped with the annual potential to emit rates of the TEGF A and TEGF B due to the integrated operation of the three flares (i.e., the HP Elevated Flare only receives vent streams when the combined capacity of the TEGF A and TEGF B is exceeded). The TEGF A, TEGF B, and HP Elevated Flare potential to emit rates do not cover emergency flaring events.

- The flare's CO emission factor was updated based upon the revised CO emission factor in Table 13.5-2 of AP-42, Section 13.5 which was revised from 0.37 to 0.31 lb/MMBtu in February 2018.

- The flare's sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

- The flare's n-hexane emission factor was updated to equal the n-hexane emission factor indicated for a flare in the Natural Gas Fired External Combustion Equipment table in the May 17, 2001, VCAPCD AB 2588 Combustion Emission Factors document rather than the n-hexane emission factor documented in AP-42, Section 1.4, Table 1.4-3; 2.84E-05 lb/MMBtu compared to 1.76E-03 lb/MMBtu used previously.

Table 28: TEGF A, TEGF B, and HP Elevated Flare Calculation Parameters

Source	MMBtu/hr	VOC C3- to Flare	VOC C4+ to Flare	VOC DRE C3-	VOC DRE C4+
TEGF A and B Vent Gas / Short-Term Max	7,800	111.84 MT/hr	21.44 MT/hr	98%	98%
HP Elevated Flare Vent Gas / Short-Term Max	3,900	55.92 MT/hr	10.72 MT/hr	98%	98%
TEGF A, TEGF B, and HP Elevated Flare Vent Gas / Annual Average	161.2	1.06 MT/hr	0.18 MT/hr	98%	98%
TEGF A, TEGF B, and HP Elevated Flare Supplemental Gas / Annual Average	257.3	NG/TG Only	-	-	-
TEGF A, TEGF B, and HP Elevated Flare Pilots / Annual Average	3.25	-	-	-	-

(1) Annual average heat input based on amount of supplemental gas needed to increase combustion gas heating value to the 40 CFR Part 63 Subpart YY (EMACT) 800 Btu/scf requirement.
(2) Annual average heat input assumes approximately 90% of supplement is from Tail Gas and 10% is from Natural Gas.
(3) Short-term VOC mass rates represent maximum expected short-term rates excluding emergency flaring and are based on actual process data.
(4) Annual average VOC mass rates represent annual average anticipated flaring rates excluding emergency flaring and are based on actual process data.
(5) VOC to flare is in metric tons per hour. 1 metric ton = 1,000 kilograms = 2,204.62 pounds. Ethylene production is often measured in metric tons and is a standard unit of mass used in the chemical and petrochemical industries. Total annual average VOC to the TEGF A, TEGF B, and HP Elevated Flare is 1.24 MT/hr, or 11,974 tpy.
(6) NG/TG is natural gas/tail gas.

Destruction Efficiency

In Section 1.7, Potential to Emit Calculation Reconciliations of the September 13, 2024, plan approval application, Shell notes that the TEGF A, TEGF B, and HP Elevated Flare PTE "…was reconciled by using a 99% destruction efficiency for organic compounds containing 3 or fewer carbon atoms, which is consistent with EPA guidance." In Appendix B, Potential to Emit Calculations, of the Application, the basis for emission factors for these flares (Source IDs C204B, C205A, C205B, and C205C) for VOC states that:

> VOC based on 99% DRE for incoming C3- VOC and 98% DRE for incoming C4+ VOC consistent with TCEQ and EPA approvals/testing and DEP guidance.

In part, the Department's December 24, 2024, technical deficiency letter requested that Shell provide supporting information to justify the increased destruction efficiency from 98% to 99% for the MPGF, TEGF A, TEGF B, and HP Elevated Flare. In Shell's March 7, 2025, response to the Department, a May 24, 2023, Consent Order and Agreement (COA) between the Department and Shell is referenced as supporting the use of a 99% destruction efficiency for hydrocarbon compounds containing three or fewer carbon atoms that are combusted at the TEGF A, TEGF B, and HP Elevated Flare.

The Department does not have its own guidance on the destruction efficiency of flares to control VOC and HAP emissions from ethylene production. Destruction efficiency values were identified for emission reporting purposes under the COA settlement.

As a means to demonstrate compliance with the proposed increased destruction efficiency, Attachment 2 for the MPGF and Attachment 7 for the TEGF A, TEGF B, and HP Elevated Flare of the response to the December 24, 2024, technical deficiency letter, cite compliance with PA-04-00740C Section E Group Name G05 (NESHAP Part 63 Subpart YY) Condition #021 which is as follows: "The Owner/Operator shall comply with the applicable flare requirements of 40 CFR Part 63 Subpart CC as specified in 40 CFR §63.1103(e)(4)."

PA-04-00740C Section E Group Name G05 includes the applicable requirements of 40 CFR Part 63 Subpart YY, or the Ethylene Production MACT (EMACT). 40 CFR §63.1103(e)(4) of the EMACT requires compliance with the requirements of 40 CFR Part 63 Subpart CC, or the Refinery MACT.

On July 15, 2024, the U.S. Environmental Protection Agency (EPA) sent a letter to the Texas Commission on Environmental Quality (TCEQ) regarding TCEQ's longstanding guidance-based 99% destruction and removal efficiency (DRE) assumption for both assisted and non-assisted flares for C1-C3 compounds[32]. The letter communicated technical concerns related to TCEQ's flare DRE assumptions and the lack of adequate monitoring and operating requirements necessary to assure continuous compliance with emission limitations, such as those that rely on 99% DRE. Without adequate monitoring and recordkeeping assuring a specific DRE is maintained, there is potential for underestimating actual emissions when sources do not achieve the presumptive 99% DRE in practice.

[32] See Letter from David Garcia, Director, Air and Radiation Division, Region 6, U.S. EPA to Corey Chism, Director, Office of Air, TCEQ, Texas Commission on Environmental Quality Flare Operating and Monitoring Requirements as Specified in Clean Air Act New Source Review and Title V Operating Permits (July 15, 2024), available at https://www.epa.gov/system/files/documents/2024-07/2024.07.15.epa-comments-on-tceq-flare-assumptions.pdf.

The July 15, 2024, EPA letter emphasizes that the Refinery MACT and EMACT requirements can ensure a 98% destruction efficiency of HAPs when in continuous compliance with these regulations. This is also documented in the preamble to the EMACT. The letter also cites that the EPA made similar findings for flares in the April 25, 2023, proposed amendments to the New Source Performance Standards for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and the National Emission Standards for Hazardous Air Pollutants that apply to the SOCMI (commonly known as the Hazardous Organic NESHAP or "HON") and Group I and II Polymers and Resins Industries. See 88 Fed. Reg. 25151 (April 25, 2023).

EPA concludes that:

> The Petroleum Refinery MACT, Ethylene Production MACT, and HON all require enhanced flare stream monitoring requirements and operating limits that exceed TCEQ's current VOC Tier I presumptive BACT requirements for flares. However, as the EPA has already explained, even the enhanced monitoring and operating limits contained in these rulemakings were not designed to ensure flares will continuously achieve 99% DRE.

To date, Shell has not provided the referenced "EPA approvals/testing" as cited in the September 13, 2024, application for plan approval in order to demonstrate that the flares will continuously achieve 99% DRE.

Based on the above information, the Department has determined that Shell has not provided technically-sound, supporting rationale for the 99% DRE for hydrocarbon compounds containing three or fewer carbon atoms sufficient to validate the proposed hourly and annual VOC mass emission potential to emit. As such, Shell has revised the VOC PTE to base it on 98% DRE for all VOC after discussions with the Department which is reflected in the most recently provided calculations on September 5, 2025.

Vent Stream

In response to the Department's December 24, 2024, deficiency letter, on March 7, 2025, Shell provided the vent stream flow rate and composition data that were used to calculate the potential to emit rates proposed for the TEGF A, TEGF, B, and HP Elevated Flare. The vent stream flow rate and composition data are included in Attachment 8 of the response. The baseline VOC mass flowrate has since been revised by Shell with the calculations provided on September 5, 2025.

In addition to revising the DRE to 98% for all VOC, Shell reduced the TEGF A, TEGF B, and HP Elevated Flare VOC baseline flow rate from 400 kg/hr used originally in the application for PA-04-00740D to 250 kg/hr in the revised PTE. On October 15, 2025, via email, Shell provided the following additional information regarding the baseline flow:

> The HP Flare System PTE basis was reevaluated for development and eventual submittal of the plan approval application for EMACT RTR compliance, WWTP controls upgrades, and reconciliation. HP Flare System PTE was part of both the EMACT RTR compliance update to account for supplemental gas needed to achieve a minimum 800 Btu/scf NHVcz for the TEGFs as well as the reconciliation to account for process gas flow rates and HAPs that are part of expected flaring events including startup, shutdown, and maintenance events. When the application was in development in February and March, 2024, the baseline HP Flare System vent gas flow rate was reevaluated by a combination of review of past actual flare data and

engineering inputs where there was limited actual flare data. Most past actual data was based upon operation without PE3 as PE3 only successfully started up and entered a shakedown period on February 22, 2024, and below maximum ECU design rates as all three PE Units were not available to receive ethylene. An engineering input margin to HP Flare System vent gas baseline VOC remained to account for worst-case PE3 operation as well as ECU performance at higher rates and depending on expanders performance. Subsequent review of more recent past actual HP Flare System data shows that the HP Flare System baseline VOC is normally lower than previously represented when using worst case engineering inputs for PE3 and ECU and may be reduced. To adjust the baseline rate, more recent ethylene flaring data from 2025 including with all PE Units operating and ECU operating at design rates was reviewed, and it was determined that >75% of all hours had ethylene below 250 kg/hr.

Net Heating Value

Shell is required to operate the TEGF A, TEGF B, and HP Elevated Flare to maintain the net heating value of flare combustion zone gas (NHV_{CZ}) at or above the applicable limits in 40 CFR 63.670(e)(1) and (2) determined on a 15-minute block period basis when regulated material is routed to the flares for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{CZ} as specified in 40 CFR 63.670(m). For each pressure-assisted flare (TEGF A and TEGF B), the requirement is 800 Btu/scf. Shell previously used direct measurement by GC. Shell now uses direct measurement by calorimeter. Combusting additional supplemental gas to maintain the NHV_{CZ} of 800 Btu/scf compared to the previous requirement of 500 Btu/scf is the reason for the combustion emissions increases from the TEGF A and TEGF B.

Hexane

Shell has revised the n-hexane emissions based on the VCAPCD emission factor for hexane. See the justification above in the MPGF section.

Calculations have been found acceptable and the PTE from the high-pressure flares is shown in the table below.

Table 29: TEGF A, TEGF B, and HP Elevated Flare PTE

Pollutant	TEGF A, TEGF B, and HP Elevated Flare					
	PA-D				PA-C	Change
	Vent Gas and Supplemental Gas Emission Factor (lb/MMBtu)	Vent Gas + Pilots (tpy)	Supplemental Gas (tpy)	**Total (tpy)**	(tpy)	(tpy)
NOx	0.068	49.40	76.64	**126.03**	39.56	86.47
CO	0.31	220.00	349.37	**569.37**	215.26	354.11
PM (Filterable)	0.0019	1.34	2.10	**3.44**	1.08	2.36
PM_{10}	0.0075	5.37	8.40	**13.76**	4.34	9.42
$PM_{2.5}$	0.0075	5.37	8.40	**13.76**	4.34	9.42
SO_2	0.0015	1.06	1.66	**2.72**	0.86	1.86
VOC	0.3391/0.0054 [a]	239.45	6.08	**245.52**	237.17	8.35
Hexane	2.84E-05 [b]	-	-	**0.89**	1.03	-0.14
HAP [c]	Variable	-	-	**8.04**	1.08	6.96
CO_2e	Variable	95,619	98,238	**193,857**	76,696	117,161

[a] TEGF A, TEGF B, and HP Elevated Flare Vent Gas / TEGF A, TEGF B, and HP Elevated Flare Supplemental Gas emission factor.
[b] Hexane emission factor used to calculate hexane potential to emit that may result as a combustion product from vent gas and supplemental gas combustion at TEGF A, TEGF B, and HP Elevated Flare. The hexane potential to emit that may occur as a result of less than 100% destruction of hexane contained in the vent gas combusted at the flares was calculated using the concentration of hexane estimated to be in the vent gas, which was based on process knowledge, and the flares' DRE for hexane.
[c] See Appendix B of the plan approval application for each individual HAP emission factor, including metal HAP emission factors. Each individual organic HAP emission factor is based on AP-42, Table 1.4-3, except hexane. Hexane is based on VCAPCD AB 2588 as discussed above.

Source ID C206: SCTO (formerly known as Spent Caustic Vent Incinerator)

- NOx emissions calculations have been revised by Shell based upon the proposed LAER emission limit of 0.06 lb/MMBtu compared to the previous LAER limit of 0.068 lb/MMBtu, the design heat input (HHV) of 11.07 MMBtu/hr, and an operation time of 8,760 hours per year.

- The SCTO's potential to emit calculation has been revised by Shell to use a 99.9% destruction efficiency for the VOC and organic HAP contained in the vent streams combusted in the thermal oxidizer rather than a 99% destruction efficiency for those compounds to more accurately represent the designed VOC and organic HAP destruction efficiency of the thermal oxidizer.

  The SCTO was tested on May 23, 2024, and the test report indicates a VOC destruction efficiency of greater than 99.99%. Based on the Department's January 31, 2025, Source Test Audit Review memo, "The results for PM (Runs 2 & 3 only), CO, NO_X, THC, and benzene are acceptable to the Department of Environmental Protection (DEP) for determining compliance under conditions like those during testing." This plan approval will require additional testing of the SCTO destruction efficiency once the WWTP Permanent Controls Project equipment is commissioned to demonstrate compliance with the new emission limitation and additional load.

- The SCTO's potential to emit calculation has been revised by Shell to include the additional amount of supplemental fuel gas that has been estimated to be required to maintain the thermal oxidizer's temperature at a level necessary to ensure the minimum destruction efficiency required by applicable regulations and SPM's plan approval is achieved.

- The SCTO's potential to emit calculation has been revised by Shell to include updates to vent stream flow rates and compositions based on a review of operating data. Supporting vent stream data was provided by Shell on February 28, 2025.

- The SCTO's potential to emit calculation has been updated to include the vent streams from the new Wastewater Treatment Vessels that are proposed to be installed in the WWTP in association with the WWTP Permanent Controls Project. Supporting vent stream data from the WWTP was provided by Shell on February 28, 2025.

- The SCTO's SO_2 emission factor has been revised by Shell to include the small amount of SO2 generated by the combustion of natural gas in the thermal oxidizer.

- The SCTO's sulfuric acid emission factor has been revised by Shell to use the molecular weight of sulfuric acid rather than sulfur trioxide.

- The SCTO's n-hexane emission factor has been updated by Shell to equal the n-hexane emission factor indicated for a flare in the Natural Gas Fired External Combustion Equipment table in the May 17, 2001, VCAPCD AB 2588 Combustion Emission Factors document rather than the n-hexane emission factor documented in AP-42, Section 1.4, Table 1.4-3. According to the applicant, there is no n-hexane present in the waste gas to the SCTO, and n-hexane is only emitted as a product of combustion of the waste gas and fuel gas in the thermal oxidizer. As such, the SCTO was not performance tested for n-hexane emissions and the PTE was based upon the referenced VCAPCD emission factor which has been found acceptable to the Department.

The SCTO is used to control VOC, reduced sulfur compounds, and organic HAPs contained in the vent streams from the Spent Caustic Storage Tank, Spent Caustic Oxidation Unit, FEOR Tanks, Recovered Oil Storage Tank, and temporary primary treatment vessels in SPM's WWTP. Additionally, Shell is proposing to control the VOC and organic HAPs contained in the vent streams from the new Wastewater Treatment Vessels by routing their vents to the thermal oxidizer for combustion. The table below summarizes the SCTO PTE.

Table 30: SCTO Potential to Emit

Pollutant	PA-D[a] Emission Factor (lb/MMBtu)	PA-D[a] Short-Term Emission Rate (lb/hr)	PA-D[a] Emission Rate (tpy)	PA-C [b] Emission Rate (tpy)	Change (tpy)
NOx	0.06	0.66	**2.91**	3.19	-0.28
CO	0.0824	0.91	**3.99**	3.87	0.12
PM (Filterable)	0.0019	0.02	**0.09**	0.09	0.00
PM_{10}	0.0075	0.08	**0.36**	0.35	0.01
$PM_{2.5}$	0.0075	0.08	**0.36**	0.35	0.01
SO_2	0.0865	0.96	**4.19**	4.13	0.06
H_2SO_4	0.0043	0.05	**0.21**	0.17	0.04
VOC	0.0043[c]	0.05	**0.21**	1.42	-1.21
Hexane	2.84E-05	3.15E-04	**1.38E-03**	0.083	-0.082
HAP	-	0.03	**0.13**	1.42	-1.29
CO_2e	124.66	1,380	**6,044**	5,870	174

[a] PA-04-00740D based on heat input of 11.07 MMBtu/hr; Design basis based on waste gas flow and composition and natural gas flow (VOC + NG).
[b] PA-04-00740C based on heat input of 10.07 MMBtu/hr; Preliminary design basis based on treated gas flow and composition (VOC + NG).
[c] VOC Controlled EF based on actual process data plus VOC from WWTP and 99.9% DRE

<u>Source ID 301: Polyethylene Pellet Material Storage/Handling/Loadout</u>

- The emission source's VOC potential to emit calculation has been updated by Shell by increasing the PE Units 1-3 total annual polyethylene production rate to reflect the units' as-built polyethylene production rate capability (1,931,247 tons/year to 2,073,265 tons/year).

- The emission source's VOC potential to emit calculation has been revised based on the proposed LAER limit of 35.08 ppmw residual VOC concentration in the polyethylene pellets compared to the previous limit of 50 ppmw.

Particulate matter PTE calculations are unchanged from PA-04-00740C and shown in the following table. Revised VOC emissions are shown in the subsequent table and compared to PA-04-00740C.

Table 31: Polyethylene Pellet Material Storage/Handling/Loadout (Particulate Emissions)

Source	PM Emission Rate (tpy)	PM10 Emission Rate (tpy)	PM2.5 Emission Rate (tpy)
Blending Silos	3.52	1.20	1.20
Railcar Handling & Storage Silos	2.83	0.96	0.96
Truck Handling & Storage Silos	1.96	0.67	0.67
Railcar Loading	0.04	0.04	0.04
Truck Loading	0.02	0.02	0.02
Total	**8.36**	**2.88**	**2.88**

(1) Annual PE pellet rate based on actual process data and expected production/loading rates.
(2) PE pellet-to-air ratio based on actual design/process data.
(3) PM exit grain loading based on LAER limit of 0.005 gr/dscf.
(4) PM10/2.5 grain loading based on actual design data and engineering judgement.

Table 32: Polyethylene Pellet Material Storage/Handling/Loadout (VOC Emissions)

Annual PE Pellet Production Rate	2,073,265 tons/yr	Total as-built design basis for PE Units 1-3
PE Pellet Residual VOC Concentration	35.08 ppmw	LAER Limit
Fraction of Residual VOC Emitted	100%	Worst-case assumption
PA-D VOC PTE	**72.73 tpy**	(Pellet prod) x (VOC conc) x (fraction of VOC emitted)/(1,000,000)
PA-C VOC PTE	1,931,247 tons/yr	Design basis of Franklin plant scaled to 8,760 hours/yr
	50 ppmw	Previous LAER Limit
	88.18 tpy	(Pellet prod) x (VOC conc) x (fraction of VOC emitted) x (8,000 hr/yr / 8,760 hr/yr) / (1,000,000)
Change	-15.45	

* Residual VOC in PE pellets does not contain HAP.

Source ID 303: Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, and PE3 Heavies)

PTE from organic liquid loadout, Source ID 303, was calculated in PA-04-0040C to be 0.05 tpy VOC and 0.05 tpy HAP. As part of this application, the applicant has noted that emissions from this source are controlled by vapor capture and routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header**. Emission calculations for organic liquid loadout were provided in Shell's February 28, 2025, and March 7, 2025, responses to the Department in relation to the vent streams to the CVTO and MPGF. PTE from Source ID 303 is accounted for with the CVTO and MPGF PTE.

Source ID 304: Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)

- The emission source's potential to emit calculation has been revised by Shell to more accurately represent the number of railcar loading and unloading events that may occur for the specific materials covered by the emission source.

As noted above, in Section 1.7 of the application for PA-04-00740D, the applicant states that emissions from Source ID 304 have been revised to accurately represent the number of railcar loading and unloading events. Emissions for C3+ loading and C3, butene and isobutane (C4), and hexene and isopentane (C6) unloading were calculated by the applicant in this application based on the annual number of railcars loaded and/or unloaded, the number of hose coupling disconnects per event, vendor emission factor of 0.35 ml H_2O/coupling for 2-inch TODO Gas DN50 couplings, the density of each constituent (C3, C3+, C4, and C6), and the ratio of the density of water to each constituent. The resulting emission factors range from approximately 0.00135 to 0.00273 lb VOC per railcar. The PTE is shown in the table below.

Table 33: Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref) PTE

Source	VOC	HAP
	Emission Rate (tpy)	Emission Rate (tpy)
C_3+	0.0027	0.001
Butene and Isobutane	0.0007	-
Hexene and Isopentane	0.0015	-
Total	**0.005**	**0.001**
PA-C	0.005	0

* C3+ HAP concentrations for PA-04-00740D: 39.0 wt.% 1,3 butadiene, 12.0 wt.% benzene, and 1.0 wt.% toluene.

<u>Source ID 501: Equipment Components</u>

- The equipment leak potential to emit calculation has been revised by Shell by updating the component inventory and composition of the materials contained in those components to more accurately represent the number of equipment components at SPM and the material compositions at SPM. The equipment component counts and class/type were based on data from the site’s LDAR program.

- The equipment leak potential to emit calculation has been revised by Shell by revising the control efficiencies for the compressor seals and certain relief valves at SPM to reflect the collection and routing of leaked materials from those components to an enclosed collection system and control device or closed system process equipment rather than the implementation of an LDAR program on the referenced components.

According to the applicant, the VOC PTE decreased overall for Source ID 501 Equipment Components due to a combination of updates to equipment component counts, class/type of components, compressor seal and relief valve leakage collection and control configurations, and stream compositions. For the previous, design-based plan approvals, the equipment component counts and class/type estimates were based on model plant data and a contingency percent increase. Stream compositions were also more broadly estimated based on worse case VOC compositions.

For this plan approval application, the equipment component counts and class/type were based on data directly from SPM’s LDAR program database. Compressor seals and certain relief valves were indicated to be controlled in the PTE calculation because the seals and valves are equipped with collection systems that route seal leakage or valve leakage to a control device or closed system process equipment. Stream compositions are based on more narrow heat and material balance documentation and site engineering determinations.

Fugitive emissions from equipment components have been broken down into four categories: ethylene manufacturing unit, PE Units 1 and 2, PE Unit 3, and “outside the boundary limits” (OSBL). PTE was calculated by the applicant based upon synthetic organic chemical manufacturing industry (SOCMI) average emission factors (lb/hr/component), number of components, LAER control efficiency, and the wt.% of VOC, HAP, CH4, CO, and CO_2. This includes any potentially leaking components in gas/vapor, light liquid, or heavy liquid service which contain or contact VOC, HAP, CH_4, and/or CO.

See appendix B of the application for control efficiencies which range from 0% to 100% and the weight % of each constituent. Equipment component emissions are shown in the table below.

Table 34: Fugitive Emissions from Equipment Components PTE

Source	VOC	HAP	CO	CO_2e
	Emission Rate (tpy)	Emission Rate (tpy)	Emission Rate (tpy)	Emission Rate (tpy)
Ethylene Manufacturing Unit	11.36	2.06	0.03	248.7
PE Units 1 & 2	11.18	0	0	5.5
PE Unit 3	5.41	0.012	2.78	7.5
OSBL	7.33	1.05	0	139.4
Total	**35.28**	**3.12**	**2.81**	**401**
PA-C	67.88	4.11	-	138
Change	-32.60	-0.99	2.81	263

[a] Outside the boundary limits” (OSBL): Components outside of the ethylene and polyethylene manufacturing lines; including tanks, cogeneration plant, engines, cooling towers, and wastewater treatment.

Source ID 502: Wastewater Treatment Plant (Secondary and Tertiary Treatment)

The WWTP consists of primary treatment (oils, grease, and VOC removal operations), secondary treatment (biotreatment operations), and tertiary treatment (filtration operations) of process wastewater and potentially contaminated stormwater generated at SPM. Wastewater enters the WWTP and flows through the FEOR Tanks, which are IFR tanks that vent to the SCTO. Oil that rises to the top of the liquid in the FEOR Tanks is skimmed off and flows to the Recovered Oil Storage Tank, which is also an IFR tank that vents to the SCTO. Effluent from the FEOR Tanks currently flows to the following temporary equipment for the removal of additional oils, grease, and VOC: a WEMCO mechanical INF device and an EC-15 hydraulic INF device. The effluents from this temporary equipment and the FEOR Tanks are routed to the Biotreater Aeration Tanks, which also receive WWTP recycle, nutrient additive, and pH adjustment streams. However, after the WWTP Permanent Controls Project, the new Wastewater Treatment Vessels will be integrated with the FEOR Tanks, and specific effluents from these vessels and tanks will be routed to the Biotreater Aeration Tanks. The previously referenced temporary WWTP equipment will be removed after the successful commissioning of the WWTP Permanent Controls Project.

Effluent from the Biotreater Aeration Tanks flows to two Secondary Clarifier Tanks. The overflow stream from the clarifiers is pumped through a sand filter. Clarifier underflow is pumped to a biosludge holding tank that feeds a centrifuge used for concentrating clarifier solids into a cake. Cooling water tower blowdown is pumped directly to the Sand Filter. Effluent from this filter is discharged through an outfall to the Ohio River. Sand filter backwash is pumped into the Sand Filter Backwash Receiver and then recycled back to the Biotreater Aeration Tanks.

The WWTP is a source of VOC and HAP emissions which are minimized by venting the FEOR Tanks, Recovered Oil Storage Tank, and temporary WWTP equipment referenced above to the SCTO. Additionally, the vents from the new Wastewater Treatment Vessels will be routed to the SCTO for combustion.

The following is a summary of the changes to the Wastewater Treatment Plant (Secondary and Tertiary Treatment) emissions calculations in this application.

- The potential to emit calculation model used by Shell for the Wastewater Treatment Plant (Secondary and Tertiary Treatment) was revised from WATER9 to Toxchem Version 4.4, which is a calculation tool mainly used for estimating VOC emissions from wastewater collection, preliminary/primary/secondary treatment, and disposal facilities.

- The potential to emit calculation for the Wastewater Treatment Plant (Secondary and Tertiary Treatment) has been revised by Shell by increasing the wastewater flow rate through the WWTP to more accurately represent the rates that flow through the WWTP, increasing the aeration area of the Biotreater Aeration Tanks to reflect the as-built dimensions of the tanks, and increasing the number of organic compounds indicated to be present in the wastewater treated in the WWTP based on actual operations data.

- The potential to emit calculation for the Wastewater Treatment Plant (Secondary and Tertiary Treatment) has been updated by Shell to include the effects of the improved primary treatment that is expected to be achieved by the new Wastewater Treatment Vessels that are proposed to be installed in the WWTP in association with the WWTP Permanent Controls Project.

Note that the following WWTP equipment that will be controlled by the SCTO are included with the SCTO PTE.

- Two (2) FEOR Tanks
- Recovered Oil Storage Tank
- Settlement Drum (*proposed equipment that will vent to a closed vent system that will be routed to the SCTO*)
- Two (2) DNF Units (*proposed equipment that will vent to a closed vent system that will be routed to the SCTO*)
- Float/Sludge Drum (*proposed equipment that will vent to a closed vent system that will be routed to the SCTO*)
- Steam Stripper and associated Reflux Drum (*proposed equipment that will vent to a closed vent system that will be routed to the SCTO*)

The EPA developed WATER9 as a tool for estimating air emissions from wastewater facilities, and it was used in emissions inventory calculations and residual risk and technology review processes. WATER9 uses fundamental mass transfer equations and mass balances to perform wastewater emission calculations. WATER9

Version 3.0, was released June 29, 2006. According to EPA's website:[33]

> WATER9, the wastewater treatment model, is a Windows based computer program and consists of analytical expressions for estimating air emissions of individual waste constituents in wastewater collection, storage, treatment, and disposal facilities; a database listing many of the organic compounds; and procedures for obtaining reports of constituent fates, including air emissions and treatment effectiveness.
>
> The WATER9 model was developed using a software that is now outdated. Because of this, the model is not reliably functional on computers using certain operating systems such as Windows Vista or Windows 7. We are anticipating that additional problems will arise as PCs switch to the other operating systems. Therefore, we can no longer provide assistance to users of WATER9.
>
> The model will remain on the website to be used at your discretion and at your own risk.

Toxchem is a wastewater modeling program offered through Hydromantis Environmental Software Solutions Inc. According to Hydromantis's website:[34]

> Toxchem is mainly used for estimating VOC air emissions from wastewater collection, preliminary/primary/secondary treatment and disposal facilities. The site specific wastewater characteristics, contaminant properties and the process design and operating information are used to estimate VOC emission rates.
>
> In addition to air emission estimates, Toxchem can also be used to estimate the concentrations/loads of contaminants in the water effluent, or oil and residual solids streams.
>
> Toxchem is based on fundamental mass transfer equations and mass balances including the removal mechanism of stripping and volatilization, biodegradation and sorption. Thus, it can also be used to determine the fate of any synthetic chemical compounds for which the physical, chemical and biodegrading properties are known.
>
> Toxchem was developed in early 1990s as an alternative to Water8 (Water9) software developed by EPA to overcome limitations of Water8/9, including improved mass transfer processes, sorption of contaminants to solids, and a compound database containing critically-reviewed physical, chemical and biological properties.
>
> The National Emission Standards for Hazardous Air Pollutants (NESHAPs) promulgated after the 1990 Clean Air Act Amendments are found in 40 CFR Part 63. These standards provide guidelines to meet the compliance with wastewater rules that regulate emissions of semi-volatile and volatile organic compounds (VOC). Toxchem was specifically included in Appendix C of 40 CFR Part 63 as an accepted alternative to Water 8 for estimation of wastewater treatment emissions.

WATER9 has been a commonly used wastewater air emission tool as it is a freeware Windows software

[33] https://www.epa.gov/chief/water9-version-30
[34] https://www.hydromantis.com/Toxchem.html

provided by EPA that is free to download and use, and includes a large selection of wastewater component choices, a user-expandable chemical property database, and is capable of modeling complex systems. Drawbacks to using EPA's WATER9 model for wastewater emission calculations include its outdated software, limited functionality on modern operating systems, and limited or no assistance to users.

Shell has revised the WWTP's potential to emit calculations using Toxchem rather than WATER9. Like WATER9, Toxchem is a wastewater collection, storage, separation, and treatment system emissions estimation model that uses fundamental mass transfer equations and mass balances to perform wastewater emission calculations. Toxchem is documented by EPA in 40 CFR Part 63, Appendix C[35] as an acceptable alternative to WATER7/WATER8/WATER9. Toxchem is also listed as a preferred method of estimating emissions in EPA's Volume II, Chapter 5 – *Preferred and Alternative Methods for Estimating Air Emissions from Wastewater Collection and Treatment*[36], March 1997. According to the EPA document, the preferred method for estimating emissions from wastewater collection and treatment (WWCT) is the use of computer-based emissions models and the use of site-specific data is always preferred over the use of default data. The emission calculations provided by Shell using Toxchem are based on site specific sample data from SPM, which was provided to the Department on February 7, 2025, in response to the Department's December 24, 2024, technical deficiency letter.

Although the WWTP is subject to 40 CFR Part 61 Subpart FF and 40 CFR Part 63 Subparts XX and YY, there are no federal regulations applicable to the WWTP at SPM that stipulate the use of WATER9 for air emission calculations. After review, Toxchem has been found by the Department to be an acceptable method to calculate emissions from the Wastewater Treatment Plant (Secondary and Tertiary Treatment) at SPM.

Wastewater Treatment Plant (Secondary and Tertiary Treatment) Calculations

On February 7, 2025, Shell provided additional information regarding the Wastewater Treatment Plant (Secondary and Tertiary Treatment) emissions in response to the Department's December 24, 2024, technical deficiency letter, including wastewater sample data, Biotreater inlet stream hydrocarbon concentrations that were input into Toxchem to calculate the potential to emit rates proposed for the Wastewater Treatment Plant (Secondary and Tertiary Treatment), and additional calculation methodology information.

The new Steam Stripper will treat wastewater before it is routed to the Biotreaters. The Steam Stripper is expected to achieve a hydrocarbon removal efficiency greater than 98%. However, Shell conservatively estimated the Biotreater inlet stream hydrocarbon concentrations input into Toxchem on the basis that the Steam Stripper will achieve lower hydrocarbon removal efficiencies in order to estimate worst-case emissions from the Biotreaters and WWTP equipment downstream of the Biotreaters during normal operations. For BTEX and other compounds[37], the Biotreater inlet stream concentration was estimated by using a 30% removal efficiency of the average of the 1/10/23-3/31/24 Biotreater inlet stream sample concentrations. For chloroform, which was not detected in the referenced samples, the Biotreater inlet stream concentration was estimated using the minimum detection limit of 0.0006 mg/L with an 80% removal efficiency. Vapors from the Steam Stripper are routed to the SCTO for control. For other hydrocarbons[38] detected at concentrations less than 0.01 mg/L, the

---

[35] eCFR :: Appendix C to Part 63, Title 40 -- Determination of the Fraction Biodegraded (Fbio) in a Biological Treatment Unit
[36] https://www.epa.gov/sites/default/files/2015-08/documents/ii05.pdf
[37] Steam stripper removal efficiency of 30% has been assumed for the following hydrocarbons: Benzene, phenol, toluene, ethylbenzene, xylene, styrene, and naphthalene.
[38] Concentrations of the following compounds has been estimated to be 0.01 mg/L: Dibutylphthalate, acenaphthene, acenaphthylene,

concentration of these hydrocarbons was conservatively set at 0.01 mg/L. The table below shows the WWTP (Secondary and Tertiary Treatment) PTE calculated by the applicant using Toxchem Version 4.4.

Table 35: Wastewater Treatment Plant (Secondary and Tertiary Treatment) PTE

Pollutant	Toxchem Output	PTE	Calculation Basis
	lb/hr	tpy	
Benzene	8.41E-03	0.037	Toxchem
Phenol	1.28E-07	5.59E-07	Toxchem
Toluene	2.58E-02	0.113	Toxchem
Ethylbenzene	1.35E-03	5.91E-03	Toxchem
Xylene	3.70E-03	0.016	Toxchem
Styrene	2.53E-02	0.111	Toxchem
Naphthalene	2.10E-04	9.20E-04	Toxchem
Dibutyl phthalate	2.01E-07	8.81E-07	Toxchem
Chloroform	3.33E-05	1.46E-04	Toxchem
Acenaphthene	3.23E-05	1.42E-04	Toxchem
Acenaphthylene	1.64E-05	7.19E-05	Toxchem
Fluorene	1.32E-05	5.76E-05	Toxchem
Anthracene	1.62E-05	7.10E-05	Toxchem
Phenanthrene	8.45E-06	3.70E-05	Toxchem
Fluoranthene	2.77E-06	1.21E-05	Toxchem
Pyrene	1.65E-06	7.24E-06	Toxchem
VOC	**0.065**	**0.28**	Toxchem
HAP	**0.065**	**0.28**	Toxchem
PA-C VOC/HAP	0.010	0.042	EPA WATER9

(1) The WWTP includes two FEOR Tanks, a Recovered Oil Storage Tank, two temporary INF Vessels, two Biotreater Aeration Tanks, two Secondary Clarifiers, two Biosludge Holding Tanks, a Centrifuge, a Sand Filter, a Sump (for centrate and sand filter backwash), and a Treated Effluent Sump. The WWTP Permanent Controls Project proposes the installation of a Settlement Drum, two DNF Units, a Float/Sludge Drum, and a Steam Stripper to replace the two temporary INF Vessels. The two FEOR Tanks and Recovered Oil Storage Tank vent to the SCTO; therefore, their emissions are not included in the table above. Additionally, the new Settlement Drum, two DNF Units, Float/Sludge Drum, and Steam Stripper will vent to the SCTO; therefore, their emissions are not included in the table. Lastly, the two temporary INF Vessels vent to the SCTO, and they will be removed after the successful commissioning of the WWTP Permanent Controls Project; therefore, their emissions are not included in the table.
(2) Biotreater Aeration Tanks A and B account for >99% of the WWTP PTE.
(3) Emissions were modeled under worst-case conditions of dry weather flow. Dry weather flow represents normal wastewater flow conditions without stormwater inflow. If stormwater inflow is accounted for in a wastewater system, then the stormwater results in the dilution of dry weather flow VOC concentrations, which generally results in lower VOC emissions estimates for a wastewater system. Thus, dry weather flow is considered worst-case for estimating emissions from a wastewater system that can receive stormwater.
(4) The Biotreater Aeration Tanks' inlet concentrations were based on actual sample data for the 1/10/23 through 3/31/24 period, excluding ethylene manufacturing unit downtime and abnormal conditions.

Reported actual emissions from the WWTP are shown in the following table for the years 2022-2024. Emissions from the WWTP were not reported prior to 2022.

fluorene, anthracene, phenanthrene, fluoranthene, and pyrene.

Table 36: WWTP Reported Actual Emissions

Pollutant	2022	2023	2024
	tpy	tpy	tpy
1,3-Butadiene*	-	0.01	-
Ethyl Benzene*	-	0.05	0.01
Methyl Chloride Chloromethane*	-	0.02	-
Naphthalene*	-	0.06	0.07
Polycyclic Organic Matter*	-	-	0.01
Styrene*	0.01	0.13	0.09
Tetrachloroethylene*	-	0.02	-
Toluene*	0.09	1.86	0.34
Xylene*	-	0.01	-
Benzene*	0.30	2.09	0.44
Total [a]	0.40	4.25	0.96
VOC [b]	**0.70**	**5.13**	**0.97**
Total HAP [c]	**0.40**	**4.25**	**0.96**
Thruput (Th Gal)	156,800	434,400	544,000

[a] Total is the sum of the individual reported pollutants shown in the table.
[b] VOC is the reported VOC.
[c] Total HAP is the sum of the individual reported HAPs (denoted by *).

As shown in the table above, reported emissions from each year that emissions were reported for the WWTP are higher than the PTE provided in this plan approval application. As discussed in this memo, the proposed WWTP Permanent Controls Project is designed to improve the oils, grease, and VOC removal capabilities of the WWTP, reducing the PTE.

Facility-Wide PTE

The tables below summarize the revised facility-wide potential emissions due to the changes proposed in this plan approval. The proposed PTE includes the Plan Approval Reconciliations, Wastewater Treatment Plant Permanent Controls Project, and EMACT Project. The column labeled "Previous PTE" is the facility-wide emission limits from PA-04-00740C, Section C, Condition # 005.

Table 37: Facility-Wide PTE and Emission Changes

Air Contaminant	Proposed PTE (tpy)	Previous PTE (tpy)	Change in Emissions (tpy)
NOx	455.13	328.5	126.63
CO	1,214.35	983.7	230.65
PM (filterable)	78.41	74.3	4.11
PM_{10}	184.02	168.9	15.12
$PM_{2.5}$	178.15	163.7	14.45
SO_2	27.24	22.4	4.84
VOC	509.99	516.2	-6.21
HAP	23.44	32.0	-8.56
Ammonia	137.23	154	-16.77
CO_2e	2,566,563	2,304,499	262,064

Table 38: Source-by-Source Potential to Emit

Source ID	Source Description	CO	NOx	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO_2e	NH_3	HAPs
		tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy
31	Ethane Cracking Furnace #1	58.55	25.90	4.75	12.40	12.40	0.68	2.61	157,365	10.45	0.73
32	Ethane Cracking Furnace #2	58.55	25.90	4.75	12.40	12.40	0.68	2.61	157,365	10.45	0.73
33	Ethane Cracking Furnace #3	58.55	25.90	4.75	12.40	12.40	0.68	2.61	157,365	10.45	0.73
34	Ethane Cracking Furnace #4	58.55	25.90	4.75	12.40	12.40	0.68	2.61	157,365	10.45	0.73
35	Ethane Cracking Furnace #5	58.55	25.90	4.75	12.40	12.40	0.68	2.61	157,365	10.45	0.73
36	Ethane Cracking Furnace #6	58.55	25.90	4.75	12.40	12.40	0.68	2.61	157,365	10.45	0.73
37	Ethane Cracking Furnace #7	58.55	25.90	4.75	12.40	12.40	0.68	2.61	157,365	10.45	0.73
101	Combustion Turbine/Duct Buner Unit #1	15.00	23.45	5.95	20.68	20.68	4.61	11.03	366,919	21.36	1.87
102	Combustion Turbine/Duct Buner Unit #2	15.00	23.45	5.95	20.68	20.68	4.61	11.03	366,919	21.36	1.87
103	Combustion Turbine/Duct Buner Unit #3	15.00	23.45	5.95	20.68	20.68	4.61	11.03	366,919	21.36	1.87
104	Cogeneration Plant Cooling Tower	-	-	2.63	1.67	0.01	-	-	-	-	
105	Diesel-Fired Emergency Generator Engines (2); Generator 1 - Parking Garage	0.01	0.03	0.001	0.001	0.001	5.60E-05	4.54E-04	6	-	1.40E-04
105	Diesel-Fired Emergency Generator Engines (2); Generator 2 - Telecom Hut	0.005	0.02	0.002	0.002	0.001	3.65E-05	0.001	4	-	9.08E-05
106	Fire Pump Engines (2); Firewater Pump 1	0.14	0.10	0.01	0.01	0.01	2.65E-04	0.06	28	-	6.62E-04
106	Fire Pump Engines (2); Firewater Pump 2	0.14	0.10	0.01	0.01	0.01	2.65E-04	0.06	28	-	6.62E-04
107	Natural Gas-Fired Emergency Generator Engines (2); Gen 3 - Lift Station	0.01	0.03	0.001	0.001	0.001	4.17E-05	0.02	11	-	0.002
107	Natural Gas-Fired Emergency Generator Engines (2); Gen 4 - Lift Station	0.13	0.03	1.44E-06	1.86E-04	1.86E-04	1.10E-05	0.002	4	-	0.001
202	Polyethylene Manufacturing Lines	-	-	3.44	3.44	3.44	-	-	-	-	1.36E-04
203	Process Cooling Tower	-	-	6.49	4.12	0.01	-	38.88	-	-	0.97

Source ID	Source Description	CO	NOx	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO_2e	NH_3	HAPs
		tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy
C204	CVTO	65.29	47.57	1.48	5.91	5.91	1.17	30.77	109,579	-	0.11
C207	MPGF CVTO Trip	9.56	2.26	0.06	0.24	0.24	0.05	23.54	4,442	-	0.02
C208	MPGF Ethylene Tank	2.07	0.84	0.02	0.08	0.08	0.02	5.00	1,353	-	0.001
C209	MPGF PE Units 1/2 Episodic Vent	105.97	23.56	0.64	2.57	2.57	0.51	6.27	47,614	-	0.04
C205A	TEGF A	569.37	126.03	3.44	13.76	13.76	2.72	245.52	193,857	-	8.04
C205B	TEGF B										
C205C	HP Elevated Flare										
C206	SCTO	3.99	2.91	0.09	0.36	0.36	4.19	0.21	6,044	-	0.13
301	Polyethylene Pellet Material Storage/Handling/Loadout	-	-	8.36	2.88	2.88	-	72.73	-	-	-
302	Liquid Loadout (Recovered Oil)	-	-	-	-	-	-	0.005	-	-	1.04E-05
304	Liquid Loadout (C3+, Butene, isopentane, Isobutane, C3 Ref)	-	-	-	-	-	-	0.005	-	-	0.001
406	Storage Tanks (Diesel Fuel > 150 Gallons	-	-	-	-	-	-	4.25E-04	-	-	4.25E-04
501	Equipment Components	2.81	-	-	-	-	-	35.28	401	-	3.12
502	Wastewater Treatment Plant (Secondary and Tertiary Treatment)	-	-	-	-	-	-	0.28	-	-	0.28
503	Plant Roadways	-	-	0.64	0.13	0.03	-	-	-	-	-
504	Gas Insulated Switchgear (SF6)	-	-	-	-	-	-	-	880	-	-
	Total (tpy)	**1,214.35**	**455.13**	**78.41**	**184.02**	**178.15**	**27.24**	**509.99**	**2,566,563**	**137.23**	**23.44**
	PA-C (tpy)	983.7	328.5	74.3	168.9	163.7	22.4	516.2	2,304,499	154	32.0
	Change in Emissions (tpy)	**230.65**	**126.63**	**4.11**	**15.12**	**14.45**	**4.84**	**-6.21**	**262,064**	**-16.77**	**-8.56**

Air Quality Analysis

Due to the changes proposed, Shell's plan approval application for PA-04-00740D included the following air quality analyses:

- Source impact analyses of the net emissions increase of CO, NOx, and $PM_{2.5}$ due to the EMACT Project;

- Source impact analyses of the revised PTE of CO, NOx, and PM_{10} that accounts for the WWTP Permanent Controls Project and Plan Approval Reconciliations;

- Additional impact analyses of the impairment to visibility, soils, and vegetation that accounts for the net emissions increase due to the EMACT Project, the revised PTE that accounts for the WWTP Permanent Controls Project and Plan Approval Reconciliations, and associated growth; and

- Initial screening calculations to determine whether the net emissions increase from the EMACT Project, in conjunction with the revised PTE that accounts for the WWTP Permanent Controls Project and Plan Approval Reconciliations, would have negligible impacts on air quality related values (AQRV) and visibility in nearby federal Class I areas.

This modeling was evaluated by the Department's Air Quality Modeling and Risk Assessment Section. The Air Quality Modeling and Risk Assessment Section's "Air Quality Analyses for Prevention of Significant Deterioration" memorandum dated December 22, 2025, is included in Appendix A of this review memorandum.

The Department's technical review concludes that Shell's air quality analyses for both the EMACT Project and for the WWTP Permanent Controls Project and Plan Approval Reconciliations, in conjunction with the revisions made by the Department, satisfy the requirements of the PSD regulations.

In accordance with 40 CFR § 52.21(k), Shell's source impact analyses demonstrate that the net emissions increase due to the EMACT Project would not cause or contribute to air pollution in violation of the NAAQS for CO, NO_2, and $PM_{2.5}$, or the Class II Area and Class I Area PSD increments for NO_2 and $PM_{2.5}$.

Similar to the findings of previously conducted air quality analyses to support its applications for Plan Approvals 04-00740A and 04-00740C, Shell's revised source impact analyses demonstrate that the revised PTE that accounts for the WWTP Permanent Controls Project and Plan Approval Reconciliations, in conjunction with the net emissions increase due to the EMACT Project, would not cause or contribute to air pollution in violation of the NAAQS for CO, NO_2, and PM_{10}, or the Class II Area and Class I Area PSD increments for NO2 and PM-10.

In accordance with 40 CFR § 52.21(l), Shell's estimates of ambient concentrations are based on applicable air quality models, databases, and other requirements specified in the EPA's *Guideline on Air Quality Models* as well as the EPA's relevant air quality modeling policy and guidance.

In accordance with 40 CFR § 52.21(m), Shell provided an analysis of existing ambient air quality in the area that emissions from Shell Polymers Monaca Site would affect that included existing representative ambient monitoring data for CO, NOx, PM_{10}, and PM-2.5. Shell's emissions of H_2SO_4 are not subject to and emissions of PM are exempt from the requirements of 40 CFR § 52.21(m).

In accordance with 40 CFR § 52.21(n), Shell provided all information necessary to perform the air quality analyses required by the PSD regulations, including all air dispersion modeling data necessary to estimate the air quality impacts of the net emissions increase due to the EMACT Project and the revised PTE that accounts for the WWTP Permanent Controls Project and Plan Approval Reconciliations.

In accordance with 40 CFR § 52.21(o), Shell provided additional impact analyses of the impairment to visibility, soils, and vegetation that would occur as a result of the net emissions increase due to the EMACT Project, in conjunction with the revised PTE that accounts for the WWTP Permanent Controls Project and Plan Approval Reconciliations. Based on Shell's latest analyses, no residential, commercial, or industrial growth is expected from SPM.

In accordance with 40 CFR § 52.21(p), written notice of Shell's EMACT Project, WWTP Permanent Controls Project, and Plan Approval Reconciliations have been provided to the FLMs of nearby federal Class I areas. The notice included initial screening calculations that demonstrate that Shell's net emissions increase due to the EMACT Project, in conjunction with the revised PTE that accounts for the WWTP Permanent Controls Project and Plan Approval Reconciliations, would have negligible impacts on AQRVs and visibility in nearby federal Class I areas. On September 17, 2024, and October 9, 2024, the Department received notifications from the Forest Service and National Park Service, respectively, that no further Class I analysis was being requested.

Inhalation Risk Assessment

In accordance with Section C, Condition # 035 of PA-04-00740C, Shell is required to conduct an inhalation risk assessment for the Facility based upon the final as-built design parameters of the air contamination sources. Shell has submitted a revised inhalation risk assessment in accordance with Condition # 035 as part of this plan approval application. This inhalation risk assessment was evaluated by the Department's Air Quality Modeling and Risk Assessment Section.

The Department's technical review concludes that Shell's air dispersion modeling for the inhalation risk assessment, in conjunction with the revisions made by the Department, is consistent with the EPA's relevant air dispersion modeling policy and guidance. The Air Quality Modeling and Risk Assessment Section's "Air Dispersion Modeling for Inhalation Risk Assessment" memorandum dated December 22, 2025, is included in Appendix B of this review memorandum.

The Department's technical review concludes that Shell's inhalation risk assessment, in conjunction with the revisions made by the Department, demonstrates that the excess lifetime cancer risk (ELCR), chronic noncancer risk, and acute noncancer risk due to inhalation of the chemicals of potential concern (COPC) would not exceed the Department's benchmarks. The Air Quality Modeling and Risk Assessment Section's "Inhalation Risk Assessment" memorandum dated December 22, 2025, is included in Appendix C of this review memorandum.

Environmental Justice

Environmental Justice (EJ) Areas are identified as communities facing environmental justice issues using more than 30 environmental, health, and socioeconomic indicators. Census Tract 42007605500 (Potter Township, Beaver County) is an EJ Area due to a variety of social and economic factors. The Department is working to facilitate enhanced public participation to ensure that the public is informed and can be involved in the public comment and response process.

Under the EJ Policy, major modifications of a major source subject to Prevention of Significant Deterioration applications are designated as Public Participation Trigger Permits. Further enhanced public participation for this facility's Plan Approval application will include a public meeting and a public hearing. At public meetings, the public may ask questions that the Department can review and answer. At public hearings, the public may provide testimony for the Department to respond to and consider when drafting the final decision.

CONCLUSIONS AND RECOMMENDATIONS

Shell has shown in this application that emissions due to the Plan Approval Reconciliations, WWTP Permanent Controls Project, and EMACT Project will be minimized through the use of appropriate BAT, BACT, and LAER at the ethylene and polyethylene production facility known SPM located in Potter and Center Townships, Beaver County.

Shell has demonstrated that the proposed projects will not cause or contribute to air pollution in violation of the NAAQS, will not impair visibility, soils, and vegetation, will not adversely affect AQRV, including visibility, in federal Class I areas, and chronic cancer and noncancer risks as well as acute noncancer risks will not exceed the Department's benchmarks. Therefore, upon completion of the required EPA and public comment periods, I recommend issuance of a Plan Approval for a period of up to 180 days subject to the standard conditions in Section B of all plan approvals along with the following modified and additional special conditions.

Modified/New Special Conditions

SECTION C. Site Level Requirements

#005: Emissions from the Facility shall not equal or exceed the following in any consecutive 12-month period [25 Pa. Code § 127.12b]:

Air Contaminant	Emission Rate (tons)
NOx	~~328.5~~ **455.13**
CO	~~983.7~~ **1,214.35**
PM (filterable)	~~74.3~~ **78.41**
PM10	~~168.9~~ **184.02**
PM2.5	~~163.7~~ **178.15**
SOx	~~22.4~~ **27.24**
VOC	~~516.2~~ **509.99**
VOC (ERC)*	~~612~~ **591**
HAP	~~32.0~~ **23.44**
Ammonia	~~154~~ **137.23**
CO2e**	~~2,304,499~~ **2,566,563**

* This limit is included to ensure that the proper amount of VOC ERCs are secured by the applicant in accordance with the VOC offset ratios for flue and fugitive emissions under 25 Pa. Code § 127.210. Compliance with this limit will be determined by actual VOC emissions at the Facility and the following equation:

VOC (ERC) = 1.15*sum (flue VOC emissions) + 1.3*sum (fugitive VOC emissions) (Eq. 1)

Where:

Flue VOC emissions are actual emissions from the ethane cracking furnaces, combustion turbines/duct burners, ~~incinerators~~ **thermal oxidizers**, flares, engines, miscellaneous storage tanks, and polyethylene pellet residual VOC.

Fugitive VOC emissions are actual emissions from liquid loadout, component leaks, the process cooling tower, and wastewater treatment plant.

** This limit includes ~~854~~ **880** tpy CO2e from SF6-Insulated High Voltage Equipment included in PA-04-00740B.

007: ~~Total benzene quantity from facility waste shall not equal or exceed 11 tons per year as determined through 40 CFR §61.355. [This limit is for the purpose of compliance with limited requirements of 40 CFR Part 61 Subpart FF for a facility with benzene waste less than 10 Mg (11 tons) per year].~~

The Owner/Operator shall manage and treat facility waste with a flow-weighted annual average

water content of less than 10% in accordance with 40 CFR § 61.342(c)(1). The Owner/Operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content equal to or greater than 10%, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time resulting in a mixture that has an annual water content equal to or greater than 10% such that the benzene quantity for the wastes is less than or equal to 6 Mg/yr (6.6 ton/yr), as determined in accordance with 40 CFR 61.355(k) [25 Pa. Code §127.12b].

Shell has proposed that the condition be revised because SPM has a total annual benzene (TAB) quantity greater than 10 megagrams per year (Mg/yr) (11 ton/y) and the facility uses the "6 BQ" compliance option outlined in 40 CFR 61.342(e) of 40 CFR Part 61 Subpart FF to comply with the regulation's emission control requirements.

009: Performance testing shall be conducted as follows [25 Pa. Code § 127.12b]:

a. The Owner/Operator shall submit ~~two hard copies and~~ one electronic copy of a pre-test protocol to the Department for review at least ~~60~~ **90** days prior to the performance of any EPA Reference Method stack test. The Owner/Operator shall submit ~~two hard copies and~~ one electronic copy of a one-time protocol to the Department for review for the use of a portable analyzer and may repeat portable analyzer testing without additional protocol approvals provided that the same method and equipment are used. All proposed performance test methods shall be identified in the pre-test protocol and approved by the Department prior to testing.

b. The Owner/Operator shall notify the Regional Air Quality Manager and Division of Source Testing and Monitoring at least 15 days prior to any performance test so that an observer may be present at the time of the test. This notification may be sent by email. Notification shall not be made without prior receipt of a protocol acceptance letter from the Department.

c. Pursuant to 40 CFR Part 60.8(a) and 40 CFR Part 63.9(h), a complete test report shall be submitted to the Department no later than 60 calendar days after completion of the on-site testing portion of an emission test program.

d. Pursuant to 40 CFR Part 61.13(f), a complete test report shall be submitted to the Department no later than 31 calendar days after completion of the on-site testing portion of an emission test program.

e. Pursuant to 25 Pa. Code Section 139.53(b) a complete test report shall include a summary of the emission results on the first page of the report indicating if each pollutant measured is within permitted limits and a statement of compliance or non-compliance with all applicable permit conditions. The summary results will include, at a minimum, the following information:

1. A statement that the owner or operator has reviewed the report from the emissions testing body and agrees with the findings.
2. Permit number(s) and condition(s) which are the basis for the evaluation.
3. Summary of results with respect to each applicable permit condition.
4. Statement of compliance or non-compliance with each applicable permit condition.

f. Pursuant to 25 Pa. Code § 139.3 all submittals shall meet all applicable requirements specified in the most current version of the Department's Source Testing Manual.

g. All testing shall be performed in accordance with the provisions of Chapter 139 of the Rules and Regulations of the Department of Environmental Protection.

h. Pursuant to 25 Pa. Code Section 139.53(a)(1) and 139.53(a)(3) ~~all hard copy submittals shall be sent to the Pennsylvania Department of Environmental Protection, Air Quality Program, 400 Waterfront Drive, Pittsburgh, PA 15222 with deadlines verified through document postmarks. Electronic submittals shall be sent to RA epstacktesting@pa.gov. Alternatively, electronic copies may be provided on a CD along with hard copy submittals.~~

1. **All submittals, except test notifications & portable emission monitor tests, shall be accomplished through PSIMS*Online, available through https://www.depgreenport.state.pa.us/ecomm/Login.jsp, if it is available.**

2. **For test notifications & portable analyzer results, or if internet submittal cannot be accomplished, one electronic copy of the test submission (notifications, protocols, reports, supplemental information, etc.) shall be sent to both PSIMS Administration in Central Office and to the Regional Office AQ Program Manager at the following addresses:**

   CENTRAL OFFICE:
   RA-EPstacktesting@pa.gov

   SOUTHWEST REGIONAL OFFICE:
   RA-EPSWstacktesting@pa.gov

i. The permittee shall ensure all federal reporting requirements contained in the applicable subpart of 40 CFR are followed, including timelines more stringent than those contained herein. In the event of an inconsistency or any conflicting requirements between state and the federal, the most stringent provision, term, condition, method or rule shall be used by default.

011: Employees involved in the operation ~~**and/or maintenance**~~ of any air contamination sources, air cleaning devices, stacks, fugitive emission areas, or process equipment at the Facility shall conduct observations of all air contamination sources, air cleaning devices, stacks, fugitive emission areas, and process equipment at a minimum of once per shift while the Facility is in operation. These observations are to ensure continued compliance with source-specific visible emission limitations, fugitive emissions prohibited under 25 Pa. Code §§123.1 or 123.2, and malodors prohibited under 25 Pa. Code § 123.31. Observations shall be conducted for the presence of the following [25 Pa. Code § 127.12b]:

a. Visible stack emissions;
b. Fugitive emissions; and
c. Potentially objectionable odors.

If **any** visible stack emissions, fugitive emissions, or potentially objectionable odors are apparent; the

Owner/Operator shall take corrective action. Each observation of a visible stack emission, fugitive emission, or potentially objectionable odor shall be reported to a centralized incident coordinator and recorded. Records of each reported observation shall be maintained in a log and at the minimum include the date, time, name and title of the observer, along with any corrective action taken as a result.

Shell has proposed that the condition be revised as indicated above because only the Operations group at SPM is responsible for the type of compliance observations indicated in the condition. The proposed change does not relax the monitoring requirement, as it only specifies the type of employee who performs this duty at SPM. The same revision is proposed for Condition #029.

013: The Owner/Operator shall maintain the following comprehensive and accurate records [25 Pa. Code § 127.12b]:

a. Monthly rolling 12-month totals of the hours of operation in each defined operating mode for each ethane cracking furnace and each combustion turbine.

b. Calendar year totals for each diesel-fired emergency generator, natural gas-**fired** emergency generator, and fire pump engine of (and as defined in 40 CFR Part 60 Subpart IIII and 40 CFR Part 60 Subpart JJJJ):
1) Hours of emergency operation,
2) Hours of maintenance and/or testing operation,
3) Hours of non-emergency operation that is not maintenance and/or testing, and
4) Hours of operation.

c. Monthly rolling 12-month totals (in MMscf) of tail gas and natural gas consumed by each ethane cracking furnace, combustion turbine, and duct burner.

d. Monthly rolling 12-month totals (in MMscf) of gas combusted by the ~~LP incinerator~~ **CVTO**, MPGF, ~~HP ground flares, emergency elevated flare,~~ **TEGFs, HP Elevated Flare**, and ~~Spent Caustic Vent incinerator~~ **SCTO**.

e. Monthly rolling 12-month totals (in metric tons) of produced ethylene and polyethylene.

f. Monthly rolling 12-month totals (in gallons) of C3+, ~~coke residue/tar,~~ **blended pitch**, recovered oil, pyrolysis fuel oil, ~~and~~ light gasoline**, and PE3 heavies** loaded out from the Facility.

g. Rolling 12-month totals (in gallons) of methanol throughput.

h. Monthly rolling 12-month totals of calculated actual VOC and VOC (ERC) emissions in accordance with Equation 1 specified in this Plan Approval.

i. Monthly rolling 12-month averages of calculated TDS from each cooling tower.

j. Records including a description of testing methods, results, all operating data collected during tests, and a copy of the calculations performed to determine compliance with emission standards for the ethane cracking furnaces, combustion turbines, and ~~incinerators~~ **thermal oxidizers**.

k. Copies of manufacturer’s or EPC contractor’s equipment design specifications necessary to determine compliance with required control efficiencies or outlet emission rates.

l. Copies of maintenance procedures and schedules for all air contamination sources and air cleaning devices authorized under this plan approval.

m. Records of any maintenance conducted on the air contamination sources and air cleaning devices authorized under this plan approval.

n. Records that diesel fuel’s total sulfur content does not exceed 15 ppm, and that either cetane index is a minimum of 40 or aromatic content does not exceed 35 % by volume.

o. Records that each gaseous fuel’s total sulfur content does not exceed 0.5 grains per 100 dscf. This may be demonstrated by a current, valid purchase contract, tariff sheet or transportation contract for the fuel; or fuel total sulfur content monitoring in accordance with 40 CFR §§60.4360 and 60.4370, applicable to the turbines.

p. Records of observations of visible stack emissions, fugitive emissions, and potentially objectionable odors including the date, time, name, and title of the observer, along with any corrective action taken as a result.

016: Malfunction notification, reporting, and responses shall be conducted as follows [25 Pa. Code § 127.12b]:

a. For purpose of this condition a malfunction is defined as any sudden, infrequent, and not reasonably preventable failure of air pollution control or monitoring equipment, or the unauthorized operation of a source that may result in an increase in the emission of air contaminants above allowable levels. Examples of malfunctions may include, but are not limited to: large dust plumes, heavy smoke, a spill or release that results in a malodor that is detectable outside the property of the person on whose land the source is being operated.

~~b. Notify the Department by phone no later than one hour after discovery of a malfunction which poses an imminent and substantial danger to the public health and safety or the environment.~~

b. When the malfunction, emergency, or incident of excess emissions poses an imminent danger to the public health, safety, welfare, or environment, it shall be reported to the Department at 800-541-2050 and the County Emergency Management Agency by telephone within one (1) hour after the discovery of the malfunction, emergency or incident of excess emissions. The owner or operator shall submit a written or emailed report of instances of such malfunctions, emergencies, or incidents of excess emissions to the Department within three (3) business days of the telephone report. The notification shall include the items identified in (d) to the extent known.

c. Notify the Department by phone no later than the next business day after discovery of all other malfunctions. The notification shall include the items identified in (d) to the extent known.

d. The notification shall describe the:
i. Name and location of the facility;
ii. Nature and cause of the malfunction or breakdown;
iii. Time when the malfunction or breakdown was first observed;
iv. Expected duration of excess emissions; and
v. Estimated rate of emissions.

e. The Owner/Operator shall submit a written report to the Department no later than thirty (30) days following the end of a malfunction. The report shall include the following:

i. The date and time that the malfunction started and ended.
ii. An estimate of the emissions associated with the malfunction and the calculations that were used to determine that quantity;
iii. The steps, if any, that the facility took to limit the duration and/or quantity of emissions associated with the malfunction;
iv. A detailed analysis that sets forth the Root Cause of the malfunction, to the extent determinable;
v. An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of a malfunction resulting from the same Root Cause or contributing causes in the future. The analysis shall discuss the alternatives, if any, that are available, the probable effectiveness and cost of the alternatives. Possible design, operational, and maintenance changes shall be evaluated. If the facility concludes that corrective action(s) is (are) required, the report shall include a description of the action(s) and, if not already completed, a schedule for implementation, including proposed commencement and completion dates. If the facility concludes that corrective action is not required the report shall explain the basis for that conclusion;
vi. To the extent that investigations of the causes and/or possible corrective action(s) still are underway on the due date of the report, a statement of the anticipated date by which a follow-up report will be submitted.

f. To the extent that completion of the implementation of corrective action(s), if any, is not finalized at the time of the submission of the report under subsection (e), then, by no later than 30 days after completion of the implementation of corrective action(s), the Owner/Operator shall submit a written report identifying the corrective action(s) taken and the date(s) of completion of implementation.

g. In response to any malfunction, the Owner/Operator, as expeditiously as practicable, shall take such interim and/or longer-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of that malfunction.

h. Malfunction phone notifications and written reports shall be submitted to the Department at the following address:

PA DEP
Office of Air Quality
400 Waterfront Drive
Pittsburgh, PA 15222-4745
412-442-4000

029: Employees involved in the operation **~~and/or maintenance~~** of any air contamination sources, air cleaning

devices, stacks, fugitive emission areas, or process equipment at the Facility shall be trained to observe air contamination sources, air cleaning devices, stacks, fugitive emission areas, and process equipment to demonstrate compliance with Section C Condition #~~012~~ **011** [25 Pa. Code § 127.12b].

a. New employees shall be trained upon hiring.
b. Existing employees shall be trained prior to source startup.
c. Employees shall be given refresher training annually.
d. A copy of the written employee training program shall be maintained at the Facility. The training program shall include provisions for the following:
1) Equipment and areas to be observed;
2) That observation is to be made for the presence of visible stack emissions, fugitive emissions, and potentially objectionable odors;
3) Information to be collected in the event of an affirmative observation; and
4) Whom at the Facility to report affirmative observations to.
e. Records of successful completion of initial and annual training shall be maintained for a minimum of five years for each employee trained.

\# 030: Upon determination by the Owner/Operator that the source(s) covered by this Plan Approval ~~and Plan Approval PA-04-00740B~~ are in compliance with all operative conditions of the Plan Approval~~s~~**,** the Owner/Operator shall contact the Department and schedule the Initial Operating Permit Inspection [25 Pa. Code § 127.12b].

\# 031: ~~*Upon completion of the Initial Operating Permit Inspection and determination by the Department that the source(s) covered by this Plan Approval and Plan Approval PA-04-00740B are in compliance with all conditions of the Plan Approvals the Owner/Operator shall submit a Title V Operating Permit application for this Facility.*~~

Upon completion of the Initial Operating Permit Inspection and determination by the Department that the source(s) covered by this Plan Approval are in compliance with all conditions of the Plan Approval, the Owner/Operator shall submit an amendment to the Title V Operating Permit for this Facility or a revision to a pending Title V Operating Permit application, as appropriate [25 Pa. Code § 127.12b].

\# 033: This Plan Approval is for **the Ethylene Maximum Achievable Control Technology (EMACT) Project, the Wastewater Treatment Plant (WWTP) Permanent Controls Project, and the Plan Approval Reconciliations** ~~"as-built" changes in design and construction~~ and allows the ~~continued~~ construction **of these projects** and temporary operation of a petrochemicals complex by Shell Chemical Appalachia LLC ~~to be~~ located in Potter and Center Townships, Beaver County [25 Pa. Code § 127.12b].

\# 034: Air contamination sources and air cleaning devices authorized to be installed at the Facility under this Plan Approval are as follows [25 Pa. Code § 127.12b]:

- Seven (7) tail gas- and natural gas-fired ethane cracking furnaces, 620 MMBtu/hr heat input rating each; equipped with low-NOx burners and controlled by selective catalytic reduction (SCR).

- One (1) ethylene manufacturing line, ~~1,500,000~~ **1,763,000** metric tons/yr; compressor seal vents and startup/shutdown/maintenance/upsets controlled by the ~~high pressure header system (~~HP **Flare** System~~)~~.
- Two (2) gas phase polyethylene manufacturing lines, ~~550,000~~ **605,000** metric tons/yr each; VOC emission points controlled by the ~~low pressure header system (LP System)~~ **CVTO, MPGF,** or HP **Flare** System, PM emission points controlled by filters.
- One (1) slurry technology polyethylene manufacturing line, ~~500,000~~ **550,000** metric tons/yr; VOC emission points controlled by the ~~LP System~~ **CVTO, MPGF,** or HP **Flare** System, PM emission points controlled by filters.
- One (1) ~~LP System~~ **CVTO Header**; routed to the ~~LP incinerator~~ **CVTO**, ~~10 tons/hr~~ **200 MMBtu/hr** capacity~~, with backup multipoint ground flare (MPGF), 74 metric tons/hr capacity~~.
- **One (1) MPGF CVTO Trip Header; controlled by the MPGF, 186 MMBtu/hr capacity.**
- **One (1) MPGF Ethylene Tank Header receiving vent gas from Source ID 411; controlled by the MPGF, 1,152 MMBtu/hr capacity.**
- **One (1) MPGF PE Units 1/2 Episodic Vent Header receiving vent gas from Source ID 202; controlled by the MPGF, 860 MMBtu/hr capacity.**
- One (1) HP **Header** System~~, 1,800 metric tons/hr capacity~~; routed to two (2) ~~HP~~ **totally** enclosed ground flares ~~150 metric tons/hr capacity each~~, with **a** backup emergency elevated flare, ~~1,500 metric tons/hr~~ **13,257 MMBtu/hr** capacity.
- Three (3) General Electric, Frame 6B, natural gas-fired combustion turbines, 41.5 MW**e** (481.4 MMBtu/hr heat input rating) each, including natural gas- ~~or tail gas-~~fired duct burners, 234 MMBtu/hr heat input rating each; controlled by SCR and oxidation catalysts.
- Two (2) diesel-fired emergency generator engines, 67 bhp and 103 bhp rating ~~each.~~
- Two (2) diesel-fired fire pump engines, 488 bhp rating each.
- ~~Three (3)~~ **Two (2)** natural gas-fired emergency generator engines, 50 bhp~~, 113 bhp~~, and 158 bhp rating.
- One (1) process cooling tower, 26 cell counter-flow mechanical draft, 17.8 MMgal/hr water flow capacity; controlled by drift eliminators.
- One (1) ~~cogen cooling tower~~ **Cogeneration Plant Cooling Tower**, 6 cell counter-flow mechanical draft, ~~4.443~~ **7.2** MMgal/hr water flow capacity; controlled by drift eliminators.
- Polyethylene pellet blending, handling, storage, and loadout; controlled by fabric filters.
- Liquid ~~loadout~~ load**ing**~~, coke residue/tar~~ **blended pitch** ~~and recovered oil~~; controlled by vapor capture and routing back to the process or ~~Spent Caustic Vent incinerator~~ **HP Header System**, and low-leak couplings.
- **Liquid loading recovered oil; controlled by vapor capture and routing to a carbon adsorption system, and low-leak couplings.**
- Liquid ~~loadout~~ load**ing**, pyrolysis fuel oil**,** ~~and~~ light gasoline**, and PE3 heavies**; controlled by vapor capture and routing to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header**, and low-leak couplings.
- Liquid ~~loadout~~ load**ing**, C3+**, and liquid unloading**, butene, isopentane, isobutane, and ~~C3+~~ C**3** refrigerant; controlled by pressurized transfer with vapor balance and low-leak couplings.
- One (1) recovered oil, one (1) spent caustic, and two (2) equalization wastewater storage tanks, ~~23,775-to-878,000-gallon capacities~~ **521,211-gallon capacity, 345,273-gallon capacity, and 877,051-gallon capacity each**; controlled by internal floating roofs (IFR**s**) and vapor capture routed to the ~~Spent Caustic Vent incinerator~~ **SCTO**, ~~10.7~~ **11.07** MMBtu/hr.

- One (1) light gasoline, and two (2) hexene storage tanks; ~~85,856~~ **152,000-gallon capacity** and ~~607,596~~ **802,000**-gallon capacity; controlled by IFR**s** and vapor capture routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header**.
- Two (2) pyrolysis fuel oil storage tanks; ~~85,856~~ **127,000**-gallon capacity **each**; controlled by vapor capture routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header**.
- Miscellaneous storage tanks, diesel fuel, **500 to** 1,849 ~~to 18,000~~ gallon capacities~~; controlled by carbon canisters~~.
- Miscellaneous storage tanks, diesel fuel, 133 to 140 gallon capacities.
- Pressurized methanol storage vessels (36,000-gallon, 6,450-gallon, and 67,200-gallon **capacities**) and associated components; controlled by the HP **Flare** System.
- Miscellaneous components in gas, light liquid, and heavy liquid service; controlled by leak detection and repair (LDAR).
- Wastewater treatment plant (WWTP).
- Plant roadways; controlled by paving and a road dust control plan including sweeping and watering (as necessary).

035: ~~*The Owner/Operator shall conduct an inhalation risk assessment for the Facility based upon the final as-built design parameters of the air contamination sources. The inhalation risk assessment shall be conducted in accordance with the protocol previously submitted to the Department on January 7, 2015, which has already been approved. The inhalation risk assessment shall be submitted to the Department within 180 days of product in tank (commercial product production* [25 Pa. Code § 127.12b].~~

Shell has submitted a revised inhalation risk assessment in accordance with Condition # 035 as part of this plan approval application; therefore, the condition will not be included in this plan approval.

036: The Owner/Operator shall secure ~~379~~ **437** tons of NOx, ~~612~~ **591** tons of VOC, and ~~164~~ **171** tons of PM2.5 ERCs **for PA-04-00740A, PA-04-00740C, and the Plan Approval Reconciliations and WWTP Permanent Controls Project approved under PA-04-00740D**. ERCs shall be properly generated, certified by the Department and processed through the registry in accordance with 25 Pa. Code §127.206(d)(1). Upon transfer, the Owner/Operator shall provide the Department with documentation clearly specifying the details of the ERC transaction. This facility may not commence operation until the required emissions reductions are certified and registered by the Department. All required ERCs have been secured by the Owner/Operator and incorporated into this Plan Approval in accordance with 25 Pa. Code §127.208(2) [25 Pa. Code §127.206].

 # 037: The Owner/Operator shall secure 89 tons of NOx ERCs for the EMACT Project approved under PA-04-00740D. ERCs shall be properly generated, certified by the Department and processed through the registry in accordance with 25 Pa. Code §127.206(d)(1). Upon transfer, the Owner/Operator shall provide the Department with documentation clearly specifying the details of the ERC transaction. This facility may not commence operation until the required emissions reductions are certified and registered by the Department. All required ERCs have been secured by the Owner/Operator and incorporated into this Plan Approval in accordance with 25 Pa. Code §127.208(2) [25 Pa. Code §127.206].

037: ~~The Owner/Operator is approved to use NOx ERCs in place of VOC ERCs at a 1:1 ratio to satisfy VOC~~

~~emission offsetting requirements in this Plan Approval~~ [25 Pa. Code §127.206].

040: The Owner/Operator has secured 34.10 tons of PM2.5, 64 tons of VOC, and 211 tons of NOx ERCs from the shutdown of the Monaca Zinc Smelter in a transfer from Horsehead Corporation to Shell Chemical Appalachia LLC. Amounts of 8.78 tons of PM2.5 ERCs, 64 tons of VOC ERCs, and 13.4 tons of NOx ERCs have been applied to this Plan Approval and are no longer subject to expiration under 25 Pa. Code §127.206(f) except as specified in §127.206(g) as long as they remain in this Plan Approval. Amounts of 25.32 tons of PM2.5 ERCs and 197.6 tons of NOx ERCs **that** remain**ed** secured by Shell but ~~are~~ **were** not applied to ~~this~~ **a** Plan Approval ~~because they would exceed the total emissions offsetting requirement of this Plan Approval. Expiration of these ERCs remains~~ expired April 26, 2024.

 # 044: The Owner/Operator has secured 184 tons of NOx ERCs from the shutdown of Northern Star Generation LLC's facility in Cambria Township, Cambria County in a transfer from Northern Star Generation LLC to Shell Chemical Appalachia LLC. An amount of 147 tons of NOx ERCs have been applied to this Plan Approval and are no longer subject to expiration under 25 Pa. Code §127.206(f) except as specified in §127.206(g) as long as they remain in this Plan Approval. The amount of 37 tons of NOx ERCs remain secured by Shell but are not applied to this Plan Approval because they would exceed the total emissions offsetting requirement of this Plan Approval. Expiration of these ERCs remains June 19, 2029 [25 Pa. Code §127.208].

 # 045: The Owner/Operator has secured 31.03 tons of PM2.5 ERCs from INDSPEC Chemical Corporation's facility in Petrolia Borough, Butler County in a transfer from INDSPEC Chemical Corporation to Shell Chemical Appalachia LLC. An amount of 7 tons of PM2.5 ERCs have been applied to this Plan Approval and are no longer subject to expiration under 25 Pa. Code §127.206(f) except as specified in §127.206(g) as long as they remain in this Plan Approval. The amount of 24.03 tons of PM2.5 ERCs remain secured by Shell but are not applied to this Plan Approval because they would exceed the total emissions offsetting requirement of this Plan Approval. Expiration of these ERCs remains September 11, 2027 [25 Pa. Code §127.208].

Section D – Source Level Plan Approval Requirements

Source ID 104: Cogeneration Plant Cooling Tower

RESTRICTIONS

002: Maximum designed water circulation rate through the ~~cogen cooling tower~~ **Cogeneration Plant Cooling Tower** shall not exceed ~~4,443,360~~ **7,200,000** gallons per hour [25 Pa. Code § 127.12b].

TESTING REQUIREMENTS

004: The Owner/Operator shall perform TDS and electrical conductivity testing upon the ~~cogen cooling tower~~ **Cogeneration Plant Cooling Tower** water according to ASTM Methods D5907-13 ~~and D5391-14 (or other methods deemed acceptable by the Department)~~ **and correlate the results with an online conductivity analyzer**. Samples and/or measurements ~~for both tests~~ are required to be performed under identical operating conditions, at a point which is representative of the water being evaporated to the atmosphere~~, and~~

~~over the same time frame as applicable to each test method~~. A factor shall be derived from test results correlating TDS and electrical conductivity such that TDS may be approximated by future electrical conductivity measurements. Initial testing is required within 180 days of startup of the cooling towers or on an alternative schedule as approved by the Department. Subsequent TDS and electrical conductivity testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

005: The Owner/Operator shall~~, at a minimum of once per month, calculate TDS for the cogen cooling tower water. TDS shall be calculated by measuring electrical conductivity according to ASTM Method D5391-14 (or other method deemed acceptable by the Department) and multiplying the result by the correlation factor derived during the most recent simultaneous TDS and electrical conductivity test~~ **calculate TDS via continuous online conductivity analyzer readings correlated to TDS as approved by the Department** [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 107: Natural Gas-Fired Emergency Generator Engines (2)

002: The natural gas-fired emergency generator engines shall be certified to meet the following NOx, VOC, and CO emission standards: (Additional authority for this condition is derived from 40 CFR § 60.4233) [25 Pa. Code § 127.12b].

	Emission Standards (g/bhp-hr)		
Engine Size	*NOx*	*VOC*	*CO*
158 hp	*2.0*	*1.0*	*4.0*
~~*113 hp*~~	~~*5.79**~~		~~*387*~~
50 hp	*5.39**		*387*

** The emission standard~~s are~~* ***is*** *in terms of NOx + VOC.*

Section D – Source Level Plan Approval Requirements

Source ID 201: Ethylene Manufacturing Line

WORK PRACTICE REQUIREMENTS

007: Spent caustic vent vapors shall be captured and routed through a closed system to the ~~Spent Caustic Vent incinerator~~ **SCTO** [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 202: Polyethylene Manufacturing Lines

WORK PRACTICE REQUIREMENTS

010: Compressor seal gas vents; intermittent VOC process vents; and startup, shutdown, and maintenance gases associated with the gas phase polyethylene manufacturing lines shall be routed to the HP **Header** System, **CVTO Header System, MPGF CVTO Trip Header, or MPGF PE Units 1/2 Episodic Vent Header**. Emergency and malfunction event gases shall be captured and routed to the HP **Header** System**, CVTO Header System, MPGF CVTO Trip Header, or MPGF PE Units 1/2 Episodic Vent Header** as practicable. Hydrocarbon-containing equipment shall be drained, depressurized, and purged with nitrogen to the HP **Header** System**, CVTO Header System, MPGF CVTO Trip Header, or MPGF PE Units 1/2 Episodic Vent Header** prior to being opened to the atmosphere [25 Pa. Code § 127.12b].

012: Continuous VOC-containing process gas vents located upstream of and including the product purge bin in each gas phase technology polyethylene manufacturing line or upstream of the degasser in the slurry polyethylene manufacturing line shall be routed to the ~~LP System~~ **CVTO Header System** [25 Pa. Code § 127.12b].

013: Compressor seal gas vents; intermittent VOC process vents; and startup, shutdown, and maintenance gases associated with the slurry phase polyethylene manufacturing lines shall be routed to the HP **Header** System, **CVTO Header System, or MPGF CVTO Trip Header**. Emergency and malfunction event gases shall be captured and routed to the HP **Header** System**, CVTO Header System, MPGF CVTO Trip Header, or MPGF PE Units 1/2 Episodic Vent Header** as practicable. Hydrocarbon-containing equipment shall be drained, depressurized, and purged with nitrogen to the HP **Header** System**, CVTO Header System, or MPGF CVTO Trip Header** prior to being opened to the atmosphere [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 203: Process Cooling Tower

TESTING REQUIREMENTS

005: The Owner/Operator shall perform TDS ~~and electrical conductivity~~ testing upon the process cooling tower water according to ASTM Methods D5907-13 ~~and D5391-14 (or other methods deemed acceptable by the Department)~~ **and correlate the results with an online conductivity analyzer**. Samples and/or measurements ~~for both tests~~ are required to be performed under identical operating conditions, at a point which is representative of the water being evaporated to the atmosphere~~, and over the same time frame as applicable to each test method~~. A factor shall be derived from test results correlating TDS and electrical conductivity such that TDS may be approximated by ~~future~~ electrical conductivity measurements. Initial testing is required within 180 days of startup of the cooling towers or on an alternative schedule as approved by the Department. Subsequent TDS and electrical conductivity testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

006: The Owner/Operator shal~~l, at a minimum of once per month, calculate TDS for the process cooling tower water. TDS shall be calculated by measuring electrical conductivity according to ASTM Method D5391-14 (or other method deemed acceptable by the Department) and multiplying the result by the correlation factor derived during the most recent simultaneous TDS and electrical conductivity test~~ **calculate TDS via continuous online conductivity analyzer readings correlated to TDS as approved by the Department** [25 Pa. Code § 127.12b].

<u>Section D – Source Level Plan Approval Requirements</u>

Source ID 204: CVTO Header System (previously Low Pressure (LP) Header System)

<u>RESTRICTIONS</u>

001: Visible emissions from both the ~~LP incinerator and MPGF~~ **CVTO** shall not exceed 0% except for a total of five minutes during any consecutive two-hour period [25 Pa. Code § 127.12b].

002: Emissions from the ~~LP incinerator~~ **CVTO** shall not exceed the following [25 Pa. Code § 127.12b]:
a. NOx - ~~0.068~~ **0.06** lb/MMBtu
b. CO - 0.0824 lb/MMBtu
c. PM10 - 0.0075 lb/MMBtu
d. PM2.5 - 0.0075 lb/MMBtu

003: The ~~LP incinerator~~ **CVTO** shall be designed and operated to reduce collected VOC emissions by a minimum of 99.9% [25 Pa. Code § 127.12b].

<u>TESTING REQUIREMENTS</u>

004: The Owner/Operator shall perform NOx, CO, PM_{10}, PM2.5, and n-Hexane emission testing upon the ~~LP incinerator~~ **CVTO** according to the requirements of 25 Pa. Code Chapter 139. Initial performance testing is required within 180 days of startup of the ~~LP incinerator~~ **CVTO** or on an alternative schedule as approved by the Department. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified. EPA Reference Method performance testing shall be conducted for the initial and subsequent performance tests [25 Pa. Code § 127.12b].

005: The Owner/Operator shall perform VOC destruction efficiency testing upon the ~~LP incinerator~~ **CVTO** in accordance with 40 CFR §63.985(b)(1)(ii). Initial performance testing is required within 180 days of startup of the ~~LP incinerator~~ **CVTO** or on an alternative schedule as approved by the Department. Subsequent performance testing is required at a minimum of once every 5 years thereafter. Extension of the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

006: Monitoring for compliance with the 99.9% destruction efficiency requirement for the ~~LP incinerator~~ **CVTO** shall be performed in accordance with 40 CFR §63.985(c). Operating parameter monitoring shall include combustion temperature at a minimum [25 Pa. Code § 127.12b].

007: The Owner/Operator shall utilize a gas chromatograph (or equivalent monitor) to measure, calculate, and record VOC and GHG content at the ~~LP Incinerator header~~ **CVTO Header System** at a minimum of once every 15 minutes [25 Pa. Code § 127.12b].

 # 008: The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the vent gas header to the CVTO at a minimum of once every 15 minutes [25 Pa. Code § 127.12b].

WORK PRACTICE REQUIREMENTS

010: The ~~LP incinerator~~ **CVTO** shall, at all times that vapors are being collected by the ~~LP System~~ **CVTO Header System**, be operated at or above the minimum temperature at which at least 99.9% destruction efficiency is guaranteed by the manufacturer or demonstrated during performance testing [25 Pa. Code § 127.12b].

 # 011: Vent gas from the CVTO Header shall be captured and routed to the MPGF CVTO Trip Header when the CVTO is not available and during abnormal CVTO system operating conditions, such as high CVTO Header System pressure, high CVTO temperature, high CVTO combustion zone temperature, and low CVTO combustion air pressure [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 205: High Pressure (HP) Header System

RESTRICTIONS

002: The ~~HP ground flares and emergency elevated flare~~ **TEGFs and HP Elevated Flare** shall be designed and operated to reduce collected VOC emissions by a minimum of 98% [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

004: The Owner/Operator shall comply with the applicable flare monitoring and work practice requirements, including limits on maximum exit velocity and minimum net heating value requirements, specified in ~~40 CFR §60.18(c) through (f) and 40 CFR §63.11(b)~~ **40 CFR Part 63 Subpart YY, 40 CFR Part 63 Subpart FFFF, 40 CFR 63.670, and 40 CFR 63.671** [25 Pa. Code § 127.12b].

Shell has proposed that the condition be revised as indicated above to streamline the flare monitoring and work practice requirements applicable to the TEGF A, TEGF B, and HP Elevated Flare that are connected to the HP Header System, while ensuring these three flares are monitored and operated in accordance with EPA's latest flare monitoring and performance demonstration requirements. The TEGF A, TEGF B, and HP Elevated Flare are not otherwise subject to 40 CFR 60.18(c) through (f) or 40 CFR 63.11(b) flare monitoring and work practice requirements, but they are subject to EPA's more recently promulgated and comprehensive flare monitoring and work practice requirements under 40 CFR Part 63 Subpart YY, 40 CFR Part 63 Subpart FFFF, 40 CFR 63.670, and 40 CFR 63.671.

WORK PRACTICE REQUIREMENTS

012: The Owner/Operator shall minimize flaring resulting from startups, shutdowns, and unforeseeable events by operating **the HP Flare System** at all times in accordance with an approved flare minimization plan. **The plan should be updated periodically per 40 CFR 63.670(o)(2)(ii)**. **At a minimum,** the plan shall include the following [25 Pa. Code § 127.12b]:

a. Procedures for operating and maintaining the HP **Flare** ~~and LP~~ System~~s~~ during periods of process unit startup, shutdown, and unforeseeable events.
b. A program of corrective action for malfunctioning process equipment.
c. Procedures to minimize discharges either directly to the atmosphere or to the HP **Flare** ~~and MPGF~~ System~~s~~ during the planned and unplanned startup or shutdown of process unit and air pollution control equipment, **including an evaluation of flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including startup and shutdown, that considers the feasibility of performing these activities without flaring.**
d. Procedures for conducting root cause analyses.
e. Procedures for taking identified corrective actions.
f. The baseline flow to the HP **Flare** ~~and LP~~ System~~s~~ determined in accordance with the provisions of 40 CFR §60.103a(a)(4).

014: The Owner/Operator shall conduct a root cause analysis within 45 days after any startup flaring event, shutdown flaring event, or unforeseeable flaring event **at the HP Flare System**. Flaring event shall be defined as an event that exceeds the baseline by 500,000 scf within a 24-hour period. **At a minimum,** the analysis shall address the following [25 Pa. Code § 127.12b]:

a. The date and time that the flaring event started and ended.
b. The total quantity of gas flared during each event.
c. An estimate of the quantity of VOC that was emitted and the calculations used to determine the quantities.
d. The steps taken to limit the duration of the flaring event of the quantity of emissions associated with the event.
e. A detailed analysis that sets forth the root cause and all significant contributing causes of the flaring event to the extent determinable.
f. An ~~analyses~~ **analysis** of the measures that are available to reduce the likelihood of a recurrence of a flaring event resulting from the same root cause or significant contributing causes in the future. **The evaluation of prevention measures must consider the adequacy of existing maintenance schedules and protocols for equipment contributing to the flaring event.**
g. A demonstration that the actions taken during the flaring event are consistent with the procedures specified in the flare minimization plan.

h. In response to a flaring event, the Owner/Operator shall implement, as expeditiously as practicable, such interim and/or long-term corrective actions as are consistent with good engineering practice to minimize the likelihood of a recurrence of the root cause and all significant contributing causes of that flaring event.
i. If any items required to be addressed in this analysis are still under investigation 45 days after the flaring event, the Owner/Operator shall include a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Condition shall be completed.

 # 015: ~~Net heating value of the combustion zone gas at the HP ground flare header shall equal or exceed 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes~~ [25 Pa. Code § 127.12b].

The Owner/Operator shall operate the TEGF A and TEGF B to maintain the net heating value of flare combustion zone gas (NHVcz) at or above 800 Btu/scf determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHVcz as specified in 40 CFR 63.670(m) [25 Pa. Code § 127.12b].

[Additional authority for this condition is derived from 40 CFR 63.1103(e)(4)(vii)(B) and 40 CFR 63.670(e)(2)]

 # 016: **Site-specific flare guidelines, included in the Flare Minimization and Management Plan as an Appendix, shall be followed which ensures the stage sequencing and parameters at which stages open or close for the TEGFs in accordance with manufacturer's recommendations** [25 Pa. Code § 127.12b].

<u>Section D – Source Level Plan Approval Requirements</u>

Source ID 206: Spent Caustic Vent Header System

<u>RESTRICTIONS</u>

001: Visible emissions from the ~~Spent Caustic Vent incinerator~~ **SCTO** shall not exceed 0% except for a total of five minutes during any consecutive two-hour period [25 Pa. Code § 127.12b].

002: Emissions from the ~~Spent Caustic Vent incinerator~~ **SCTO** shall not exceed the following [25 Pa. Code § 127.12b]:
a. NOx - ~~0.068~~ **0.06** lb/MMBtu
b. CO - 0.0824 lb/MMBtu
c. PM10 - 0.0075 lb/MMBtu
d. PM2.5 - 0.0075 lb/MMBtu

003: The ~~Spent Caustic Vent incinerator~~ **SCTO** shall be operated to reduce collected VOC emissions by a minimum of 99**.9**% [25 Pa. Code § 127.12b].

<u>TESTING REQUIREMENTS</u>

004: The Owner/Operator shall perform NOx, CO, PM10, PM2.5, and Benzene emission testing upon the ~~Spent Caustic Vent incinerator~~ **SCTO** according to the requirements of 25 Pa. Code Chapter 139. ~~Initial p~~**P**erformance testing is required within 180 days of ~~startup~~ **upgrading or replacing the burners** of the ~~Spent Caustic Vent incinerator~~ **SCTO** or on an alternative schedule as approved by the Department. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension ~~to~~ **of** the ~~initial and subsequent~~ performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified. EPA Reference Method performance testing shall be conducted for the ~~initial and subsequent~~ performance tests [25 Pa. Code § 127.12b].

005: The Owner/Operator shall perform VOC destruction efficiency testing upon the ~~Spent Caustic Vent incinerator~~ **SCTO** in accordance with 40 CFR §63.985(b)(1)(ii). ~~Initial p~~**P**erformance testing is required within 180 days of startup of the ~~Spent Caustic Vent incinerator~~ **WWTP Permanent Controls Project equipment** or on an alternative schedule as approved by the Department. Subsequent performance testing is required at a minimum of once every 5 years thereafter. Extension of the ~~initial and subsequent~~ performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

006: Monitoring for compliance with the 99**.9**% destruction efficiency requirement for the ~~Spent Caustic Vent incinerator~~ **SCTO** shall be performed in accordance with 40 CFR §63.985(c). Operating parameter monitoring shall include combustion temperature at a minimum [25 Pa. Code § 127.12b].

 # 007: The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the flow rate in the vent gas header to the SCTO at a minimum of once every 15 minutes [25 Pa. Code § 127.12b].

RECORD KEEPING REQUIREMENTS

 # 008: The Owner/Operator shall maintain records of the flow rate in the vent gas header to the SCTO on a daily basis [25 Pa. Code § 127.12b].

WORK PRACTICE REQUIREMENTS

009: The ~~Spent Caustic Vent incinerator~~ **SCTO** shall, at all times that vapors are being collected, be operated at or above the minimum temperature at which at least 99**.9**% destruction efficiency is guaranteed by the manufacturer or demonstrated during performance testing [25 Pa. Code § 127.12b].

 # 010: The Owner/Operator shall upgrade or replace the burners of the SCTO within 180 days of issuance of PA-04-00740D [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 207: MPGF CVTO Trip Header

RESTRICTIONS

 # 001 Visible emissions from the MPGF shall not exceed 0% except for a total of five minutes during any consecutive two-hour period [25 Pa. Code § 127.12b].

 # 002: The MPGF shall be designed and operated to reduce collected VOC emissions by a minimum of 98% [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

 # 003: Monitoring for compliance with the 98% destruction efficiency requirement for the MPGF shall be performed in accordance with 40 CFR Part 63 Subpart YY, 40 CFR Part 63 Subpart FFFF, 40 CFR 63.670, and 40 CFR 63.671 [25 Pa. Code § 127.12b].

 # 004: The Owner/Operator shall comply with the applicable flare monitoring and work practice requirements, including limits on maximum exit velocity and minimum net heating value requirements, specified in 40 CFR § 63.670 and 40 CFR § 63.671 [25 Pa. Code § 127.12b].

 # 005: Net heating value of the combustion zone gas at the MPGF shall be measured and recorded at a minimum of once every 15 minutes. An adjusted net heating value of hydrogen of 1,212 Btu/scf may be used for this calculation [25 Pa. Code § 127.12b].

 # 006: The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the MPGF CVTO Trip Header that feeds the flare as well as any flare supplemental gas used [25 Pa. Code § 127.12b].

 # 007: The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air used with the MPGF [25 Pa. Code § 127.12b].

RECORDKEEPING REQUIREMENTS

 # 008: VOC and GHG content measured by the gas chromatograph (or equivalent monitor) shall be used to calculate 12-month rolling total VOC and GHG emissions for the MPGF [25 Pa. Code § 127.12b].

WORK PRACTICE REQUIREMENTS

 # 009: The MPGF shall be equipped with automated controls for control of the supplemental gas flow rate to the flare [25 Pa. Code § 127.12b].

 # 010: The Owner/Operator shall minimize flaring resulting from startups, shutdowns, and unforeseeable events by operating the MPGF at all times in accordance with an approved flare minimization plan. The plan should be updated periodically per 40 CFR 63.670(o)(2)(ii). At a minimum, the plan shall include the following [25 Pa. Code § 127.12b]:

a. Procedures for operating and maintaining the MPGF during periods of process unit startup, shutdown, and unforeseeable events.
b. A program of corrective action for malfunctioning process equipment.
c. Procedures to minimize discharges either directly to the atmosphere or to the MPGF during the planned and unplanned startup or shutdown of process unit and air pollution control equipment, including an evaluation of flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including startup and shutdown, that considers the feasibility of performing these activities without flaring.
d. Procedures for conducting root cause analyses.
e. Procedures for taking identified corrective actions.
f. The baseline flow to the MPGF determined in accordance with the provisions of 40 CFR § 60.103a(a)(4).

 # 011: The Owner/Operator shall conduct a root cause analysis within 45 days after any startup flaring event, shutdown flaring event, or unforeseeable flaring event at the MPGF. Flaring event shall be defined as an event that exceeds the baseline by 500,000 scf within a 24-hour period. At a minimum, the analysis shall address the following [25 Pa. Code § 127.12b]:

a. The date and time that the flaring event started and ended.
b. The total quantity of gas flared during each event.
c. An estimate of the quantity of VOC that was emitted and the calculations used to determine the quantities.
d. The steps taken to limit the duration of the flaring event of the quantity of emissions associated with the event.
e. A detailed analysis that sets forth the root cause and all significant contributing causes of the flaring event to the extent determinable.
f. An analysis of the measures that are available to reduce the likelihood of a recurrence of a flaring event resulting from the same root cause or significant contributing causes in the future. The evaluation of prevention measures must consider the adequacy of existing maintenance schedules and protocols for equipment contributing to flaring events.
g. A demonstration that the actions taken during the flaring event are consistent with the procedures specified in the flare minimization plan.
h. In response to a flaring event, the Owner/Operator shall implement, as expeditiously as practicable, such interim and/or long-term corrective actions as are consistent with good engineering practice to minimize the likelihood of a recurrence of the root cause and all significant contributing causes of that flaring event.
i. If any items required to be addressed in this analysis are still under investigation 45 days after the flaring event, the Owner/Operator shall include a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Condition shall be completed.

 # 012: Net heating value of the combustion zone gas at the MPGF shall equal or exceed 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes [25 Pa. Code § 127.12b].

The MPGF CVTO Trip Header is also subject to 40 CFR Part 63 Subpart YY, 40 CFR Part 63 Subpart FFFF, 40

CFR 63.670, and 40 CFR 63.671, and is required to meet the applicable requirements of those subparts. As such, Source ID 207 will be included in plan approval Group G05: NESHAP Part 63 Subpart YY and Group G09: NESHAP Part 63 Subpart FFFF (partial). NESHAP Part 63 Subpart CC is included in the plan approval by reference only since it is applicable by reference from Subpart YY.

Section D – Source Level Plan Approval Requirements

Source ID 208: MPGF Ethylene Tank Header

RESTRICTIONS

 # 001: Visible emissions from the MPGF shall not exceed 0% except for a total of five minutes during any consecutive two-hour period [25 Pa. Code § 127.12b].

 # 002: The MPGF shall be designed and operated to reduce collected VOC emissions by a minimum of 98% [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

 # 003: Monitoring for compliance with the 98% destruction efficiency requirement for the MPGF shall be performed in accordance with 40 CFR §60.18. Operating parameter monitoring shall include flame detection at a minimum [25 Pa. Code § 127.12b].

 # 004: The Owner/Operator shall comply with the applicable flare monitoring and work practice requirements specified in 40 CFR §60.18 [25 Pa. Code § 127.12b].

 # 005: Net heating value of the combustion zone gas at the MPGF header shall be measured and recorded at a minimum of once every 15 minutes based on the volumetric flow rates of the waste gas and supplemental gas in the header and the compositions of the waste gas and supplemental gas. As an alternative, net heating value of the combustion zone gas at the MPGF Ethylene Tank Header may be calculated using the net heating value of ethylene if the vent stream is comprised of ethylene only [25 Pa. Code § 127.12b].

 # 006: The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of waste gas in the MPGF Ethylene Tank Header [25 Pa. Code § 127.12b].

 # 007: The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air used with the MPGF [25 Pa. Code § 127.12b].

RECORDKEEPING REQUIREMENTS

 # 008: VOC and GHG content measured by the gas chromatograph (or equivalent monitor) shall be used to calculate 12-month rolling total VOC and GHG emissions for the MPGF. As an alternative, engineering knowledge can be used to estimate the stream composition to calculate VOC and GHG emissions [25

Pa. Code § 127.12b].

WORK PRACTICE REQUIREMENTS

 # 009: The MPGF shall be equipped with automated controls for control of the supplemental gas flow rate to the flare [25 Pa. Code § 127.12b].

 # 010: The Owner/Operator shall minimize flaring resulting from startups, shutdowns, and unforeseeable events by operating the MPGF at all times in accordance with an approved flare minimization plan. The plan should be updated periodically per 40 CFR 63.670(o)(2)(ii). At a minimum, the plan shall include the following [25 Pa. Code § 127.12b]:

a. Procedures for operating and maintaining the MPGF during periods of process unit startup, shutdown, and unforeseeable events.
b. A program of corrective action for malfunctioning process equipment.
c. Procedures to minimize discharges either directly to the atmosphere or to the MPGF during the planned and unplanned startup or shutdown of process unit and air pollution control equipment, including an evaluation of flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including startup and shutdown, that considers the feasibility of performing these activities without flaring.
d. Procedures for conducting root cause analyses.
e. Procedures for taking identified corrective actions.
f. The baseline flow to the MPGF determined in accordance with the provisions of 40 CFR § 60.103a(a)(4).

 # 011: The Owner/Operator shall conduct a root cause analysis within 45 days after any startup flaring event, shutdown flaring event, or unforeseeable flaring event at the MPGF. Flaring event shall be defined as an event that exceeds the baseline by 500,000 scf within a 24-hour period. At a minimum, the analysis shall address the following [25 Pa. Code § 127.12b]:

a. The date and time that the flaring event started and ended.
b. The total quantity of gas flared during each event.
c. An estimate of the quantity of VOC that was emitted and the calculations used to determine the quantities.
d. The steps taken to limit the duration of the flaring event of the quantity of emissions associated with the event.
e. A detailed analysis that sets forth the root cause and all significant contributing causes of the flaring event to the extent determinable.
f. An analysis of the measures that are available to reduce the likelihood of a recurrence of a flaring event resulting from the same root cause or significant contributing causes in the future. The evaluation of prevention measures must consider the adequacy of existing maintenance schedules and protocols for equipment contributing to flaring events.
g. A demonstration that the actions taken during the flaring event are consistent with the procedures specified in the flare minimization plan.
h. In response to a flaring event, the Owner/Operator shall implement, as expeditiously as practicable, such

interim and/or long-term corrective actions as are consistent with good engineering practice to minimize the likelihood of a recurrence of the root cause and all significant contributing causes of that flaring event.

i. If any items required to be addressed in this analysis are still under investigation 45 days after the flaring event, the Owner/Operator shall include a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Condition shall be completed.

 # 012: Net heating value of the combustion zone gas at the MPGF shall equal or exceed 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes [25 Pa. Code § 127.12b].

 # 013: The Owner/Operator shall comply with the applicable VOC standards specified in 40 CFR §60.112b [25 Pa. Code § 127.12b].

<u>Section D – Source Level Plan Approval Requirements</u>

Source ID 209: MPGF PE Units 1/2 Episodic Vent Header

<u>RESTRICTIONS</u>

 # 001: Visible emissions from the MPGF shall not exceed 0% except for a total of five minutes during any consecutive two-hour period [25 Pa. Code § 127.12b].

 # 002: The MPGF shall be designed and operated to reduce collected VOC emissions by a minimum of 98% [25 Pa. Code §127.12b].

<u>MONITORING REQUIREMENTS</u>

 # 003: Monitoring for compliance with the 98% destruction efficiency requirement for the MPGF shall be performed in accordance with 40 CFR §63.987(c). Operating parameter monitoring shall include flame detection at a minimum [25 Pa. Code § 127.12b].

 # 004: The Owner/Operator shall comply with the applicable flare monitoring and work practice requirements, including limits on maximum exit velocity and minimum net heating value requirements, specified in 40 CFR §63.670 and 40 CFR §63.671 [25 Pa. Code § 127.12b].

 # 005: Net heating value of the combustion zone gas at the MPGF shall be measured and recorded at a minimum of once every 15 minutes. An adjusted net heating value of hydrogen of 1,212 Btu/scf may be used for this calculation [25 Pa. Code § 127.12b].

 # 006: The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of waste gas in the MPGF PE Units 1/2 Header as well as any flare supplemental gas used [25 Pa. Code § 127.12b].

 # 007: The Owner/Operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air used with the MPGF [25 Pa. Code § 127.12b].

.

RECORD KEEPING REQUIREMENTS

 # 008: VOC and GHG content measured by the gas chromatograph (or equivalent monitor) shall be used to calculate 12-month rolling total VOC and GHG emissions for the MPGF [25 Pa. Code § 127.12b].

WORK PRACTICE REQUIREMENTS

 # 009: The MPGF shall be equipped with automated controls for control of the supplemental gas flow rate to the flare [25 Pa. Code § 127.12b].

 # 010: The Owner/Operator shall minimize flaring resulting from startups, shutdowns, and unforeseeable events by operating the MPGF at all times in accordance with an approved flare minimization plan. The plan should be updated periodically per 40 CFR 63.670(o)(2)(ii). At a minimum, the plan shall include the following [25 Pa. Code § 127.12b]:

a. Procedures for operating and maintaining the MPGF during periods of process unit startup, shutdown, and unforeseeable events.
b. A program of corrective action for malfunctioning process equipment.
c. Procedures to minimize discharges either directly to the atmosphere or to the MPGF during the planned and unplanned startup or shutdown of process unit and air pollution control equipment, including an evaluation of flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including startup and shutdown, that considers the feasibility of performing these activities without flaring.
d. Procedures for conducting root cause analyses.
e. Procedures for taking identified corrective actions.
f. The baseline flow to the MPGF determined in accordance with the provisions of 40 CFR § 60.103a(a)(4).

 # 011: The Owner/Operator shall conduct a root cause analysis within 45 days after any startup flaring event, shutdown flaring event, or unforeseeable flaring event at the MPGF. Flaring event shall be defined as an event that exceeds the baseline by 500,000 scf within a 24-hour period. At a minimum, the analysis shall address the following [25 Pa. Code § 127.12b]:

a. The date and time that the flaring event started and ended.
b. The total quantity of gas flared during each event.
c. An estimate of the quantity of VOC that was emitted and the calculations used to determine the quantities.
d. The steps taken to limit the duration of the flaring event of the quantity of emissions associated with the event.
e. A detailed analysis that sets forth the root cause and all significant contributing causes of the flaring event to the extent determinable.

f. An analysis of the measures that are available to reduce the likelihood of a recurrence of a flaring event resulting from the same root cause or significant contributing causes in the future. The evaluation of prevention measures must consider the adequacy of existing maintenance schedules and protocols for equipment contributing to flaring events.
g. A demonstration that the actions taken during the flaring event are consistent with the procedures specified in the flare minimization plan.
h. In response to a flaring event, the Owner/Operator shall implement, as expeditiously as practicable, such interim and/or long-term corrective actions as are consistent with good engineering practice to minimize the likelihood of a recurrence of the root cause and all significant contributing causes of that flaring event.
i. If any items required to be addressed in this analysis are still under investigation 45 days after the flaring event, the Owner/Operator shall include a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Condition shall be completed.

 # 012: Net heating value of the combustion zone gas at the MPGF header shall equal or exceed 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes [25 Pa. Code § 127.12b].

The MPGF PE Units 1/2 Episodic Vent Header is also subject to 40 CFR Part 63 Subparts CC and FFFF. As such, Source ID 209 will be included in plan approval Group G09: NESHAP Part 63 Subpart FFFF (partial). 40 CFR Part 63 Subpart CC is incorporated by reference only in the plan approval since it is applicable by reference from Subpart FFFF.

Section D – Source Level Plan Approval Requirements

Source ID 301: Polyethylene Pellet Material Storage/Handling/Loadout

RESTRICTIONS

 # 002: ~~Polyethylene residual VOC content shall not exceed 50 ppmw on a monthly average for each polyethylene manufacturing line.*~~

~~*As measured downstream of the product purge bin in the gas phase technology polyethylene manufacturing line and downstream of and including the degasser at the slurry polyethylene manufacturing line~~

The difference in the polyethylene residual VOC content between the following locations in PE Units 1 and 2 shall not exceed 35.08 ppmw on a monthly average: the polyethylene residual VOC content as measured downstream of the product purge bin in PE Units 1 and 2 and the polyethylene residual VOC content as measured for PE pellets being loaded out from final storage to trucks or railcars. If residual VOC is not measured for PE pellets being loaded out, then it shall be assumed to be zero for purposes of this compliance calculation [25 Pa. Code § 127.12b].

 # 003: **The difference in the polyethylene residual VOC content between the following locations in PE Unit 3 shall not exceed 35.08 ppmw on a monthly average: the polyethylene residual VOC content as measured downstream of the degasser in PE Unit 3 and the polyethylene residual VOC content as**

measured for PE pellets being loaded out from final storage to trucks or railcars. If residual VOC is not measured for PE pellets being loaded out, then it shall be assumed to be zero for purposes of this compliance calculation [25 Pa. Code § 127.12b].

TESTING REQUIREMENTS

005: Polyethylene residual VOC content shall be measured no less than once per calendar month and **at a minimum of** once per ~~product formulation change~~ **reactor grade change** for each polyethylene manufacturing line. Measurement shall be conducted by methods and techniques acceptable to the Department. A minimum of three samples shall be taken before the first uncontrolled emission point downstream of the product purge bin in each gas phase technology polyethylene manufacturing line or downstream of the degasser in the slurry polyethylene manufacturing line for each measurement. **The Owner/Operator may request a reduction of the sampling frequency upon written request and approval from the Department** [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 302: Liquid Loadout (Recovered Oil)

MONITORING REQUIREMENTS

 # 001: The Owner/Operator shall monitor the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system during each loadout procedure, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. Breakthrough shall be defined as a VOC reading above background for a single canister and greater than or equal to 50 ppmv between the primary and secondary canister for all canisters operated as part of a primary and secondary system. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system [25 Pa. Code § 127.12b].

RECORDKEEPING REQUIREMENTS

 # 002: The Owner/Operator shall demonstrate that the carbon adsorption system achieves a minimum 95% control through engineering calculations including the following [25 Pa. Code § 127.12b]:

(1) Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters.

(i) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

 # 003: If a carbon adsorber that is not regenerated directly on site in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and when the existing carbon in the control device is replaced with fresh carbon [25 Pa. Code § 127.12b].

WORK PRACTICE REQUIREMENTS

~~# 001: Vapors displaced or generated by the loadout of recovered oil shall be captured and routed through a closed system to the Spent Caustic Vent incinerator.~~

 # 004: Submerged filling or bottom loading shall be used for loading recovered oil into transport vehicles [25 Pa. Code § 127.12b].

 # 005: Vent gases generated by loading recovered oil into transport vehicles shall be vented through a closed vent system to a carbon adsorption system designed to reduce VOC emissions by a minimum of 95% [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 303: Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, PE3 Heavies)

WORK PRACTICE REQUIREMENTS

001: Vapors displaced or generated by the load~~out~~**ing** of pyrolysis fuel oil**,** ~~or~~ light gasoline**, and PE3 heavies** shall be captured and routed through a closed system to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header** [25 Pa. Code § 127.12b].

The condition is proposed to be revised to clarify that the pyrolysis fuel oil and light gasoline transfer activities represent the "loading" of those materials into railcars to be transported offsite and to document that PE3 heavies is loaded into railcars at SPM. Shell originally planned to blend PE3 heavies into light gasoline. However, PE3 heavies is loaded separately from light gasoline into railcars, and the vapors generated during the loading of PE3 heavies into railcars are collected and routed through a closed system to the CVTO or MPGF, the same as originally planned when the PE3 heavies were to be blended into light gasoline. Therefore, PE3 heavies are separately identified in the revised condition.

Section D – Source Level Plan Approval Requirements

Source ID 304: Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)

WORK PRACTICE REQUIREMENTS

001: C3+ ~~liquids~~ **shall be loaded**~~,~~ and C3~~+~~ refrigerant, butene, isopentane, and isobutane shall be **un**loaded ~~out~~ with vapor balance to pressurized storage tanks capable of maintaining working pressures sufficient at all times to prevent vapor or gas loss to the atmosphere and with no venting during loading **and unloading** operations [25 Pa. Code § 127.12b].

The condition is proposed to be revised to clarify that the C_{3+} transfer activity represents the "loading" of C_{3+} into railcars to be transported offsite, while the butene, isopentane, isobutane, and C_3 refrigerant transfer activities represent the "unloading" of those materials from railcars into storage tanks at SPM. The revised condition also correctly identifies the refrigerant referenced as C_3 refrigerant rather than C_{3+} refrigerant.

Section D – Source Level Plan Approval Requirements

Source ID 305: Liquid Loadout (Blended Pitch)

WORK PRACTICE REQUIREMENTS

 # 001: Vapors displaced or generated by the load~~out~~**ing** of ~~coke residue/tar~~ **blended pitch** shall be captured and routed through a closed system back to the process **or to the HP Header System** [25 Pa. Code § 127.12b].

The condition is proposed to be revised because SPM refers to coke residue/tar as blended pitch, and the vapors generated during the "loading" of blended pitch into trucks are alternatively routed to the HP Header System if they are not routed back to the process.

Section D – Source Level Plan Approval Requirements

Source ID 401: Storage Tanks (Recovered Oil, Equalization Wastewater)

WORK PRACTICE REQUIREMENTS

002: Recovered oil and equalization wastewater storage tanks shall be controlled by vapor recovery routed to the ~~Spent Caustic Vent incinerator~~ **SCTO** [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 402: Storage Tank (Spent Caustic)

WORK PRACTICE REQUIREMENTS

001: The spent caustic storage tank shall be controlled by vapor recovery routed to the ~~Spent Caustic Vent incinerator~~ **SCTO** [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 403: Storage Tank (Light Gasoline)

WORK PRACTICE REQUIREMENTS

\# 001: Light gasoline storage tanks shall be controlled by vapor recovery routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header** [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 404: Storage Tanks (Hexene)

WORK PRACTICE REQUIREMENTS

\# 004: Hexene storage tanks shall be controlled by vapor recovery routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header** [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 405: Storage Tanks (Misc Pressurized~~/Refrigerated~~)

WORK PRACTICE REQUIREMENTS

\# 001: Ethylene, C3+, ~~C3+~~ C3 refrigerant, butene, isopentane, isobutane, aqueous ammonia, dimethyl disulfide, ~~and~~ methanol, **and PE3 heavies** shall be stored in pressurized ~~and/or refrigerated~~ storage tanks with no uncontrolled vent directed to the atmosphere [25 Pa. Code § 127.12b].

The condition is proposed to be revised to identify the refrigerant referenced in the condition as C3 refrigerant rather than C3+ refrigerant. Additionally, PE3 heavies is included in the list of materials that are stored in pressurized storage tanks with no uncontrolled vent directed to the atmosphere.

\# 002: ~~Emergency~~ **Pressure control** relief vents for pressurized ~~or refrigerated~~ storage tanks shall vent to the HP **Header** System [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 406: Storage Tanks (Diesel Fuel > 150 Gallons)

~~# 001: *Diesel fuel storage tank vents shall be controlled by carbon canisters designed to reduce VOC emissions by a minimum of 95%.*~~

~~# 002: *The Owner/Operator shall monitor carbon canisters in accordance with the manufacturer's recommendations to ensure that the adsorption media is regenerated or replaced prior to breakthrough.*~~

~~*Breakthrough shall be defined as a VOC reading above background for a single canister and greater than or equal to 50 ppmv for all canisters operated as part of a primary and secondary system.*~~

Shell has proposed that the conditions be removed because the storage tanks do not vent to carbon canisters due to the low vapor pressure of diesel, as authorized by RFD 8799 for the 572-gallon aboveground diesel storage tanks for the two (2) firewater pump engines.

Section D – Source Level Plan Approval Requirements

Source ID 407: Storage Tanks (Pyrolysis Fuel Oil

WORK PRACTICE REQUIREMENTS

004: Pyrolysis fuel oil storage tanks shall be controlled by vapor recovery routed to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header** [25 Pa. Code § 127.12b].

Section D – Source Level Plan Approval Requirements

Source ID 411: Refrigerated Ethylene Storage Tank

TESTING REQUIREMENTS

 # 001: The Owner/Operator shall comply with the applicable storage tank testing and procedures specified in 40 CFR § 60.113b(a) and/or (c) or (d).

MONITORING REQUIREMENTS

 # 002: The Owner/Operator shall comply with the applicable storage tank monitoring requirements specified in 40 CFR § 60.116b.

REPORTING REQUIREMENTS

 # 003: The Owner/Operator shall comply with the applicable storage tank reporting and recordkeeping requirements specified in 40 CFR § 60.115b(a) and/or (c) or (d).

WORK PRACTICE REQUIREMENTS

 # 004: The refrigerated ethylene storage tank shall have no uncontrolled vent directed to the atmosphere [25 Pa. Code § 127.12b].

 # 005: Pressure control relief vents for the refrigerated ethylene storage tank shall vent to the MPGF Ethylene Tank Header [25 Pa. Code § 127.12b].

 # 006: The Owner/Operator shall comply with the applicable storage tank VOC standards specified in 40 CFR § 60.112b(a) and (b).

ADDITIONAL REQUIREMENTS

 # 007: The refrigerated ethylene storage tank is subject to the requirements of 40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.

 # 008: All terms used in 40 CFR Part 60 Subpart Kb shall have the meaning given in 40 CFR § 60.111b or else in the Clean Air Act and 40 CFR Part 60 Subpart A.

Section D – Source Level Plan Approval Requirements

Source ID 505: WWTP (Primary Treatment)

TESTING REQUIREMENTS

 # 001: Within 180 days of the startup of the WWTP Permanent Controls Project and monthly thereafter, or an alternative schedule approved by the Department, the Owner/Operator shall conduct sampling and testing at the settlement drum inlet to determine the wastewater stream speciated HAP concentrations, including, but not limited to, 1,3-Butadiene, benzene, toluene, ethylbenzene, xylene, styrene, naphthalene, dibutyl phthalate, chloroform, acenaphthene, acenaphthylene, fluorene, anthracene, phenanthrene, fluoranthene, and pyrene. The report shall be submitted to the Department no later than 30 days from the date of completion of sampling and testing. The report shall include the following [25 Pa. Code § 127.12b]:

a. Wastewater lab results and testing method used;
b. Location the sample is taken; and
c. Wastewater flow rate;

The sampling frequency may be reduced upon the acquisition of a calendar years' worth of data, the submittal of the data, and the receipt of written approval from the Department.

 # 002: The Owner/Operator shall sample at the settlement drum inlet and DNF #2 outlet for concentration of benzene, toluene, ethylbenzene, xylene, and styrene at a minimum of once per calendar week. Sample analyses shall be conducted by methods and techniques acceptable to the Department [25 Pa. Code § 127.12b].

 # 003: The Owner/Operator shall sample at the settlement drum inlet and DNF #2 outlet for concentration of Total Organic Compounds (TOC) at a minimum of once per calendar week to monitor for operational efficiency of the WWTP's primary treatment system. Sample analyses shall be conducted by methods and techniques acceptable to the Department [25 Pa. Code § 127.12b].

 # 004: The Owner/Operator shall sample at the settlement drum inlet and DNF #2 outlet for concentration of Oil and Grease (O&G), as referenced in 40 CFR 401, at least once per calendar week to monitor for O&G removal efficiency of the WWTP's primary treatment system. Sample analyses shall be conducted by methods and techniques acceptable to the Department [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

 # 005: The Owner/Operator shall monitor the pressure of nitrogen once per calendar day into the primary DNF. The minimum nitrogen pressure target shall be set within 60 days of initial operation [25 Pa. Code § 127.12b].

 # 006: The Owner/Operator shall monitor the temperature of the steam stripper bottoms each operating day. The specific location of the thermocouple shall be determined within 60 days of initial operation [25 Pa. Code § 127.12b].

 # 007: The Owner/Operator shall monitor the steam stripper inlet steam-to-water ratio on an hourly average when the steam stripper is in operation [25 Pa. Code § 127.12b].

 # 008: The Owner/Operator shall monitor the total steam supplied to the steam stripper on an hourly average when the steam stripper is in operation [25 Pa. Code § 127.12b].

 # 009: The Owner/Operator shall monitor the steam pressure supplied to the steam stripper on an hourly average when the steam stripper is in operation [25 Pa. Code § 127.12b].

 # 010: The Owner/Operator shall monitor the temperature at the outlet of the steam stripper overhead condenser on an hourly average when the condenser is in operation [25 Pa. Code § 127.12b].

RECORDKEEPING REQUIREMENTS

 # 011: The Owner/Operator shall maintain the following comprehensive and accurate records at a frequency specified in the WWTP Control Plan [25 Pa. Code § 127.12b]:

a. Speciated HAP, TOC, and O&G inlet and outlet concentrations
b. Nitrogen pressure into the primary DNF
c. Temperature of the steam stripper bottoms
d. Steam stripper inlet steam-to-water ratio, total steam supplied, and pressure of the steam
e. Steam stripper overhead condenser outlet temperature

WORK PRACTICE REQUIREMENTS

 # 012: During truck loading from the Settlement Drum or the Recovered Oil Storage Tank, carbon canisters shall be used to control vapors generated from the truck tank [25 Pa. Code § 127.12b].

 # 013: The Owner/Operator shall develop and submit a written WWTP Control Plan to the Department within 60 days of commencing operation of the WWTP Permanent Controls Project. The plan shall be updated periodically to account for changes in the operation of the WWTP primary treatment system including, but not limited to, specifications, procedures, and corrective actions in the plan [25 Pa. Code § 127.12b].

 # 014: The Owner/Operator shall operate the WWTP's primary treatment system in accordance with the written

WWTP Control Plan at all times. At a minimum, the plan shall include the following [25 Pa. Code § 127.12b]:

a. A description of the parameters to be monitored to ensure the effectiveness of the WWTP's primary treatment system, and the frequency with which monitoring of these parameters will be performed. At a minimum, parameters to be monitored shall include the settlement drum inlet and DNF #2 outlet TOC, O&G, and speciated HAP concentration, DNF nitrogen pressure, steam stripper bottoms temperature, steam stripper steam-to-water ratio, total steam supplied, and steam pressure supplied, and steam stripper overhead condenser outlet temperature.

b. The operating range for each monitoring parameter identified. The specified operating range shall represent the conditions for which the WWTP's primary treatment system is being properly operated and maintained.

c. A program of corrective action for WWTP primary treatment system equipment operating outside the specified parameter ranges.

d. Procedures and timeline for taking identified corrective actions.

ADDITIONAL REQUIREMENTS

#015: The Settlement Drum, Dissolved Nitrogen Flotation (DNF) Unit #1, DNF Unit #2, Float/Sludge Drum, and above-ground piping shall meet the applicable control standards in 40 CFR § 61.343 through § 61.347 [25 Pa. Code § 127.12b].

 # 016: The Steam Stripper shall meet the treatment processes control standards in 40 CFR § 61.348.

Section E – Source Group Plan Approval Restrictions

Group Name: G01 – Ethane Cracking Furnaces

Source ID: 031: Ethane Cracking Furnace #1
Source ID: 032: Ethane Cracking Furnace #2
Source ID: 033: Ethane Cracking Furnace #3
Source ID: 034: Ethane Cracking Furnace #4
Source ID: 035: Ethane Cracking Furnace #5
Source ID: 036: Ethane Cracking Furnace #6
Source ID: 037: Ethane Cracking Furnace #7

RESTRICTIONS

003: CO emissions from the ethane cracking furnaces shall not exceed the following [25 Pa. Code § 127.12b]:

- 0.035 lb/MMBtu from each furnace on a 12-month rolling average; excluding periods of startup, shutdown, and decoking.

- 52.2 lb/hr from each furnace during periods of startup, shutdown, and decoking.
- ~~670.4~~ **409.85** tons from all furnaces combined in any consecutive 12-month period.

\# 004: PM10 and PM2.5 emissions**, respectively,** from ~~each of~~ the ethane cracking furnaces shall not exceed the following [25 Pa. Code § 127.12b]:

- 3.10 lb/hr **from each furnace**, excluding periods of decoking.
- 1.86 lb/hr **from each furnace** during periods of decoking.
- ~~12.4~~ **86.8** tons **from all furnaces combined** in any consecutive 12-month period.

\# 005: NH3 emissions from each of the ethane cracking furnaces shall not exceed 10 ppmvd at 3% O2 **on a daily average** [25 Pa. Code § 127.12b].

\# 007: GHG emissions from the ethane cracking furnaces shall not exceed ~~1,048,670~~ **1,101,555** tons of CO_2e from all furnaces combined in any consecutive 12-month period. Compliance with this limit may be determined through CO_2e calculations in accordance with 40 CFR §98.34(b)(3) or utilizing an in-line gas chromatograph [25 Pa. Code § 127.12b].

\# 008: The Owner/Operator may only operate an ethane cracking furnace in a defined operating mode. Operating modes of the ethane cracking furnaces are defined as follows [25 Pa. Code § 127.12b]:

- Startup – Beginning when fuel is introduced to the furnace and ending when the SCR catalyst bed reaches its stable operating temperature. Stable operating temperature is achieved when the furnace coil outlet temperature (COT) reaches 750°C.
- Hot Steam Standby – When the furnace COT is greater than or equal to 750°C, ~~below 50% of the maximum allowable firing rate,~~ no hydrocarbon feed is being charged to the furnace, and the furnace is not operating in decoking, startup, or shutdown mode.
- Feed In – Beginning when hydrocarbon feed is introduced to the furnace and ending when the hydrocarbon feed reaches ~~43~~ **29** metric tons per hour.
- Normal – When the furnace is at or above a hydrocarbon feed rate of ~~43~~ **29** metric tons per hour.
- Feed Out – Beginning when the furnace drops below a hydrocarbon feed rate of ~~43~~ **29** metric tons per hour and ending when hydrocarbon feed is isolated from the furnace.
- Shutdown – Beginning when the SCR catalyst bed drops below its stable operating temperature and ending upon removing all fuel from the furnace. Stable operating temperature is lost when the furnace COT drops below 750°C.
- Decoking – Beginning when air is introduced to the furnace for the purpose of decoking and ending when decoking air is removed.

\# 010: A startup for each furnace shall not exceed 24 hours and shall not exceed 25% of the maximum allowable firing rate, except during startups requiring refractory dry out which is limited to 72 hours at 25% or less of the maximum allowable firing rate. **The 25% maximum allowable firing rate limitation does not apply at times during a startup when a furnace's NOx emissions are 6.2 lb/hr or less** [25 Pa. Code § 127.12b].

MONITORING REQUIREMENTS

014: The Owner/Operator shall continuously monitor and record the catalyst bed inlet ~~and outlet~~ temperature for each SCR system [25 Pa. Code § 127.12b].

016: **The Owner/Operator shall continuously monitor for ammonia slip from each ethane cracking furnace via in-situ tunable diode laser (TDL), or equivalent monitor, as approved by the Department** [25 Pa. Code § 127.12b].

Section E – Source Group Plan Approval Restrictions

Group Name: G02 – Cogeneration Units

Source ID: 101: Combustion Turbine/Duct Burner Unit #1
Source ID: 102: Combustion Turbine/Duct Burner Unit #2
Source ID: 103: Combustion Turbine/Duct Burner Unit #3

RESTRICTIONS

001: CO emissions from the combustion turbines with duct burners shall not exceed the following [25 Pa. Code § 127.12b]:

- 2 ppmvd @ 15% O2 from each turbine/duct burner on a 1-hour average, excluding periods of defined startup or shutdown.
- 276 lb/hr from each turbine/duct burner during periods of startup or shutdown.
- 45.0 tons from all turbines and duct burners combined in any consecutive 12-month period.

For purposes of determining compliance with these CO limits, startup is defined as beginning upon commencement of ignition and ending when the combustion turbine reaches 55% of its baseload operating level.

For purposes of determining compliance with these CO limits, shutdown is defined as beginning when the combustion turbine ~~drops below 55% of its baseload operating level and ending when fuel is cut to this unit~~ **is transitioned out of low NOx firing mode and ending upon removing all fuel from the turbine**. Each shutdown event shall not exceed 30 minutes in duration.

For purposes of determining compliance with these CO limits, low NOx firing mode is defined as a lean premixed mode where air and fuel are mixed before entering the turbine combustor (versus the diffusion mode where fuel and air are injected into the combustor separately).

005: NH3 emissions from each of the combustion turbines with duct burners shall not exceed 5 ppmvd at 15% O2 **on a daily average** [25 Pa. Code § 127.12b].

007: NOx emissions from the combustion turbines with duct burners shall not exceed the following [25 Pa. Code § 127.12b]:

- 2 ppmvd @ 15% O2 from each turbine/duct burner on a 1-hour average, excluding periods of defined startup or shutdown.
- 113 lb/hr from each turbine/duct burner during periods of startup or shutdown.
- 70.4 tons from all turbines and duct burners combined in any consecutive 12-month period.

For purposes of determining compliance with these NOx limits, startup is defined as beginning when fuel is introduced into the turbine and ending when the SCR catalyst bed reaches its design operating temperature **of 316° C**.

For purposes of determining compliance with these NOx limits, shutdown is defined as beginning when the ~~SCR catalyst bed drops below its design operating temperature~~ **combustion turbine is transitioned out of low NOx firing mode** and ending upon removing all fuel from the turbine. **Each shutdown event shall not exceed 30 minutes in duration.**

For purposes of determining compliance with these NOx limits, low NOx firing mode is defined as a lean premixed mode where air and fuel are mixed before entering the turbine combustor (versus the diffusion mode where fuel and air are injected into the combustor separately).

MONITORING REQUIREMENTS

 # 018: **The Owner/Operator shall continuously monitor for ammonia slip from each ethane cracking furnace via in-situ tunable diode laser (TDL), or equivalent monitor, as approved by the Department** [25 Pa. Code § 127.12b].

REPORTING REQUIREMENTS

026: ~~The Owner/Operator of lean premix stationary combustion turbines is only required to comply with the initial notification requirements of 40 CFR Part 63 Subpart YYYY as specified in 40 CFR §63.6095.~~

#027: ~~The Owner/Operator shall comply with the applicable initial notification requirements of 40 CFR Part 63 Subpart YYYY as specified in 40 CFR §63.6145(c).~~

ADDITIONAL REQUIREMENTS

031: ~~The three combustion turbines are subject to limited requirements of 40 CFR Part 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.~~

032: ~~All terms used in 40 CFR Part 63 Subpart YYYY shall have the meaning given in 40 CFR §63.6175 or else in the Clean Air Act and 40 CFR Part 63 Subpart A~~.

Section E – Source Group Plan Approval Restrictions

Group Name: G14 – NESHAP Part 63 Subpart YYYY

Source ID: 101: Combustion Turbine/Duct Burner Unit #1
Source ID: 102: Combustion Turbine/Duct Burner Unit #2
Source ID: 103: Combustion Turbine/Duct Burner Unit #3

RESTRICTIONS

001: **The Owner/Operator shall comply with the applicable emission and operating limitations as specified in 40 CFR §63.6100.**

TESTING REQUIREMENTS

002: **The Owner/Operator shall comply with the applicable performance testing requirements as specified in 40 CFR §63.6115.**

003: **The Owner/Operator shall comply with the applicable performance testing and procedures as specified in 40 CFR §63.6120.**

MONITORING REQUIREMENTS

004: **The Owner/Operator shall comply with the applicable monitoring requirements as specified in 40 CFR §63.6125.**

005: **The Owner/Operator shall comply with the applicable monitoring requirements to demonstrate continuous compliance as specified in 40 CFR §63.6135.**

RECORDKEEPING REQUIREMENTS

006: **The Owner/Operator shall comply with the applicable recordkeeping requirements as specified in 40 CFR §63.6155.**

007: **The Owner/Operator shall maintain the appropriate records as specified in 40 CFR §63.6160.**

REPORTING REQUIREMENTS

008: **The Owner/Operator shall comply with the applicable reporting requirements as specified in 40 CFR § 63.6140.**

009: **The Owner/Operator shall comply with the applicable notification requirements as specified in 40 CFR § 63.6145.**

 # 010: The Owner/Operator shall comply with the applicable reporting requirements as specified in 40 CFR § 63.6150.

WORK PRACTICE REQUIREMENTS

 # 011: The Owner/Operator shall comply with the applicable work practice requirements as specified in 40 CFR § 63.6105.

ADDITIONAL REQUIREMENTS

 # 012: The three combustion turbines are subject to the requirements of 40 CFR Part 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.

 # 013: All terms used in 40 CFR Part 63 Subpart YYYY shall have the meaning given in 40 CFR §63.6175 or else in the Clean Air Act and 40 CFR Part 63 Subpart A.

Section E – Source Group Plan Approval Restrictions

Group Name: G05 – NESHAP Part 63 Subpart YY

Source IDs 031-037: Ethane Cracking Furnaces
Source ID 201: Ethylene Manufacturing Line
Source ID 203: Process Cooling Tower
Source ID 204: ~~Low Pressure (LP)~~ **CVTO** Header System
Source ID 205: High Pressure (HP) Header System
Source ID 206: Spent Caustic Vent Header System
Source ID 207: MPGF CVTO Trip Header
Source ID 302: Liquid Loadout (Recovered Oil)
Source ID 303: Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline)
Source ID 304: Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)
Source ID 305: Liquid Loadout (Blended Pitch)
Source ID 401: Storage Tanks (Recovered Oil, Equalization Wastewater)
Source ID 402: Storage Tanks (Spent Caustic)
Source ID 403: Storage Tanks (Light Gasoline)
Source ID 407: Storage Tanks (Pyrolysis Fuel Oil)
Source ID 501: Equipment Components
Source ID 502: Wastewater Treatment Plant
Source ID 505: WWTP (Primary Treatment)

001: The Owner/Operator shall reduce emissions of total organic HAP from the light gasoline and pyrolysis fuel oil storage tanks by [a minimum of] 98 wt% by venting emissions through a closed vent system to any combination of control devices and meet the requirements of §63.982(a)(1) as specified in Table 7(b)(1)(ii) to 40 CFR §63.1103(e). [Compliance with the LAER VOC control requirements to install an IFR and capture and route vapors to the ~~LP System~~ **CVTO Header System or MPGF CVTO Trip Header** will show compliance with this requirement]

<u>Section E – Source Group Plan Approval Restrictions</u>

Group Name: G08 – NESHAP Part 63 Subpart SS

Source ID 201: Ethylene Manufacturing Line
Source ID 202: Polyethylene Manufacturing Line
Source ID 204: ~~Low Pressure (LP)~~ **CVTO** Header System
Source ID 205: High Pressure (HP) Header System
Source ID 206: Spent Caustic Vent Header System

<u>TESTING REQUIREMENTS</u>

001: The Owner/Operator shall comply with the applicable performance testing and compliance assessment requirements for the ~~Spent Caustic Vent and LP incinerators MPGF, and HP flares~~ **SCTO and CVTO** specified in 40 CFR § 63.997.

<u>MONITORING REQUIREMENTS</u>

002: The Owner/Operator shall comply with the applicable general monitoring requirements for the ~~Spent Caustic Vent incinerator, LP System, and HP System~~ **SCTO and CVTO** specified in 40 CFR § 63.996.

<u>WORK PRACTICE REQUIREMENTS</u>

~~# 007: The Owner/Operator shall comply with the applicable flare requirements for the MPGF, and HP ground flares and elevated flare specified in 40 CFR §63.987.~~

007: The Owner/Operator shall comply with the applicable incinerator requirements for the ~~LP incinerator~~ **CVTO** specified in 40 CFR § 63.988.

<u>Section E – Source Group Plan Approval Restrictions</u>

Group Name: G09 – NESHAP Part 63 Subpart FFFF (partial)

Source ID 202: Polyethylene Manufacturing Line
Source ID 203: Process Cooling Tower
Source ID 204: CVTO Header System
Source ID 207: MPGF CVTO Trip Header
Source ID 209: MPGF PE Units 1/2 Episodic Vent Header
Source ID 401: Storage Tanks (Recovered Oil, Equalization Wastewater)
Source ID 501: Equipment Components
Source ID 502: Wastewater Treatment Plant (Secondary and Tertiary Treatment)
Source ID 505: WWTP (Primary Treatment)

WORKPARACTICE REQUIREMENTS

 # 006: The Owner/Operator shall comply with the applicable flare requirements of 40 CFR Part 63 Subpart CC as specified in 40 CFR § 63.2450(e).

Section E – Source Group Plan Approval Restrictions

Group Name: G10 – Liquid Loadout

Source ID 302: Liquid Loadout (Recovered Oil)
Source ID 303: Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, **PE3 Heavies**)
Source ID 304: Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3~~+~~ Ref)
Source ID 305: Liquid Loadout (~~Coke Residue/Tar~~ **Blended Pitch**)

MONITORING REQUIREMENTS

001: The Owner/Operator shall monitor for pressure relief valve releases during liquid load~~out~~**ing** operations. Records of any pressure relief event shall be maintained onsite and include the following details at a minimum [25 Pa. Code § 127.12b]:

a. Date and time of the pressure relief event;
b. Name and title of the observer;
c. Duration of the event;
d. Estimated emission rate during the event; and,
e. Corrective action taken as a result of the event.

WORK PRACTICE REQUIREMENTS

004: Liquid loadout hoses shall be equipped with ~~OPW's Drylok™ Dry Disconnect Coupling (or equivalent)~~ low-leak couplings **designed to close off the loading hose at the coupling prior to disconnect and operated in accordance with the manufacturer's specifications** [25 Pa. Code § 127.12b].

 # 007: **Pre-transfer leak checks shall be performed on hoses and fittings by pressuring with nitrogen. Any leaks detected shall be repaired prior to introducing hydrocarbons into a transfer hose** [25 Pa. Code § 127.12b].

Section H – Miscellaneous

This is a major Title V facility for NOx, CO, PM_{10}, $PM_{2.5}$, VOC, ~~Hexane, Total HAP~~, and CO_2e and as such, actual emissions may equal or exceed the following in any consecutive 12-month period.

100.0 tons of NOx (NITROGEN OXIDES)
100.0 tons of CO (CARBON MONOXIDE)
100.0 tons of PM-10 (PARTICULATE MATTER < 10 MICRONS)
100.0 tons of PM-2.5 (PARTICULATE MATTER < 2.5 MICRONS)

50.0 tons of VOC (VOLATILE ORGANIC COMPOUNDS)
~~10.0 tons of HEXANE~~
~~25.0 tons of ALL HAP COMBINED (HAZARDOUS AIR POLLUTANT)~~

This is a natural minor facility with respect to SOx and as such, actual emissions cannot equal or exceed the following in any consecutive 12-month period:

100.0 tons of SOx (SULFUR OXIDES)