Shell Chemical Appalachia LLC
300 Frankfort Rd
Monaca, PA 15061

April 11, 2025

Alexander Sandy
Air Quality Engineering Specialist
Pennsylvania Department of Environmental Protection
Bureau of Air Quality - Southwest Regional Office
400 Waterfront Drive
Pittsburgh, PA 15222-4745

Re: Shell Chemical Appalachia LLC
Shell Polymers Monaca
Potter and Center Townships, Beaver County
Fifth Response to Plan Approval Application Technical Deficiency Letter

Dear Mr. Sandy:

On September 13, 2024, Shell Chemical Appalachia LLC ("Shell") submitted a plan approval application to the Pennsylvania Department of Environmental Protection (DEP) proposing the Wastewater Treatment Plant (WWTP) Permanent Controls Project and Ethylene Maximum Achievable Control Technology (EMACT) Project at Shell Polymers Monaca ("SPM"), as well as Plan Approval Reconciliations for SPM's current plan approval. On December 24, 2024, DEP provided Shell with a technical deficiency letter for the referenced plan approval application, which included itemized requests for additional information. Shell has already submitted four responses to DEP's December 24, 2024 technical deficiency letter. The initial response was submitted on January 23, 2025, to respond to Request Nos. 6-16 in the letter; the second response was submitted on February 7, 2025, to respond to Request No. 21; the third response was submitted on February 28, 2025, to respond to Request Nos. 17 and 20; and, the fourth response was submitted on March 7, 2025, to respond to Request Nos. 18 and 19. Shell is submitting this fifth and final response to the December 24, 2024 technical deficiency letter to respond to Request Nos. 1-5 in the letter.

Below are Shell's responses to Request Nos. 1-5 as they are presented in DEP's December 24, 2024 technical deficiency letter.

1. *Source by source change in potential emissions comparing PA-04-00740C with the proposed potential emissions.*

   Response: Please see Attachment 1 herein for a source-by-source comparison of PA-04-00740B and PA-04-00740C potential to emit rates against proposed potential to emit rates.

2. *Source by source change in potential emissions comparing PA-04-00740C with the proposed potential emissions related to nonattainment new source review and prevention of significant deterioration for all air contamination sources and air cleaning devices affected by:*

   a. *Plan approval reconciliations; and*

   b. *Wastewater treatment plant (WWTP) permanent controls project.*

   Response: Please see Attachment 1 herein for a source-by-source comparison of PA-04-00740B and PA-04-00740C potential to emit rates against proposed potential to emit rates, as well as a comparison of respective Plan Approval Reconciliations/WWTP Permanent Controls Project and EMACT Project emissions increases against relevant NNSR and PSD thresholds.

3. *Revised analysis of 25 Pa. Code Chapter 127 Subchapter E requirements including, but not limited to:*

   a. *A revised analysis of the Lowest Achievable Emission Rate (LAER) under 25 Pa. Code §127.205(1) for all air contamination sources and air cleaning devices associated with the plan approval reconciliations;*

   Response: Please see Attachment 2 herein for revised LAER analyses for relevant emission sources addressed by the Plan Approval Reconciliations.

   b. *Source of the required emission offsets in accordance with 25 Pa. Code §127.205(4), §127.206, §127.208, and §127.210; and*

   Response: Please see Attachment 3 for copies of the respective NOx and $PM_{2.5}$ emission reduction credit (ERC) transfer requests that Shell recently submitted to DEP. In summary, Shell requested DEP to confirm the creditable status of 184 tons per year (tpy) of NOx ERCs that were requested to be transferred from Northern Star Generation LLC to Shell. Shell plans to use 61 tpy of these NOx ERCs to satisfy the NOx offset requirements for the Plan Approval Reconciliations/WWTP Permanent Controls Project. Additionally, Shell plans to use 87 tpy of the NOx ERCs to satisfy the NOx offset requirements for the EMACT Project. Shell separately requested DEP 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 plans to use 7 tpy of these 31.03 tpy of $PM_{2.5}$ ERCs to satisfy the $PM_{2.5}$ offset requirements for the Plan Approval Reconciliations/WWTP Permanent Controls Project. The calculation of these NOx and $PM_{2.5}$ ERC requirements for the Plan Approval Reconciliations/WWTP Permanent Controls Project and EMACT Project, respectively, are documented in Attachment 1.

   c. *A new alternatives analysis as required under 25 Pa. Code §127.205(5) for the plan approval reconciliations and WWTP permanent controls project.*

   Response: Please see Attachment 4 herein for an alternatives analysis for the Plan Approval Reconciliations and Attachment 5 herein for an alternatives analysis for the WWTP Permanent Controls Project.

4. *Revised Best Available Technology (BAT) analysis for all air contamination sources associated with the plan approval reconciliations in accordance with 25 Pa. Code § 127.1 and 25 Pa. Code § 121.1.*

   Response: Please see Attachment 6 herein for revised BAT analyses for relevant emission sources addressed by the Plan Approval Reconciliations.

5. *Revised Best Available Control Technology analysis per the requirements of 40 CFR Part § 52.21 for CO, NOx (NO_2), PM (filterable only), PM_{10}, and GHGs emissions from air contamination sources and air cleaning devices associated with the plan approval reconciliations.*

   Response: Please see Attachment 7 herein for revised BACT analyses for relevant emission sources addressed by the Plan Approval Reconciliations.

If you have any questions regarding this fifth and final response to the December 24, 2024 technical deficiency letter, please contact Kimberly Kaal at kimberly.kaal@shell.com.

Sincerely,

Kimberly Kaal

Kimberly Kaal
Environmental Manager, Attorney-in-Fact

CC: Mark Gorog, PADEP Air Quality Program Regional Manager
Sheri Guerrieri, PADEP Environmental Group Manager (New Source Review)
Tom Joseph, PADEP Environmental Group Manager (Permits)
Brad Spayd, PADEP Air Quality Engineering Specialist
Andrew Fleck, Air Quality Modeling and Risk Assessment Section Environmental Group Manager
Martin Padilla, SPM HSSE Manager
Alan Binder, Shell Sr. Environmental Engineer - Air Quality
Laura Sabolyk, Senior Regulatory Advisor
Michael Carbon, Landau Associates Senior Principal

Enclosures

Attachment 1

Request Nos. 1 and 2 Information

SPM Source-by-Source Comparison of PA-04-00740B and PA-04-00740C Potential to Emit (PTE) Rates Against Proposed PTE Rates

Source ID	Source Description	PTE Category	CO	NOx	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO_2e	Lead	H_2SO_4	Ammonia	HAPs
			Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)
031	Ethane Cracking Furnace #1	**Proposed PTE**	58.47	25.90	4.75	12.40	12.40	0.67	2.61	158,990	2.24E-04	0.03	10.45	0.73
		PA-04-00740C PTE	95.77	25.90	4.87	12.40	12.40	0.51	4.63	149,810	1.38E-04	0.02	10.35	2.60
		Change in PTE	-37.30	0	-0.12	0	0	0.16	-2.02	9,180	8.60E-05	0.01	0.10	-1.87
032	Ethane Cracking Furnace #2	**Proposed PTE**	58.47	25.90	4.75	12.40	12.40	0.67	2.61	158,990	2.24E-04	0.03	10.45	0.73
		PA-04-00740C PTE	95.77	25.90	4.87	12.40	12.40	0.51	4.63	149,810	1.38E-04	0.02	10.35	2.60
		Change in PTE	-37.30	0	-0.12	0	0	0.16	-2.02	9,180	8.60E-05	0.01	0.10	-1.87
033	Ethane Cracking Furnace #3	**Proposed PTE**	58.47	25.90	4.75	12.40	12.40	0.67	2.61	158,990	2.24E-04	0.03	10.45	0.73
		PA-04-00740C PTE	95.77	25.90	4.87	12.40	12.40	0.51	4.63	149,810	1.38E-04	0.02	10.35	2.60
		Change in PTE	-37.30	0	-0.12	0	0	0.16	-2.02	9,180	8.60E-05	0.01	0.10	-1.87
034	Ethane Cracking Furnace #4	**Proposed PTE**	58.47	25.90	4.75	12.40	12.40	0.67	2.61	158,990	2.24E-04	0.03	10.45	0.73
		PA-04-00740C PTE	95.77	25.90	4.87	12.40	12.40	0.51	4.63	149,810	1.38E-04	0.02	10.35	2.60
		Change in PTE	-37.30	0	-0.12	0	0	0.16	-2.02	9,180	8.60E-05	0.01	0.10	-1.87
035	Ethane Cracking Furnace #5	**Proposed PTE**	58.47	25.90	4.75	12.40	12.40	0.67	2.61	158,990	2.24E-04	0.03	10.45	0.73
		PA-04-00740C PTE	95.77	25.90	4.87	12.40	12.40	0.51	4.63	149,810	1.38E-04	0.02	10.35	2.60
		Change in PTE	-37.30	0	-0.12	0	0	0.16	-2.02	9,180	8.60E-05	0.01	0.10	-1.87
036	Ethane Cracking Furnace #6	**Proposed PTE**	58.47	25.90	4.75	12.40	12.40	0.67	2.61	158,990	2.24E-04	0.03	10.45	0.73
		PA-04-00740C PTE	95.77	25.90	4.87	12.40	12.40	0.51	4.63	149,810	1.38E-04	0.02	10.35	2.60
		Change in PTE	-37.30	0	-0.12	0	0	0.16	-2.02	9,180	8.60E-05	0.01	0.10	-1.87
037	Ethane Cracking Furnace #7	**Proposed PTE**	58.47	25.90	4.75	12.40	12.40	0.67	2.61	158,990	2.24E-04	0.03	10.45	0.73
		PA-04-00740C PTE	95.77	25.90	4.87	12.40	12.40	0.51	4.63	149,810	1.38E-04	0.02	10.35	2.60
		Change in PTE	-37.30	0	-0.12	0	0	0.16	-2.02	9,180	8.60E-05	0.01	0.10	-1.87
101	Combustion Turbine/Duct Burner Unit #1	**Proposed PTE**	15.00	23.45	5.95	20.68	20.68	4.61	11.03	366,919	0.002	0.23	21.36	1.87
		PA-04-00740C PTE	15.00	23.45	5.84	20.68	20.68	4.61	11.03	366,921	0.002	0.18	21.36	0.32
		Change in PTE	0	0	0.11	0	0	0	0	-2	0	0.05	0	1.55

SPM Source-by-Source Comparison of PA-04-00740B and PA-04-00740C Potential to Emit (PTE) Rates Against Proposed PTE Rates

Source ID	Source Description	PTE Category	CO	NOx	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO_2e	Lead	H_2SO_4	Ammonia	HAPs
			Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)
102	Combustion Turbine/Duct Burner Unit #2	**Proposed PTE**	15.00	23.45	5.95	20.68	20.68	4.61	11.03	366,919	0.002	0.23	21.36	1.87
		PA-04-00740C PTE	15.00	23.45	5.84	20.68	20.68	4.61	11.03	366,921	0.002	0.18	21.36	0.32
		Change in PTE	0	0	0.11	0	0	0	0	-2	0	0.05	0	1.55
103	Combustion Turbine/Duct Burner Unit #3	**Proposed PTE**	15.00	23.45	5.95	20.68	20.68	4.61	11.03	366,919	0.002	0.23	21.36	1.87
		PA-04-00740C PTE	15.00	23.45	5.84	20.68	20.68	4.61	11.03	366,921	0.002	0.18	21.36	0.32
		Change in PTE	0	0	0.11	0	0	0	0	-2	0	0.05	0	1.55
104	Cogeneration Plant Cooling Tower	**Proposed PTE**	-	-	2.63	1.67	0.01	-	-	-	-	-	-	-
		PA-04-00740C PTE	-	-	1.62	1.03	0.003	-	-	-	-	-	-	-
		Change in PTE	-	-	1.01	0.64	0.007	-	-	-	-	-	-	-
105	Diesel-Fired Emergency Generator Engines (2); Generator 1 - Parking Garage	**Proposed PTE**	0.01	0.03	0.001	0.001	0.001	5.60E-05	4.54E-04	6	-	2.76E-06	-	1.40E-04
		PA-04-00740C PTE	0.03	0.03	0.001	0.001	0.001	5.60E-05	4.54E-04	6	-	2.25E-06	-	1.40E-04
		Change in PTE	-0.02	0	0	0	0	0	0	0	-	5.10E-07	-	0
105	Diesel-Fired Emergency Generator Engines (2); Generator 2 - Telecom Hut	**Proposed PTE**	0.005	0.02	0.002	0.002	0.001	3.65E-05	0.001	4	-	1.79E-06	-	9.08E-05
		PA-04-00740C PTE	0.02	0.02	0.002	0.002	0.001	3.65E-05	0.001	4	-	1.46E-06	-	9.08E-05
		Change in PTE	-0.02	0	0	0	0	0	0	0	-	3.30E-07	-	0
106	Fire Pump Engines (2); Firewater Pump 1	**Proposed PTE**	0.14	0.10	0.01	0.01	0.01	2.65E-04	0.06	28	-	1.31E-05	-	6.62E-04
		PA-04-00740C PTE	0.14	0.10	0.01	0.01	0.01	2.65E-04	0.06	28	-	2.13E-05	-	2.61E-04
		Change in PTE	0	0	0	0	0	0	0	0	-	-8.20E-06	-	4.01E-04
106	Fire Pump Engines (2); Firewater Pump 2	**Proposed PTE**	0.14	0.10	0.01	0.01	0.01	2.65E-04	0.06	28	-	1.31E-05	-	6.62E-04
		PA-04-00740C PTE	0.14	0.10	0.01	0.01	0.01	2.65E-04	0.06	28	-	2.13E-05	-	2.61E-04
		Change in PTE	0	0	0	0	0	0	0	0	-	-8.20E-06	-	4.01E-04
107	Natural Gas-Fired Emergency Generator Engines (2); Generator 3 - Lift Station	**Proposed PTE**	0.01	0.03	0.001	0.001	0.001	4.17E-05	0.02	11	-	2.05E-06	-	0.002
		PA-04-00740C PTE	0.02	0.04	0.001	0.001	0.001	4.17E-05	0.02	14	-	1.67E-06	-	0.01
		Change in PTE	-0.01	-0.01	0	0	0	0	0	-3	-	3.80E-07	-	-0.008
107	Natural Gas-Fired Emergency Generator Engines (2); Generator 4 - Lift Station	**Proposed PTE**	0.13	0.03	1.44E-06	1.86E-04	1.86E-04	1.10E-05	0.002	4	-	5.40E-07	-	0.001
		PA-04-00740C PTE	0.14	0.03	1.44E-06	1.85E-04	1.85E-04	1.10E-05	0.002	4	-	4.41E-07	-	0.001
		Change in PTE	-0.01	0	0	1.00E-06	1.00E-06	0	0	0	-	9.90E-08	-	0

SPM Source-by-Source Comparison of PA-04-00740B and PA-04-00740C Potential to Emit (PTE) Rates Against Proposed PTE Rates

Source ID	Source Description	PTE Category	CO	NOx	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO_2e	Lead	H_2SO_4	Ammonia	HAPs
			Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)
202	Polyethylene Manufacturing Lines	**Proposed PTE**	-	-	3.42	3.42	3.42	-	-	-	-	-	-	1.36E-04
		PA-04-00740C PTE	-	-	3.63	3.63	3.63	-	-	-	-	-	-	1.93E-04
		Change in PTE	-	-	-0.21	-0.21	-0.21	-	-	-	-	-	-	-5.70E-05
203	Process Cooling Tower	**Proposed PTE**	-	-	6.49	4.12	0.01	-	38.88	-	-	-	-	0.97
		PA-04-00740C PTE	-	-	6.49	4.12	0.01	-	38.88	-	-	-	-	3.89
		Change in PTE	-	-	0	0	0	-	0	-	-	-	-	-2.92
C204A	CVTO	**Proposed PTE**	65.29	47.57	1.48	5.91	5.91	1.17	30.77	109,579	3.89E-04	0.06	-	0.11
		PA-04-00740C PTE	38.51	31.80	0.89	3.48	3.48	0	16.42	68,260	2.29E-04	0	-	0.89
		Change in PTE	26.78	15.77	0.59	2.43	2.43	1.17	14.35	41,319	1.60E-04	0.06	-	-0.78
C204B	MPGF	**Proposed PTE**	117.60	26.66	0.72	2.89	2.89	0.57	23.56	49,817	1.90E-04	0.03	-	0.06
		PA-04-00740C PTE	9.55	1.76	0.05	0.19	0.19	0.04	0.10	3,141	1.27E-05	0.002	-	0.05
		Change in PTE	108.05	24.90	0.67	2.70	2.70	0.54	23.46	46,676	1.77E-04	0.03	-	0.01
C205A	TEGF A	**Proposed PTE**	572.11	126.63	3.46	13.83	13.83	2.73	156.74	188,993	0.001	0.13	-	8.04
C205B	TEGF B													
C205C	HP Elevated Flare													
C205A	TEGF A	**PA-04-00740C PTE**	215.26	39.56	1.08	4.34	4.34	0.86	237.17	76,696	2.85E-04	0.03	-	1.08
C205B	TEGF B													
C205C	HP Elevated Flare													
C205A	TEGF A	**Change in PTE**	356.85	87.07	2.38	9.49	9.49	1.87	-80.43	112,297	7.15E-04	0.10	-	6.96
C205B	TEGF B													
C205C	HP Elevated Flare													
C206	SCTO	**Proposed PTE**	3.99	2.91	0.09	0.57	0.57	4.19	0.21	6,044	-	0.21	-	0.13
		PA-04-00740C PTE	3.87	3.19	0.09	0.35	0.35	4.13	1.42	5,870	-	0.17	-	0.63
		Change in PTE	0.12	-0.28	0	0.22	0.22	0.06	-1.21	174	-	0.04	-	-0.50

SPM Source-by-Source Comparison of PA-04-00740B and PA-04-00740C Potential to Emit (PTE) Rates Against Proposed PTE Rates

Source ID	Source Description	PTE Category	CO	NOx	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO_2e	Lead	H_2SO_4	Ammonia	HAPs
			Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)	Annual (tpy)
301	Polyethylene Pellet Material Storage/Handling/Loadout	**Proposed PTE**	-	-	8.36	2.88	2.88	-	72.73	-	-	-	-	-
		PA-04-00740C PTE	-	-	8.36	2.88	2.88	-	88.18	-	-	-	-	-
		Change in PTE	-	-	0	0	0	-	-15.45	-	-	-	-	-
302	Liquid Loadout (Recovered Oil)	**Proposed PTE**	-	-	-	-	-	-	0.10	-	-	-	-	0.10
		PA-04-00740C PTE	-	-	-	-	-	-	0.10	-	-	-	-	0.10
		Change in PTE	-	-	-	-	-	-	0	-	-	-	-	0
304	Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)	**Proposed PTE**	-	-	-	-	-	-	0.005	-	-	-	-	0.001
		PA-04-00740C PTE	-	-	-	-	-	-	0.004	-	-	-	-	0.001
		Change in PTE	-	-	-	-	-	-	0.001	-	-	-	-	0
406	Storage Tanks (Diesel Fuel > 150 Gallons)	**Proposed PTE**	-	-	-	-	-	-	4.25E-04	-	-	-	-	4.25E-04
		PA-04-00740C PTE	-	-	-	-	-	-	0.002	-	-	-	-	0.002
		Change in PTE	-	-	-	-	-	-	-0.002	-	-	-	-	-0.002
501	Equipment Components	**Proposed PTE**	0.35	-	-	-	-	-	35.17	349	-	-	-	4.95
		PA-04-00740C PTE	-	-	-	-	-	-	67.88	138	-	-	-	4.11
		Change in PTE	0.35	-	-	-	-	-	-32.71	212	-	-	-	0.84
502	Wastewater Treatment Plant	**Proposed PTE**	-	-	-	-	-	-	0.28	-	-	-	-	0.28
		PA-04-00740C PTE	-	-	-	-	-	-	0.04	-	-	-	-	0.04
		Change in PTE	-	-	-	-	-	-	0.24	-	-	-	-	0.24
503	Plant Roadways	**Proposed PTE**	-	-	0.64	0.13	0.03	-	-	-	-	-	-	-
		PA-04-00740C PTE	-	-	0.54	0.10	0.03	-	-	-	-	-	-	-
		Change in PTE	-	-	0.10	0.03	0	-	-	-	-	-	-	-

SPM Source-by-Source Comparison of PA-04-00740B and PA-04-00740C Potential to Emit (PTE) Rates Against Proposed PTE Rates

Source ID	Source Description	PTE Category	CO Annual (tpy)	NOx Annual (tpy)	PM Annual (tpy)	PM_{10} Annual (tpy)	$PM_{2.5}$ Annual (tpy)	SO_2 Annual (tpy)	VOC Annual (tpy)	CO_2e Annual (tpy)	Lead Annual (tpy)	H_2SO_4 Annual (tpy)	Ammonia Annual (tpy)	HAPs Annual (tpy)
504	Gas Insulated Switchgear (SF6)	**Proposed PTE**	-	-	-	-	-	-	-	880	-	-	-	-
		PA-04-00740B PTE	-	-	-	-	-	-	-	854	-	-	-	-
		Change in PTE	-	-	-	-	-	-	-	26	-	-	-	-
Total Proposed PTE, including EMACT Project (tpy)			**1,214.07**	**455.73**	**78.41**	**184.28**	**178.41**	**27.18**	**409.95**	**2,569,430**	**0.01**	**1.32**	**137.23**	**25.36**
Total PA-04-00740B/PA-04-00740C PTE (tpy)			**983.1**	**328.3**	**74.4**	**169.0**	**163.8**	**22.4**	**515.8**	**2,304,476**	**0.01**	**0.89**	**136.53**	**29.96**
Total Change in PTE (tpy)			**231.00**	**127.45**	**4.03**	**15.30**	**14.64**	**4.76**	**-105.89**	**264,955**	**0**	**0.44**	**0.70**	**-4.60**
EMACT Project Increase (tpy)			**343.12**	**75.27**	**2.06**	**8.25**	**8.25**	**1.63**	**5.97**	**92,588**	**5.43E-04**	**0.08**	**0**	**0.13**
Relevant NNSR Major Facility/Significant and PSD Significant Thresholds for EMACT Project (tpy)			**100 (PSD)**	**40 (NNSR/PSD)**	**25 (PSD)**	**15 (PSD)**	**10 (PSD)**	**100 (NNSR)**	**40 (NNSR)**	**75,000 (PSD)**	**100 (NNSR)**	**7 (PSD)**	**-**	**-**
Total Proposed PTE, excluding EMACT Project (tpy)			**870.95**	**380.46**	**76.35**	**176.03**	**170.16**	**25.55**	**403.98**	**2,476,842**	**0.01**	**1.24**	**137.23**	**25.23**
Plan Approval Reconciliations/WWTP Permanent Controls Project Change-Only Change in PTE (tpy)			**-112.13**	**52.18**	**1.97**	**7.05**	**6.39**	**3.13**	**-111.86**	**172,367**	**0**	**0.36**	**0.70**	**-4.73**
Relevant NNSR Major Facility and PSD Major Source Thresholds (tpy)			**100 (PSD)**	**100 (NNSR/PSD)**	**100 (PSD)**	**100 (PSD)**	**100 (NNSR)**	**100 (NNSR)**	**50 (NNSR)**	**-**	**100 (NNSR)**	**100 (PSD)**	**-**	**-**
Relevant NNSR Major Facility/Significant and PSD Significant Thresholds for a Modification (tpy)			**100 (PSD)**	**40 (NNSR/PSD)**	**25 (PSD)**	**15 (PSD)**	**10 (NNSR)**	**100 (NNSR)**	**40 (NNSR)**	**75,000 (PSD)**	**100 (NNSR)**	**7 (PSD)**	**-**	**-**
ERCs Required for EMACT Project (tpy)			**-**	**87**	**-**	**-**	**-**	**-**	**0**	**-**	**-**	**-**	**-**	**-**
ERCs Required for Plan Approval Reconciliations/WWTP Permanent Controls Project (tpy)			**-**	**61**	**-**	**-**	**7**	**-**	**0**	**-**	**-**	**-**	**-**	**-**

Attachment 2

Request No. 3.a Information

1.0 LOWEST ACHIEVABLE EMISSION RATE (LAER)

The Pennsylvania Department of Environmental Protection's (DEP's) Nonattainment New Source Review (NNSR) regulations under Chapter 127, Subchapter E require the application of lowest achievable emission rate (LAER) when constructing a new major facility subject to NNSR permitting and carrying out a major modification at an existing major facility subject to NNSR permitting. "LAER" is defined at 25 Pa Code §121.1 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.*

As indicated by this definition, unlike best available control technology (BACT), LAER does not consider energy, environmental, or economic factors when evaluating the applicability of an emission control technology for a particular source, except a control technology is not considered achievable if its cost would be so great that a source could not be built or operated using the control technology. LAER generally is specified as a numerical limitation. However, design, equipment, work practice, or operation requirements may be established rather than a numerical limitation if technical feasibility factors limit the application of a measurement methodology to demonstrate compliance with such a limitation.

1.1 LAER Applicability

For a new major facility, a LAER determination must be made for each emissions unit constructed as part of the new facility that would have the potential to emit a regulated NNSR pollutant for which the facility is determined to have the potential to emit at or above the applicable major facility threshold. Alternatively, for a major modification at an existing major facility, a LAER determination must be made for the two types of emissions units described below:

- Each new emissions unit constructed as part of the major modification that would have the potential to emit a regulated NNSR pollutant for which the facility is determined to have the potential to emit at or above the applicable major facility threshold and for which the modification is determined to result in a significant net emissions increase; and
- Each existing emissions unit undergoing a physical change or change in the method of operation as part of the major modification that would experience an emissions increase of a regulated NNSR pollutant for which the facility is determined to have the potential to emit at or above the

applicable major facility threshold and for which the modification is determined to result in a significant net emissions increase.

1.1.1 Plan Approval Reconciliations

In accordance with the LAER applicability criteria summarized above for the construction of a new major facility such as SPM, Shell contemporaneously completed a LAER analysis for each proposed SPM emissions unit that was estimated to have the potential to emit a regulated NNSR pollutant for which SPM was determined to have the potential to emit in a significant amount. Specifically, for a particular proposed emissions unit, Shell contemporaneously completed a LAER analysis for each regulated NNSR pollutant that the emissions unit was proposed to emit, and that SPM was determined to have the potential to emit in a significant amount.

Shell has retrospectively evaluated the Plan Approval Reconciliations as part of the initial SPM construction for NSR applicability purposes. As discussed in the September 13, 2024 plan approval application, Shell determined that the Plan Approval Reconciliations will not retrospectively cause the initial construction of SPM to require NNSR permitting for any additional regulated NNSR pollutants relative to the NNSR applicability determinations that were made contemporaneous with DEP's authorization of the initial construction of SPM. As a result, the Plan Approval Reconciliations do not require the initial construction of SPM to be subject to any retrospective LAER analyses for regulated NNSR pollutants that were not contemporaneously evaluated as part of the plan approval process that was completed for the initial construction of SPM. However, as documented in Table 1 beginning on the following page, Shell has evaluated 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.

Table 1. Evaluation of Emissions Units Potentially Requiring a Revised LAER Analysis due to the Plan Approval Reconciliations

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
031	Ethane Cracking Furnace #1	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the furnace is not potentially subject to reevaluation.
032	Ethane Cracking Furnace #2	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the furnace is not potentially subject to reevaluation.
033	Ethane Cracking Furnace #3	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the furnace is not potentially subject to reevaluation.
034	Ethane Cracking Furnace #4	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the furnace is not potentially subject to reevaluation.
035	Ethane Cracking Furnace #5	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the furnace is not potentially subject to reevaluation.
036	Ethane Cracking Furnace #6	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the furnace is not potentially subject to reevaluation.

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
037	Ethane Cracking Furnace #7	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the furnace is not potentially subject to reevaluation.	No, the furnace's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the furnace is not potentially subject to reevaluation.
101	Combustion Turbine/Duct Burner Unit #1	No, the combustion turbine/duct burner unit's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.
102	Combustion Turbine/Duct Burner Unit #2	No, the combustion turbine/duct burner unit's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.
103	Combustion Turbine/Duct Burner Unit #3	No, the combustion turbine/duct burner unit's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
104	Cogeneration Plant Cooling Tower	Not Applicable (N/A)	Yes, although the cooling tower's $PM_{2.5}$ potential to emit is proposed to increase by only 14 pounds per year (lb/yr) because of a proposed increase in the cooling tower's potential recirculation rate, Shell has conservatively reevaluated the $PM_{2.5}$ LAER determination for the cooling tower, mainly in coordination with the PM and PM_{10} BACT determination reevaluations that have been determined to be warranted for the cooling tower due to the greater increases in the cooling tower's PM and PM_{10} potentials to emit that are associated with the proposed increase in the cooling tower's recirculation rate.	N/A
105	Diesel-Fired Emergency Generator Engines (2); Generator 1 - Parking Garage	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the engine is not potentially subject to reevaluation.
105	Diesel-Fired Emergency Generator Engines (2); Generator 2 - Telecom Hut	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the engine is not potentially subject to reevaluation.
106	Fire Pump Engines (2); Firewater Pump 1	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the engine is not potentially subject to reevaluation.
106	Fire Pump Engines (2); Firewater Pump 2	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the engine is not potentially subject to reevaluation.

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
107	Natural Gas-Fired Emergency Generator Engines (2); Generator 3 - Lift Station	No, the engine's NOx potential to emit is proposed to decrease; therefore, the prior NOx LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the engine is not potentially subject to reevaluation.
107	Natural Gas-Fired Emergency Generator Engines (2); Generator 4 - Lift Station	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx LAER determination for the engine is not potentially subject to reevaluation.	No, the engine's $PM_{2.5}$ potential to emit is proposed to increase by only 0.002 lb/yr, and this increase is because of a proposed correction of a typo in the previous emission calculation's condensable PM emission factor that is from AP-42, Section 3.2, Table 3.2-2 (i.e., typo of 0.009**8**1 versus 0.009**9**1 lb/MMBtu) and that is used to calculate the engine's $PM_{2.5}$ potential to emit, not because of a change in the method of operation of the engine or physical change to the engine.	No, the engine's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the engine is not potentially subject to reevaluation.
202	Polyethylene Manufacturing Lines	N/A	No, the source's $PM_{2.5}$ potential to emit is proposed to decrease; therefore, the prior $PM_{2.5}$ LAER determination for the source is not potentially subject to reevaluation.	N/A
203	Process Cooling Tower	N/A	No, the cooling tower's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the cooling tower is not potentially subject to reevaluation.	No, the cooling tower's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the cooling tower is not potentially subject to reevaluation.
C204A	CVTO	Yes, the thermal oxidizer's NOx potential to emit is proposed to increase by 15.77 tons per year (tpy) because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer.	Yes, the thermal oxidizer's $PM_{2.5}$ potential to emit is proposed to increase by 2.43 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer.	Yes, the thermal oxidizer's VOC potential to emit is proposed to increase by 14.35 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer.
C204B	MPGF	Yes, the flare's NOx potential to emit is proposed to increase by 24.90 tpy because of a proposed increase in the amount of combustion that may occur at the flare.	Yes, the flare's $PM_{2.5}$ potential to emit is proposed to increase by 2.70 tpy because of a proposed increase in the amount of combustion that may occur at the flare.	Yes, the flare's VOC potential to emit is proposed to increase by 23.46 tpy because of a proposed increase in the amount of combustion that may occur at the flare.

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
C205A	TEGF A	Yes, the flare's NOx potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 87.07 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's $PM_{2.5}$ potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 9.49 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	No, the flare's VOC potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to decrease; therefore, the prior VOC LAER determination for the flare is not potentially subject to reevaluation.
C205B	TEGF B	Yes, the flare's NOx potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 87.07 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's $PM_{2.5}$ potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 9.49 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	No, the flare's VOC potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to decrease; therefore, the prior VOC LAER determination for the flare is not potentially subject to reevaluation.
C205C	HP Elevated Flare	Yes, the flare's NOx potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 87.07 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's $PM_{2.5}$ potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 9.49 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	No, the flare's VOC potential to emit in combination with the TEGF A and TEGF B is proposed to decrease; therefore, the prior VOC LAER determination for the flare is not potentially subject to reevaluation.
C206	SCTO	Yes, the thermal oxidizer's NOx potential to emit would be proposed to increase because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer. However, the proposed revision to the prior NOx LAER determination for the thermal oxidizer is proposed to result in a 0.28 tpy decrease in the thermal oxidizer's NOx potential to emit.	Yes, although the thermal oxidizer's $PM_{2.5}$ potential to emit is proposed to increase by only 0.22 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer and due to properly accounting for the thermal oxidizer's condensable PM emissions that may occur due to the combustion of the spent caustic oxidation treatment operation vent gas in the thermal oxidizer, Shell has conservatively reevaluated the $PM_{2.5}$ LAER determination for the thermal oxidizer.	No, the thermal oxidizer's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the thermal oxidizer is not potentially subject to reevaluation.

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
301	Polyethylene Pellet Material Storage/Handling/Loadout	N/A	No, the source's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the source is not potentially subject to reevaluation.	Yes, the source's VOC potential to emit would be proposed to increase because of a proposed increase in the total annual amount of polyethylene that may be handled by the source, as documented in the source's VOC potential to emit calculation. However, the proposed revision to the prior VOC LAER determination for the source is proposed to result in a 15.45 tpy decrease in the source's VOC potential to emit. Note that the source's PM, PM_{10}, and $PM_{2.5}$ potential to emit calculation already accounted for the higher total annual amount of polyethylene that may be handled by the source; therefore, that calculation did not require a change.
302	Liquid Loadout (Recovered Oil)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
303	Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, PE3 Heavies)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
304	Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)	N/A	N/A	No, the source's VOC potential to emit is proposed to increase only 2 lb/yr because of a proposed increase in the combined number of C3+ railcar loading and C3 railcar unloading events in a year, and the source's VOC emissions represent the volatilization of less than 0.5 milliliter of residual material that may be present on a dry-break coupling after each loading and unloading event, which it is not practical to further minimize.
305	Liquid Loadout (Blended Pitch)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
401	Storage Tanks (Recovered Oil, Equalization Wastewater)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
402	Storage Tank (Spent Caustic)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
403	Storage Tanks (Light Gasoline)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
404	Storage Tanks (Hexene)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
405	Storage Tanks (Misc Pressurized/Refrigerated)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
406	Storage Tanks (Diesel Fuel > 150 Gallons)	N/A	N/A	No, the source's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
407	Storage Tanks (Pyrolysis Fuel Oil)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
408	Storage Tanks (Diesel Fuel < 150 Gallons)	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
409	Methanol Storage Vessels and Associated Components	N/A	N/A	No, the source's VOC potential to emit is not proposed to increase; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.
501	Equipment Components	N/A	N/A	No, the source's VOC potential to emit is proposed to decrease; therefore, the prior VOC LAER determination for the source is not potentially subject to reevaluation.

Source ID	Source Description	Revised LAER Analysis Needed for NOx?	Revised LAER Analysis Needed for $PM_{2.5}$?	Revised LAER Analysis Needed for VOC?
502	Wastewater Treatment Plant	N/A	N/A	Yes, although the source's VOC potential to emit is proposed to increase by only 0.24 tpy, Shell has conservatively reevaluated the VOC LAER determination for the source.
503	Plant Roadways	N/A	No, the source's $PM_{2.5}$ potential to emit is not proposed to increase; therefore, the prior $PM_{2.5}$ LAER determination for the source is not potentially subject to reevaluation.	N/A
504	Gas Insulated Switchgear (SF6)	N/A	N/A	N/A

1.2 LAER Analysis Process

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 United States Environmental Protection Agency's (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 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.

1.3 Summary of LAER Determinations

Table 2 below summarizes the LAER determinations made for the Plan Approval Reconciliations.

Table 2. Summary of LAER Determinations

Emissions Unit	Pollutant	Control Technology/ Work Practice	Emissions Level
Cogeneration Plant Cooling Tower	$PM_{2.5}$	• High-efficiency drift eliminator: ≤ 0.0005% drift loss design • Manage cooling water total dissolved solids (TDS) levels: ≤ 2,000 parts per million by weight (ppmw) TDS in cooling water, 12-month rolling average	-
CVTO	NOx	• Low NOx burners (LNBs) • Good combustion practices	≤ 0.06 pounds per MMBtu (lb/MMBtu), 3-hour average
	$PM_{2.5}$	Good combustion practices	≤ 0.0075 lb/MMBtu, 3-hour average
	VOC	Good combustion practices: ≥ minimum combustion chamber temperature guaranteed to demonstrate/demonstrating ≥ 99.9% VOC destruction efficiency	≥ 99.9% VOC destruction efficiency

Emissions Unit	Pollutant	Control Technology/ Work Practice	Emissions Level
MPGF	NOx	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 Code of Federal Regulations (CFR) 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
	$PM_{2.5}$	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
	VOC	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	• ≥ 99% destruction and removal efficiency (DRE) for VOC containing three or fewer carbon atoms (C3- VOC) • ≥ 98% DRE for VOC containing four or more carbon atoms (C4+ VOC)
TEGF A, TEGF B, and HP Elevated Flare	NOx	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-

Emissions Unit	Pollutant	Control Technology/ Work Practice	Emissions Level
TEGF A, TEGF B, and HP Elevated Flare (cont'd)	$PM_{2.5}$	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
SCTO	NOx	• LNBs • Good combustion practices	≤ 0.06 lb/MMBtu, 3-hour average
	$PM_{2.5}$	Good combustion practices	≤ 0.012 lb/MMBtu, 3-hour average
Polyethylene Pellet Material Storage/Handling/Loadout	VOC	• For PE Units 1 and 2, minimize the residual amount of VOC contained in and emitted from polyethylene pellets that are handled and stored in and by uncontrolled equipment and operations after the product purge bin through the loading of polyethylene pellets into trucks and railcars • For PE Unit 3, minimize the residual amount of VOC contained in and emitted from polyethylene pellets that are handled and stored in and by uncontrolled equipment and operations after the degasser through the loading of polyethylene pellets into trucks and railcars	• For PE Units 1 and 2, ≤ 35.08 lb VOC emitted/million pounds (MMlb) of polyethylene pellets after the product purge bin through the loading of polyethylene pellets into trucks and railcars, 12-month rolling basis • For PE Unit 3, ≤ 35.08 lb VOC emitted/MMlb of polyethylene pellets after the degasser through the loading of polyethylene pellets into trucks and railcars, 12-month rolling basis
Wastewater Treatment Plant	VOC	• Internal floating roofs and thermal oxidation (SCTO) for primary wastewater treatment vessels • Biological treatment for secondary wastewater treatment	≥ 99.9% VOC destruction efficiency for thermal oxidation (SCTO)

Below, Shell documents the analysis that was completed to make these LAER determinations.

1.4 Cogeneration Plant Cooling Tower LAER Determinations

As presented below, Shell has reevaluated the $PM_{2.5}$ LAER determination that was previously made for the Cogeneration Plant Cooling Tower at SPM contemporaneous with the construction of the facility.

1.4.1 $PM_{2.5}$

The Cogeneration Plant Cooling Tower is a counter-flow mechanical draft recirculating cooling tower that provides cooling water to the three cogeneration units at SPM. In a wet cooling tower, the cooling water circulating through the tower makes direct contact with the air passing through the tower. The air exiting the tower contains a certain amount of entrained cooling water, and these cooling water droplets are referenced as "drift." This drift contains the same TDS as the water circulating in the tower. $PM_{2.5}$ emissions result from the drift when the water comprising the water droplet evaporates, and the TDS contained in the water droplet remain suspended in the atmosphere. However, the Cogeneration Plant Cooling Tower is equipped with high-efficiency drift eliminators to minimize the amount of drift from the cooling tower.

The Cogeneration Plant Cooling Tower is currently subject to the following $PM_{2.5}$ LAER requirements.

- The cooling tower shall be equipped with drift/mist eliminators designed not to exceed 0.0005% drift loss.
- The cooling tower water TDS shall not exceed 2,000 ppmw on a monthly 12-month rolling average.

1.4.1.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 3 below summarizes potential $PM_{2.5}$ limits and emission control technologies identified for the Cogeneration Plant Cooling Tower based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, and BAAQMD BACT/TBACT Workbook.

Table 3. Potential $PM_{2.5}$ Limits and Emission Control Technologies Identified for the Cogeneration Plant Cooling Tower

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Utility and Industrial Cooling Water Towers	• High-efficiency drift eliminator • Manage cooling water TDS levels	• 0.0005-0.005% drift loss design • Varying TDS levels depending on TDS level of cooling water makeup water

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.4.1.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes a $PM_{2.5}$ LAER limit for the Cogeneration Plant Cooling Tower that is equal to or more stringent than the limits indicated above. Therefore, no additional analysis is necessary under this step.

1.4.1.3 Step 3: Select LAER

Shell determined that high-efficiency drift eliminators and managing cooling water TDS levels represent the LAER technologies applicable to the Cogeneration Plant Cooling Tower's $PM_{2.5}$ emissions. Shell proposes the following $PM_{2.5}$ LAER requirements for the Cogeneration Plant Cooling Tower, which are the same $PM_{2.5}$ LAER 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.

1.5 CVTO LAER Determinations

As presented below, Shell has reevaluated the NOx, $PM_{2.5}$, and VOC LAER determinations that were previously made for the CVTO at SPM contemporaneous with the construction of the facility.

1.5.1 NOx

NOx can be emitted by the CVTO due to three fundamentally different mechanisms that generate NOx when a material is combusted. The three NOx generation mechanisms are the thermal NOx, prompt NOx, and fuel-bound NOx mechanisms.

Thermal NOx results from the high temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen. The rate of thermal NOx generation is affected by the following three factors: oxygen concentration, peak flame temperature, and duration at peak flame temperature. As these three factors increase in value, the rate of thermal NOx generation increases.

Prompt NOx occurs when nitrogen molecules in combustion air react with hydrocarbon radicals from the material undergoing combustion. Prompt NOx reactions occur only within the combustion flame and are typically negligible compared to NOx emissions formed via the thermal NOx mechanism.

Fuel-bound NOx results from the reaction of fuel-bound nitrogen compounds with oxygen during the combustion reactions. Therefore, a fuel without any nitrogen compounds will not result in fuel-bound NOx emissions, while a fuel with a considerable amount of nitrogen compounds will result in elevated fuel-bound NOx emissions.

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

The CVTO is currently subject to the following NOx LAER requirement.

- The thermal oxidizer's NOx emissions shall not exceed 0.068 lb/MMBtu.

1.5.1.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 4 below summarizes potential NOx limits and emission control technologies identified for operating thermal oxidizers that are used to control ethylene and polyethylene manufacturing unit process vents based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Table 4. Potential NOx Limits and Emission Control Technologies Identified for the CVTO (Ethylene and Polyethylene Operation Thermal Oxidizers)

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
TX-0815	Total Petrochemicals & Refining USA Inc. Port Arthur, TX	1/17/17	Thermal Oxidizer	Good combustion practices and design.	0.13 lb/MMBtu
TX-0858	GCGV Asset Holding LLC Complex Gregory, TX	6/12/19	Thermal Oxidizers	Best combustion practices and natural gas supplemental fuel.	0.06 lb/MMBtu
TX-0889	Chevron Phillips Chemical Company LP Sweeny Old Ocean Facilities Sweeny, TX	8/8/20	Thermal Oxidizer	Use natural gas as assist gas and good combustion practices.	0.06 lb/MMBtu
TX-0928	Chevron Phillips Chemical Company LP Sweeny Old Ocean Facilities Sweeny, TX	10/15/21	Thermal Oxidizer	Good combustion practices.	0.06 lb/MMBtu

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.5.1.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes a NOx LAER limit for the CVTO that is equal to or more stringent than the limits indicated above. Therefore, no additional analysis is necessary under this step.

1.5.1.3 Step 3: Select LAER

Shell determined that LNBs and good combustion practices represent the LAER technologies applicable to the CVTO's NOx emissions. Shell proposes 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. Note that a May 21, 2024 performance test of the CVTO demonstrated compliance with the proposed NOx LAER limit of 0.06 lb/MMBtu (3-hour average).

1.5.2 $PM_{2.5}$

$PM_{2.5}$ is emitted by the CVTO due to metals that may be present in trace amounts 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 CVTO is pipeline quality natural gas, which is comprised of easily combustible light hydrocarbons and a negligible amount of metals. Additionally, the vent gases combusted in the thermal oxidizer have the same characteristics – they contain easily combustible light hydrocarbons and a negligible amount of metals. Furthermore, the vent gases do not contain compounds (e.g., sulfur-containing compounds, chloride-containing compounds) that would result in the generation of acid gases (condensable PM) when combusted. Therefore, the CVTO emits $PM_{2.5}$ at very low levels.

The CVTO is currently subject to the following $PM_{2.5}$ LAER requirement.

- The thermal oxidizer's $PM_{2.5}$ emissions shall not exceed 0.0075 lb/MMBtu.

1.5.2.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 5 below summarizes potential $PM_{2.5}$ limits and emission control technologies identified for operating thermal oxidizers that are used to control ethylene and polyethylene manufacturing unit process vents based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, and BAAQMD BACT/TBACT Workbook.

Table 5. Potential $PM_{2.5}$ Limits and Emission Control Technologies Identified for the CVTO (Ethylene and Polyethylene Operation Thermal Oxidizers)

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
TX-0858	GCGV Asset Holding LLC Complex Gregory, TX	6/12/19	Thermal Oxidizers	Best combustion practices and natural gas supplemental fuel.	0.0075 lb/MMBtu

The above limit and control technology that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.5.2.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes a $PM_{2.5}$ LAER limit for the CVTO that is equal to the limit indicated above. Therefore, no additional analysis is necessary under this step.

1.5.2.3 Step 3: Select LAER

Shell determined that good combustion practices represent the LAER technology applicable to the CVTO's $PM_{2.5}$ emissions. Shell proposes a $PM_{2.5}$ LAER limit of 0.0075 lb/MMBtu (3-hour average) for the CVTO, which is the same as the $PM_{2.5}$ LAER limit that is currently applicable to the thermal oxidizer.

1.5.3 VOC

VOC is emitted by the CVTO due to the incomplete combustion of hydrocarbons present in the fuel and vent gases combusted in the thermal oxidizer. However, the fuel combusted in the CVTO is pipeline quality natural gas, which is comprised of easily combustible light hydrocarbons. Additionally, the vent gases combusted in the CVTO, which are generated by SPM's three polyethylene manufacturing units and equipment associated with SPM's ethylene manufacturing unit, are primarily comprised of easily combustible light hydrocarbons.

The destruction efficiency of a thermal oxidizer is a measure of the amount of hydrocarbon present in the vent gases combusted in the thermal oxidizer that oxidizes to CO, CO_2, and water. A thermal oxidizer's destruction efficiency is primarily affected by vent gas characteristics (e.g., Btu content, composition), thermal oxidizer burner design, residence time at the proper operating temperature in the thermal oxidizer, and oxygen levels in the thermal oxidizer's combustion chamber. A properly designed and operated thermal oxidizer emits VOC at very low levels.

The CVTO is currently subject to the following VOC LAER requirements.

- The thermal oxidizer shall be designed and operated to reduce collected VOC emissions by a minimum of 99.9%.
- The thermal oxidizer shall, at all times that vapors are being collected by the LP 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.

1.5.3.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 6 below summarizes potential VOC limits and emission control technologies identified for operating thermal oxidizers that are used to control ethylene and polyethylene manufacturing unit process vents based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, and BAAQMD BACT/TBACT Workbook.

Table 6. Potential VOC Limits and Emission Control Technologies Identified for the CVTO (Ethylene and Polyethylene Operation Thermal Oxidizers)

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
TX-0858	GCGV Asset Holding LLC Complex Gregory, TX	6/12/19	Thermal Oxidizers	Best combustion practices and natural gas supplemental fuel.	99.9% destruction efficiency
TX-0889	Chevron Phillips Chemical Company LP Sweeny Old Ocean Facilities Sweeny, TX	8/8/20	Thermal Oxidizer	Use natural gas as assist gas and good combustion practices.	99.9% destruction efficiency
TX-0928	Chevron Phillips Chemical Company LP Sweeny Old Ocean Facilities Sweeny, TX	10/15/21	Thermal Oxidizer	Good combustion practices.	99.9% destruction efficiency
TX-0962	Formosa Plastics Corporation Texas Complex Point Comfort, TX	9/22/23	PE3 Plant Thermal Oxidizer	Use of pipeline quality natural gas as supplemental fuel. Good combustion practices are used.	99.9% destruction efficiency

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.5.3.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes a VOC LAER limit for the CVTO that is equal to or more stringent than the limits indicated above. Therefore, no additional analysis is necessary under this step.

1.5.3.3 Step 3: Select LAER

Shell determined that good combustion practices represent the LAER technology applicable to the CVTO's VOC emissions. Shell proposes a VOC LAER limit of 99.9% VOC destruction efficiency for the CVTO, which is the same as the VOC LAER limit that is currently applicable to the thermal oxidizer.

1.6 MPGF LAER Determinations

As presented below, Shell has reevaluated the NOx, $PM_{2.5}$, and VOC LAER determinations that were previously made for the MPGF at SPM contemporaneous with the construction of the facility.

1.6.1 NOx

NOx can be emitted by the MPGF due to three fundamentally different mechanisms that generate NOx when a material is combusted. As previously discussed, the three NOx generation mechanisms are the thermal NOx, prompt NOx, and fuel-bound NOx mechanisms.

For the open flame combustion process occurring at the MPGF, NOx emissions are relatively low and estimated to mostly result from the thermal NOx mechanism. The MPGF may emit a minor amount of NOx formed by the prompt NOx mechanism. However, the MPGF is not expected to emit fuel-bound NOx because it does not combust vent gases that contain fuel-bound nitrogen compounds since SPM does generate vent gases containing fuel-bound nitrogen compounds, and the supplemental gas and pilot fuel combusted at the MPGF does not contain fuel-bound nitrogen compounds.

The MPGF is currently subject to the following NOx LAER requirements.

- The flare must be operated in accordance with a flare minimization plan.
- The flare must be operated in accordance with good combustion practices.

1.6.1.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 7 below summarizes potential NOx limits and emission control technologies identified for the MPGF based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Table 7. Potential NOx Limits and Emission Control Technologies Identified for the MPGF

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Chemical Plant Flares	• Flare minimization • Good combustion practices (i.e., flare designed and operated in accordance with 40 CFR 60.18, 40 CFR 63.11, 40 CFR 63 Subpart SS, 40 CFR 63 Subpart PPP, and/or 40 CFR 63 Subpart FFFF flare control device design, operating, and monitoring requirements)	• 0.068-0.138 lb/MMBtu • Wide-ranging lb/hr and tpy emission rates

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Refinery Flares	• Flare minimization • Good combustion practices (i.e., flare designed and operated in accordance with 40 CFR 60.18 or 40 CFR 63 Subpart CC flare control device design, operating, and monitoring requirements)	• 0.068 lb/MMBtu • Wide-ranging lb/hr emission rates
SCAQMD Rule 1118. Control of Emissions from Refinery Flares	-	Rule Date: 4/5/24	Refinery Flares	• Flare minimization, including not routing vent gas to the flare except during emergencies, shutdowns, startups, turnarounds, or essential operational needs; and, potentially operating in accordance with a flare minimization plan • Good combustion practices (i.e., flare designed and operated in accordance with specific design, operating, and monitoring requirements)	-
BAAQMD Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Refineries	-	Rule Date: 11/3/21	Refinery Flares	Flare minimization (i.e., flare operated in accordance with a flare minimization plan)	-

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.6.1.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes NOx LAER design, work practice, and operation requirements for the MPGF that are equal to or more stringent than the requirements indicated above. Therefore, no additional analysis is necessary under this step.

1.6.1.3 Step 3: Select LAER

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents LAER for the NOx emissions from the MPGF, which is the same as the NOx LAER that is currently applicable to the flare. Shell will operate the MPGF in accordance with a flare minimization plan that will include the following:

- Procedures for operating and maintaining the flare during periods of process unit startup, shutdown, and unforeseeable events;
- A program of corrective action for malfunctioning process equipment;
- Procedures to minimize discharges to the flare during the planned and unplanned startup or shutdown of process equipment;
- Procedures for conducting root cause analyses; and
- Procedures for taking identified corrective actions.

Also, Shell will operate the MPGF in accordance with the good combustion practice requirements in 40 CFR 60 Subpart Kb, 40 CFR 63 Subpart YY, and 40 CFR 63 Subpart FFFF, as applicable, which include design requirements, minimum flare combustion zone gas heating value requirements, and extensive monitoring requirements for the flare.

1.6.2 $PM_{2.5}$

$PM_{2.5}$ is emitted by the MPGF due to the incomplete combustion of hydrocarbons present in the flare vent gas combusted at the flare. However, the flare combusts mostly low molecular weight hydrocarbons (e.g., methane, ethane, ethylene, and butane) that combust relatively easily, minimizing the generation of carbon particles. Additionally, the MPGF is designed to use assist air to promote proper air and flare vent gas mixing in the flame zone at its flare tips, which results in smokeless flare operation (i.e., negligible carbon particles escaping oxidation to CO and CO_2).

The MPGF is currently subject to the following $PM_{2.5}$ LAER requirements.

- The flare must be operated in accordance with a flare minimization plan.
- The flare must be operated in accordance with good combustion practices.

1.6.2.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 8 below summarizes potential $PM_{2.5}$ limits and emission control technologies identified for the MPGF based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Table 8. Potential $PM_{2.5}$ Limits and Emission Control Technologies Identified for the MPGF

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Chemical Plant Flares	• Flare minimization • Good combustion practices (i.e., flare designed and operated in accordance with 40 CFR 60.18, 40 CFR 63.11, 40 CFR 63 Subpart SS, and/or 40 CFR 63 Subpart FFFF flare control device design, operating, and monitoring requirements)	• 0.007-0.0075 lb/MMBtu • Wide-ranging lb/hr and tpy emission rates
SCAQMD Rule 1118. Control of Emissions from Refinery Flares	-	Rule Date: 4/5/24	Refinery Flares	• Flare minimization, including not routing vent gas to the flare except during emergencies, shutdowns, startups, turnarounds, or essential operational needs; and, potentially operating in accordance with a flare minimization plan • Good combustion practices (i.e., flare designed and operated in accordance with specific design, operating, and monitoring requirements)	-
BAAQMD Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Refineries	-	Rule Date: 11/3/21	Refinery Flares	Flare minimization (i.e., flare operated in accordance with a flare minimization plan)	-

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.6.2.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes $PM_{2.5}$ LAER design, work practice, and operation requirements for the MPGF that are equal to or more stringent than the requirements indicated above. Therefore, no additional analysis is necessary under this step.

1.6.2.3 Step 3: Select LAER

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents LAER for the $PM_{2.5}$ emissions from the MPGF, which is the same as the $PM_{2.5}$ LAER that is currently applicable to the flare. Therefore, Shell will operate the flare in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.6.1.3.

1.6.3 VOC

VOC is emitted by the MPGF due to the incomplete combustion of hydrocarbons present in the flare vent gas combusted at the flare. However, the flare combusts mostly low molecular weight hydrocarbons (e.g., methane, ethane, ethylene, and butane) that combust relatively easily, minimizing the amount of vent gas hydrocarbon that is not fully oxidized to CO_2 at the flare. Additionally, the MPGF is designed to use assist air to promote proper air and flare vent gas mixing in the flame zone at its flare tips, resulting in the flare achieving a high destruction efficiency, which is a measure of the amount of hydrocarbon present in the vent gases combusted at the flare that oxidizes to CO, CO_2, and water. A flare's destruction efficiency is affected by flare vent gas characteristics (e.g., Btu content, composition), flare tip velocity, and oxygen levels at the flare's combustion zone.

The MPGF is currently subject to the following VOC LAER requirements.

- The flare shall be designed and operated to reduce collected VOC emissions by a minimum of 98%.
- The flare must be operated in accordance with a flare minimization plan.
- The flare must be operated in accordance with good combustion practices.

1.6.3.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 9 below summarizes potential VOC limits and emission control technologies identified for the MPGF based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Table 9. Potential VOC Limits and Emission Control Technologies Identified for the MPGF

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Chemical Plant Flares	• Flare minimization • Good combustion practices (i.e., flare designed and operated in accordance with 40 CFR 60.18, 40 CFR 63.11, 40 CFR 63 Subpart SS, 40 CFR 63 Subpart PPP, and/or 40 CFR 63 Subpart FFFF flare control device design, operating, and monitoring requirements)	• 98%/99% DRE • Wide-ranging lb/hr and tpy emission rates
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Refinery Flares	• Flare minimization • Good combustion practices (i.e., flare designed and operated in accordance with 40 CFR 60.18 flare control device design, operating, and monitoring requirements)	• 98%/99% DRE • Wide-ranging lb/hr emission rates
SCAQMD Rule 1118. Control of Emissions from Refinery Flares	-	Rule Date: 4/5/24	Refinery Flares	• Flare minimization, including not routing vent gas to the flare except during emergencies, shutdowns, startups, turnarounds, or essential operational needs; and, potentially operating in accordance with a flare minimization plan • Good combustion practices (i.e., flare designed and operated in accordance with specific design, operating, and monitoring requirements)	-

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
BAAQMD Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Refineries	-	Rule Date: 11/3/21	Refinery Flares	Flare minimization (i.e., flare operated in accordance with a flare minimization plan)	-

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.6.3.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes VOC LAER design, work practice, and operation requirements for the MPGF that are equal to or more stringent than the requirements indicated above. Therefore, no additional analysis is necessary under this step.

1.6.3.3 Step 3: Select LAER

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents LAER for the VOC emissions from the MPGF, which is the same as the VOC LAER that is currently applicable to the flare. Therefore, Shell will operate the flare in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.6.1.3.

1.7 TEGF A, TEGF B, and HP Elevated Flare LAER Determinations

As presented below, Shell has reevaluated the NOx and $PM_{2.5}$ LAER determinations that were previously made for the TEGF A, TEGF B, and HP Elevated Flare at SPM contemporaneous with the construction of the facility.

1.7.1 NOx

NOx can be emitted by the TEGF A, TEGF B, and HP Elevated Flare due to three fundamentally different mechanisms that generate NOx when a material is combusted. As previously discussed, the three NOx generation mechanisms are the thermal NOx, prompt NOx, and fuel-bound NOx mechanisms.

For the open flame combustion process occurring at the TEGF A, TEGF B, and HP Elevated Flare, NOx emissions are relatively low and estimated to mostly result from the thermal NOx mechanism. The TEGF A, TEGF B, and HP Elevated Flare may emit a minor amount of NOx formed by the prompt NOx mechanism. However, the TEGF A, TEGF B, and HP Elevated Flare are not expected to emit fuel-bound

NOx because they do not combust vent gases that contain fuel-bound nitrogen compounds since SPM does generate vent gases containing fuel-bound nitrogen compounds, and the supplemental gas and pilot fuel combusted at the flares do not contain fuel-bound nitrogen compounds.

The TEGF A, TEGF B, and HP Elevated Flare are currently subject to the following NOx LAER requirements.

- Each flare must be operated in accordance with a flare minimization plan.
- Each flare must be operated in accordance with good combustion practices.

1.7.1.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 10 below summarizes potential NOx limits and emission control technologies identified for the TEGF A, TEGF B, and HP Elevated Flare based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Table 10. Potential NOx Limits and Emission Control Technologies Identified for the TEGF A, TEGF B, and HP Elevated Flare

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Chemical Plant Flares	• Flare minimization • Good combustion practices (i.e., flare designed and operated in accordance with 40 CFR 60.18, 40 CFR 63.11, 40 CFR 63 Subpart SS, 40 CFR 63 Subpart PPP, and/or 40 CFR 63 Subpart FFFF flare control device design, operating, and monitoring requirements)	• 0.068-0.138 lb/MMBtu • Wide-ranging lb/hr and tpy emission rates
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Refinery Flares	• Flare minimization • Good combustion practices (i.e., flare designed and operated in accordance with 40 CFR 60.18 or 40 CFR 63 Subpart CC flare control device design, operating, and monitoring requirements)	• 0.068 lb/MMBtu • Wide-ranging lb/hr emission rates

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
SCAQMD Rule 1118. Control of Emissions from Refinery Flares	-	Rule Date: 4/5/24	Refinery Flares	• Flare minimization, including not routing vent gas to the flare except during emergencies, shutdowns, startups, turnarounds, or essential operational needs; and, potentially operating in accordance with a flare minimization plan • Good combustion practices (i.e., flare designed and operated in accordance with specific design, operating, and monitoring requirements)	-
BAAQMD Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Refineries	-	Rule Date: 11/3/21	Refinery Flares	Flare minimization (i.e., flare operated in accordance with a flare minimization plan)	-

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.7.1.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes NOx LAER design, work practice, and operation requirements for the TEGF A, TEGF B, and HP Elevated Flare that are equal to or more stringent than the requirements indicated above. Therefore, no additional analysis is necessary under this step.

1.7.1.3 Step 3: Select LAER

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents LAER for the NOx emissions from the TEGF A, TEGF B, and HP Elevated Flare, which is the same as the NOx LAER that is currently applicable to the flares. Therefore, Shell will operate the TEGF A, TEGF B, and HP Elevated Flare in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.6.1.3.

1.7.2 $PM_{2.5}$

$PM_{2.5}$ is emitted by the TEGF A, TEGF B, and HP Elevated Flare due to the incomplete combustion of hydrocarbons present in the flare vent gas combusted at the flares. However, these flares combust mostly low molecular weight hydrocarbons (e.g., methane, ethane, and ethylene) that combust relatively easily, minimizing the generation of carbon particles. Additionally, the TEGF A and TEGF B are designed to use high pressure upstream of their flare tips, while the HP Elevated Flare uses assist steam, to draw air into the flame zone at the tips of the flares to promote proper air and flare vent gas mixing in the flame zone, which results in smokeless flare operation (i.e., negligible carbon particles escaping oxidation to CO and CO_2).

The TEGF A, TEGF B, and HP Elevated Flare are currently subject to the following $PM_{2.5}$ LAER requirements.

- Each flare must be operated in accordance with a flare minimization plan.
- Each flare must be operated in accordance with good combustion practices.

1.7.2.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 11 below summarizes potential $PM_{2.5}$ limits and emission control technologies identified for the TEGF A, TEGF B, and HP Elevated Flare based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Table 11. Potential $PM_{2.5}$ Limits and Emission Control Technologies Identified for the TEGF A, TEGF B, and HP Elevated Flare

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
EPA RBLC Database: Multiple Entries	See Attachment 2-1	See Attachment 2-1	Chemical Plant Flares	• Flare minimization • Good combustion practices (i.e., flare designed and operated in accordance with 40 CFR 60.18, 40 CFR 63.11, 40 CFR 63 Subpart SS, and/or 40 CFR 63 Subpart FFFF flare control device design, operating, and monitoring requirements)	• 0.007-0.0075 lb/MMBtu • Wide-ranging lb/hr and tpy emission rates

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
SCAQMD Rule 1118. Control of Emissions from Refinery Flares	-	Rule Date: 4/5/24	Refinery Flares	• Flare minimization, including not routing vent gas to the flare except during emergencies, shutdowns, startups, turnarounds, or essential operational needs; and, potentially operating in accordance with a flare minimization plan • Good combustion practices (i.e., flare designed and operated in accordance with specific design, operating, and monitoring requirements)	-
BAAQMD Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Refineries	-	Rule Date: 11/3/21	Refinery Flares	Flare minimization (i.e., flare operated in accordance with a flare minimization plan)	-

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.7.2.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes $PM_{2.5}$ LAER design, work practice, and operation requirements for the TEGF A, TEGF B, and HP Elevated Flare that are equal to or more stringent than the requirements indicated above. Therefore, no additional analysis is necessary under this step.

1.7.2.3 Step 3: Select LAER

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents LAER for the $PM_{2.5}$ emissions from the TEGF A, TEGF B, and HP Elevated Flare, which is the same as the $PM_{2.5}$ LAER that is currently applicable to the flares. Therefore, Shell will operate the TEGF A, TEGF B, and HP Elevated Flare in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.6.1.3.

1.8 SCTO LAER Determinations

As presented below, Shell has reevaluated the NOx and $PM_{2.5}$ LAER determinations that were previously made for the SCTO at SPM contemporaneous with the construction of the facility.

1.8.1 NOx

NOx can be emitted by the SCTO due to three fundamentally different mechanisms that generate NOx when a material is combusted. As previously discussed, the three NOx generation mechanisms are the thermal NOx, prompt NOx, and fuel-bound NOx mechanisms.

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 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 following NOx LAER requirement.

- The thermal oxidizer's NOx emissions shall not exceed 0.068 lb/MMBtu.

1.8.1.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 12 below summarizes potential NOx limits and emission control technologies identified for operating thermal oxidizers that are used to control ethylene and polyethylene manufacturing unit process vents based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Table 12. Potential NOx Limits and Emission Control Technologies Identified for the SCTO (Ethylene and Polyethylene Operation Thermal Oxidizers)

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
TX-0815	Total Petrochemicals & Refining USA Inc. Port Arthur, TX	1/17/17	Thermal Oxidizer	Good combustion practices and design.	0.13 lb/MMBtu
TX-0858	GCGV Asset Holding LLC Complex Gregory, TX	6/12/19	Thermal Oxidizers	Best combustion practices and natural gas supplemental fuel.	0.06 lb/MMBtu
TX-0889	Chevron Phillips Chemical Company LP Sweeny Old Ocean Facilities Sweeny, TX	8/8/20	Thermal Oxidizer	Use natural gas as assist gas and good combustion practices.	0.06 lb/MMBtu

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
TX-0928	Chevron Phillips Chemical Company LP Sweeny Old Ocean Facilities Sweeny, TX	10/15/21	Thermal Oxidizer	Good combustion practices.	0.06 lb/MMBtu

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.8.1.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes a NOx LAER limit for the SCTO that is equal to or more stringent than the limits indicated above. Therefore, no additional analysis is necessary under this step.

1.8.1.3 Step 3: Select LAER

Shell determined that LNBs and good combustion practices represent the LAER technologies applicable to the SCTO's NOx emissions. Shell proposes 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. Note that Shell plans to modify or replace the LNBs currently installed in the SCTO by June 1, 2026, to meet the more stringent NOx LAER limit of 0.06 lb/MMBtu (3-hour average).

1.8.2 $PM_{2.5}$

$PM_{2.5}$ is emitted by the SCTO due to metals that may be present in trace amounts 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 a negligible amount of metals. Additionally, the vent gases combusted in the thermal oxidizer have the same characteristics – they contain easily combustible hydrocarbons and a negligible amount of metals. Furthermore, the composite vent gas stream combusted in the SCTO, which is comprised of vent gases generated by SPM's spent caustic storage tank, SPM's spent caustic oxidation treatment operation, and SPM's Wastewater Treatment Plant-related equipment, does not contain appreciable amounts of compounds (e.g., sulfur-containing compounds, chloride-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 would have the potential to 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, though, the SCTO emits $PM_{2.5}$ at relatively low levels.

The SCTO is currently subject to the following $PM_{2.5}$ LAER requirement.

- The thermal oxidizer's $PM_{2.5}$ emissions shall not exceed 0.0075 lb/MMBtu.

1.8.2.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 13 below summarizes potential $PM_{2.5}$ limits and emission control technologies identified for operating thermal oxidizers that are used to control ethylene and polyethylene manufacturing unit process vents based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, and BAAQMD BACT/TBACT Workbook.

Table 13. Potential $PM_{2.5}$ Limits and Emission Control Technologies Identified for the SCTO (Ethylene and Polyethylene Operation Thermal Oxidizers)

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
TX-0858	GCGV Asset Holding LLC Complex Gregory, TX	6/12/19	Thermal Oxidizers	Best combustion practices and natural gas supplemental fuel.	0.0075 lb/MMBtu

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.8.2.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes a $PM_{2.5}$ LAER limit for the SCTO that is greater than the limit indicated above because 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. Instead, the thermal oxidizer at the GCGV Asset Holding LLC Complex combusts vent gases that have similar characteristics to the vent gases combusted in the CVTO, which would not result in the small additional amount of condensable PM that may be emitted when combusting a vent gas comparable to the spent caustic oxidation treatment operation vent gas that is generated at SPM. Therefore, the $PM_{2.5}$ emissions performance of the thermal oxidizer at the GCGV Asset Holding LLC Complex does not represent $PM_{2.5}$ LAER for the SCTO.

1.8.2.3 Step 3: Select LAER

Shell determined that good combustion practices represent the LAER technology applicable to the SCTO's $PM_{2.5}$ emissions. Shell proposes a $PM_{2.5}$ LAER limit of 0.012 lb/MMBtu (3-hour average) for the SCTO, which is greater than the $PM_{2.5}$ LAER limit that is currently applicable to the thermal oxidizer, but the current SCTO $PM_{2.5}$ LAER limit mistakenly does not account for the condensable PM that may be emitted when combusting SPM's spent caustic oxidation treatment operation vent gas.

1.9 Polyethylene Pellet Material Storage/Handling/Loadout LAER Determinations

As presented below, Shell has reevaluated the VOC LAER determination that was previously made for the Polyethylene Pellet Material Storage/Handling/Loadout emission source at SPM contemporaneous with the construction of the facility.

1.9.1 VOC

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 PE Units 1 and 2 and downstream of and including the degasser in PE Unit 3.

1.9.1.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 14 below summarizes potential VOC limits and emission control technologies identified for operating Polyethylene Pellet Material Storage/Handling/Loadout emission sources associated with gas phase and liquid phase slurry polyethylene manufacturing processes based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements. The potential VOC limits and emission control technologies identified in this table are specific to gas phase and liquid phase slurry polyethylene manufacturing processes because SPM only has gas phase and liquid phase slurry polyethylene manufacturing units.

Table 14. Potential VOC Limits and Emission Control Technologies Identified for Polyethylene Pellet Material Storage/Handling/Loadout (Gas Phase and Liquid Phase Slurry Polyethylene Manufacturing Process Polyethylene Pellet Material Storage/Handling/Loadout)

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
TX-0858	GCGV Asset Holding LLC Complex Gregory, TX	6/12/19	Polyethylene Pellet Handling - Railyard	Granular polyethylene must be degassed to such an extent that total VOC emissions from the extruded pellets does not exceed 50 lb/MMlb of polyethylene produced.	50 lb VOC/MMlb of polyethylene pellets
TX-0928	Chevron Phillips Chemical Company LP Sweeny Old Ocean Facilities Sweeny, TX	10/15/21	Polyethylene Pellet Handling and Loadout	Good operational practices. The total VOC emitted from Unit 40 and Unit 41 to the atmosphere after the extruder through product loadout shall not exceed 35.08 lb VOC/MMlb of polyethylene pellets on a 12-month rolling basis.	35.08 lb VOC/MMlb of polyethylene pellets on a 12-month rolling basis

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.9.1.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes a VOC LAER limit for the Polyethylene Pellet Material Storage/Handling/Loadout emission source that is equal to or more stringent than the limits indicated above. Therefore, no additional analysis is necessary under this step.

1.9.1.3 Step 3: Select LAER

Shell determined that minimizing the residual amount of VOC contained in and emitted from polyethylene pellets that are handled and stored in and by uncontrolled equipment and operations represents the LAER technology applicable to the VOC emissions from the Polyethylene Pellet Material Storage/Handling/Loadout emission source. Shell proposes the following VOC LAER limit for the Polyethylene Pellet Material Storage/Handling/Loadout emission source, which is more stringent than the VOC LAER limit that is currently applicable to the source.

- For PE Units 1 and 2, minimize the residual amount of VOC contained in and emitted from polyethylene pellets that are handled and stored in and by uncontrolled equipment and operations after the product purge bin through the loading of polyethylene pellets into trucks and railcars such that ≤ 35.08 lb VOC is emitted per MMlb of polyethylene pellets on a 12-month rolling basis.

- For PE Unit 3, minimize the residual amount of VOC contained in and emitted from polyethylene pellets that are handled and stored in and by uncontrolled equipment and operations after the degasser through the loading of polyethylene pellets into trucks and railcars such that ≤ 35.08 lb VOC is emitted per MMlb of polyethylene pellets on a 12-month rolling basis.

1.10 Wastewater Treatment Plant LAER Determinations

As presented below, Shell has reevaluated the VOC LAER determination that was previously made for the Wastewater Treatment Plant at SPM contemporaneous with the construction of the facility.

1.10.1 VOC

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

- Two Flow Equalization and Oil Removal (FEOR) Tanks, which vent to a closed-vent system (CVS) that routes collected vent gases to the SCTO
- A Recovered Oil Storage Tank, which vents to a CVS that routes collected vent gases to the SCTO
- Two Biotreater Aeration Tanks
- Two Secondary Clarifiers
- Two Biosludge Holding Tanks
- A Centrifuge
- A Sand Filter
- A Sump (for centrate and sand filter backwash)
- A 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 in the FEOR Tanks 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 most 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 internal floating roof and controlled by vapor recovery routed to the SCTO.
- The Recovered Oil Storage Tank shall be equipped with an internal floating roof and controlled by vapor recovery routed to the SCTO.

1.10.1.1 Step 1: Identify NNSR Permit, PSD Permit, and SIP Limits for the Same Class or Category of Source

Table 15 below summarizes potential VOC limits and emission control technologies identified for the Wastewater Treatment Plant based on a review of information sources that included EPA's RBLC database, SCAQMD BACT Guidelines, BAAQMD BACT/TBACT Workbook, and California RACT requirements.

Table 15. Potential VOC Limits and Emission Control Technologies Identified for the Wastewater Treatment Plant

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
BAAQMD Regulation 8: Organic Compounds, Rule 8: Wastewater Collection and Separation Systems	-	Rule Date: 12/20/23	Wastewater Separators	Equip the wastewater separator with a fixed cover that does not vent during normal operations, a floating cover equipped with primary and secondary rim seals, a fixed cover equipped with a closed-vent system vented to an air pollution control device that has a combined collection and destruction efficiency of at least 95% for total organic compounds, or a fixed cover with a pressure/vacuum valve that does not emit total organic compounds in excess of 1,000 parts per million by volume (expressed as methane) above background.	Air pollution control device option: 95% destruction efficiency for total organic compounds

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
BAAQMD Regulation 8: Organic Compounds, Rule 8: Wastewater Collection and Separation Systems	-	Rule Date: 12/20/23	Air Flotation Units	Equip the air flotation unit with a fixed cover with a pressure/vacuum valve or a fixed cover equipped with a closed-vent system vented to an air pollution control device that has a combined collection and destruction efficiency of at least 70% for total organic compounds.	Air pollution control device option: 70% destruction efficiency for total organic compounds
TX-0876	Port Arthur Ethane Cracker Jefferson, TX	2/6/20	Wastewater Treatment Plant	Covered conveyances, benzene stripper, activated sludge biological treatment, and thermal oxidizer.	99.9% destruction efficiency
LA-0364	FG LA LLC St. James Parish, LA	1/6/20	Wastewater Treatment System	Good design and venting the emissions to a control device in the primary treatment system.	None
TX-0865	Equistar Chemicals, LP Channelview, TX	9/9/19	Wastewater Treatment	The wastewater tank emissions are routed to a multi-point ground flare for control at an efficiency of 98%.	98% destruction efficiency
TX-0858	GCGV Asset Holding LLC Gregory, TX	6/12/19	Wastewater Treatment Plant	All vapors from the equalization tanks and the dissolved air flotation basin must also be captured and controlled. The required controls are a catalytic oxidizer and the shared vent system, respectively. The catalytic oxidizer must achieve a minimum destruction efficiency of 99%, to be demonstrated through stack sampling.	99% destruction efficiency
LA-0382	Big Lake Fuels LLC Calcasieu Parish, LA	4/25/19	Wastewater Treatment Plant	Comply with 40 CFR 63 Subpart G.	None

Reference ID	Facility Name	Permit Issuance Date	Process Description	Control Technology Description	Emissions Limit
OH-0378	PTGCA Belmont, OH	12/21/18	Wastewater Collection and Treatment	Route emissions from wastewater generated in the ethylene manufacturing process to a thermal oxidizer designed to achieve >99.5% destruction efficiency for VOC. Cover and route emissions from the process wastewater equalization tank, waste oil drum, oily wastewater storage tank, and wet air oxidation unit to a thermal oxidizer designed to achieve >99.5% destruction efficiency for VOC.	99.5% destruction efficiency
LA-0301	Sasol Chemicals Lake Charles, LA	5/23/14	Benzene Stripper	Route emissions to the fuel gas system.	None
LA-0301	Sasol Chemicals Lake Charles, LA	5/23/14	Wastewater Drums and Sumps	Route the drums and sumps through a closed-vent system to a ground flare.	None
LA-0301	Sasol Chemicals Lake Charles, LA	5/23/14	Sour Water Stripper	Route emissions to the fuel gas system.	None
LA-0301	Sasol Chemicals Lake Charles, LA	5/23/14	Process Wastewater Treatment Plant	Compliance with 40 CFR 63 Subpart G and 40 CFR 61 Subpart FF.	40.01 tpy
LA-0301	Sasol Chemicals Lake Charles, LA	5/23/14	Process Water Tanks	Internal floating roof.	17.82 tpy
LA-0302	Sasol Chemicals Lake Charles, LA	5/23/14	Wastewater VOC Stripper (Vent)	Combustion in a process heat boiler.	None
SCAQMD	Sunoco Chemicals Philadelphia, PA	7/27/99	WWT system at chemical plant. VOC-contaminated water air stripped of VOC.	Wastewater is required to be air-stripped with stripper vented to thermal oxidizer with minimum 95% destruction efficiency.	95% destruction efficiency
SCAQMD Rule 1176. VOC Emissions from Wastewater Systems	-	Rule Date: 9/13/96	Wastewater Separators	Equip the wastewater separator with a floating cover equipped with a primary rim seal, a fixed cover equipped with a closed-vent system vented to an air pollution control device, or an approved equivalent alternative control technology.	Air pollution control device option: 95% control efficiency

The above limits and control technologies that were obtained from EPA's RBLC database are further documented in Attachment 2-1.

1.10.1.2 Step 2: Confirm the Limits Achieved in Practice

Shell proposes a VOC LAER limit for the Wastewater Treatment Plant that is equal to or more stringent than the limits indicated above. Therefore, no additional analysis is necessary under this step.

1.10.1.3 Step 3: Select LAER

Shell determined that equipping and maintaining an internal floating roof 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 a thermal oxidizer (the SCTO) that achieves a 99.9% VOC destruction efficiency represents LAER for the VOC emissions from these primary wastewater treatment vessels in the Wastewater Treatment Plant, which is the same VOC LAER that is currently applicable to the vessels. Additionally, Shell 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.

Attachment 2-1

Request No. 3.a EPA RBLC Database Information

Process Type: 99.009 - Industrial Process Cooling Towers

Pollutant: $PM_{2.5}$

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	4/1/2015	Cooling tower	40,000	gpm	PM2.5	Drift eliminator is 0.0005% efficient.	0.12	lb/hr	OTHER CASE-BY-CASE	
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	6/4/2015	Cooling Towers			PM2.5	Drift eliminators.	0.0005	% drift rate	BACT-PSD	
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	Mechanical draft cooling tower			PM2.5	High efficiency drift eliminators (integral part of the design).	0.0005	% drift rate	BACT-PSD	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	8/25/2015	Wet Cooling Tower (P005)	165,470	gpm	PM2.5	Drift eliminator with a maximum drift rate of 0.0005% and TDS concentration of the cooling water less than or equal to 3,075 mg/L.	0.51	lb/hr	BACT-PSD	
TX-0774	BISHOP FACILITY	TICONA POLYMERS, INC.	11/12/2015	Cooling Tower	10,400		PM2.5	Drift eliminators meeting 0.001% drift.	0.01	tpy	BACT-PSD	
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	6/30/2016	Cooling Towers			PM2.5	Drift eliminators.	0.0005	%	BACT-PSD	
TX-0803	PL PROPYLENE HOUSTON OLEFINS PLANT	FLINT HILLS RESOURCES HOUSTON CHEMICAL LLC	7/12/2016	Cooling Tower			PM2.5	Drift eliminators.	0.001	% drift	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Cooling towers - 007	86,500	gpm	PM2.5	Drift eliminators.	0.0005	%	BACT-PSD	
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	9/23/2016	Cooling Towers (2 identical, P005 and P006)	118,441	gpm	PM2.5	High efficiency drift eliminators and minimize TDS.	0.534	lb/hr	BACT-PSD	Advanced drift eliminators with a drift rate of less than 0.0005% and maintain the TDS concentration of the cooling water less than or equal to 4,500 mg/L.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	EUCOOLTWR (Cooling Tower--Wet Mechanical Draft)			PM2.5	Mist/drift eliminators.	2.37	tpy	BACT-PSD	Mist/drift eliminator with a maximum drift rate of 0.0005%.
*LA-0306	TOPCHEM POLLOCK, LLC	TOPCHEM POLLOCK, LLC	12/20/2016	Cooling Tower CT-16-1 (EQT032)	1,000	gpm	PM2.5	High efficiency drift eliminator.	0.001	lb/hr	BACT-PSD	0.001% drift.
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	12/22/2016	Cooling towers (I-CT-621, II-CT-621)	66,000	gpm (each)	PM2.5	Drift eliminators.	0.001	%	BACT-PSD	
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	1/9/2017	Cooling Water Tower	18,000	gpm	PM2.5	Drift eliminators with drift factor of 0.003%.	0.003	%	BACT-PSD	Drift eliminators with drift factor of 0.003%.
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	4/19/2017	Cooling Towers #1 & #2 (P010 & P011)	79,800	gpm	PM2.5	Drift eliminators with a maximum drift rate specification of 0.0005% or less and TDS concentration of the cooling water less than or equal to 5,000 mg/L.	0.0018	lb/hr	BACT-PSD	
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	6/30/2017	ECT-14 - Econamine Cooling Tower (EQT0018)	29,120	gpm	FPM2.5	High efficiency drift eliminators.	0.01	tpy	BACT-PSD	Use high efficiency drift eliminators with a maximum drift rate of 0.0005%; a cooling Water Circulation Rate <= 29,100 gpm; and a TDS Concentration <= 2,660 ppm for PM/PM10/PM2.5 control. The permittee shall determine and record the concentration of TDS in the cooling water at least once per week using Standard Method 2540C or EPA Method 160.1.
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	6/30/2017	CT-13 - Cooling Tower (EQT0007)	231,000	gpm	FPM2.5	High efficiency drift eliminators.	0.01	lb/hr	BACT-PSD	Use high efficiency drift eliminators with a maximum drift rate of 0.0005%; a cooling Water Circulation Rate <= 231,000 gpm; and a Total TDS Concentration <= 2,660 ppm for PM/PM10/PM2.5 control. The permittee shall determine and record the concentration of TDS in the cooling water at least once per week using Standard Method 2540C or EPA Method 160.1.
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	9/7/2017	Wet Cooling Tower (P005)	155,083	gpm	PM2.5	Drift eliminator with a maximum drift rate of 0.0005% and TDS concentration of the cooling water less than or equal to 3,500 mg/L.	0.54	lb/hr	BACT-PSD	
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	9/27/2017	Wet Cooling Tower (P005)	155,083	gpm	PM2.5	Drift eliminator with a maximum drift rate of 0.0005% and TDS concentration of the cooling water less than or equal to 3,500 mg/L.	0.36	lb/hr	BACT-PSD	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Wet Mechanical Draft Cooling Tower (P003)	120,000	gpm	PM2.5	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and TDS content not to exceed 5,000 mg/l.	1.58	tpy	BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: $PM_{2.5}$
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	EUCOOLTWR (Cooling Tower--Wet Mechanical Drift)			PM2.5	Mist/drift eliminators.	0.0006	%	BACT-PSD	Emission Limit 1 above is 0.0006%, vendor-certified maximum drift rate. Emission Limit 2 above is 7700 ppmw, maximum TDS in cooling water. The estimated efficiency is to reduce drift loss to 0.0006%. There are no BACT emission limits in the permit, but there is a requirement for the permittee to equip and maintain EUCOOLTWR with mist/drift eliminators with a vendor-certified maximum drift rate of 0.0006% or less, and there is also a limit of 7700 ppmw maximum TDS in cooling water.
TX-0832	EXXONMOBIL BEAUMONT REFINERY	EXXONMOBIL OIL CORPORATION	1/9/2018	Cooling Towers			PM2.5	Drift eliminators.			BACT-PSD	
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	2/9/2018	Wet Cooling Tower (P005)	24,766	gpm	PM2.5	Drift eliminator with a maximum drift rate of 0.0005% and TDS concentration of the cooling water less than or equal to 1,100 parts per million by weight (ppmw).	0.01	lb/hr	BACT-PSD	
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	3/30/2018	Cooling Tower	9,864,000	gal/hr	PM2.5	Drift eliminators.			BACT-PSD	
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT		4/24/2018	P02A-P & P03A-P Cooling Towers			PM2.5	Drift eliminator & cooling additive control system.			BACT-PSD	BACT is: Use of a drift eliminator with a design drift rate of no more than 0.0005% of circulating water flow; Total cooling water circulation rate for each cooling tower may not exceed 18,000 gpm; and Use of a cooling additive control system that results in a TDS concentration of not more than 2,500 ppm.
VA-0328	C4GT, LLC	NOVI ENERGY	4/26/2018	Cooling Tower			FPM2.5	PM emissions from the cooling tower will be controlled to a drift rate of 0.00050% of the circulating water flow with mist eliminators and a TDS content of the cooling water effluent shall not exceed 6250 mg/L.			BACT-PSD	
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	6/29/2018	EUCOOLTOWER (North Plant): Cooling Tower	170,000	gpm	PM2.5	High efficiency drift/mist eliminators	2.85	tpy	BACT-PSD	There is a third emission limit which is Maximum TDS in circulating water = 3000 PPMW; monthly as determined based upon weekly and monthly parameter monitoring. The estimated efficiency is to reduce drift loss to 0.0005%.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	6/29/2018	EUCOOLTOWER (South Plant): Cooling Tower	170,000	gpm	PM2.5	High efficiency drift/mist eliminators.	2.85	tpy	BACT-PSD	There is a third emission limit in the permit as follows: Maximum TDS in circulating water = 3000 ppmw; monthly as determined based upon weekly and monthly parameter monitoring. The estimated efficiency of the add on controls is to reduce drift loss to 0.0005%.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	7/16/2018	EUCOOLINGTWR: Cooling Tower			PM2.5	High efficiency drift/mist eliminators.	0.48	lb/hr	BACT-PSD	There is a third emission limit in the permit as follows: Maximum TDS in circulating water = 3000 ppmw; monthly as determined based upon weekly and monthly parameter monitoring. The estimated efficiency of the add on controls is to reduce drift loss to 0.0005%.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Cooling Tower (P011)	13.88	MMgal/hr	PM2.5	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a TDS content not to exceed 2,000 ppm in the circulating cooling water based on a rolling 12-month average.	0.01	tpy	BACT-PSD	
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	6/11/2019	Cooling tower EU-6001	32,000	gal/hr	PM2.5	Drift eliminators.	2,395	mg/L	BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: $PM_{2.5}$
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	8/21/2019	FGCOOLTWR	92,500	gpm	PM2.5	Particulate in water droplets will be controlled with high efficiency drift/mist eliminators	0.6	tpy	BACT-PSD	As part of normal operation, some of the circulating water may become entrained in the air leaving the cool tower. This water is in droplet form (also known as "drift" droplets) and contains the same impurities as the circulating water. Therefore, any particulate matter that is dissolved in the circulating water may be emitted as PM, PM10 and PM2.5. No other pollutants will be emitted from the cooling towers. High efficiency drift eliminators were proposed by Thomas Township Energy as BACT with a drift rate of 0.0005%. The dissolved solids content of the circulating water also contributes to the emissions; therefore, there is also a proposed material limit of 2,000 ppmw dissolved solids content in the circulating water.
TX-0863	POLYETHYLENE 7 FACILITY	THE DOW CHEMICAL COMPANY	9/3/2019	Cooling Tower			PM2.5	Drift eliminators.	0		BACT-PSD	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Cooling Tower			PM2.5	Drift eliminators.	0.005	% drift	BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Cooling Tower			PM2.5	Drift eliminators.	6,000	ppmw	BACT-PSD	
AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	9/23/2019	Cooling Towers			PM2.5	Drift eliminators. Low TDS.	0.0005	% drift loss	BACT-PSD	
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	9/27/2019	Contact Cooling Towers (P014)	6.41	MMgal/hr	FPM2.5	i. Use of drift eliminator(s) designed to achieve a 0.003% drift rate; ii. Maintenance of a TDS content (for the 5 individual cooling towers) not to exceed the ppm in the circulating cooling water based on a rolling 12-month average as indicated in the table below: Cooling Tower - TDS (ppm) Meltshop Cooling Tower (501) - 800 Caster Non-Contact Cooling Tower (6 Cell) - 800 Caster Contact Cooling Tower (503) - 1100 Mill Contact Cooling Tower (505) - 2000 Laminar Flow Cooling Tower (506) - 1400	0.02	tpy	BACT-PSD	
WI-0311	SUPERIOR REFINING COMPANY LLC	SUPERIOR REFINING COMPANY LLC	9/27/2019	Cooling Tower No.1 (P80)	10,000	gpm	PM2.5	Drift eliminator, cooling additive control system that results in a TDS concentration of not more than 3,000 ppm.	0.0005	% drift	BACT-PSD	May demonstrate compliance with the TDS limitation through measurement of cooling water conductivity.
TX-0873	PORT ARTHUR REFINERY	MOTIVA ENTERPRISES LLC	2/4/2020	Cooling Tower	35,000	gpm	PM2.5	Drift eliminators.			BACT-PSD	
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	2/6/2020	Cooling Tower			FPM2.5	Drift eliminators.	1,200	ppm	BACT-PSD	
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	4/23/2020	Cooling Towers			PM2.5	Drift eliminators.			BACT-PSD	
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-01 - Melt Shop ICW Cooling Tower	52,000	gpm	PM2.5	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.0008	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,365 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-02 - Melt Shop DCW Cooling Tower	5,900	gpm	PM2.5	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.0001	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-03 - Rolling Mill ICW Cooling Tower	8,500	gpm	PM2.5	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.0001	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,365 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-04 - Rolling Mill DCW Cooling Tower	22,750	gpm	PM2.5	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.0004	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.

Process Type: 99.009 - Industrial Process Cooling Towers

Pollutant: $PM_{2.5}$

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-05 - Rolling Mill Quench/ACC Cooling Tower	90,000	gpm	PM2.5	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.0017	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,729 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-06 - Light Plate Quench DCW Cooling Tower	8,000	gpm	PM2.5	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.0001	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-07 - Heavy Plate Quench DCW Cooling Tower	3,000	gpm	PM2.5	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.0001	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-08 - Air Separation Plant Cooling Tower	14,000	gpm	PM2.5	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.0002	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		9/9/2020	Cooling Tower			PM2.5	Non-contact design and drift eliminators.			BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	Cooling Tower			PM2.5	Drift eliminators 0.001%.			BACT-PSD	
TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	3/17/2021	Cooling Tower			PM2.5	Drift eliminators at 0.0005%.	60,000	ppm	BACT-PSD	
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Laminar Cooling Tower - Hot Mill Cells (EP 03-09)	35,000	gpm	PM2.5	Mist eliminator, 0.001% drift loss.	0.0006	lb/hr	BACT-PSD	TDS limited to 1729 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Direct Cooling Tower-Caster Roughing Mill Cells (EP 03-10)	26,300	gpm	PM2.5	Mist eliminator, 0.001% drift loss.	0.0004	lb/hr	BACT-PSD	TDS limited to 1495 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Melt Shop #2 Cooling Tower (indirect) (EP 03-11)	59,500	gpm	PM2.5	Mist eliminator, 0.001% drift loss.	0.0008	lb/hr	BACT-PSD	TDS limited to 1365 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Cold Mill Cooling Tower (EP 03-12)	20,000	gpm	PM2.5	Mist eliminator, 0.001% drift loss.	0.0003	lb/hr	BACT-PSD	TDS limited to 1365 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Air Separation Plant Cooling Tower (EP 03-13)	15,000	gpm	PM2.5	Mist eliminator, 0.001% drift loss.	0.0002	lb/hr	BACT-PSD	TDS limited to 1125 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	DCW Auxiliary Cooling Tower (EP 03-14)	9,250	gpm	PM2.5	Mist eliminator, 0.001% drift loss.	0.0001	lb/hr	BACT-PSD	TDS limited to 1309 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).

Process Type: 99.009 - Industrial Process Cooling Towers

Pollutant: $PM_{2.5}$

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Cooling Tower			PM2.5	Drift eliminators required. Maximum drift 0.0005%. TDS limit of 3,500 ppmw in the cooling water. Daily sampling for TDS required, or weekly TDS sampling is allowed if conductivity is monitored daily and a TDS to conductivity ratio is established.			BACT-PSD	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Cooling Tower			PM2.5	Drift eliminators with 0.001% drift.			BACT-PSD	
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	MAGNOLIA POWER LLC	6/3/2022	Cooling Tower	8,400	gpm	PM2.5	High-efficiency drift eliminators.	0.0005	%	BACT-PSD	Equipped with high-efficiency drift eliminators <= 0.0005% drift rate.
TX-0922	HOUSTON PLANT - 46307	TPC GROUP LLC	6/13/2022	Cooling Tower			PM2.5	Drift eliminators with 0.0005% drift.			BACT-PSD	
KY-0116	NOVELIS CORPORATION - GUTHRIE	NOVELIS CORPORATION	7/25/2022	EU 043 - Cooling Tower #1	0.15	MMgal/hr	PM2.5	Mist eliminator (0.001% drift loss), TDS concentration limit of 1000 ppm.	0	lb/hr	BACT-PSD	Initial compliance demonstration with BACT will be shown by properly installing mist eliminators on EU043 and using parametric monitoring for the cooling tower to ensure the TDS remains below 1000 ppm. Emissions calculated using the vendor design specification for the mist eliminator of 0.001% drift loss and 1,000 ppm TDS, and Reisman-Frisbie interpolation.
TX-0940	FIBERGLASS MANUFACTURING FACILITY	KNAUF INSULATION, INC.	9/6/2022	Cooling Tower	2,175	gpm	PM2.5	Drift eliminators.	0.001	%	BACT-PSD	
OH-0387	INTEL OHIO SITE	INTEL OHIO SITE	9/20/2022	Cooling Towers: P054 through P178			PM2.5	Drift eliminators.	0.0005	%	BACT-PSD	
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	ENTERGY TEXAS, INC.	3/13/2023	Cooling Tower	13,734,000	gal/hr	PM2.5	0.001% drift eliminators.			BACT-PSD	
*OH-0391	VALENCIA PROJECT LLC	VALENCIA PROJECT LLC	10/27/2023	Cooling Towers (P023, P024, P025)			PM2.5	A drift eliminator achieving drift loss equal to or less than 0.0005%.	0.02	lb/hr	BACT-PSD	A drift eliminator achieving drift loss equal to or less than 0.0005%.
*SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD PLANT	SCOUT MOTORS INC A DELAWARE CORPORATION	10/31/2023	Cooling Towers			PM2.5	Drift eliminators.	0.001	% drift rate	BACT-PSD	
*LA-0394	GEISMAR PLANT	SHELL CHEMICAL LP	12/12/2023	04-22 - AO-5 Cooling Water Tower, W-S5401	47,410	gpm	PM2.5		0.15	lb/hr	BACT-PSD	
*LA-0402	DESTREHAN OIL PROCESSING FACILITY	BUNGE CHEVRON AG RENEWABLES, LLC	12/13/2023	HLK40 - Cooling Towers (EQT0095)	125,856	gpm	FPM2.5	Drift elimination system.	0.02	lb/hr	BACT-PSD	Employ a drift elimination system with a maximum design drift rate of 0.0005%.
*LA-0401	KOCH METHANOL (KME) FACILITY	KOCH METHANOL ST. JAMES, LLC	12/20/2023	CWT - Cooling Water Tower	200,000	gpm	PM2.5	Use of high efficiency drift eliminators.			BACT-PSD	
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Cooling Tower	145,310	gpm	PM2.5	High efficiency drift eliminators.	0.0005	%	BACT-PSD	Monthly sampling to determine TDS content of water circulating in cooling tower.
*TX-0967	QUAIL RUN CARBON CAPTURE PLANT	QUAIL RUN CARBON, LLC	2/5/2024	Cooling Towers	142,700	gpm	PM2.5	Drift eliminators 0.0005%.			BACT-PSD	
*TX-0938	VALERO CORPUS CHRISTI REFINERY WEST PLANT	VALERO REFINING-TEXAS, L.P.	5/3/2024	Cooling Tower			PM2.5	Drift eliminators 0.001% drift.			BACT-PSD	
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4C-4 - C/A Cooling Tower	64,600	gpm	PM2.5	High efficiency drift eliminators.	0.14	lb/hr	BACT-PSD	
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4M-7 - VCM Cooling Tower 1	122,269	gpm	PM2.5	Drift eliminators.	0.21	lb/hr	BACT-PSD	
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4M-18 - VCM Cooling Tower 2	28,620	gpm	PM2.5	Drift eliminators.	0.05	lb/hr	BACT-PSD	

Process Type: 19.200 - Emission Control Afterburners & Incinerators (Combustion Gases Only) (Ethylene and Polyethylene Operations)

Pollutant: NOx

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0815	PORT ARTHUR ETHANE SIDE CRACKER	TOTAL PETROCHEMICALS & REFINING USA, INC.	1/17/2017	Thermal Oxidizer	5.3	MMBtu/hr	NOx	Good combustion practices and design.	0.13	lb/MMBtu	BACT-PSD	
TX-0858	GULF COAST GROWTH VENTURES PROJECT	GCGV ASSET HOLDING LLC	6/12/2019	Thermal Oxidizers			NOx	Best combustion practices and natural gas supplemental fuel.	0.06	lb/MMBtu	BACT-PSD	
TX-0889	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	8/8/2020	Thermal Oxidizer			NOx	Use natural gas as assist gas and good combustion practices.	0.06	lb/MMBtu	LAER	
TX-0928	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	10/15/2021	Thermal Oxidizer			NOx	Good combustion practices.	0.06	lb/MMBtu	LAER	

Process Type: 19.200 - Emission Control Afterburners & Incinerators (Combustion Gases Only) (Ethylene and Polyethylene Operations)
Pollutant: $PM_{2.5}$
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0858	GULF COAST GROWTH VENTURES PROJECT	GCGV ASSET HOLDING LLC	6/12/2019	Thermal Oxidizers			PM2.5	Best combustion practices and natural gas supplemental fuel.			BACT-PSD	0.0075 lb/MMBtu

Process Type: 19.200 - Emission Control Afterburners & Incinerators (Combustion Gases Only) (Ethylene and Polyethylene Operations)

Pollutant: VOC

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0858	GULF COAST GROWTH VENTURES PROJECT	GCGV ASSET HOLDING LLC	6/12/2019	Thermal Oxidizers			VOC	Best combustion practices and natural gas supplemental fuel.			BACT-PSD	99.9% VOC destruction efficiency
TX-0889	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	8/8/2020	Thermal Oxidizer			VOC	Use natural gas as assist gas and good combustion practices.	0.0054	lb/MMBtu	LAER	99.9% VOC destruction efficiency
TX-0928	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	10/15/2021	Thermal Oxidizer			VOC	Good combustion practices.	0.0054	lb/MMBtu	LAER	99.9% VOC destruction efficiency
*TX-0962	POINT COMFORT PLANT	FORMOSA PLASTICS CORPORATION	9/22/2023	PE3 Plant Thermal Oxidizer			VOC	Use of pipeline quality natural gas as supplemental fuel. Good combustion practices are used.			BACT-PSD	99.9% VOC destruction efficiency

Process Type: 19.310 - Chemical Plant Flares
Pollutant: NOx
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Multi-Point Ground Flares (EQT 836 & 837)			NOx	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subparts FFFF and SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987; minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	1,072.86	lb/hr	BACT-PSD	
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	LLPDE/LDPE Multi-Point Ground Flare (EQT 640)			NOx	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.	174.09	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. BACT is also determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.
LA-0299	LAKE CHARLES CHEMICAL COMPLEX ETHOXYLATION UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	ETO/Guerbet Elevated Flare (EQT 1079)			NOx	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart PPP.	8.51	lb/hr	BACT-PSD	The permittee shall continuously monitor and record the volume of vent gas routed to the following flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips.
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 981)			NOx	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	12,383.13	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.

Process Type: 19.310 - Chemical Plant Flares
Pollutant: NOx
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Ground Flare (EQT 982)			NOx	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	8,565.31	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare and Ground Flare (EQTs 1012 & 1013)			NOx	Compliance with 40 CFR 63.11(b) and the closed vent system requirements of 40 CFR 63.148; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	2.43	lb/hr	BACT-PSD	Pound per hour NOx limitations are per flare. *Annual NOx emissions from both flares are limited to the TPY value reported.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 133)			NOx	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	55.32	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Emission Combustion Unit #3 Ground Flare (EQT 500)			NOx	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	49.68	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	NOx	Natural gas pilot and flare minimization practices.	0.068	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	NOx	Natural gas pilot and flare minimization practices.	0.068	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	NOx	Natural gas pilot and flare minimization practices.	0.068	lb/MMBtu	BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: NOx

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	NOx	Natural gas pilot and flare minimization practices.	0.068	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	NOx	Natural gas pilot and flare minimization practices.	0.068	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	NOx	Natural gas pilot and flare minimization practices.	0.068	lb/MMBtu	BACT-PSD	
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	4/1/2015	ammonia flare	106,396	MMBtu/yr	NOx	No control.	223.41	lb/hr	LAER	The TPY emission rate is based on all operating scenarios. the lb/hr rate is based on worst case MSS scenarios.
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	6/30/2016	Flares	1,008	MMBtu/hr	NOx				BACT-PSD	
LA-0295	WESTLAKE FACILITY	EQUISTAR CHEMICALS, LP	7/12/2016	Cogeneration Plant Flare (449, EQT 326)			NOx		12.6	lb/hr	BACT-PSD	Annual NOx emissions from the Cogeneration Plant Flare (449, EQT 326); the M-Line Production Area Flare (Z2, EQT 19); and the Plant 5 Flare (Z1, EQT 138) (not addressed in the PSD permit) are limited to 36.65 TPY (GRP 12).
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Flare No. 1 - 008	85,097	MMBtu/yr	NOx	Complying with 40 CFR 60.18 and good combustion practices (including establishment of flare minimization practices).	0.068	lb/MMBtu	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Pyrolysis Gasoline Tank Flare - 009	0.66	MMBtu/hr	NOx	Complying with 40 CFR 60.18 and 63.11 and good combustion practices (including establishment of flare minimization practices).	0.068	lb/MMBtu	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	vessel evacuation flare - 018	3.04	MMBtu/hr	NOx	Good combustion practices (including establishment of flare minimization practices).	0.068	lb/MMBtu	BACT-PSD	
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	12/22/2016	flares (I-X-703, II-X-703)	3,723	MMBtu/hr	NOx	Complying with 40 CFR 63.11.			BACT-PSD	BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	1/9/2017	Emergency Flare	0.4	MMBtu/hr	NOx	Proper design and operation.			BACT-PSD	
TX-0815	PORT ARTHUR ETHANE SIDE CRACKER	TOTAL PETROCHEMICALS & REFINING USA, INC.	1/17/2017	Multi Point Ground Flare			NOx	Good combustion practices and design.	94.27	tpy	BACT-PSD	Emission rate of 94.27 tpy is the sum of 35.86 tpy NOx for routine operations and 58.41 tpy NOx for MSS operations.
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	1/4/2018	Flares (4)	6.6	MMBtu/hr	NOx	Complying with 40 CFR 63.11(b).			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	High and Low Pressure Flare cap			NOx	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	UDEX FLARE			NOx	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	PARAXYLENE FLARE			NOx	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	C & S FLARE			NOx	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	High Pressure Ground Flare (P003)	1.8	MMBtu/hr	NOx	Use of natural gas as pilot light fuel.	0.536	tpy	BACT-PSD	The high pressure (HP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the HP ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The HP flare controls VOC emissions from units P801, P802, P803, P804, and P805.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Low Pressure Ground Flare (P004)	0.78	MMBtu/hr	NOx	Use of natural gas as pilot light fuel.	0.232	tpy	BACT-PSD	The low pressure (LP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the ECU ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The LP flare controls VOC emissions from units P804 and P805.

Process Type: 19.310 - Chemical Plant Flares

Pollutant: NOx

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	4/25/2019	Flares (EQT0012, EQT0039, EQT0040)			NOx	Comply with requirements of 40 CFR 63.11(b).			BACT-PSD	
TX-0863	POLYETHYLENE 7 FACILITY	THE DOW CHEMICAL COMPANY	9/3/2019	FLARE			NOx	Good combustion practices.			BACT-PSD	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Multi Point Ground Flare			NOx	Good combustion practices, design, and natural gas fuel.			BACT-PSD	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Elevated Flare			NOx	Good combustion practices, design, and natural gas fuel.			BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	MULTIPOINT GROUND FLARE			NOx	Good combustion practices and proper design and operation.			BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	MEROX ELEVATED FLARE			NOx	Good combustion practices and proper design and operation.			BACT-PSD	
TX-0893	HYDOW DROCARBONS FACILITIES	THE DOW CHEMICAL COMPANY	8/7/2020	Flare			NOx	Good combustion practices.	0.138	lb/MMBtu	LAER	
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		9/9/2020	FLARE			NOx	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	FLARE			NOx	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
TX-0894	CHEVRON PHILLIPS CHEMICAL SWEENY COMPLEX	CHEVRON PHILLIPS CHEMICAL COMPANY LP	10/30/2020	Unit 81 Flare (EPN 81-97-9611)			NOx	Good combustion practices, proper design and operation.	0.068	lb/MMBtu	LAER	
TX-0901	EQUISTAR CHEMICALS LA PORTE COMPLEX	EQUISTAR CHEMICALS, LP	11/6/2020	FLARE			NOx	Good combustion practices, proper design and operation, and steam assisted.			LAER	
TX-0917	POLYETHYLENE UNIT 1799	CHEVRON PHILLIPS CHEMICAL COMPANY LP	1/29/2021	Flare FS-9004 (EPN 1799-20)			NOx	Good combustion practices, proper design and operation. Meets the design and operating requirements of 40 CFR 60.18. The flare is an air-assisted flare and can operate as a high or low Btu flare. The flare is equipped with a continuous flow monitor, composition analyzer, and has continuous pilot flame monitoring.			LAER	
TX-0917	POLYETHYLENE UNIT 1799	CHEVRON PHILLIPS CHEMICAL COMPANY LP	1/29/2021	Flare FS-9004 (EPN 1799-20)			NOx	Good combustion practices, proper design and operation. Meets the design and operating requirements of 40 CFR 60.18. The flare is an air-assisted flare and can operate as a high or low Btu flare. The flare is equipped with a continuous flow monitor, composition analyzer, and has continuous pilot flame monitoring.			LAER	
TX-0916	CEDAR BAYOU	CHEVRON PHILLIPS CHEMICAL COMPANY LP	2/1/2021	Flare EPN 1592-40 and 1592-16			NOx	Good combustion practices, proper design and operation. Meets the design and operating requirements of 40 CFR 60.18. High Btu stream-assisted flare equipped with flow monitor and GC analyzer. Continuous monitoring of pilot flame.			LAER	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	FLARE			NOx	Good combustion practices and use of gaseous fuel.			BACT-PSD	
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	INEOS OLIGOMERS USA LLC	3/14/2023	FLARE			NOx	Burner tip design and supplemental fuel control assure combustion. Open air combustion does not add temperature to the NOx formation potential.			LAER	
TX-0945	FORMOSA POINT COMFORT PLANT OL3	FORMOSA PLASTICS CORPORATION, TEXAS	4/6/2023	FLARES			NOx	Clean fuel and good combustion practices.			BACT-PSD	
*TX-0956	ENTERPRISE MONT BELVIEU COMPLEX	ENTERPRISE PRODUCTS OPERATING LLC	6/8/2023	FLARE			NOx	Good design and combustion practices.			LAER	
*TX-0964	NEDERLAND FACILITY	LINDE, INC	10/5/2023	FLARE			NOx	40 CFR 60.18 and good combustion practices.			BACT-PSD	
*LA-0401	KOCH METHANOL (KME) FACILITY	KOCH METHANOL ST. JAMES, LLC	12/20/2023	FLR - Flare			NOx	Use of good operating practices and compliance with 40 CFR 60.18 and 40 CFR 63.11.			BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: $PM_{2.5}$

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Multi-Point Ground Flares (EQT 836 & 837)			PM2.5	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subparts FFFF and SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987; minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	170.84	lb/hr	BACT-PSD	
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	LLPDE/LDPE Multi-Point Ground Flare (EQT 640)			PM2.5	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.	37.51	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. BACT is also determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.
LA-0299	LAKE CHARLES CHEMICAL COMPLEX ETHOXYLATION UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	ETO/Guerbet Elevated Flare (EQT 1079)			PM2.5	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart PPP.	0.23	lb/hr	BACT-PSD	The permittee shall continuously monitor and record the volume of vent gas routed to the following flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips.
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 981)			PM2.5	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	562.23	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.

Process Type: 19.310 - Chemical Plant Flares

Pollutant: $PM_{2.5}$

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Ground Flare (EQT 982)			PM2.5	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	1041.94	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare and Ground Flare (EQTs 1012 & 1013)			PM2.5	Compliance with 40 CFR 63.11(b) and the closed vent system requirements of 40 CFR 63.148; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	0.18	lb/hr	BACT-PSD	Pound per hour PM2.5 limitations are per flare. *Annual PM2.5 emissions from both flares are limited to the TPY value reported.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 133)			PM2.5	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	0.9	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Emission Combustion Unit #3 Ground Flare (EQT 500)			PM2.5	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	1.52	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	PM2.5	Natural gas pilot and flare minimization practices.	7.6	lb/MMcf	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	PM2.5	Natural gas pilot and flare minimization practices.	0.0075	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	PM2.5	Natural gas pilot and flare minimization practices.	0.0075	lb/MMBtu	BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares
Pollutant: $PM_{2.5}$
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	PM2.5	Natural gas pilot and flare minimization practices.	7.6	lb/MMcf	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	PM2.5	Natural gas pilot and flare minimization practices.	0.0075	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	PM2.5	Natural gas pilot and flare minimization practices.	0.0075	lb/MMBtu	BACT-PSD	
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	1/6/2015	Three (3) Flares	1.25	MMBtu/hr	PM2.5	Work practice requirements and limited use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events).	0.0074	lb/MMBtu	BACT-PSD	
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	6/30/2016	Flares	1008	MMBtu/hr	PM2.5	Good flare design.			BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Flare No. 1 - 008	85097	MMBtu/yr	PM2.5	Complying with 40 CFR 60.18, good combustion practices (including establishment of flare minimization practices), and steam assisted.	0.007	lb/MMBtu	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Pyrolysis Gasoline Tank Flare - 009	0.66	MMBtu/hr	PM2.5	Complying with 40 CFR 60.18 and 63.11, good combustion practices (including establishment of flare minimization practices), and steam assisted.	0.007	lb/MMBtu	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	vessel evacuation flare - 018	3.04	MMBtu/hr	PM2.5	Good combustion practices (including establishment of flare minimization practices).	0.007	lb/MMBtu	BACT-PSD	
*LA-0306	TOPCHEM POLLOCK, LLC	TOPCHEM POLLOCK, LLC	12/20/2016	Process Flare FL-16-1 (EQT034)	2.17	MMBtu/hr	PM2.5	Compliance with the Louisiana non-NSPS flare requirements.	0.01	lb/hr	BACT-PSD	Correct flare design and proper combustion.
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	12/22/2016	flares (I-X-703, II-X-703)	3723	MMBtu/hr	PM2.5	Complying with 40 CFR 63.11.			BACT-PSD	
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	1/9/2017	Emergency Flare	0.4	MMBtu/hr	PM2.5	Proper design and operation.			BACT-PSD	
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	1/4/2018	Flares (4)	6.6	MMBtu/hr	PM2.5	Complying with 40 CFR 63.11(b).			BACT-PSD	
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	High Pressure Ground Flare (P003)	1.8	MMBtu/hr	PM2.5	Use of natural gas as pilot light fuel.	0.059	tpy	BACT-PSD	The high pressure (HP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the HP ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The HP flare controls VOC emissions from units P801, P802, P803, P804, and P805.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Low Pressure Ground Flare (P004)	0.78	MMBtu/hr	PM2.5	Use of natural gas as pilot light fuel.	0.026	tpy	BACT-PSD	The low pressure (LP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the ECU ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The LP flare controls VOC emissions from units P804 and P805.
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	4/25/2019	Flares (EQT0012, EQT0039, EQT0040)			PM2.5	Comply with requirements of 40 CFR 63.11(b).			BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	FLARE			PM2.5	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
KY-0113	WESTLAKE CHEMICAL OPCO, LP	WESTLAKE CHEMICAL OPCO, LP	9/21/2020	Ethylene Flare EU#007 (EPN321)	5979	MMBtu/hr	PM2.5	Employ natural gas as a pilot fuel, good flare design, and the use of appropriate instrumentation, control and best operational practices as BACT for reducing PM/PM10/PM2.5 emissions from the pilot flame of the flare.			BACT-PSD	The flare must be operated in compliance with 40 CFR 60.18 and 40 CFR 63.11 in order to meet BACT. The permittee shall conduct a visible emission test by EPA Test Method 22, with a 2 hour observation period within 5 years of the previous test approved by the Division. Final design could be elevated flare or ground flare.

Process Type: 19.310 - Chemical Plant Flares

Pollutant: $PM_{2.5}$

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	3/26/2021	Three (3) Flares	1.25	MMBtu/hr	PM2.5	Work practice requirements and limited use.	0.0075	lb/MMBtu	BACT-PSD	Limited to 168 hours per year for each flare.
LA-0388	LACC LLC US - ETHYLENE PLANT	LACC, LLC US	2/25/2022	Ethylene Plant Flares Emissions Cap			PM2.5	Minimize flaring.	4.33	tpy	BACT-PSD	
*TX-0956	ENTERPRISE MONT BELVIEU COMPLEX	ENTERPRISE PRODUCTS OPERATING LLC	6/8/2023	FLARE			PM2.5	Good design and combustion practices.			BACT-PSD	
*LA-0401	KOCH METHANOL (KME) FACILITY	KOCH METHANOL ST. JAMES, LLC	12/20/2023	FLR - Flare			PM2.5	Use of good operating practices and compliance with 40 CFR 60.18 and 40 CFR 63.11.			BACT-PSD	
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Front End Flare	2.22	MMBtu/hr	PM2.5	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.0075	lb/MMBtu	BACT-PSD	Also 0.10 tons/year and 0.10 tons/bi-month period during commissioning/shakedown period.
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Flare	2.22	MMBtu/hr	PM2.5	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.0075	lb/MMBtu	BACT-PSD	Also 0.07 tons/year and 0.07 tons/bi-month period during commissioning/shakedown period.
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Storage Flare	0.4	MMBtu/hr	PM2.5	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.01	tpy	BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: VOC

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0697	ETHYLENE PRODUCTION PLANT	THE DOW CHEMICAL COMPANY	3/27/2014	Low Pressure Flare	10,000	Btu/scf	VOC	Flare will meet NSPS 60.18 standards for continuous pilot flame, waste gas heat content and tip velocity.	98	%	BACT-PSD	
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Multi-Point Ground Flares (EQT 836 & 837)			VOC	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subparts FFFF and SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987; minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	461.81	lb/hr	BACT-PSD	
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	LLPDE/LDPE Multi-Point Ground Flare (EQT 640)			VOC	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.	305.08	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. BACT is also determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.
LA-0299	LAKE CHARLES CHEMICAL COMPLEX ETHOXYLATION UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	ETO/Guerbet Elevated Flare (EQT 1079)			VOC	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart PPP.	33.29	lb/hr	BACT-PSD	The permittee shall continuously monitor and record the volume of vent gas routed to the following flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips.
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 981)			VOC	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	45,046.76	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.

Process Type: 19.310 - Chemical Plant Flares
Pollutant: VOC
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Ground Flare (EQT 982)			VOC	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	24,759.74	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare and Ground Flare (EQTs 1012 & 1013)			VOC	Compliance with 40 CFR 63.11(b) and the closed vent system requirements of 40 CFR 63.148; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	278.13	lb/hr	BACT-PSD	Pound per hour VOC limitations are per flare. *Annual VOC emissions from both flares are limited to the TPY value reported.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 133)			VOC	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	420.67	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Emission Combustion Unit #3 Ground Flare (EQT 500)			VOC	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	566.97	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	VOC	Natural gas pilot and flare minimization practices.	0.0054	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	VOC	Natural gas pilot and flare minimization practices.	0.0054	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	VOC	Natural gas pilot and flare minimization practices.	0.0054	lb/MMBtu	BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: VOC

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	VOC	Natural gas pilot and flare minimization practices.	0.0054	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	VOC	Natural gas pilot and flare minimization practices.	0.0054	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	VOC	Natural gas pilot and flare minimization practices.	0.0054	lb/MMBtu	BACT-PSD	
TX-0681	OLEFINS PLANT	FORMOSA PLASTICS CORPORATION	8/8/2014	Flare			VOC	98% DRE for VOC.			BACT-PSD	
TX-0703	LOW DENSITY POLYETHYLENE (LDPE) PLANT	FORMOSA PLASTICS CORPORATION	8/8/2014	Flare			VOC	Flare combustion of VOC vent emissions. Flare will achieve 98% DRE.			BACT-PSD	
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	1/6/2015	Three (3) Flares	1.25	MMBtu/hr	VOC	Work practice requirements and limited use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events).	0.0054	lb/MMBtu	BACT-PSD	
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	1/23/2015	Drilling, HP, and LP Flares	50	MMscf/yr	VOC		0.14	lb/MMBtu	BACT-PSD	
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	4/1/2015	ammonia flare	106,396	MMBtu/yr	VOC		9.32	lb/hr	OTHER CASE-BY-CASE	All VOC is from fuel gas not waste gas. Emission rates provided are for worst-case MSS scenarios.
LA-0295	WESTLAKE FACILITY	EQUISTAR CHEMICALS, LP	7/12/2016	M-Line Production Area Flare (FL061) (Z2, EQT 19)			VOC	Good combustion practices.	8,882.92	lb/hr	BACT-PSD	Annual VOC emissions from the Cogeneration Plant Flare (449, EQT 326); the M-Line Production Area Flare (Z2, EQT 19); and the Plant 5 Flare (Z1, EQT 138) (not addressed in the PSD permit) are limited to 465.93 TPY (GRP 12).
LA-0295	WESTLAKE FACILITY	EQUISTAR CHEMICALS, LP	7/12/2016	Cogeneration Plant Flare (449, EQT 326)			VOC	Good combustion practices.	165.75	lb/hr	BACT-PSD	Annual VOC emissions from the Cogeneration Plant Flare (449, EQT 326); the M-Line Production Area Flare (Z2, EQT 19); and the Plant 5 Flare (Z1, EQT 138) (not addressed in the PSD permit) are limited to 465.93 TPY (GRP 12).
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Flare No. 1 - 008	85,097	MMBtu/yr	VOC	Complying with 40 CFR 60.18, good combustion practices (including establishment of flare minimization practices), and steam assisted.	98	%	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Pyrolysis Gasoline Tank Flare - 009	0.66	MMBtu/hr	VOC	Complying with 40 CFR 60.18 and 63.11, good combustion practices (including establishment of flare minimization practices), and steam assisted.	98	%	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	vessel evacuation flare - 018	3.04	MMBtu/hr	VOC	Good combustion practices (including establishment of flare minimization practices).	98	%	BACT-PSD	
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	1/4/2018	Flares (4)	6.6	MMBtu/hr	VOC	Complying with 40 CFR 63.11(b).			BACT-PSD	
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	High Pressure Ground Flare (P003)	1.8	MMBtu/hr	VOC	The high pressure (HP) flare controls VOC emissions from units P801, P802, P803, P804, and P805. The control efficiency is 98%.	4.494	tpy	BACT-PSD	The HP ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the HP ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The HP flare controls VOC emissions from units P801, P802, P803, P804, and P805.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Low Pressure Ground Flare (P004)	0.78	MMBtu/hr	VOC	The low pressure (LP) flare controls VOC emissions from units P804 and P805. The control efficiency is 98%.	1.97	tpy	BACT-PSD	The LP ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the ECU ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The LP flare controls VOC emissions from units P804 and P805.
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	4/25/2019	Flares (EQT0012, EQT0039, EQT0040)			VOC	Comply with requirements of 40 CFR 63.11(b).			BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: VOC

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0340	GEISMAR SITE-ETHYLENE OXIDE (EO)/ETHYLENE GLYCOL (EG) PLANT	BASF CORPORTATION	5/2/2019	EO/EG Flare	2,883.6	MMBtu/hr	VOC	Compliance with all applicable requirements of 40 CFR 63 Subpart A (40 CFR 63.11(b) and 40 CFR 63.18) and Consent Agreement and Final Order [Docket No. CAA-06-2018-3313] as required in Appendices A thru D for the EO/EG Flare.	668.7	lb/hr	BACT-PSD	
TX-0863	POLYETHYLENE 7 FACILITY	THE DOW CHEMICAL COMPANY	9/3/2019	FLARE			VOC	Good combustion practices.			BACT-PSD	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Multi Point Ground Flare			VOC	Good combustion practices.			LAER	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Elevated Flare			VOC	Good combustion practices, design, and natural gas fuel.			LAER	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	MULTIPOINT GROUND FLARE			VOC	Good combustion practices and proper design and operation.			LAER	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	MEROX ELEVATED FLARE			VOC	Good combustion practices and proper design and operation.			LAER	
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		9/9/2020	FLARE			VOC	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	FLARE			VOC	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
KY-0113	WESTLAKE CHEMICAL OPCO, LP	WESTLAKE CHEMICAL OPCO, LP	9/21/2020	Ethylene Flare EU#007 (EPN321)	5,979	MMBtu/hr	VOC	Employ natural gas as a pilot fuel, good flare design, and the use of appropriate instrumentation, control and best operational practices as BACT for reducing VOC emissions from the pilot flame of the flare.			BACT-PSD	The flare must be operated in compliance with 40 CFR 60.18 and 40 CFR 63.11 in order to meet BACT.
TX-0902	EQUISTAR LA PORTE COMPLEX	EQUISTAR CHEMICALS, LP.	9/25/2020	FLARE			VOC	Good combustion practices and proper design and operation.			LAER	
TX-0894	CHEVRON PHILLIPS CHEMICAL SWEENY COMPLEX	CHEVRON PHILLIPS CHEMICAL COMPANY LP	10/30/2020	Unit 81 Flare (EPN 81-97-9611)			VOC	Good combustion practices and proper design and operation.			LAER	
TX-0901	EQUISTAR CHEMICALS LA PORTE COMPLEX	EQUISTAR CHEMICALS, LP	11/6/2020	FLARE			VOC	Good combustion practices and proper design and operation. 99% DRE for all VOC up to three carbons and 98% DRE for all other VOCs.			LAER	
AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	3/26/2021	Three (3) Flares	1.25	MMBtu/hr	VOC	Work practice requirements and limited use.	0.66	lb/MMBtu	BACT-PSD	Limited to 168 hours per year for each flare.
TX-0929	FORMOSA POINT COMFORT PLANT	FORMOSA PLASTICS CORPORATION, TEXAS	10/15/2021	FLARE	122,926	scf/hr	VOC	Good combustion practices and proper design and operation, use of natural gas as fuel, meets the design and operating requirements of 40 CFR 60.18, high Btu stream-assisted flare equipped with flow monitor and GC analyzer, and continuous monitoring of pilot flame.			BACT-PSD	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	FLARE			VOC	Good combustion practices and use of gaseous fuel.			BACT-PSD	
LA-0388	LACC LLC US - ETHYLENE PLANT	LACC, LLC US	2/25/2022	Ethylene Plant Flares Emissions Cap			VOC	Compliance with 40 CFR 63.11(b).	120.49	tpy	BACT-PSD	
TX-0945	FORMOSA POINT COMFORT PLANT OL3	FORMOSA PLASTICS CORPORATION, TEXAS	4/6/2023	FLARES			VOC	Clean fuel and good combustion practices.			BACT-PSD	
*TX-0956	ENTERPRISE MONT BELVIEU COMPLEX	ENTERPRISE PRODUCTS OPERATING LLC	6/8/2023	FLARE			VOC	Good design and combustion practices.			LAER	
*TX-0962	POINT COMFORT PLANT	FORMOSA PLASTICS CORPORATION	9/22/2023	PE3 Plant Elevated Flare			VOC	Use of pipeline quality natural gas as supplemental fuel, no flaring of halogenated compounds, and good combustion practices are used.			BACT-PSD	
*TX-0962	POINT COMFORT PLANT	FORMOSA PLASTICS CORPORATION	9/22/2023	Enclosed Ground Flare			VOC	Use of pipeline quality natural gas as supplemental fuel, no flaring of halogenated compounds, and good combustion practices are used.			BACT-PSD	
*TX-0966	EQUSTAR LAPORTE COMPLEX	EQUISTAR CHEMICALS, LP	11/14/2023	FLARE			VOC	Use of pipeline quality natural gas as supplemental fuel, no flaring of halogenated compounds, and good combustion practices are used.			LAER	
*LA-0401	KOCH METHANOL (KME) FACILITY	KOCH METHANOL ST. JAMES, LLC	12/20/2023	FLR - Flare			VOC	Use of good operating practices and compliance with 40 CFR 60.18 and 40 CFR 63.11.			BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: VOC

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Front End Flare	2.22	MMBtu/hr	VOC	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.0054	lb/MMBtu	BACT-PSD	Also 1.48 tons/year (both Pilot and SSM) and 1.48 tons/bi-month period during commissioning/shakedown period.
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Flare	2.22	MMBtu/hr	VOC	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.0054	lb/MMBtu	BACT-PSD	Also 0.69 tons/year (Pilot and SSM) and 0.69 tons/bi-month period (Pilot and SSM) during commissioning/shakedown period.
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Storage Flare	0.4	MMBtu/hr	VOC	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.0054	lb/MMBtu	BACT-PSD	
*TX-0965	ORANGE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	12/29/2023	FLARE			VOC	Good combustion practices.			BACT-PSD	

Process Type: 19.330 - Refinery Flares
Pollutant: NOx
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
NM-0052	ZIA II GAS PLANT	DCP MIDSTREAM L.P.	4/25/2014	Units FL1 & FL2: Refinery Flares (Inlet Gas Flare & Acid Gas Flare)	2.3	MMBtu/hr	NOx	NOx, CO, PM10, PM2.5, and SO2 controlled through good combustion practices (GCP), pipeline quality natural gas for pilot, and limits on flaring events. VOC and CO2e controlled through GCP, limits on flaring, and meeting 40 CFR 60.18.	695.2	lb/hr	BACT-PSD	The 2 emissions limits represent limits for Units FL1 and FL2.
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	BUCKEYE TEXAS PROCESSING, LLC	8/29/2019	Flare			NOx	Good combustion practices.			BACT-PSD	
TX-0873	PORT ARTHUR REFINERY	MOTIVA ENTERPRISES LLC	2/4/2020	Flare			NOx	Steam-assisted flare equipped with CPMS and flow meter, hourly net heating value calculated, continuous pilot flame, and limited hourly and yearly tank degassing.			BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Main Flare			NOx	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.	0.068	lb/MMBtu	BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Butane (Rail Car) Flare			NOx	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.	0.068	lb/MMBtu	BACT-PSD	

Process Type: 19.330 - Refinery Flares

Pollutant: $PM_{2.5}$

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes

None

Process Type: 19.330 - Refinery Flares

Pollutant: VOC

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
NM-0052	ZIA II GAS PLANT	DCP MIDSTREAM L.P.	4/25/2014	Units FL1 & FL2: Refinery Flares (Inlet Gas Flare & Acid Gas Flare)	2.3	MMBtu/hr	VOC	NOx, CO, PM10, PM2.5, and SO2 controlled through good combustion practices (GCP), pipeline quality natural gas for pilot, and limits on flaring events. VOC and CO2e controlled through GCP, limits on flaring, and meeting 40 CFR 60.18.	2,558.4	lb/hr	BACT-PSD	
TX-0812	CRUDE OIL PROCESSING FACILITY	GRAVITY MIDSTREAM CORPUS CHRISTI LLC	10/31/2016	Refinery Flares			VOC	The flare must conform to 40 CFR 60.18 requirements. Vent stream composition and flow must be continuously monitored to demonstrate compliance.			BACT-PSD	NSPS Ja, 30 TAC 115, SUBCHAPTER D
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	BUCKEYE TEXAS PROCESSING, LLC	8/29/2019	Flare			VOC	Good combustion practices.			BACT-PSD	
TX-0872	CONDENSATE SPLITTER FACILITY	MAGELLAN PROCESSING, L.P.	10/31/2019	Flare (Routine and MSS)	12,000		VOC	Control for desalter wastewater, piping/vessel degassing, and pressurized tank vapors. Authorized for fuel gas combustion when the heaters are out-of-service. The flare is designed to meet 40 CFR 60.18 with a VOC DRE of 98% for compounds with four carbons and more, and 99% for compounds with three or less. The flare has a continuous flow monitor and composition analyzer installed.	19.13	lb/hr	BACT-PSD	NSPS Ja
TX-0873	PORT ARTHUR REFINERY	MOTIVA ENTERPRISES LLC	2/4/2020	Flare			VOC	Steam-assisted flare equipped with CPMS and flow meter, hourly net heating value calculated, continuous pilot flame, and limited hourly and yearly tank degassing.			BACT-PSD	
TX-0903	SWEENY REFINERY	PHILLIPS 66 COMPANY	9/9/2020	Flare			VOC	Meet the design and operating requirements of 40 CFR 60.18. Steam-assisted flare equipped with flow monitor and GC analyzer. Continuous monitoring of pilot flame.			LAER	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Main Flare			VOC	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.	0.0005	lb/MMBtu	BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Butane (Rail Car) Flare			VOC	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.	0.0005	lb/MMBtu	BACT-PSD	

Process Type: 63.999 - Other Polymer and Resin Manufacturing Sources (Gas Phase and Liquid Phase Slurry Polyethylene Manufacturing Processes)
Pollutant: VOC
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0858	GULF COAST GROWTH VENTURES PROJECT	GCGV ASSET HOLDING LLC	6/12/2019	Pellet Handling - Railyard			VOC	Granular PE must be degassed to such an extent that total VOC emissions from the extruded pellets does not exceed 50 lb per million pounds of PE produced.	50	lb/MMlb	BACT-PSD	Total VOC emitted to the atmosphere after the purge column through product loadout from each polyethylene unit shall not exceed 50 pounds per million pounds of polyethylene pellets produced.
TX-0928	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	10/15/2021	Pellet Handling and Loadout			VOC	Good operational practices. The extruder feed hopper vents shall be controlled with a thermal oxidizer.	35.08	ppm	LAER	LAER was previously established in Project No. 301495 as a cap limit for total VOC emitted from Unit 40 and Unit 41 for the pellet dewatering dryer, pellet surge hopper, and loadout vents shall not exceed 35.08 ppmw. Total VOC emitted from Unit 40 and Unit 41 to the atmosphere after the extruder through product loadout shall not exceed 35.08 pounds of VOC/million (MM) pounds of polyethylene pellets on a 12-month rolling basis. For Unit 40 this includes emissions from the Pellet Dewatering Dryer, Pellet Surge Hopper, Off-Spec Silos, Storage Silos, and Loadout (EPNs: 40-25-6300, 40-25-6301, 40-35-6310, 40-35-8021, 40-35-80LO, and 40-35-8011A/B/C). For Unit 41 this includes emissions from the Pellet Dewatering Dryer, Pellet Surge Hopper, Off-Spec Silos, Storage Silos, and Loadout (EPNs: 41-25-6301, 41-25-6310, 41-35-8021, 41-35-80LO, and 41-35-8011A/B/C).

Process Type: 64.006 - SOCMI Wastewater Collection and Treatment

Pollutant: VOC

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Benzene Stripper (EQT 1135)			VOC	Route emissions to the fuel gas system.			BACT-PSD	
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Wastewater Drums and Sumps			VOC	Flare			BACT-PSD	BACT is determined to be routing the above drums and sumps through a closed vent system to the Ground Flare (EQT 0982).
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Sour Water Stripper (EQT 1128)			VOC	Route emissions to the fuel gas system.			BACT-PSD	
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Process Wastewater Treatment Plant (FUG 18)	12,647	gpm	VOC	Compliance with 40 CFR 63 Subpart G and 40 CFR 61 Subpart FF.	40.01	tpy	BACT-PSD	The wastewater treatment plant will receive Group 2 wastewater streams from multiple process units.
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Process Water Tanks (EQTs 987, 988, & 989)	730,531	gal/yr	VOC	Internal Floating Roof	17.82	tpy	BACT-PSD	VOC limit is per tank.
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Wastewater VOC Stripper (Vent) (EQT 1072)			VOC	Combustion (Process Heat Boiler)			BACT-PSD	BACT is determined to be routing the above vent through a closed vent system to Process Heat Boiler B-910A (EQT 1008) or to Process Heat Boiler B-910B (EQT 1009).
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Wastewater Collection and Treatment (P806)			VOC	i. Use an enhanced biodegradation unit to maintain the annual benzene quantity from facility waste at less than 10 megagrams (MG; 11 tons) by combining waste streams with greater than 10 ppmw benzene with waste streams with less than 10 ppmw benzene to form a combined waste stream with a benzene concentration less than 10 ppmw; ii. Route emissions from wastewater generated in the ethylene manufacturing process to a thermal oxidizer designed to achieve >99.5% destruction efficiency for volatile organic compounds (VOC); iii. Cover and route emissions from the process wastewater equalization tank (T-6503), the waste oil drum (T-6502), the oily wastewater storage tank (T-6501) and the wet air oxidation unit to a thermal oxidizer designed to achieve >99.5% destruction efficiency for VOC; iv. Emissions from wastewater generated in the high-density polyethylene units must comply with the applicable requirements of 40 CFR Part 63, Subpart FFFF.	0.01	lb/hr	BACT-PSD	
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	4/25/2019	Wastewater Treatment Plant (EQT0045)			VOC	Comply with 40 CFR 63 Subpart G.			BACT-PSD	
TX-0858	GULF COAST GROWTH VENTURES PROJECT	GCGV ASSET HOLDING LLC	6/12/2019				VOC	Glycol Plant and the Olefins plant must be covered and the vapor space must be directed to the shared vent system for control. Stormwater drains and wastewater conveyances associated with the polyethylene plants do not require control because they do not have the potential to accept contaminated process water. All vapors from the equalization tanks and the dissolved air flotation basin must also be captured and controlled. The required controls are a catalytic oxidizer and the shared vent system, respectively. The catalytic oxidizer must achieve a minimum destruction efficiency of 99%, to be demonstrated through stack sampling. The level of mixed liquor suspended solids (MLSS) in the biological oxidation treatment unit must be maintained above 2000 mg/L.			BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Wastewater Collection and Treatment			VOC	Process wastewater will be collected via covered sumps and hard-piped to the wastewater tank (EPN: TK8511) and then piped to the existing enhanced wastewater treatment facility (under NSR Permit No. 49120) at the site that will treat the VOCs contained in the wastewater to remove greater than 90%. The wastewater tank emissions are routed to the multi-point ground flare for control at an efficiency of 98%.			LAER	

Process Type: 64.006 - SOCMI Wastewater Collection and Treatment

Pollutant: VOC

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0364	FG LA COMPLEX	FG LA LLC	1/6/2020	Wastewater Treatment System			VOC	Good design and venting the emissions to a control device in the primary treatment system before the wastewater enters the biological treatment unit.			BACT-PSD	
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	2/6/2020	Wastewater treatment plant			VOC	Covered conveyances, benzene stripper, activated sludge biological treatment, thermal oxidizer	3,100	mg/L	BACT-PSD	

Attachment 3

Request No. 3.b Information

Shell Chemical Appalachia LLC
300 Frankfort Rd
Monaca, PA 15061

March 26, 2025

Pennsylvania Department of Environmental Protection
Attn: Mr. Sean Wenrich, Environmental Engineer Manager
400 Market Street 12th Floor
Harrisburg, PA 17101

Re: Transfer of NOx Emission Reduction Credits from Northern Star Generation LLC to Shell Chemical Appalachia LLC

Dear Mr. Wenrich:

Northern Star Generation LLC, By its agent, Cambria Cogen Company ("Seller") has agreed to transfer ownership and use of 184 tons per year of Nitrogen Oxide Emission Reduction Credits ("NOx ERCs") to Emissions Experts Inc's client, Shell Chemical Appalachia LLC ("Buyer"). Please perform any required RACT analysis to ensure the 184 NOx ERCs are surplus and available for use prior to transfer.

Cambria Cogeneration Power Facility located in Cambria County, Pennsylvania created 688.4 tons of NOx ERCs with an expiration date of June 19th, 2029. Buyer is requesting transfer for use at Buyer's facility located in Potter Township, Beaver County, Pennsylvania.

Buyer's representative for this matter and relevant contact information is:

Kimberly Kaal, 724-709-2467, Kimberly.Kaal@shell.com

Please send notification once NOx ERCs transfer is complete to my contact information listed above. In addition, if you have any questions or require further information, please contact me at the phone number and/or email address as referenced above.

Thank you for your prompt attention to this matter.

If you have any questions regarding this response, please contact me at (724) 709-2467 or kimberly.kaal@shell.com.

Sincerely,

Kimberly Kaal

Kimberly Kaal
SPM Environmental Manager

Shell Chemical Appalachia LLC
300 Frankfort Rd
Monaca, PA 15061

April 3, 2025

Pennsylvania Department of Environmental Protection
Attn: Mr. Sean Wenrich, Environmental Engineer Manager
400 Market Street 12th Floor
Harrisburg, PA 17101

Re: Transfer of PM2.5 Emission Reduction Credits from INDSPEC Chemical Corporation to Shell Chemical Appalachia LLC

Dear Mr. Wenrich:

INDSPEC Chemical Corporation ("Seller") has agreed to transfer ownership and use of 31.03 tons per year of Particulate Matter 2.5 (PM2.5) Emission Reduction Credits ("PM2.5 ERCs") to Shell Chemical Appalachia LLC ("Buyer"). Please perform any required RACT analysis to confirm the ERCs are surplus and available for use prior to transfer.

The INDSPEC Petrolia Plant located in Butler County, Pennsylvania generated 31.03 tons of PM2.5 ERCs which expire on September 11, 2027. Buyer is requesting transfer for use at Buyer's facility located in Potter Township, Beaver County, Pennsylvania. Note that the ERCs were generated in the same PM2.5 non-attainment area as Buyer's facility.

Buyer's representative for this matter and relevant contact information is:

Kimberly Kaal, 724-709-2467, Kimberly.Kaal@shell.com

Shell kindly requests notification once the PM2.5 ERC transfer is complete to the contact information listed above. Thank you for your prompt attention to this matter.

Sincerely,

Kimberly Kaal

Kimberly Kaal
SPM Environmental Manager

Attachment 4

Request No. 3.c Information

1.0 ALTERNATIVES ANALYSIS

The Pennsylvania Department of Environmental Protection's (DEP's) Nonattainment New Source Review (NNSR) regulations at 25 Pa. Code §127.205(5) require a major new or modified facility to provide an "analysis…of alternative sites, sizes, production processes and environmental control techniques, 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." Generally, an alternatives analysis completed pursuant to 25 Pa. Code §127.205(5) documents the efforts an applicant will take to avoid or minimize environmental impacts that may result from a major new or modified facility subject to NNSR permitting under Chapter 127, Subchapter E.

1.1 Plan Approval Reconciliations

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 NSR applicability purposes. As discussed in the September 13, 2024 plan approval application, Shell determined that the Plan Approval Reconciliations will not retrospectively cause the initial construction of SPM to require NNSR permitting for any additional regulated NNSR pollutants relative to the NNSR applicability determinations that were made contemporaneous with DEP's authorization of the initial construction of SPM. 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.

1.1.1 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.

1.1.2 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.

1.1.3 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.

1.1.4 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.

Attachment 5

Request No. 3.c Information

1.0 ALTERNATIVES ANALYSIS

The Pennsylvania Department of Environmental Protection's (DEP's) Nonattainment New Source Review (NNSR) regulations at 25 Pa. Code §127.205(5) require a major new or modified facility to provide an "analysis…of alternative sites, sizes, production processes and environmental control techniques, 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." Generally, an alternatives analysis completed pursuant to 25 Pa. Code §127.205(5) documents the efforts an applicant will take to avoid or minimize environmental impacts that may result from a major new or modified facility subject to NNSR permitting under Chapter 127, Subchapter E.

1.1 WWTP Permanent Controls Project

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 determined that the WWTP Permanent Controls Project is subject to NNSR permitting because it has been retrospectively evaluated as part of the initial construction of SPM for NSR applicability purposes. As discussed in the September 13, 2024 plan approval application, Shell determined that the WWTP Permanent Controls Project will not retrospectively cause the initial construction of SPM to require NNSR permitting for any additional regulated NNSR pollutants relative to the NNSR applicability determinations that were made contemporaneous with DEP's authorization of the initial construction of SPM. However, 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.

1.1.1 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 Wastewater Treatment Plant, which will result in an improvement in the overall wastewater treatment performance of the Wastewater Treatment Plant. As a result, it is not an option to perform the project at a site other than SPM while also ensuring environmentally beneficial improvements in SPM's Wastewater Treatment Plant.

1.1.2 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 nonapplicable.

1.1.3 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.

1.1.4 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 previously documented for the WWTP Permanent Controls Project in the September 13, 2024 plan approval application, 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.

Attachment 6

Request No. 4 Information

1.0 BEST AVAILABLE TECHNOLOGY (BAT)

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 the best available technology (BAT). *BAT* is defined at 25 Pa Code §121.1 as "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." For a plan approval applicant subject to Prevention of Significant Deterioration (PSD) or Nonattainment New Source Review NNSR permitting requirements, 25 Pa. Code 127.205(7) provides that the Pennsylvania Department of Environmental Protection (DEP) may determine BAT requirements are equivalent to best available control technology (BACT) or lowest achievable emission rate (LAER) requirements.

1.1 BAT Applicability

A BAT determination must be made for the emissions from each new emission source that is proposed in a plan approval application.

1.1.1 Plan Approval Reconciliations

In accordance with the BAT applicability criteria summarized above for the construction of new emission sources at a new stationary source such as SPM, Shell contemporaneously completed a BAT analysis for each proposed SPM emission source. Shell has retrospectively evaluated the Plan Approval Reconciliations as part of the initial SPM construction. Therefore, Shell has evaluated the Plan Approval Reconciliations to determine if they potentially require revised BAT analyses for any emission sources that were constructed as part of the initial construction of SPM. Table 1 beginning on the following page documents Shell's evaluation of emission sources potentially requiring a revised BAT analysis due to the Plan Approval Reconciliations.

Table 1. Evaluation of Emission Sources Potentially Requiring a Revised BAT Analysis due to the Plan Approval Reconciliations

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
031	Ethane Cracking Furnace #1	Yes, although the furnace's SO_2 potential to emit is proposed to increase by only 0.16 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the SO_2 BAT determination for the furnace.	No, although the furnace's lead potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace, the proposed potential to emit increase is only 0.17 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the furnace.	No, although the furnace's sulfuric acid mist potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace and a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, the proposed potential to emit increase is only 20 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the furnace.	Yes, although the furnace's ammonia potential to emit is proposed to increase by only 0.1 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the ammonia BAT determination for the furnace.	No, the furnace's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the furnace is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
032	Ethane Cracking Furnace #2	Yes, although the furnace's SO_2 potential to emit is proposed to increase by only 0.16 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the SO_2 BAT determination for the furnace.	No, although the furnace's lead potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace, the proposed potential to emit increase is only 0.17 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the furnace.	No, although the furnace's sulfuric acid mist potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace and a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, the proposed potential to emit increase is only 20 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the furnace.	Yes, although the furnace's ammonia potential to emit is proposed to increase by only 0.1 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the ammonia BAT determination for the furnace.	No, the furnace's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the furnace is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
033	Ethane Cracking Furnace #3	Yes, although the furnace's SO_2 potential to emit is proposed to increase by only 0.16 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the SO_2 BAT determination for the furnace.	No, although the furnace's lead potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace, the proposed potential to emit increase is only 0.17 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the furnace.	No, although the furnace's sulfuric acid mist potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace and a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, the proposed potential to emit increase is only 20 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the furnace.	Yes, although the furnace's ammonia potential to emit is proposed to increase by only 0.1 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the ammonia BAT determination for the furnace.	No, the furnace's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the furnace is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
034	Ethane Cracking Furnace #4	Yes, although the furnace's SO_2 potential to emit is proposed to increase by only 0.16 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the SO_2 BAT determination for the furnace.	No, although the furnace's lead potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace, the proposed potential to emit increase is only 0.17 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the furnace.	No, although the furnace's sulfuric acid mist potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace and a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, the proposed potential to emit increase is only 20 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the furnace.	Yes, although the furnace's ammonia potential to emit is proposed to increase by only 0.1 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the ammonia BAT determination for the furnace.	No, the furnace's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the furnace is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
035	Ethane Cracking Furnace #5	Yes, although the furnace's SO_2 potential to emit is proposed to increase by only 0.16 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the SO_2 BAT determination for the furnace.	No, although the furnace's lead potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace, the proposed potential to emit increase is only 0.17 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the furnace.	No, although the furnace's sulfuric acid mist potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace and a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, the proposed potential to emit increase is only 20 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the furnace.	Yes, although the furnace's ammonia potential to emit is proposed to increase by only 0.1 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the ammonia BAT determination for the furnace.	No, the furnace's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the furnace is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
036	Ethane Cracking Furnace #6	Yes, although the furnace's SO_2 potential to emit is proposed to increase by only 0.16 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the SO_2 BAT determination for the furnace.	No, although the furnace's lead potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace, the proposed potential to emit increase is only 0.17 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the furnace.	No, although the furnace's sulfuric acid mist potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace and a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, the proposed potential to emit increase is only 20 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the furnace.	Yes, although the furnace's ammonia potential to emit is proposed to increase by only 0.1 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the ammonia BAT determination for the furnace.	No, the furnace's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the furnace is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
037	Ethane Cracking Furnace #7	Yes, although the furnace's SO_2 potential to emit is proposed to increase by only 0.16 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the SO_2 BAT determination for the furnace.	No, although the furnace's lead potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace, the proposed potential to emit increase is only 0.17 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the furnace.	No, although the furnace's sulfuric acid mist potential to emit is proposed to increase because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture combusted in the furnace and a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, the proposed potential to emit increase is only 20 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the furnace.	Yes, although the furnace's ammonia potential to emit is proposed to increase by only 0.1 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace, Shell has conservatively reevaluated the ammonia BAT determination for the furnace.	No, the furnace's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the furnace is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
101	Combustion Turbine/Duct Burner Unit #1	No, the combustion turbine/duct burner unit's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's lead potential to emit is not proposed to increase; therefore, the prior lead BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, although the combustion turbine/duct burner unit's sulfuric acid mist potential to emit is proposed to increase, this increase is because of a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, not because of a change in the method of operation of the engine or physical change to the combustion turbine/duct burner unit. Additionally, the proposed potential to emit increase is only 100 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the combustion turbine/duct burner unit.	No, the combustion turbine/duct burner unit's ammonia potential to emit is not proposed to increase; therefore, the prior ammonia BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	Yes, 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 (DE) 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 DE is proposed to be reduced from 90% to 30% for organic HAP emission rates calculated using AP-42, Section 3.1, Table 3.1-3 emission factors because the 90% CO DE guaranteed for the oxidation catalyst was mistakenly used for the oxidation catalyst's organic HAP DE instead of the 30% VOC DE guaranteed for the oxidation catalyst.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
102	Combustion Turbine/Duct Burner Unit #2	No, the combustion turbine/duct burner unit's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's lead potential to emit is not proposed to increase; therefore, the prior lead BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, although the combustion turbine/duct burner unit's sulfuric acid mist potential to emit is proposed to increase, this increase is because of a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, not because of a change in the method of operation of the engine or physical change to the combustion turbine/duct burner unit. Additionally, the proposed potential to emit increase is only 100 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the combustion turbine/duct burner unit.	No, the combustion turbine/duct burner unit's ammonia potential to emit is not proposed to increase; therefore, the prior ammonia BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	Yes, 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 DE 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 DE is proposed to be reduced from 90% to 30% for organic HAP emission rates calculated using AP-42, Section 3.1, Table 3.1-3 emission factors because the 90% CO DE guaranteed for the oxidation catalyst was mistakenly used for the oxidation catalyst's organic HAP DE instead of the 30% VOC DE guaranteed for the oxidation catalyst.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
103	Combustion Turbine/Duct Burner Unit #3	No, the combustion turbine/duct burner unit's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's lead potential to emit is not proposed to increase; therefore, the prior lead BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, although the combustion turbine/duct burner unit's sulfuric acid mist potential to emit is proposed to increase, this increase is because of a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, not because of a change in the method of operation of the engine or physical change to the combustion turbine/duct burner unit. Additionally, the proposed potential to emit increase is only 100 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the combustion turbine/duct burner unit.	No, the combustion turbine/duct burner unit's ammonia potential to emit is not proposed to increase; therefore, the prior ammonia BAT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	Yes, 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 DE 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 DE is proposed to be reduced from 90% to 30% for organic HAP emission rates calculated using AP-42, Section 3.1, Table 3.1-3 emission factors because the 90% CO DE guaranteed for the oxidation catalyst was mistakenly used for the oxidation catalyst's organic HAP DE instead of the 30% VOC DE guaranteed for the oxidation catalyst.
104	Cogeneration Plant Cooling Tower	Not Applicable (N/A)	N/A	N/A	N/A	N/A

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
105	Diesel-Fired Emergency Generator Engines (2); Generator 1 - Parking Garage	No, the engine's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the engine is not potentially subject to reevaluation.	N/A	No, although the engine's sulfuric acid mist potential to emit is proposed to increase, this increase is because of a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, not because of a change in the method of operation of the engine or physical change to the engine. Additionally, the engine's proposed sulfuric acid mist potential to emit increase is only 0.001 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the engine.	N/A	No, the engine's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the engine is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
105	Diesel-Fired Emergency Generator Engines (2); Generator 2 - Telecom Hut	No, the engine's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the engine is not potentially subject to reevaluation.	N/A	No, although the engine's sulfuric acid mist potential to emit is proposed to increase, this increase is because of a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, not because of a change in the method of operation of the engine or physical change to the engine. Additionally, the engine's proposed sulfuric acid mist potential to emit increase is only 0.0007 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the engine.	N/A	No, the engine's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the engine is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
106	Fire Pump Engines (2); Firewater Pump 1	No, the engine's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the engine is not potentially subject to reevaluation.	N/A	No, the engine's sulfuric acid mist potential to emit is proposed to decrease; therefore, the prior sulfuric acid mist BAT determination for the engine is not potentially subject to reevaluation.	N/A	No, although the engine's HAP potential to emit is proposed to increase, this increase is because of a correction of the engine's HAP emission factors so that they are sourced from AP-42, Section 3.3, which applies to small diesel engines (engines ≤ 600 hp), rather than AP-42, Section 3.4, which applies to large diesel engines (engines > 600 hp), not because of a change in the method of operation of the engine or physical change to the engine. Additionally, the engine's proposed HAP potential to emit increase is only 0.80 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the HAP BAT determination for the engine.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
106	Fire Pump Engines (2); Firewater Pump 2	No, the engine's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the engine is not potentially subject to reevaluation.	N/A	No, the engine's sulfuric acid mist potential to emit is proposed to decrease; therefore, the prior sulfuric acid mist BAT determination for the engine is not potentially subject to reevaluation.	N/A	No, although the engine's HAP potential to emit is proposed to increase, this increase is because of a correction of the engine's HAP emission factors so that they are sourced from AP-42, Section 3.3, which applies to small diesel engines (engines ≤ 600 hp), rather than AP-42, Section 3.4, which applies to large diesel engines (engines > 600 hp), not because of a change in the method of operation of the engine or physical change to the engine. Additionally, the engine's proposed HAP potential to emit increase is only 0.80 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the HAP BAT determination for the engine.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
107	Natural Gas-Fired Emergency Generator Engines (2); Generator 3 - Lift Station	No, the engine's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the engine is not potentially subject to reevaluation.	N/A	No, although the engine's sulfuric acid mist potential to emit is proposed to increase, this increase is because of a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, not because of a change in the method of operation of the engine or physical change to the engine. Additionally, the engine's proposed sulfuric acid mist potential to emit increase is only 0.0008 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the engine.	N/A	No, the engine's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the engine is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
107	Natural Gas-Fired Emergency Generator Engines (2); Generator 4 - Lift Station	No, the engine's SO_2 potential to emit is not proposed to increase; therefore, the prior SO_2 BAT determination for the engine is not potentially subject to reevaluation.	N/A	No, although the engine's sulfuric acid mist potential to emit is proposed to increase, this increase is because of a proposed calculation correction to use the molecular weight of sulfuric acid rather than sulfur trioxide to calculate the sulfuric acid mist potential to emit rate, not because of a change in the method of operation of the engine or physical change to the engine. Additionally, the engine's proposed sulfuric acid mist potential to emit increase is only 0.0002 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the engine.	N/A	No, the engine's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the engine is not potentially subject to reevaluation.
202	Polyethylene Manufacturing Lines	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
203	Process Cooling Tower	N/A	N/A	N/A	N/A	No, the cooling tower's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the cooling tower is not potentially subject to reevaluation.
C204A	CVTO	Yes, the thermal oxidizer's SO_2 potential to emit is proposed to equal 1.17 tpy, and an SO_2 BAT determination was not previously completed for the thermal oxidizer because it was not proposed to have the potential to emit SO_2.	No, although the thermal oxidizer's lead potential to emit is proposed to increase because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer, the proposed potential to emit increase is only 0.32 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the thermal oxidizer.	Yes, the thermal oxidizer's sulfuric acid mist potential to emit is proposed to equal 0.06 tpy, and a sulfuric acid mist BAT determination was not previously completed for the thermal oxidizer because it was not proposed to have the potential to emit sulfuric acid mist.	N/A	No, the thermal oxidizer's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the thermal oxidizer is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
C204B	MPGF	Yes, the flare's SO_2 potential to emit is proposed to increase by 0.54 tpy because of a proposed increase in the amount of combustion that may occur at the flare.	No, although the flare's lead potential to emit is proposed to increase because of a proposed increase in the amount of combustion that may occur at the flare, the proposed potential to emit increase is only 0.35 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the flare.	No, although the flare's sulfuric acid mist potential to emit is proposed to increase because of a proposed increase in the amount of combustion that may occur at the flare, the proposed potential to emit increase is only approximately 53 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the sulfuric acid mist BAT determination for the flare.	N/A	No, although the flare's HAP potential to emit is proposed to increase because of a proposed increase in the amount of combustion that may occur at the flare, the proposed potential to emit increase is only approximately 27 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the HAP BAT determination for the flare.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
C205A	TEGF A	Yes, the flare's SO_2 potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 1.87 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	No, although the flare's lead potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase because of a proposed increase in the amount of combustion that may occur at the flares, the proposed potential to emit increase is only 1.43 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the flare.	Yes, although the flare's sulfuric acid mist potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by only 0.1 tpy because of a proposed increase in the amount of combustion that may occur at the flares, Shell has conservatively reevaluated the sulfuric acid mist BAT determination for the flare.	N/A	Yes, the flare's HAP potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 6.96 tpy because of a proposed increase in the amount of combustion that may occur at the flares.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
C205B	TEGF B	Yes, the flare's SO_2 potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 1.87 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	No, although the flare's lead potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase because of a proposed increase in the amount of combustion that may occur at the flares, the proposed potential to emit increase is only 1.43 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the flare.	Yes, although the flare's sulfuric acid mist potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by only 0.1 tpy because of a proposed increase in the amount of combustion that may occur at the flares, Shell has conservatively reevaluated the sulfuric acid mist BAT determination for the flare.	N/A	Yes, the flare's HAP potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 6.96 tpy because of a proposed increase in the amount of combustion that may occur at the flares.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
C205C	HP Elevated Flare	Yes, the flare's SO_2 potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 1.87 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	No, although the flare's lead potential to emit in combination with the TEGF A and TEGF B is proposed to increase because of a proposed increase in the amount of combustion that may occur at the flares, the proposed potential to emit increase is only 1.43 lb/yr, which would not affect the technical and economic feasibility analyses that were previously completed in support of the lead BAT determination for the flare.	Yes, although the flare's sulfuric acid mist potential to emit in combination with the TEGF A and TEGF B is proposed to increase by only 0.1 tpy because of a proposed increase in the amount of combustion that may occur at the flares, Shell has conservatively reevaluated the sulfuric acid mist BAT determination for the flare.	N/A	Yes, the flare's HAP potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 6.96 tpy because of a proposed increase in the amount of combustion that may occur at the flares.
C206	SCTO	Yes, although the thermal oxidizer's SO_2 potential to emit is proposed to increase by only 0.06 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer, Shell has conservatively reevaluated the SO_2 BAT determination for the thermal oxidizer.	N/A	Yes, although the thermal oxidizer's sulfuric acid mist potential to emit is proposed to increase by only 0.04 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer, Shell has conservatively reevaluated the sulfuric acid mist BAT determination for the thermal oxidizer.	N/A	No, the thermal oxidizer's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the thermal oxidizer is not potentially subject to reevaluation.
301	Polyethylene Pellet Material Storage/Handling/Loadout	N/A	N/A	N/A	N/A	N/A

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
302	Liquid Loadout (Recovered Oil)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
303	Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, PE3 Heavies)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
304	Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
305	Liquid Loadout (Blended Pitch)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
401	Storage Tanks (Recovered Oil, Equalization Wastewater)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
402	Storage Tank (Spent Caustic)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
403	Storage Tanks (Light Gasoline)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
404	Storage Tanks (Hexene)	N/A	N/A	N/A	N/A	N/A
405	Storage Tanks (Misc Pressurized/Refrigerated)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
406	Storage Tanks (Diesel Fuel > 150 Gallons)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is proposed to decrease; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
407	Storage Tanks (Pyrolysis Fuel Oil)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
408	Storage Tanks (Diesel Fuel < 150 Gallons)	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.
409	Methanol Storage Vessels and Associated Components	N/A	N/A	N/A	N/A	No, the source's HAP potential to emit is not proposed to increase; therefore, the prior HAP BAT determination for the source is not potentially subject to reevaluation.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
501	Equipment Components	N/A	N/A	N/A	N/A	No, although the source's HAP potential to emit is proposed to increase by 0.84 tpy, this minor increase is because of proposed updates to SPM's component inventory and the composition of the materials contained in those components to more accurately represent the number of equipment leak components constructed at SPM and the material compositions at SPM, which is a common type of as-built reconciliation for an entirely new facility that does not warrant a revised control technology analysis when it results in a minor emissions increase. Additionally, the minor increase in the source's HAP potential to emit would not affect the technical and economic feasibility analyses that were previously completed in support of the HAP BAT determination for the source.

Source ID	Source Description	Revised BAT Analysis Needed for SO_2?	Revised BAT Analysis Needed for Lead?	Revised BAT Analysis Needed for Sulfuric Acid Mist?	Revised BAT Analysis Needed for Ammonia?	Revised BAT Analysis Needed for HAPs?
502	Wastewater Treatment Plant	N/A	N/A	N/A	N/A	Yes, although the source's HAP potential to emit is proposed to increase by only 0.24 tpy, Shell has conservatively reevaluated the HAP BAT determination for the source.
503	Plant Roadways	N/A	N/A	N/A	N/A	N/A
504	Gas Insulated Switchgear (SF6)	N/A	N/A	N/A	N/A	N/A

1.2 BAT Analysis Process

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.

1.3 Summary of BAT Determinations

Table 2 below summarizes the BAT determinations made for the Plan Approval Reconciliations.

Table 2. Summary of BAT Determinations

Emission Source	Pollutant	Control Technology/ Work Practice	Emissions Level
Ethane Cracking Furnaces #1 through #7	SO_2	Low-sulfur fuels: Tail gas and natural gas	-
	Ammonia	Limit ammonia slip	≤ 10 parts per million by volume on a dry basis (ppmvd) at 3% oxygen
Combustion Turbine/Duct Burner Units #1 through #3	HAPs	• Good combustion practices • Catalytic oxidation	≤ 91 parts per billion by volume on a dry basis (ppbvd) formaldehyde at 15% oxygen
CVTO	SO_2	• Low-sulfur vent gases • Low-sulfur fuel: Natural gas	-
	Sulfuric Acid Mist	• Low-sulfur vent gases • Low-sulfur fuel: Natural gas	-
MPGF	SO_2	• Flare minimization: flare operated in accordance with a flare minimization plan • Low-sulfur vent gases • Low-sulfur fuel: Natural gas	-
TEGF A, TEGF B, and HP Elevated Flare	SO_2	• Flare minimization: flare operated in accordance with a flare minimization plan • Low-sulfur vent gases • Low-sulfur fuels: Tail gas and natural gas	-
	Sulfuric Acid Mist	• Flare minimization: flare operated in accordance with a flare minimization plan • Low-sulfur vent gases • Low-sulfur fuels: Tail gas and natural gas	-

Emission Source	Pollutant	Control Technology/ Work Practice	Emissions Level
TEGF A, TEGF B, and HP Elevated Flare (cont'd)	HAPs	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 Code of Federal Regulations (CFR) 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	• ≥ 99% destruction and removal efficiency (DRE) for VOC containing three or fewer carbon atoms (C3- VOC) • ≥ 98% DRE for VOC containing four or more carbon atoms (C4+ VOC)
SCTO	SO_2	• Low-sulfur vent gases • Low-sulfur fuel: Natural gas	-
	Sulfuric Acid Mist	• Low-sulfur vent gases • Low-sulfur fuel: Natural gas	-
Wastewater Treatment Plant	HAPs	• Internal floating roofs and thermal oxidation (SCTO) for primary wastewater treatment vessels • Biological treatment for secondary wastewater treatment	≥ 99.9% VOC DE for thermal oxidation (SCTO)

Below, Shell documents the analysis that was completed to make these BAT determinations.

1.4 Ethane Cracking Furnace BAT Determinations

As presented below, Shell has reevaluated the SO_2 and ammonia BAT determinations that were previously made for the seven identical ethane cracking furnaces at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BAT determination reevaluations for the ethane cracking furnaces is documented in Attachment 6-1.

1.4.1 SO_2

The ethane cracking furnaces combust a combination of tail gas, which is a byproduct of SPM's ethylene manufacturing unit that is comprised mostly of hydrogen and methane, and pipeline quality natural gas. During certain intermittent operating modes (e.g., startup and shutdown operations), the ethane cracking furnaces combust only natural gas, but the ethane cracking furnaces normally combust a fuel gas stream comprised of a blend of tail gas and natural gas.

The tail gas combusted in the ethane cracking furnaces does not contain measurable amounts of sulfur; therefore, the combustion of tail gas in the ethane cracking furnaces does not result in SO_2 emissions.

Additionally, the pipeline quality natural gas combusted in the ethane cracking furnaces contains negligible amounts of sulfur because it must be treated in one or more sulfur removal processes before it arrives at SPM to ensure its sulfur levels meet pipeline transport specifications (generally ≤ 0.5 grains of sulfur per 100 standard cubic feet (scf)). As a result of these tail gas and natural gas sulfur characteristics, the ethane cracking furnaces emit only a small amount of SO_2.

1.4.1.1 Step 1: Identify Control Technologies

The following are available SO_2 emission control technologies for the ethane cracking furnaces.

- Low-sulfur fuels
- Flue gas desulfurization

These technologies are generally described below.

Low-Sulfur Fuels

There are fuels that inherently contain low levels of sulfur, but fuels oftentimes must be treated using a sulfur removal technology, such as a liquid absorption or solid adsorption technology, to reduce the fuel's sulfur content to low levels. For example, natural gas may be from a well that naturally produces natural gas containing low levels of sulfur, or it may be from a well that produces natural gas that must be treated to achieve an acceptably low level of sulfur to meet pipeline transport specifications. Low-sulfur fuels result in low levels of SO_2 emissions when they are combusted.

Flue Gas Desulfurization

Flue gas desulfurization is commonly used to reduce SO_2 emissions from coal-fired and oil-fired combustion sources due to the relatively high concentrations of SO_2 (thousands of ppmv SO_2) contained in the flue gases generated by these sources because of the high levels of sulfur routinely found in the coal and oil fuels combusted in the sources. Flue gas desulfurization can be accomplished using wet, semi-dry, and dry scrubbers, although wet scrubbers are normally capable of higher SO_2 removal efficiencies than semi-dry and dry scrubbers.

In a wet scrubber, an aqueous slurry of sorbent is injected into a source's flue gas and the SO_2 contained in the gas dissolves into the slurry droplets where it reacts with an alkaline compound present in the slurry. The treated flue gas is then emitted to the atmosphere after passing through a mist eliminator that is designed to remove any entrained slurry droplets, while the falling slurry droplets make their way to the bottom of the scrubber where they are collected and either regenerated and recycled or removed as a waste or byproduct.

Semi-dry scrubbers are like wet scrubbers, but the slurry used in a semi-dry scrubber has a higher sorbent concentration, which results in the complete evaporation of the slurry water and the formation of a dry spent sorbent material that is entrained in the treated flue gas. This dry spent sorbent is removed from the flue gas using a filter (baghouse) or electrostatic precipitator (ESP). In a dry scrubber, a dry sorbent material is pneumatically injected into a source's flue gas and the dry spent sorbent material entrained in the treated flue gas is removed using a baghouse or ESP.

1.4.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the SO_2 emission control technologies determined to be available for the ethane cracking furnaces is evaluated below.

Low-Sulfur Fuels

This option is technically feasible for the ethane cracking furnaces.

Flue Gas Desulfurization

The ethane cracking furnaces emit less than 1 ppmv of SO_2 due to the negligible levels of sulfur contained in the fuel they combust. This flue gas SO_2 concentration is considerably below the concentrations seen in exhaust streams from the most effective wet scrubber flue gas desulfurization units, indicating it would not be feasible to design a wet scrubber, semi-dry scrubber, or dry scrubber to install on the ethane cracking furnaces for SO_2 emissions reduction purposes. Additionally, liquid carryover in the exhaust stream from a wet scrubber or solid carryover in the exhaust stream from a semi-dry or dry scrubber achieving essentially no SO_2 emissions reduction would result in additional PM emissions to the atmosphere from the ethane cracking furnace's operations. These factors indicate it would not be technically feasible to use flue gas desulfurization to control SO_2 emissions from the ethane cracking furnaces, which is further supported by the fact that EPA's RBLC database indicates flue gas desulfurization has not been used to control SO_2 emissions from comparable combustion devices.

1.4.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible SO_2 emission control technology for the ethane cracking furnaces is low-sulfur fuels.

1.4.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the only remaining emission control technology determined to be available for the ethane cracking furnaces to control their SO_2 emissions. Therefore, no additional analysis is necessary under this step.

1.4.1.5 Step 5: Select BAT

Shell determined that combusting low-sulfur fuels represents BAT for the SO_2 emissions from the ethane cracking furnaces, which is the same SO_2 BAT that is currently applicable to the furnaces. Accordingly, Shell will combust only tail gas and natural gas in the ethane cracking furnaces.

1.4.2 Ammonia

Each ethane cracking furnace is equipped with a selective catalytic reduction (SCR) system that reduces the amount of NOx it emits to the atmosphere. These SCR systems use ammonia as the reducing agent to react with NOx in the SCR catalyst to produce innocuous nitrogen and water. However, unreacted ammonia reagent may exit the SCR catalyst due to a variety of reasons (e.g., considerable combustion device firing rate fluctuations, residual ammonia buildup in the SCR catalyst, and insufficient SCR catalyst temperatures), resulting in ammonia emissions to the atmosphere from the ethane cracking furnaces. The unreacted ammonia exiting the SCR catalyst is generally referenced as "ammonia slip."

The ethane cracking furnaces and the SCR systems installed on the furnaces are equipped with process control equipment that is programmed to monitor ethane cracking furnace and SCR system operating parameters to make on-line optimization adjustments to the amount of ammonia injected into the SCR system to achieve optimal SCR system NOx emissions reduction performance while minimizing the amount of ammonia slip from the ethane cracking furnace SCR systems. This process control equipment and process control logic greatly assists in limiting ammonia slip (ammonia emissions) from the ethane cracking furnaces.

The ethane cracking furnaces are currently subject to the following ammonia BAT limitation.

- Ammonia emissions from each of the ethane cracking furnaces shall not exceed 10 ppmvd at 3% oxygen.

1.4.2.1 Step 1: Identify Control Technologies

The following are available ammonia emission control technologies for the ethane cracking furnaces.

- Limiting ammonia slip
- Absorption

These technologies are generally described below.

Limiting Ammonia Slip

An SCR system using ammonia includes process control equipment and process control logic to manage ammonia injection rates into the system to minimize the injection of excess amounts of ammonia over a variety of operating conditions and scenarios. These ammonia injection control features and operations limit ammonia slip, thus limiting ammonia emissions to the atmosphere due to the operation of the SCR system.

Absorption

Absorption is primarily a physical process – though it can also include a chemical mechanism – in which a pollutant in a gas phase contacts a liquid media and is removed from the gas phase by the liquid media. A common absorption device is a wet scrubber, which provides an intimate contacting environment for a soluble pollutant to be dissolved in a scrubbing liquid. Water is often used as the scrubbing liquid for the control of pollutants, but it may be necessary to use a very low vapor pressure organic liquid or aqueous mixture or other type of liquid as the scrubbing liquid when the pollutants requiring control are less soluble in water and/or the chemical absorption mechanism is key to the absorption process. There are several types of wet scrubber designs, including packed-bed counterflow scrubbers, packed-bed cross-flow scrubbers, bubble plate scrubbers, and tray scrubbers.

1.4.2.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the ammonia emission control technologies determined to be available for the ethane cracking furnaces is evaluated below.

Limiting Ammonia Slip

This option is technically feasible for the ethane cracking furnaces.

Absorption

The ethane cracking furnaces emit less than 10 ppmvd ammonia at 3% oxygen. This concentration is near or below the levels typically seen in exhaust streams from wet scrubbers that are used to control ammonia emissions, indicating it would not be feasible to design a wet scrubber to install on the ethane cracking furnaces that would effectively reduce ammonia emissions from the furnaces. Additionally, liquid carryover in the exhaust stream from a wet scrubber achieving essentially no ammonia emissions reduction would result in additional PM emissions to the atmosphere from the ethane cracking furnace's operations. These factors indicate it would not be technically feasible to use a wet scrubber to control ammonia emissions from the ethane cracking furnaces.

1.4.2.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible ammonia emission control technology for the ethane cracking furnaces is limiting ammonia slip.

1.4.2.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the only remaining emission control technology determined to be available for the ethane cracking furnaces to control their ammonia emissions. Therefore, no additional analysis is necessary under this step.

1.4.2.5 Step 5: Select BAT

Shell determined that limiting ammonia slip represents BAT for the ammonia emissions from the ethane cracking furnaces. Shell proposes the following ammonia BAT limit for the ethane cracking furnaces, which is the same ammonia BAT limit that is currently applicable to the furnaces.

- Limit the ammonia emissions from each ethane cracking furnace to ≤ 10 ppmvd at 3% oxygen.

1.5 Combustion Turbine/Duct Burner Unit BAT Determinations

As presented below, Shell has reevaluated the HAP BAT determination that was previously made for the three identical combustion turbine/duct burner units at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BAT determination reevaluation for the combustion turbine/duct burner units is documented in Attachment 6-1.

1.5.1 HAPs

The combustion turbine/duct burner units only combust pipeline quality natural gas. As a result, the combustion turbine/duct burner units emit very little HAPs because pipeline quality natural gas is an easily combustible fuel that is mostly comprised of low molecular weight, simple chemical structure and formula hydrocarbons that do not contain chlorides or oxides. Additionally, each combustion turbine/duct burner unit is equipped with an oxidation catalyst, which further minimizes each unit's HAP emissions by oxidizing a portion of the organic HAP emissions to CO_2 and water.

The combustion turbine/duct burner units are subject to the following 40 CFR 63 Subpart YYYY HAP emission and operating limitations.

- Formaldehyde ≤ 91 ppbvd at 15% oxygen, except during turbine startup.
- Maintain the 4-hour rolling average of the oxidation catalyst inlet temperature within the range suggested by the catalyst manufacturer.

Additionally, the combustion turbine/duct burner units are currently subject to the following HAP BAT emission and operating limitations.

- Formaldehyde emissions from each of the combustion turbines with duct burners shall not exceed 91 ppbvd at 15% oxygen.
- Continuously monitor and maintain the 4-hour rolling average of each combustion turbine's oxidation catalyst inlet temperature within its designed operating temperature range.

1.5.1.1 Step 1: Identify Control Technologies

The following are available organic HAP emission control technologies for the combustion turbine/duct burner units.

- Good combustion practices
- Catalytic oxidation

These technologies are generally described below.

Good Combustion Practices

Incomplete combustion of fuel hydrocarbons in a combustion device, which is indicative of poor combustion mechanisms, can result in elevated organic HAP emissions from the device. Incomplete combustion may result from poor design, operation, and/or maintenance of the combustion device. However, as indicated by their high overall energy efficiency, modern combustion turbines that are equipped with duct burners are designed to maximize fuel combustion efficiency to minimize their fuel usage cost while maximizing their energy output. Good combustion practices for a combustion device generally include a properly set and controlled air-to-fuel ratio and appropriately designed and set combustion time, temperature, and turbulence parameters, which are essential to minimizing incomplete combustion and thus achieving low organic HAP emission levels. In general, good combustion practices are achieved by following a combustion device manufacturer's operating procedures and guidelines, as well as the manufacturer's routine maintenance procedures and programs.

Catalytic Oxidation

Catalytic oxidation uses catalysts comprised of precious metals such as platinum, palladium, or rhodium to reduce the temperature at which organic HAPs oxidize to CO_2. The organic HAP removal effectiveness of catalytic oxidation is dependent on an exhaust stream's temperature, the concentration of organic HAPs in the stream, and the presence of potentially poisoning contaminants in the stream. The amount of catalyst required for a particular application is dependent upon a stream's flow rate, composition, and temperature, as well as the desired organic HAP removal efficiency. The catalyst in a catalytic oxidation system will experience activity loss over time due to physical deterioration and/or chemical deactivation. Therefore, periodic testing of the catalyst is necessary to monitor its activity (i.e., oxidation promoting effectiveness) and predict its remaining useful life. As needed, the catalyst will require periodic replacement. Catalyst life varies from manufacturer-to-manufacturer, but a three to six-year window is not uncommon.

1.5.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the organic HAP emission control technologies determined to be available for the combustion turbine/duct burner units is evaluated below.

Good Combustion Practices

This option is technically feasible for the combustion turbine/duct burner units.

Catalytic Oxidation

This option is technically feasible for the combustion turbine/duct burner units.

1.5.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the two emission control technologies determined to be available for the combustion turbine/duct burner units to control their HAP emissions. Therefore, no additional analysis is necessary under this step.

1.5.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the two emission control technologies determined to be available for the combustion turbine/duct burner units to control their HAP emissions. Therefore, no additional analysis is necessary under this step.

1.5.1.5 Step 5: Select BAT

Shell determined that good combustion practices and catalytic oxidation represent BAT for the combustion turbine/duct burner units' HAP emissions. Shell proposes the following formaldehyde BAT limit for the combustion turbine/duct burner units, which is the same formaldehyde BAT limit that is currently applicable to the units.

- Limit the formaldehyde emissions from each combustion turbine/duct burner unit to ≤ 91 ppbvd at 15% oxygen.

1.6 CVTO BAT Determinations

As presented below, Shell has reevaluated the SO_2 and sulfuric acid mist BAT determinations that were previously made for the CVTO at SPM contemporaneous with the construction of the facility. Because the same emission control technologies are generally applicable to the control of SO_2 and sulfuric acid mist from a combustion device, the CVTO's SO_2 and sulfuric acid mist BAT determinations were reevaluated together. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BAT determination reevaluations for the CVTO is documented in Attachment 6-1.

1.6.1 SO_2 and Sulfuric Acid Mist

The CVTO combusts a combination of vent gases, which are generated by SPM's three polyethylene manufacturing units and equipment associated with SPM's ethylene manufacturing unit, and pipeline quality natural gas. The vent gases combusted in the CVTO have been conservatively estimated to contain sulfur at the same level as pipeline quality natural gas, which is considerably low, even though the ethylene and polyethylene manufacturing unit-related vent gases are not expected to contain measurable levels of sulfur because the materials contained in the ethylene and polyethylene manufacturing unit equipment generating the vent gases do not contain measurable levels of sulfur. As a result of these vent gas and natural gas sulfur characteristics, the CVTO emits a small amount of SO_2 and sulfuric acid mist, respectively.

1.6.1.1 Step 1: Identify Control Technologies

The following are available SO_2 and sulfuric acid mist emission control technologies for the CVTO.

- Low-sulfur vent gases
- Low-sulfur fuels
- Absorption
- Adsorption

These technologies are generally described below.

Low-Sulfur Vent Gases

There are vent gases that inherently contain low levels of sulfur, but vent gases oftentimes must be treated using a sulfur removal technology, such as a liquid absorption or solid adsorption technology, to reduce their sulfur content to low levels. For example, a vent gas may be generated by a process that does contain sulfur compounds and thus the vent gas will not contain sulfur; or, a vent gas may be generated by a process that includes a feedstock containing sulfur and thus the vent gas may contain sulfur at a level requiring treatment prior to combustion to minimize SO_2 and sulfuric acid mist emissions. Low-sulfur vent gases result in low levels of SO_2 and sulfuric acid mist emissions when they are combusted.

Low-Sulfur Fuels

Please see Section 1.4.1.1 herein for a discussion of this technology.

Absorption

Please see Section 1.4.2.1 herein for a discussion of this technology. For a vent gas containing sulfur, an absorption technology can be used to remove sulfur-containing compounds from the vent gas prior to combustion to minimize the generation of SO_2 and sulfuric acid mist when the treated vent gas is combusted, or an absorption technology can be used to reduce the amount of SO_2 and sulfuric acid mist contained in the exhaust from an enclosed combustion device that combusts the untreated vent gas.

Adsorption

Adsorption can be used to capture a specific compound, or a variety of compounds, present in a gas phase on the surface of a solid adsorbent. For a combustion device generating SO_2 and sulfuric acid mist due to the combustion of a vent gas containing sulfur, an adsorption technology would be evaluated as potentially available for the removal of sulfur-containing compounds from the vent gas prior to combustion to minimize the generation of SO_2 and sulfuric acid mist when the treated vent gas is combusted.

Adsorption performance depends on the characteristics of the target compound(s), the concentration of the target compound(s) in the gaseous stream considered for treatment, and the temperature, pressure, and moisture content of the gaseous stream. Adsorbers can be a fixed-bed or fluidized bed design. If regenerable, a fixed-bed's adsorbent must be periodically regenerated in place or removed, replaced, and regenerated externally, while a fluidized-bed's adsorbent is continuously regenerated in place. Additionally, portable, easily replaceable adsorption units are used in some applications. A portable unit is not normally regenerated at the facility where it is used. Instead, a portable unit is typically returned to the supplier of the unit, and the supplier regenerates or disposes of the unit's spent adsorbent.

1.6.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the SO_2 and sulfuric acid mist emission control technologies determined to be available for the CVTO is evaluated below.

Low-Sulfur Vent Gases

This option is technically feasible for the CVTO.

Low-Sulfur Fuels

This option is technically feasible for the CVTO.

Absorption

The vent gases combusted in the CVTO do not contain measurable amounts of sulfur; therefore, it would not be feasible to design an absorption unit to reduce the sulfur content of these vent gases prior to combustion in the CVTO to further minimize the generation of SO_2 and sulfuric acid mist resulting from the combustion of the vent gases. Additionally, the CVTO emits less than 1 ppmv of SO_2 and sulfuric acid mist, respectively, due to the very low levels of sulfur contained in the vent gases that it combusts. These flue gas SO_2 and sulfuric acid mist concentrations are below the concentrations seen in exhaust streams from wet scrubbers used to control SO_2 and sulfuric acid mist emissions, indicating it would not be feasible to design an absorption unit to reduce the CVTO's SO_2 and sulfuric acid mist emissions. Furthermore, in consideration of the elevated temperatures of the flue gas in the CVTO's stack (> 1,300 °F), the CVTO's sulfuric acid mist emissions are likely formed after the flue gas exits the CVTO's stack, which means that the CVTO's flue gas would need to be considerably quenched to promote the formation of sulfuric acid mist to attempt to achieve any sulfuric acid mist emissions reduction using a post-combustion absorption unit (wet scrubber). Moreover, liquid carryover in the exhaust stream from a wet scrubber achieving essentially no SO_2 and sulfuric acid mist emissions reduction would result in additional PM emissions to the atmosphere from the CVTO's operations. All these factors indicate it would not be technically feasible to use a pre-combustion or post-combustion absorption technology to control SO_2 and sulfuric acid mist emissions from the CVTO.

Adsorption

As discussed above, the vent gases combusted in the CVTO do not contain measurable amounts of sulfur; therefore, it would not be feasible to design an adsorption unit to reduce the sulfur content of these vent gases prior to combustion in the CVTO to further minimize the generation of SO_2 and sulfuric acid mist resulting from the combustion of the vent gases. As a result, it would not be technically feasible to use a pre-combustion adsorption technology to control SO_2 and sulfuric acid mist emissions from the CVTO.

1.6.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the only remaining emission control technologies determined to be available for the CVTO to control its SO_2 and sulfuric acid mist emissions. Therefore, no additional analysis is necessary under this step.

1.6.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the only remaining emission control technologies determined to be available for the CVTO to control its SO_2 and sulfuric acid mist emissions. Therefore, no additional analysis is necessary under this step.

1.6.1.5 Step 5: Select BAT

Shell determined that combusting low-sulfur vent gases and low-sulfur fuels represents BAT for the SO_2 and sulfuric acid mist emissions from the CVTO, which is the same SO_2 and sulfuric acid mist BAT that is currently applicable to the CVTO. Accordingly, Shell will combust only vent gases generated by equipment and activities associated with SPM's polyethylene and ethylene manufacturing units and use natural gas as fuel in the CVTO.

1.7 MPGF BAT Determinations

As presented below, Shell has reevaluated the SO_2 BAT determination that was previously made for the MPGF at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BAT determination reevaluation for the MPGF is documented in Attachment 6-1.

1.7.1 SO_2

The MPGF combust a combination of vent gases, which are generated by SPM's three polyethylene manufacturing units and equipment associated with SPM's ethylene manufacturing and polyethylene manufacturing units, and pipeline quality natural gas. The vent gases combusted in the MPGF have been conservatively estimated to contain sulfur at the same level as pipeline quality natural gas, which is considerably low, even though the ethylene and polyethylene manufacturing unit-related vent gases are not expected to contain measurable levels of sulfur because the materials contained in the ethylene and polyethylene manufacturing unit equipment generating the vent gases do not contain measurable levels of sulfur. As a result of these vent gas and natural gas sulfur characteristics, the MPGF emits a small amount of SO_2.

The MPGF is currently subject to the following SO_2 BAT requirement.

- The flare must be operated in accordance with a flare minimization plan.

1.7.1.1 Step 1: Identify Control Technologies

The following are available SO_2 emission control technologies for the MPGF.

- Flare minimization
- Low-sulfur vent gases
- Low-sulfur fuels
- Absorption
- Adsorption

These technologies are generally described below.

Flare Minimization

A facility typically develops a flare minimization plan to document and guide its flare minimization design features, procedures, and practices. In general, a flare minimization plan is used to minimize flaring at a facility without compromising its safe operations and practices, especially during planned startup, shutdown, and maintenance events. A flare minimization plan results in reduced emissions of combustion pollutants such as CO, NOx, PM, PM_{10}, $PM_{2.5}$, SO_2, and CO_2, as well as VOC and HAPs, from a flare because it promotes a reduction in the occurrence of certain flaring events, the amount of waste gas generated during flaring events, and the duration of flaring events. Key components of an effective flare minimization plan are careful planning to minimize flaring events, measuring and monitoring flaring events when they occur, and investigative evaluation of the causes of flaring events, especially large or unplanned flaring events. Regarding unplanned flaring events, a flare minimization plan usually includes procedures to evaluate the events and their causes to develop strategies and measures to minimize the likelihood for the reoccurrence of the same or similar events.

Low-Sulfur Vent Gases

Please see Section 1.6.1.1 herein for a discussion of this technology.

Low-Sulfur Fuels

Please see Section 1.4.1.1 herein for a discussion of this technology.

Absorption

Please see Section1.4.2.1 herein for a discussion of this technology. For a flare generating SO_2 due to the combustion of a vent gas containing sulfur, an absorption technology would be evaluated as potentially available for the removal of sulfur-containing compounds from the vent gas prior to combustion to minimize the generation of SO_2 by the flare.

Adsorption

Please see Section 1.6.1.1 herein for a discussion of this technology. For a flare generating SO_2 due to the combustion of a vent gas containing sulfur, an adsorption technology would be evaluated as potentially available for the removal of sulfur-containing compounds from the vent gas prior to combustion to minimize the generation of SO_2 by the flare.

1.7.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the SO_2 emission control technologies determined to be available for the MPGF is evaluated below.

Flare Minimization

This option is technically feasible for the MPGF.

Low-Sulfur Vent Gases

This option is technically feasible for the MPGF.

Low-Sulfur Fuels

This option is technically feasible for the MPGF.

Absorption

The vent gases combusted in the MPGF do not contain measurable amounts of sulfur; therefore, it would not be feasible to design an absorption unit to reduce the sulfur content of these vent gases prior to combustion in the MPGF to further minimize the generation of SO_2 resulting from the combustion of the vent gases. As a result, it would not be technically feasible to use a pre-combustion absorption technology to control SO_2 emissions from the MPGF.

Adsorption

As discussed above, the vent gases combusted in the MPGF do not contain measurable amounts of sulfur; therefore, it would not be feasible to design an adsorption unit to reduce the sulfur content of these vent gases prior to combustion in the MPGF to further minimize the generation of SO_2 resulting from the combustion of the vent gases. As a result, it would not be technically feasible to use a pre-combustion adsorption technology to control SO_2 emissions from the MPGF.

1.7.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the only remaining emission control technologies determined to be available for the MPGF to control its SO_2 emissions. Therefore, no additional analysis is necessary under this step.

1.7.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the only remaining emission control technologies determined to be available for the MPGF to control its SO_2 emissions. Therefore, no additional analysis is necessary under this step.

1.7.1.5 Step 5: Select BAT

Shell determined that operating in accordance with a flare minimization plan and combusting low-sulfur vent gases and low-sulfur fuels represent BAT for the SO_2 emissions from the MPGF, which is the same SO_2 BAT that is currently applicable to the flare. Shell will operate the MPGF in accordance with a flare minimization plan that will include the following:

- Procedures for operating and maintaining the flare during periods of process unit startup, shutdown, and unforeseeable events;
- A program of corrective action for malfunctioning process equipment;
- Procedures to minimize discharges to the flares during the planned and unplanned startup or shutdown of process equipment;
- Procedures for conducting root cause analyses; and
- Procedures for taking identified corrective actions.

Additionally, Shell will combust only vent gases generated by equipment and activities associated with SPM's polyethylene and ethylene manufacturing units and use natural gas as fuel at the MPGF.

1.8 TEGF A, TEGF B, and HP Elevated Flare BAT Determinations

As presented below, Shell has reevaluated the SO_2, sulfuric acid mist, and HAP BAT determinations that were previously made for the TEGF A, TEGF B, and HP Elevated Flare at SPM contemporaneous with the construction of the facility. Because the same emission control technologies are generally applicable to the control of SO_2 and sulfuric acid mist from a combustion device, the TEGF A, TEGF B, and HP Elevated Flare's SO_2 and sulfuric acid mist BAT determinations were reevaluated together. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BAT determination reevaluations for the TEGF A, TEGF B, and HP Elevated Flare is documented in Attachment 6-1.

1.8.1 SO_2 and Sulfuric Acid Mist

The TEGF A, TEGF B, and HP Elevated Flare combust a combination of vent gases, which are generated by SPM's ethylene manufacturing unit, SPM's three polyethylene manufacturing units, and equipment associated with SPM's ethylene manufacturing and polyethylene manufacturing units, and pipeline quality natural gas. The vent gases combusted in the TEGF A, TEGF B, and HP Elevated Flare have been conservatively estimated to contain sulfur at the same level as pipeline quality natural gas, which is considerably low, even though the ethylene and polyethylene manufacturing unit-related vent gases are not expected to contain measurable levels of sulfur because the materials contained in the ethylene and polyethylene manufacturing unit equipment generating the vent gases do not contain measurable levels of sulfur. As a result of these vent gas and natural gas sulfur characteristics, the TEGF A, TEGF B, and HP Elevated Flare emit a small amount of SO_2 and sulfuric acid mist, respectively.

The TEGF A, TEGF B, and HP Elevated Flare are currently subject to the following SO_2 and sulfuric acid mist BAT requirements.

- Each flare must be operated in accordance with a flare minimization plan.

1.8.1.1 Step 1: Identify Control Technologies

The following are available SO_2 and sulfuric acid mist emission control technologies for the TEGF A, TEGF B, and HP Elevated Flare.

- Flare minimization
- Low-sulfur vent gases
- Low-sulfur fuels
- Absorption
- Adsorption

These technologies are generally described below.

Flare Minimization

Please see Section 1.7.1.1 herein for a discussion of this technology.

Low-Sulfur Vent Gases

Please see Section 1.6.1.1 herein for a discussion of this technology.

Low-Sulfur Fuels

Please see Section 1.4.1.1 herein for a discussion of this technology.

Absorption

Please see Section 1.4.2.1 herein for a discussion of this technology. For a flare generating SO_2 and sulfuric acid mist due to the combustion of a vent gas containing sulfur, an absorption technology would be evaluated as potentially available for the removal of sulfur-containing compounds from the vent gas prior to combustion to minimize the generation of SO_2 and sulfuric acid mist by the flare.

Adsorption

Please see Section 1.6.1.1 herein for a discussion of this technology. For a flare generating SO_2 and sulfuric acid mist due to the combustion of a vent gas containing sulfur, an adsorption technology would be evaluated as potentially available for the removal of sulfur-containing compounds from the vent gas prior to combustion to minimize the generation of SO_2 and sulfuric acid mist by the flare.

1.8.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the SO_2 and sulfuric acid mist emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare is evaluated below.

Flare Minimization

This option is technically feasible for the TEGF A, TEGF B, and HP Elevated Flare.

Low-Sulfur Vent Gases

This option is technically feasible for the TEGF A, TEGF B, and HP Elevated Flare.

Low-Sulfur Fuels

This option is technically feasible for the TEGF A, TEGF B, and HP Elevated Flare.

Absorption

The vent gases combusted in the TEGF A, TEGF B, and HP Elevated Flare do not contain measurable amounts of sulfur; therefore, it would not be feasible to design an absorption unit to reduce the sulfur content of these vent gases prior to combustion in the TEGF A, TEGF B, and HP Elevated Flare to further minimize the generation of SO_2 and sulfuric acid mist resulting from the combustion of the vent gases. As a result, it would not be technically feasible to use a pre-combustion absorption technology to control SO_2 and sulfuric acid mist emissions from the TEGF A, TEGF B, and HP Elevated Flare.

Adsorption

As discussed above, the vent gases combusted in the TEGF A, TEGF B, and HP Elevated Flare do not contain measurable amounts of sulfur; therefore, it would not be feasible to design an adsorption unit to reduce the sulfur content of these vent gases prior to combustion in the TEGF A, TEGF B, and HP Elevated Flare to further minimize the generation of SO_2 and sulfuric acid mist resulting from the combustion of the vent gases. As a result, it would not be technically feasible to use a pre-combustion adsorption technology to control SO_2 and sulfuric acid mist emissions from the TEGF A, TEGF B, and HP Elevated Flare.

1.8.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the only remaining emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their SO_2 and sulfuric acid mist emissions. Therefore, no additional analysis is necessary under this step.

1.8.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the only remaining emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their SO_2 and sulfuric acid mist emissions. Therefore, no additional analysis is necessary under this step.

1.8.1.5 Step 5: Select BAT

Shell determined that operating in accordance with a flare minimization plan and combusting low-sulfur vent gases and low-sulfur fuels represent BAT for the SO_2 and sulfuric acid mist emissions from the TEGF A, TEGF B, and HP Elevated Flare, which is the same SO_2 and sulfuric acid mist BAT that is currently applicable to the flares. Shell will operate the TEGF A, TEGF B, and HP Elevated Flare in accordance with a flare minimization plan that will include the following:

- Procedures for operating and maintaining the flares during periods of process unit startup, shutdown, and unforeseeable events;
- A program of corrective action for malfunctioning process equipment;
- Procedures to minimize discharges to the flares during the planned and unplanned startup or shutdown of process equipment;
- Procedures for conducting root cause analyses; and
- Procedures for taking identified corrective actions.

Additionally, Shell will combust only vent gases generated by equipment and activities associated with SPM’s polyethylene and ethylene manufacturing units and use tail gas and natural gas as fuel at the TEGF A, TEGF B, and HP Elevated Flare.

1.8.2 HAPs

HAPs are primarily emitted by the TEGF A, TEGF B, and HP Elevated Flare due to the incomplete oxidation of hydrocarbons and HAPs present in the flare vent gas combusted at the flares. The DE of a flare is a measure of the amount of hydrocarbon present in the flare vent gas that oxidizes to CO and CO_2 at the flare tip. The DE of a flare is affected by flare vent gas characteristics (e.g., Btu content, composition), flare tip velocity, and oxygen levels at the flare’s combustion zone.

The TEGF A, TEGF B, and HP Elevated Flare are currently subject to the following HAP BAT requirements.

- Each flare must be operated in accordance with a flare minimization plan.

- Each flare must be operated in accordance with good combustion practices.

1.8.2.1 Step 1: Identify Control Technologies

The following are available HAP emission control technologies for the TEGF A, TEGF B, and HP Elevated Flare.

- Flare minimization
- Good combustion practices

These technologies are generally described below.

Flare Minimization

Please see Section 1.7.1.1 herein for a discussion of this technology.

Good Combustion Practices

Good combustion practices for a flare promote appropriate flame zone residence time, temperature, and turbulence to achieve low CO, NOx, PM, PM_{10}, $PM_{2.5}$, VOC, HAP, and methane emission levels. The following are design and operating parameters that are typically used to measure or indicate good combustion practices for a flare: flare vent gas heating value, flare vent gas flow rate, assist gas flow rate, and visible emissions. A flare is generally recognized as achieving and demonstrating good combustion practice operations when it follows the design, operating, and monitoring requirements specified in 40 CFR 63 Subpart CC, which are specifically referenced and required to be met by 40 CFR 63 Subpart YY and 40 CFR 63 Subpart FFFF with minor revisions.

1.8.2.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the HAP emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare is evaluated below.

Flare Minimization

This option is technically feasible for the flares.

Good Combustion Practices

This option is technically feasible for the flares.

1.8.2.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the two emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their HAP emissions. Therefore, no additional analysis is necessary under this step.

1.8.2.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the two emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their HAP emissions. Therefore, no additional analysis is necessary under this step.

1.8.2.5 Step 5: Select BAT

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents BAT for the HAP emissions from the TEGF A, TEGF B, and HP Elevated Flare, which is the same HAP BAT that is currently applicable to the flares. Shell will operate the TEGF A, TEGF B, and HP Elevated Flare in accordance with a flare minimization plan, as previously described in Section 1.8.1.5. Also, Shell will operate the TEGF A, TEGF B, and HP Elevated Flare in accordance with the good combustion practice requirements in 40 CFR 63 Subpart YY and 40 CFR 63 Subpart FFFF, as applicable, which include design requirements, minimum flare combustion zone gas heating value requirements, and extensive monitoring requirements for the flares.

1.9 SCTO BAT Determinations

As presented below, Shell has reevaluated the SO_2 and sulfuric acid mist BAT determinations that were previously made for the SCTO at SPM contemporaneous with the construction of the facility. Because the same emission control technologies are generally applicable to the control of SO_2 and sulfuric acid mist from a combustion device, the SCTO's SO_2 and sulfuric acid mist BAT determinations were reevaluated together. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BAT determinations for the SCTO is documented in Attachment 6-1.

1.9.1 SO_2 and Sulfuric Acid Mist

The SCTO combusts a combination of vent gases, which are generated by SPM's spent caustic storage tank, SPM's spent caustic oxidation treatment operation, and SPM's 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.

1.9.1.1 Step 1: Identify Control Technologies

The following are available SO_2 and sulfuric acid mist emission control technologies for the SCTO.

- Low-sulfur vent gases
- Low-sulfur fuels
- Absorption
- Adsorption

These technologies are generally described below.

Low-Sulfur Vent Gases

Please see Section 1.6.1.1 herein for a discussion of this technology.

Low-Sulfur Fuels

Please see Section 1.4.1.1 herein for a discussion of this technology.

Absorption

Please see Section 1.4.2.1 herein for a discussion of this technology.

Adsorption

Please see Section 1.6.1.1 herein for a discussion of this technology.

1.9.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the SO_2 and sulfuric acid mist emission control technologies determined to be available for the SCTO is evaluated below.

Low-Sulfur Vent Gases

This option is technically feasible for the SCTO.

Low-Sulfur Fuels

This option is technically feasible for the SCTO.

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 unit to reduce the sulfur content of those vent gases prior to combustion in the SCTO to further minimize the generation of SO_2 and sulfuric acid mist resulting from the combustion of the vent gases. Additionally, the spent caustic oxidation treatment operation vent gas, which is generated during the pretreatment of a spent scrubbing media that is produced by an absorption process so that the referenced scrubbing media is suitable to be further treated in SPM's Wastewater Treatment Plant, contains sulfur at levels that are at the low end of the concentrations seen exiting absorption units. Thus, it would not be technically feasible to use an absorption unit to reduce the sulfur content of this vent gas prior to combustion in the SCTO to further minimize the generation of SO_2 and sulfuric acid mist resulting from the combustion of the vent gas.

Additionally, the SCTO emits SO_2 and sulfuric acid mist, respectively, at levels that are below or at the low end of the concentrations seen in exhaust streams from wet scrubbers used to control SO_2 and sulfuric acid mist emissions, indicating it would not be feasible to design an absorption unit to reduce the SCTO's SO_2 and sulfuric acid mist emissions. Furthermore, in consideration of the elevated temperatures of the flue gas in the SCTO's stack (> 1,000 °F), the SCTO's sulfuric acid mist emissions are likely formed after the flue gas exits the SCTO's stack, which means that the SCTO's flue gas would need to be considerably quenched to promote the formation of sulfuric acid mist to attempt to achieve any sulfuric acid mist emissions reduction using a post-combustion absorption unit (wet scrubber). Moreover, liquid carryover in the exhaust stream from a wet scrubber achieving minor SO_2 and sulfuric acid mist emissions reduction would result in additional PM emissions to the atmosphere from the SCTO's operations. All these factors indicate it would not be technically feasible to use a post-combustion absorption technology to control SO_2 and sulfuric acid mist emissions from the SCTO.

Adsorption

As discussed above, 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 adsorption unit to reduce the sulfur content of those vent gases prior to combustion in the SCTO to further minimize the generation of SO_2 and sulfuric acid mist resulting from the combustion of the vent gases. Additionally, the spent caustic oxidation treatment operation vent gas contains sulfur at levels that are at the low end of the concentrations seen exiting adsorption units. As a result, it would not be technically feasible to use a pre-combustion adsorption technology to control SO_2 and sulfuric acid mist emissions from the SCTO.

1.9.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the only remaining emission control technologies determined to be available for the SCTO to control its SO_2 and sulfuric acid mist emissions. Therefore, no additional analysis is necessary under this step.

1.9.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the only remaining emission control technologies determined to be available for the SCTO to control its SO_2 and sulfuric acid mist emissions. Therefore, no additional analysis is necessary under this step.

1.9.1.5 Step 5: Select BAT

Shell 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, which is the same SO_2 and sulfuric acid mist BAT that is currently applicable to the SCTO. Accordingly, Shell will combust only vent gases generated by SPM's spent caustic storage tank, spent caustic oxidation treatment operation, and Wastewater Treatment Plant-related equipment and use natural gas as fuel in the SCTO.

1.10 Wastewater Treatment Plant BAT Determinations

Shell reevaluated the VOC LAER determination previously made for the Wastewater Treatment Plant at SPM, as presented separately. Shell also determined that it would reevaluate the HAP BAT determination previously made for the Wastewater Treatment Plant. However, the Wastewater Treatment Plant's VOC emissions are partially comprised of its HAP emissions. LAER for a specific pollutant (VOC/HAP) emitted by an emission source is at least as stringent as BAT for the same pollutant from the emission source. Therefore, the VOC LAER determination reevaluation completed for the Wastewater Treatment Plant serves as the HAP BAT determination reevaluation for the Wastewater Treatment Plant.

Attachment 6-1

Request No. 4 EPA RBLC Database Information

11.310 - Gaseous Fuel & Gaseous Fuel Mixtures (>250 MMBtu/hr) - Natural Gas (Includes Propane and LPG)

Pollutant: SO_2

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	Three (3) Building Heat Medium Heaters	275	MMBtu/hr	SO2	Good combustion practices and clean burning fuel (NG).	96	ppmv S in fuel	BACT-PSD	Potential SO2 emissions of 4.13 tpy and 0.69 tpy per heater @ 96 ppmv and 16 ppmv total sulfur in fuel respectively.
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	HOLLYFRONTIER EL DORADO REFINING LLC	10/30/2019	L3804	456.5	MMBtu/hr	SO2	Low sulfur fuel gas.	0.0034	lb/MMBtu	BACT-PSD	
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	HOLLYFRONTIER EL DORADO REFINING LLC	10/30/2019	New Boiler	360.2	MMBtu/hr	SO2	Low sulfur fuel gas.	162	PPMV	BACT-PSD	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	PR Reactor Charge Heater	277	MMBtu/hr	SO2	Use of pipeline quality natural gas or fuel gas.	0.04	lb/hr	BACT-PSD	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	Boilers	1200	MMBtu/hr	SO2	Use of pipeline quality natural gas or fuel gas	0.69	lb/hr	BACT-PSD	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	Pyrolysis Furnaces	372	MMBtu/hr	SO2	Use of pipeline quality natural gas or fuel gas.	0.22	lb/hr	BACT-PSD	
LA-0385	GARYVILLE REFINERY	MARATHON PETROLEUM COMPANY LP	02/11/2021	FCCU Charge Heater (EQT0163)	315	MMBtu/hr	SO2	Comply with 40 CFR 60 Subpart J: Fuel gas H2S <=162 ppmv (3-hour rolling average). Fuel gas H2S <=60 ppmv (365-day rolling average).			BACT-PSD	
LA-0385	GARYVILLE REFINERY	MARATHON PETROLEUM COMPANY LP	02/11/2021	Crude Heaters (EQT0292)	745	MMBtu/hr	SO2	Fueled by natural gas and/or refinery fuel gas. Total Sulfur in fuel gas <= 40 ppmv and H2S in fuel gas <= 25 ppmv (annual average) based on monthly fuel gas sampling for sulfur plus CEMS weekly H2S average.			BACT-PSD	
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	04/23/2020	Boilers	250	MMBtu/hr	SO2	Good combustion practice and clean fuel.	2	gr/100 scf	BACT-PSD	

11.390 - Gaseous Fuel & Gaseous Fuel Mixtures (>250 MMBtu/hr) - Other Gaseous Fuel & Gaseous Fuel Mixtures

Pollutant: SO_2

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
AR-0162	ENERGY SECURITY PARTNERS GTL PLANT		01/10/2020	SGU Process Heater	391.5	MMBtu/hr	SO2	Low sulfur-content fuel gas.	0.0006	lb/MMBtu	BACT-PSD	
LA-0355	GARYVILLE REFINERY	MARATHON PETROLEUM COMPANY LP	09/06/2018	Coke Charge Heater - Unit 205 (EQT0201)	468.53	MMBtu/hr	SO2	Use fuel gas that meets requirements of 40 CFR 60 Subpart Ja.			BACT-PSD	
LA-0355	GARYVILLE REFINERY	MARATHON PETROLEUM COMPANY LP	09/06/2018	Coke Charge Heater - Unit 05 (EQT0173)	432.01	MMBtu/hr	SO2	Use fuel gas that meets requirements of 40 CFR 60 Subpart Ja.			BACT-PSD	
LA-0356	GARYVILLE REFINERY	MARATHON PETROLEUM COMPANY LP	09/27/2019	HCU Fractionator Heater (13-08, EQT0199)	408.67	MMBtu/hr	SO2	Use refinery fuel gas that meets requirements of 40 CFR 60 Subpart Ja.			BACT-PSD	
LA-0356	GARYVILLE REFINERY	MARATHON PETROLEUM COMPANY LP	09/27/2019	Coker Charger Heater (305-1401, EQT0357)	419.45	MMBtu/hr	SO2	Use refinery fuel gas that meets requirements of 40 CFR 60 Subpart Ja.			BACT-PSD	
*LA-0396	MARATHON GARYVILLE REFINERY	MARATHON PETROLEUM CO LP	12/04/2023	Vacuum Tower Heaters 210-1403 and 210-1404	338.77	MMBtu/hr	SO2	Limiting sulfur and hydrogen sulfide in fuel gas.	40	ppmv	BACT-PSD	Emission limit 1 is maximum total sulfur concentration in the fuel gas. Emission limit 2 is the maximum hydrogen sulfide concentration in the fuel gas. Limits are based on monthly fuel gas sampling for sulfur plus CEMS weekly H2S average.
TX-0832	EXXONMOBIL BEAUMONT REFINERY	EXXONMOBIL OIL CORPORATION	01/09/2018	F-1001 Crude Charge Furnace	630.8	MMBtu/hr	SO2	Use low sulfur gas fuel.	162	ppmvd	BACT-PSD	NSPS Ja, MACT CC, DDDDD
TX-0906	PORT ARTHUR REFINERY	THE PREMCOR REFINING GROUP INC.	10/30/2020	Boiler	250	MMBtu/hr	SO2	Low sulfur content in fuel.			BACT-PSD	
*TX-0938	VALERO CORPUS CHRISTI REFINERY WEST PLANT	VALERO REFINING-TEXAS, L.P.	05/03/2024	Boiler	462	MMBtu/hr	SO2	Good combustion practices and the use of gaseous fuel.	60	ppmvd	BACT-PSD	

11.310 - Gaseous Fuel & Gaseous Fuel Mixtures (>250 MMBtu/hr) - Natural Gas (Includes Propane and LPG)

Pollutant: NH_3

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	RV-13 - Reformer Vent (EQT0001)	3148	MMBtu/hr	NH3				BACT-PSD	
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	B1-13 - Boiler 1 (EQT0003)	350	MMBtu/hr	NH3				BACT-PSD	
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	B2-13 - Boiler 2 (EQT0004)	350	MMBtu/hr	NH3				BACT-PSD	
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	04/23/2020	Boilers	250	MMBtu/hr	NH3	Minimizing NH3 slip.	10	ppmvd	BACT-PSD	

15.210 - Combined Cycle and Cogeneration (>25 MW) - Natural Gas (Includes Propane and LPG)
Pollutant: HAPs
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	RENOVO ENERGY CENTER LLC	04/29/2021	Combustion Turbine w Duct Burner #1 (Natural Gas)	4,546	MMBtu/hr	Formaldehyde	SCR, Catalytic Oxidizer.	0.58	lb/hr	LAER	
PA-0334	RENOVO ENERGY CENTER LLC/RENOVO PLT	RENOVO ENERGY CENTER LLC	04/29/2021	Combustion Turbine w Duct Burner #2 (Natural Gas)	4,546	MMBtu/hr	Formaldehyde	SCR, Catalytic Oxidizer.	0.58	lb/hr	LAER	

Process Type: 19.200 - Emission Control Afterburners & Incinerators (Combustion Gases Only) (SOCMI, Including Ethylene and Polyethylene Operations)

Pollutant: SO_2

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes

None

Process Type: 19.310 - Chemical Plant Flares

Pollutant: SO_2

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Multi-Point Ground Flares (EQT 836 & 837)			SO2	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subparts FFFF and SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987; minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	0.95	lb/hr	BACT-PSD	
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	LLPDE/LDPE Multi-Point Ground Flare (EQT 640)			SO2	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.	1.15	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. BACT is also determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.
LA-0299	LAKE CHARLES CHEMICAL COMPLEX ETHOXYLATION UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	ETO/Guerbet Elevated Flare (EQT 1079)			SO2	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart PPP.	0.21	lb/hr	BACT-PSD	The permittee shall continuously monitor and record the volume of vent gas routed to the following flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips.
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 981)			SO2	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	8.96	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.

Process Type: 19.310 - Chemical Plant Flares
Pollutant: SO_2
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Ground Flare (EQT 982)			SO2	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	803.84	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare and Ground Flare (EQTs 1012 & 1013)			SO2	Compliance with 40 CFR 63.11(b) and the closed vent system requirements of 40 CFR 63.148; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	0.01	lb/hr	BACT-PSD	Pound per hour SO2 limitations are per flare. *Annual SO2 emissions from both flares are limited to the TPY value reported.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 133)			SO2	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	0.51	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Emission Combustion Unit #3 Ground Flare (EQT 500)			SO2	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	20.79	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	6/30/2016	Flares	1,008	MMBtu/hr	SO2				BACT-PSD	
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	4/1/2015	ammonia flare	106,396	MMBtu/yr	SO2		1.02	lb/hr	OTHER CASE-BY-CASE	Emission rates provided are for worst-case MSS scenarios.
TX-0863	POLYETHYLENE 7 FACILITY	THE DOW CHEMICAL COMPANY	9/3/2019	FLARE			SO2	Good combustion practices.			BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: SO_2

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	FLARE			SO2	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
TX-0911	FORMOSA POINT COMFORT PLANT	FORMOSA PLASTICS CORPORATION, TEXAS	12/15/2020	FLARE			SO2	Clean gas fuel.			BACT-PSD	
TX-0945	FORMOSA POINT COMFORT PLANT OL3	FORMOSA PLASTICS CORPORATION, TEXAS	4/6/2023	FLARES			SO2	Clean fuel and good combustion practices.			BACT-PSD	

Process Type: 19.330 - Refinery Flares

Pollutant: SO_2

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
NM-0052	ZIA II GAS PLANT	DCP MIDSTREAM L.P.	4/25/2014	Units FL1 & FL2: Refinery Flares (Inlet Gas Flare & Acid Gas Flare)	2.3	MMBtu/hr	SO2	NOx, CO, PM10, PM2.5, and SO2 controlled through good combustion practices (GCP), pipeline quality natural gas for pilot, and limits on flaring events. VOC and CO2e controlled through GCP, limits on flaring, and meeting 40 CFR 60.18.	13,023.6	lb/hr	BACT-PSD	
KS-0032	CHS MCPHERSON REFINERY, INC.	CHS MCPHERSON REFINERY, INC.	12/14/2015	Main Flare and Alky Flare			SO2				BACT-PSD	BACT for sulfur dioxide and PM/PM10 consists of design and workplace standards since there is no currently feasible method to measure emissions exiting the flares. BACT is using a flare design that meets the requirements of the 40 CFR 60.18 and API recommended practice 520 and 521. Workplace standards include continuously monitoring the pilot flame with infrared sensors, maintaining a natural gas/refinery gas purge so that the heating value of gases to the flares is not less than 300 Btu/scf, and using steam assisted mixing at the flare tip for smokeless operation.
TX-0832	EXXONMOBIL BEAUMONT REFINERY	EXXONMOBIL OIL CORPORATION	1/9/2018	No.12 Flare			SO2	Meets 40 CFR 60.18 and MACT CC design requirements.	8.4	tpy	BACT-PSD	NSPS Ja, MACT CC
TX-0873	PORT ARTHUR REFINERY	MOTIVA ENTERPRISES LLC	2/4/2020	Flare			SO2	Good combustion practices will be used to reduce emissions, including maintain proper air-to-fuel ratio, necessary residence time, temperature, and turbulence. Limit sulfur concentration in fuel and waste gas.			BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Main Flare			SO2	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.	0.2	gr/dscf	BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Butane (Rail Car) Flare			SO2	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.	0.2	gr/dscf	BACT-PSD	

Attachment 7

Request No. 5 Information

1.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The Pennsylvania Department of Environmental Protection's (DEP's) Prevention of Significant Deterioration (PSD) regulations at 25 Pa. Code §127.83 adopt the United States Environmental Protection Agency's (EPA's) PSD regulations in 40 Code of Federal Regulations (CFR) 52 in their entirety. EPA's PSD regulations at 40 CFR 52.21 require the application of best available control technology (BACT) when constructing a new major stationary source subject to PSD permitting and carrying out a major modification at an existing major stationary source subject to PSD permitting.

BACT is defined at 40 CFR 52.21(b)(12) as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…." As indicated by this definition, BACT is evaluated on a case-by-case basis, and a BACT determination is made based on an evaluation of the amount of emissions reduction that each available emissions-reducing technology or technique can achieve, as well as the energy, environmental, and economic impacts associated with each technology or technique. For a specific pollutant emitted by a particular emissions unit, a BACT analysis can result in the establishment of a numerical emissions limitation that reflects the maximum degree of reduction achievable for the pollutant through the application of the selected technology or technique on that emissions unit. However, design, equipment, work practice, or operation requirements may be established for a pollutant rather than a numerical emissions limitation if technical or economic factors limit the application of a measurement methodology to demonstrate compliance with such a limitation.

1.1 BACT Applicability

For a new major stationary source, a BACT determination must be made for each emissions unit constructed as part of the new stationary source that would have the potential to emit a regulated PSD pollutant for which the stationary source is determined to have the potential to emit in a significant amount. Alternatively, for a major modification at an existing major stationary source, a BACT determination must be made for the two types of emissions units described below:

- Each new emissions unit constructed as part of the major modification that would have the potential to emit a regulated PSD pollutant for which the modification is determined to result in a significant net emissions increase; and
- Each existing emissions unit undergoing a physical change or change in the method of operation as part of the major modification that would experience an emissions increase of a regulated PSD pollutant for which the modification is determined to result in a significant net emissions increase.

1.1.1 Plan Approval Reconciliations

In accordance with the BACT applicability criteria summarized above for the construction of a new major stationary source such as SPM, Shell contemporaneously completed a BACT analysis for each proposed SPM emissions unit that was estimated to have the potential to emit a regulated PSD pollutant for which SPM was determined to have the potential to emit in a significant amount. Specifically, for a particular proposed emissions unit, Shell contemporaneously completed a BACT analysis for each regulated PSD pollutant that the emissions unit was proposed to emit, and that SPM was determined to have the potential to emit in a significant amount.

Shell has retrospectively evaluated the Plan Approval Reconciliations as part of the initial SPM construction for NSR applicability purposes. As discussed in the September 13, 2024 plan approval application, Shell determined that the Plan Approval Reconciliations will not retrospectively cause the initial construction of SPM to require PSD permitting for any additional regulated PSD pollutants relative to the PSD applicability determinations that were made contemporaneous with DEP's authorization of the initial construction of SPM. As a result, the Plan Approval Reconciliations do not require the initial construction of SPM to be subject to any retrospective BACT analyses for regulated PSD pollutants that were not contemporaneously evaluated as part of the plan approval process that was completed for the initial construction of SPM. However, as documented in Table 1 beginning on the following page, 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.

Table 1. Evaluation of Emissions Units Potentially Requiring a Revised BACT Analysis due to the Plan Approval Reconciliations

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
031	Ethane Cracking Furnace #1	No, the furnace's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM (filterable only) potential to emit is proposed to decrease; therefore, the prior PM (filterable only) BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the furnace is not potentially subject to reevaluation.	Yes, the furnace's CO_2e potential to emit is proposed to increase by 9,180 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace.
032	Ethane Cracking Furnace #2	No, the furnace's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM (filterable only) potential to emit is proposed to decrease; therefore, the prior PM (filterable only) BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the furnace is not potentially subject to reevaluation.	Yes, the furnace's CO_2e potential to emit is proposed to increase by 9,180 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace.
033	Ethane Cracking Furnace #3	No, the furnace's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM (filterable only) potential to emit is proposed to decrease; therefore, the prior PM (filterable only) BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the furnace is not potentially subject to reevaluation.	Yes, the furnace's CO_2e potential to emit is proposed to increase by 9,180 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
034	Ethane Cracking Furnace #4	No, the furnace's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM (filterable only) potential to emit is proposed to decrease; therefore, the prior PM (filterable only) BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the furnace is not potentially subject to reevaluation.	Yes, the furnace's CO_2e potential to emit is proposed to increase by 9,180 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace.
035	Ethane Cracking Furnace #5	No, the furnace's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM (filterable only) potential to emit is proposed to decrease; therefore, the prior PM (filterable only) BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the furnace is not potentially subject to reevaluation.	Yes, the furnace's CO_2e potential to emit is proposed to increase by 9,180 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace.
036	Ethane Cracking Furnace #6	No, the furnace's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM (filterable only) potential to emit is proposed to decrease; therefore, the prior PM (filterable only) BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the furnace is not potentially subject to reevaluation.	Yes, the furnace's CO_2e potential to emit is proposed to increase by 9,180 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
037	Ethane Cracking Furnace #7	No, the furnace's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM (filterable only) potential to emit is proposed to decrease; therefore, the prior PM (filterable only) BACT determination for the furnace is not potentially subject to reevaluation.	No, the furnace's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the furnace is not potentially subject to reevaluation.	Yes, the furnace's CO_2e potential to emit is proposed to increase by 9,180 tpy because of a proposed increase in the natural gas-to-tail gas ratio for the gaseous fuel mixture that is combusted in the furnace.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
101	Combustion Turbine/Duct Burner Unit #1	No, the combustion turbine/duct burner unit's CO potential to emit is not proposed to increase; therefore, the prior CO BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, although the combustion turbine/duct burner unit's PM (filterable only) potential to emit is proposed to increase, this increase is because of a proposed correction of an incorrect emission factor reference in the previous emission calculation's filterable PM calculation (i.e., incorrect reference to the AP-42, Section 1.4, Table 1.4-2 emission factor of 1.9 lb/MMscf, or 0.00186 lb/MMBtu, instead of the AP-42, Section 3.1, Table 3.1-2a emission factor of 0.0019 lb/MMBtu), not because of a change in the method of operation of the unit or physical change to the unit. Additionally, the unit's proposed PM (filterable only) potential to emit increase is only 0.11 tpy, which would not affect the technical and economic feasibility analyses that were previously completed in support of the PM (filterable only) BACT determination for the unit.	No, the combustion turbine/duct burner unit's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's CO_2e potential to emit is proposed to decrease; therefore, the prior GHG BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
102	Combustion Turbine/Duct Burner Unit #2	No, the combustion turbine/duct burner unit's CO potential to emit is not proposed to increase; therefore, the prior CO BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, although the combustion turbine/duct burner unit's PM (filterable only) potential to emit is proposed to increase, this increase is because of a proposed correction of an incorrect emission factor reference in the previous emission calculation's filterable PM calculation (i.e., incorrect reference to the AP-42, Section 1.4, Table 1.4-2 emission factor of 1.9 lb/MMscf, or 0.00186 lb/MMBtu, instead of the AP-42, Section 3.1, Table 3.1-2a emission factor of 0.0019 lb/MMBtu), not because of a change in the method of operation of the unit or physical change to the unit. Additionally, the unit's proposed PM (filterable only) potential to emit increase is only 0.11 tpy, which would not affect the technical and economic feasibility analyses that were previously completed in support of the PM (filterable only) BACT determination for the unit.	No, the combustion turbine/duct burner unit's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's CO_2e potential to emit is proposed to decrease; therefore, the prior GHG BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
103	Combustion Turbine/Duct Burner Unit #3	No, the combustion turbine/duct burner unit's CO potential to emit is not proposed to increase; therefore, the prior CO BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, although the combustion turbine/duct burner unit's PM (filterable only) potential to emit is proposed to increase, this increase is because of a proposed correction of an incorrect emission factor reference in the previous emission calculation's filterable PM calculation (i.e., incorrect reference to the AP-42, Section 1.4, Table 1.4-2 emission factor of 1.9 lb/MMscf, or 0.00186 lb/MMBtu, instead of the AP-42, Section 3.1, Table 3.1-2a emission factor of 0.0019 lb/MMBtu), not because of a change in the method of operation of the unit or physical change to the unit. Additionally, the unit's proposed PM (filterable only) potential to emit increase is only 0.11 tpy, which would not affect the technical and economic feasibility analyses that were previously completed in support of the PM (filterable only) BACT determination for the unit.	No, the combustion turbine/duct burner unit's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.	No, the combustion turbine/duct burner unit's CO_2e potential to emit is proposed to decrease; therefore, the prior GHG BACT determination for the combustion turbine/duct burner unit is not potentially subject to reevaluation.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
104	Cogeneration Plant Cooling Tower	Not Applicable (N/A)	N/A	Yes, the cooling tower's PM (filterable only) potential to emit is proposed to increase by 1.01 tpy because of a proposed increase in the cooling tower's potential recirculation rate.	Yes, the cooling tower's PM_{10} potential to emit is proposed to increase by 0.64 tpy because of a proposed increase in the cooling tower's potential recirculation rate.	N/A
105	Diesel-Fired Emergency Generator Engines (2); Generator 1 - Parking Garage	No, the engine's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's CO_2e potential to emit is not proposed to increase; therefore, the prior GHG BACT determination for the engine is not potentially subject to reevaluation.
105	Diesel-Fired Emergency Generator Engines (2); Generator 2 - Telecom Hut	No, the engine's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's CO_2e potential to emit is not proposed to increase; therefore, the prior GHG BACT determination for the engine is not potentially subject to reevaluation.
106	Fire Pump Engines (2); Firewater Pump 1	No, the engine's CO potential to emit is not proposed to increase; therefore, the prior CO BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's CO_2e potential to emit is not proposed to increase; therefore, the prior GHG BACT determination for the engine is not potentially subject to reevaluation.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
106	Fire Pump Engines (2); Firewater Pump 2	No, the engine's CO potential to emit is not proposed to increase; therefore, the prior CO BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's CO_2e potential to emit is not proposed to increase; therefore, the prior GHG BACT determination for the engine is not potentially subject to reevaluation.
107	Natural Gas-Fired Emergency Generator Engines (2); Generator 3 - Lift Station	No, the engine's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's NOx potential to emit is proposed to decrease; therefore, the prior NOx BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's CO_2e potential to emit is proposed to decrease; therefore, the prior GHG BACT determination for the engine is not potentially subject to reevaluation.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
107	Natural Gas-Fired Emergency Generator Engines (2); Generator 4 - Lift Station	No, the engine's CO potential to emit is proposed to decrease; therefore, the prior CO BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's NOx potential to emit is not proposed to increase; therefore, the prior NOx BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the engine is not potentially subject to reevaluation.	No, the engine's PM_{10} potential to emit is proposed to increase by only 0.002 lb/yr, and this increase is because of a proposed correction of a typo in the previous emission calculation's condensable PM emission factor that is from AP-42, Section 3.2, Table 3.2-2 (i.e., typo of 0.009**8**1 versus 0.009**9**1 lb/MMBtu) and that is used to calculate the engine's PM_{10} potential to emit, not because of a change in the method of operation of the engine or physical change to the engine. Additionally, the engine's proposed PM_{10} potential to emit increase of only 0.002 lb/yr would not affect the technical and economic feasibility analyses that were previously completed in support of the PM_{10} BACT determination for the engine.	No, the engine's CO_2e potential to emit is not proposed to increase; therefore, the prior GHG BACT determination for the engine is not potentially subject to reevaluation.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
202	Polyethylene Manufacturing Lines	N/A	N/A	No, the source's PM (filterable only) potential to emit is proposed to decrease; therefore, the prior PM (filterable only) BACT determination for the source is not potentially subject to reevaluation.	No, the source's PM_{10} potential to emit is proposed to decrease; therefore, the prior PM_{10} BACT determination for the source is not potentially subject to reevaluation.	N/A
203	Process Cooling Tower	N/A	N/A	No, the cooling tower's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the cooling tower is not potentially subject to reevaluation.	No, the cooling tower's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the cooling tower is not potentially subject to reevaluation.	N/A
C204A	CVTO	Yes, the thermal oxidizer's CO potential to emit is proposed to increase by 26.78 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer.	Yes, the thermal oxidizer's NOx potential to emit is proposed to increase by 15.77 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer.	Yes, the thermal oxidizer's PM (filterable only) potential to emit is proposed to increase by 0.59 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer.	Yes, the thermal oxidizer's PM_{10} potential to emit is proposed to increase by 2.43 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer.	Yes, the thermal oxidizer's CO_2e potential to emit is proposed to increase by 41,319 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
C204B	MPGF	Yes, the flare's CO potential to emit is proposed to increase by 108.05 tpy because of a proposed increase in the amount of combustion that may occur at the flare.	Yes, the flare's NOx potential to emit is proposed to increase by 24.90 tpy because of a proposed increase in the amount of combustion that may occur at the flare.	Yes, the flare's PM (filterable only) potential to emit is proposed to increase by 0.67 tpy because of a proposed increase in the amount of combustion that may occur at the flare.	Yes, the flare's PM_{10} potential to emit is proposed to increase by 2.70 tpy because of a proposed increase in the amount of combustion that may occur at the flare.	Yes, the flare's CO_2e potential to emit is proposed to increase by 46,676 tpy because of a proposed increase in the amount of combustion that may occur at the flare.
C205A	TEGF A	Yes, the flare's CO potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 356.85 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's NOx potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 87.07 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's PM (filterable only) potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 2.38 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's PM_{10} potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 9.49 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's CO_2e potential to emit in combination with the TEGF B and HP Elevated Flare is proposed to increase by 112,297 tpy because of a proposed increase in the amount of combustion that may occur at the flares.
C205B	TEGF B	Yes, the flare's CO potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 356.85 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's NOx potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 87.07 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's PM (filterable only) potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 2.38 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's PM_{10} potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 9.49 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's CO_2e potential to emit in combination with the TEGF A and HP Elevated Flare is proposed to increase by 112,297 tpy because of a proposed increase in the amount of combustion that may occur at the flares.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
C205C	HP Elevated Flare	Yes, the flare's CO potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 356.85 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's NOx potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 87.07 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's PM (filterable only) potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 2.38 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's PM_{10} potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 9.49 tpy because of a proposed increase in the amount of combustion that may occur at the flares.	Yes, the flare's CO_2e potential to emit in combination with the TEGF A and TEGF B is proposed to increase by 112,297 tpy because of a proposed increase in the amount of combustion that may occur at the flares.
C206	SCTO	Yes, although the thermal oxidizer's CO potential to emit is proposed to increase by only 0.12 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer, Shell has conservatively reevaluated the CO BACT determination for the thermal oxidizer.	Yes, the thermal oxidizer's NOx potential to emit would be proposed to increase because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer. However, the proposed revision to the prior NOx LAER (BACT) determination for the thermal oxidizer is proposed to result in a 0.28 tpy decrease in the thermal oxidizer's NOx potential to emit.	No, the thermal oxidizer's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the thermal oxidizer is not potentially subject to reevaluation.	Yes, although the thermal oxidizer's PM_{10} potential to emit is proposed to increase by only 0.22 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer and due to properly accounting for the thermal oxidizer's condensable PM emissions that may occur due to the combustion of the spent caustic oxidation treatment operation vent gas in the thermal oxidizer, Shell has conservatively reevaluated the PM_{10} BACT determination for the thermal oxidizer.	Yes, although the thermal oxidizer's CO_2e potential to emit is proposed to increase by only 174 tpy because of a proposed increase in the amount of combustion that may occur in the thermal oxidizer, Shell has conservatively reevaluated the GHG BACT determination for the thermal oxidizer.

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
301	Polyethylene Pellet Material Storage/Handling/Loadout	N/A	N/A	No, the source's PM (filterable only) potential to emit is not proposed to increase; therefore, the prior PM (filterable only) BACT determination for the source is not potentially subject to reevaluation.	No, the source's PM_{10} potential to emit is not proposed to increase; therefore, the prior PM_{10} BACT determination for the source is not potentially subject to reevaluation.	N/A
302	Liquid Loadout (Recovered Oil)	N/A	N/A	N/A	N/A	N/A
303	Liquid Loadout (Pyrolysis Fuel Oil, Light Gasoline, PE3 Heavies)	N/A	N/A	N/A	N/A	N/A
304	Liquid Loadout (C3+, Butene, Isopentane, Isobutane, C3 Ref)	N/A	N/A	N/A	N/A	N/A
305	Liquid Loadout (Blended Pitch)	N/A	N/A	N/A	N/A	N/A
401	Storage Tanks (Recovered Oil, Equalization Wastewater)	N/A	N/A	N/A	N/A	N/A
402	Storage Tank (Spent Caustic)	N/A	N/A	N/A	N/A	N/A
403	Storage Tanks (Light Gasoline)	N/A	N/A	N/A	N/A	N/A
404	Storage Tanks (Hexene)	N/A	N/A	N/A	N/A	N/A
405	Storage Tanks (Misc Pressurized/Refrigerated)	N/A	N/A	N/A	N/A	N/A
406	Storage Tanks (Diesel Fuel > 150 Gallons)	N/A	N/A	N/A	N/A	N/A

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
407	Storage Tanks (Pyrolysis Fuel Oil)	N/A	N/A	N/A	N/A	N/A
408	Storage Tanks (Diesel Fuel < 150 Gallons)	N/A	N/A	N/A	N/A	N/A
409	Methanol Storage Vessels and Associated Components	N/A	N/A	N/A	N/A	N/A

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
501	Equipment Components	Yes, although the source's CO potential to emit is proposed to equal only 0.35 tpy, a CO BACT determination was not previously completed for the source because it was not proposed to have the potential to emit CO.	N/A	N/A	N/A	No, although the source's CO_2e potential to emit is proposed to increase by 212 tpy (6.95 tpy increase in methane), this minor increase is primarily because of proposed updates to SPM's component inventory and the composition of the materials contained in those components to more accurately represent the number of equipment leak components constructed at SPM and the material compositions at SPM, which is a common type of as-built reconciliation for an entirely new facility that does not warrant a revised control technology analysis when it results in a minor emissions increase. Additionally, EPA increased methane's global warming potential (GWP) from 25 to 28 effective January 1, 2025, which also contributed to the proposed increase in the source's CO_2e potential to emit.
502	Wastewater Treatment Plant	N/A	N/A	N/A	N/A	N/A

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
503	Plant Roadways	N/A	N/A	No, although the source's PM (filterable only) potential to emit is proposed to increase by 0.10 tpy, this minor increase is because of proposed minor updates to the total onsite mileage travelled by trucks that are used to transport materials in and out of SPM, as well as the average weight of these trucks, which is a common type of as-built reconciliation for an entirely new facility that does not warrant a revised control technology analysis when it results in a minor emissions increase. Additionally, the source's proposed PM (filterable only) potential to emit increase of only 0.10 tpy would not affect the technical and economic feasibility analyses that were previously completed in support of the PM (filterable only) BACT determination for the source.	No, although the source's PM_{10} potential to emit is proposed to increase by 0.03 tpy, this minor increase is because of proposed minor updates to the total onsite mileage travelled by trucks that are used to transport materials in and out of SPM, as well as the average weight of these trucks, which is a common type of as-built reconciliation for an entirely new facility that does not warrant a revised control technology analysis when it results in a minor emissions increase. Additionally, the source's proposed PM_{10} potential to emit increase of only 0.03 tpy would not affect the technical and economic feasibility analyses that were previously completed in support of the PM_{10} BACT determination for the source.	N/A

Source ID	Source Description	Revised BACT Analysis Needed for CO?	Revised BACT Analysis Needed for NOx?	Revised BACT Analysis Needed for PM (filterable only)?	Revised BACT Analysis Needed for PM_{10}?	Revised BACT Analysis Needed for GHGs?
504	Gas Insulated Switchgear (SF6)	N/A	N/A	N/A	N/A	No, although the source's CO_2e potential to emit is proposed to increase by 26 tpy, this increase is a result of EPA increasing sulfur hexafluoride's GWP from 22,800 to 23,500 effective January 1, 2025, not because of a change in the method of operation of the source or physical change to the source.

1.2 BACT Analysis Process

The process typically used to perform a BACT analysis is the five-step "top-down" BACT process. Although this specific process is not required by EPA's PSD regulations, Shell has used it to make the BACT determinations in this submittal.[1] In general, the top-down BACT process starts with consideration of the control technology that would achieve the maximum degree of emissions limitation (lowest emission rate) for an emissions unit and that can be or has been applied to the same type of emissions unit or to a similar type of emissions unit. The top-ranked control technology that is considered technically available may be eliminated based on economic, environmental, and/or energy impacts. If the top-ranked control technology is not chosen, then the analysis proceeds to the next most stringent control technology. This process continues until a BACT decision is reached. The following is a detailed outline of the steps used to perform the top-down BACT process.

1.2.1.1 Step 1: Identify All Control Technologies

The first step in the top-down BACT process is to define the spectrum of process and/or add-on emission control alternatives potentially available for application to an emissions unit. Under the federal statutory definition of BACT, "in no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 [New Source Performance Standards (NSPS)] or 112 [National Emission Standards for Hazardous Air Pollutants (NESHAP)] of this Act [Clean Air Act]." Consequently, an applicable NSPS or NESHAP emission limitation represents a "floor" or "baseline" when making a BACT determination. Consistent with this concept, Shell did not identify as available for a specific emissions unit any control technology that, at a minimum, would not comply with NSPS and/or NESHAP emission limitations applicable to the emissions unit. Shell primarily relied upon a review of EPA's reasonably available control technology (RACT)/BACT/LAER Clearinghouse (RBLC) database to identify BACT alternatives.

1.2.1.2 Step 2: Eliminate Technically Infeasible Options

The second step is to evaluate the technical feasibility of the alternatives identified in Step 1 and to reject those which are technically infeasible based on an engineering evaluation or due to chemical or physical principles. The following criteria are considered in determining technical feasibility: previous commercial scale demonstrations, precedents based on previous permits, and technology transfer from similar emissions units. EPA stated the following in its 1990 Draft New Source Review Workshop Manual[2] regarding technical feasibility for newly developing technologies.

> *Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice.* B.11.

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[1] On July 23, 1996, EPA proposed to revise the federal PSD regulations to incorporate the top-down process (61 Federal Register 38250). However, that proposed revision has never been promulgated.

[2] EPA. *New Source Review Workshop Manual*. Draft. October 1990.

When evaluating the technical feasibility of a control technology that has been operated successfully on a type of emissions unit that is different than the unit type under review, EPA has indicated that the "availability" and "applicability" of the control technology to the unit type under review should be considered to eliminate the control technology as technically infeasible. For this situation, EPA stated in its March 2011 GHG Permitting Guidance[3] that it "considers a technology to be 'available' where it can be obtained through commercial channels or is otherwise available within the common meaning of the term." In the same document, EPA stated that it "considers an available technology to be 'applicable' if it can reasonably be installed and operated on the source type under consideration."

1.2.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

The third step involves an assessment of the emissions level achievable by each technically feasible control technology when taking into consideration the specific operating constraints of the emissions unit undergoing review. After determining the control efficiency achievable by each of the technically feasible control technologies, they are ranked from most to least stringent control technology.

1.2.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

The fourth step is to evaluate the economic, environmental, and energy impacts of the top or most stringent control technology. To reject the top control technology, it must be demonstrated to be infeasible based on the results of this impacts analysis. If a control technology is determined to be infeasible due to costs or adverse energy or environmental impacts (including toxic pollutant impacts), then it is rejected as BACT, and the impacts analysis is performed on the next most stringent control technology alternative. Regarding the cost evaluation performed in this step, both average cost effectiveness and incremental cost effectiveness may be derived for the control technology alternatives. Cost effectiveness is the cost of a control technology divided by the mass of emissions (in tons) reduced by that control technology. For a specific control technology, average cost effectiveness is the cost per ton that would be incurred compared with a baseline control level (i.e., either uncontrolled or the control level that would be required in the absence of BACT requirements, such as NSPS, NESHAP, or DEP standards). Incremental cost effectiveness is the difference in cost per ton of emissions reduced at the next most stringent level of control, when comparing two control technology options.

1.2.1.5 Step 5: Select BACT

BACT is identified as the control technology option with the highest control effectiveness that was not eliminated in Step 4.

1.3 Summary of BACT Determinations

Table 2 below summarizes the BACT determinations made for the Plan Approval Reconciliations.

[3] EPA. Office of Air Quality Planning and Standards. Air Quality Policy Division. *PSD and Title V Permitting Guidance for Greenhouse Gases*. EPA-457/B-11-001. March 2011.

Table 2. Summary of BACT Determinations

Emissions Unit	Pollutant	Control Technology/ Work Practice	Emissions Level
Ethane Cracking Furnaces #1 through #7	GHGs	• Low-carbon fuels: Tail gas and natural gas • Energy efficient design: Exhaust gas temperature from each ethane cracking furnace stack ≤ 350°F on a 12-month rolling average, excluding periods of startup, shutdown, hot steam standby, and decoking • Good combustion practices: Tune-up of each furnace at a minimum of once every 5 years	≤ 1,112,927 tpy CO_2e combined, 12-month rolling period
Cogeneration Plant Cooling Tower	PM (filterable only)	• High-efficiency drift eliminator: ≤ 0.0005% drift loss design • Manage cooling water total dissolved solids (TDS) levels: ≤ 2,000 parts per million by weight (ppmw) TDS in cooling water, 12-month rolling average	-
	PM_{10}	• High-efficiency drift eliminator: ≤ 0.0005% drift loss design • Manage cooling water TDS levels: ≤ 2,000 ppmw TDS in cooling water, 12-month rolling average	-
CVTO	CO	Good combustion practices	≤ 0.0824 pounds per MMBtu (lb/MMBtu), 3-hour average
	NOx	• Low NOx burners (LNBs) • Good combustion practices	≤ 0.06 lb/MMBtu, 3-hour average
	PM (filterable only)	Good combustion practices	≤ 0.0019 lb/MMBtu, 3-hour average
	PM_{10}	Good combustion practices	≤ 0.0075 lb/MMBtu, 3-hour average
	GHGs	• Low-carbon fuel: Natural gas • Good combustion practices	-

Emissions Unit	Pollutant	Control Technology/ Work Practice	Emissions Level
MPGF	CO	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
	NOx	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
	PM (filterable only)	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
	PM_{10}	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-

Emissions Unit	Pollutant	Control Technology/ Work Practice	Emissions Level
MPGF (cont'd)	GHGs	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements • Low-carbon fuel: Natural gas	-
TEGF A, TEGF B, and HP Elevated Flare	CO	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
	NOx	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
	PM (filterable only)	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-

Emissions Unit	Pollutant	Control Technology/ Work Practice	Emissions Level
TEGF A, TEGF B, and HP Elevated Flare (cont'd)	PM_{10}	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements	-
	GHGs	• Flare minimization: flare operated in accordance with a flare minimization plan • Good combustion practices: flare designed and operated in accordance with 40 CFR 63 Subparts CC/YY flare control device design, operating, and monitoring requirements • Low-carbon fuels: Tail gas and natural gas	-
SCTO	CO	Good combustion practices	≤ 0.0824 lb/MMBtu, 3-hour average
	NOx	• LNBs • Good combustion practices	≤ 0.06 lb/MMBtu, 3-hour average
	PM_{10}	Good combustion practices	≤ 0.012 lb/MMBtu, 3-hour average
	GHGs	• Low-carbon fuel: Natural gas • Good combustion practices	-
Equipment Components	CO	• Equipment design • Leak detection and repair (LDAR)	-

Below, Shell documents the analysis that was completed to make these BACT determinations.

1.4 Ethane Cracking Furnace BACT Determinations

As presented below, Shell has reevaluated the GHG BACT determination that was previously made for the seven identical ethane cracking furnaces at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BACT determination reevaluation for the ethane cracking furnaces is documented in Attachment 7-1.

1.4.1 GHGs

The ethane cracking furnaces heat ethane feedstock to very high temperatures by combusting the tail gas that is generated by SPM's ethylene manufacturing unit, which is augmented as needed by natural gas to achieve the ethane cracking furnace design heat input rate. Ethane cracking furnace combustion products include the following GHGs: carbon dioxide (CO_2), which is the product of combustion of a carbon-based fuel; methane, which is a product of incomplete combustion; and, nitrous oxide, which is generated by the oxidation of nitrogen in the combustion air.[4] Despite having greater GWP than CO_2, the small quantities of methane and nitrous oxide generated by the ethane cracking furnaces make their contribution to the furnaces' total GHG emissions insignificant, and they are therefore not considered in this analysis.

Additionally, the ethane cracking furnaces will periodically be decoked to maintain efficient operation, extend the life of the tubes in the radiant section of the furnace, and prevent tube failure. GHGs are emitted during the decoking process, but less than during normal furnace operation due to the reduced furnace firing rate associated with the decoking process.

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.

1.4.1.1 Step 1: Identify Control Technologies

All available GHG emission reduction alternatives that could potentially be applied to the ethane cracking furnaces have been identified for consideration as BACT. Available alternatives are those with a practical potential for application to the emissions unit under review, which have been demonstrated in practice on full scale operations and are commercially available.

Most GHG emission reduction alternatives seek to decrease GHG emission intensity by increasing efficiency, whether it be through better use of fuels or raw materials, or improved equipment or process design. The following are potentially available GHG emission control technologies identified for the ethane cracking furnaces.

- Low-carbon fuels
- Energy efficient design
- Good combustion practices
- Carbon capture and storage (CCS)

[4] Nitrous oxide is also formed from the oxidation of organic nitrogen compounds in the fuel, but the tail gas and natural gas, contain few if any of these compounds, so the quantity of nitrous oxide generated by this formation mechanism is negligible.

These technologies are generally described below.

Low-Carbon Fuels

Low-carbon fuels emit a reduced amount of GHGs per unit of thermal energy production relative to other fuels. SPM uses a combination of tail gas and natural gas as fuel in the ethane cracking furnaces. Tail gas and natural gas are low-carbon fuels based on their composition. Tail gas is mostly comprised of hydrogen and methane. Hydrogen combustion does not result in GHGs, as water is the product of hydrogen combustion. Natural gas, which is primarily comprised of the single carbon atom compound methane, results in lower CO_2 emissions per unit of thermal energy production compared to alternative gaseous, liquid, and solid fuels that are comprised of hydrocarbon compounds containing two or more carbon atoms.

Energy Efficient Design

Energy efficient design features for enclosed combustion devices such as the ethane cracking furnaces minimize fuel use while maximizing thermal efficiency. As such, these design features are generally incorporated into a combustion device's design to reduce its fuel operating costs and increase its productivity. Below are energy efficient design features that enclosed combustion devices may utilize.

- Heat exchanger(s) that preheat a combustion device's combustion air using the device's hot exhaust gases
- Heat exchanger(s) in a combustion device's convection section that recover heat from the device's hot exhaust gases to heat a process fluid or water to higher temperatures, produce steam, and/or heat saturated steam to produce superheated steam
- Instrumentation and process control features that allow for accurate, real-time monitoring and optimization of a combustion device's combustion operations

Good Combustion Practices

Good combustion practices for an enclosed combustion device require a properly set and controlled air-to-fuel ratio and appropriate combustion zone residence time, temperature, and turbulence parameters to ensure steady and efficient combustion operations. Inefficient and incomplete combustion requires increased amounts of fuel combustion to achieve the necessary heat transfer in an enclosed combustion device such as a boiler, heater, or furnace. This undesirable operating scenario can occur because of improper combustion mechanisms, which may result from poor burner/combustion device design, operation, and/or maintenance.

CCS

CCS is a process that involves capturing CO_2 at its source and storing it (or using it) to avoid its release to the atmosphere. More specifically, the CCS process consists of four steps: (1) removing or segregating CO_2 from a gas stream mixture containing CO_2, (2) compressing the separated CO_2, (3) transporting the CO_2 to a location where it can be stored or used, and (4) permanently storing the CO_2 (i.e., in a permitted Class VI well) or using it in a beneficial way (i.e., enhanced oil recovery or other industrial use).

Below are three basic approaches available to capture CO_2 that is generated in association with hydrocarbon fuel combustion processes.

- Post-combustion capture – the hydrocarbon fuel is combusted using ambient air and the CO_2 that is generated is removed from the combustion exhaust gases using a solvent scrubbing system, physical filter, cryogenic condensation system, or membrane separation system.
- Pre-combustion capture – the hydrocarbon fuel is first converted to a syngas composed largely of CO_2 and hydrogen; then, the CO_2 is removed from the syngas, and the remaining hydrogen is combusted using ambient air, which produces combustion exhaust gases comprised almost completely of water.
- Oxy-fuel combustion – the hydrocarbon fuel is combusted using high-purity oxygen instead of ambient air, which produces combustion exhaust gases containing a concentrated amount of CO_2 that allows for a smaller-scale system to remove CO_2 from the exhaust gases.

In each of the above cases, the captured CO_2 would be compressed and transported via pipeline to a storage or industrial use location to complete the CCS process.

1.4.1.2 Step 2: Eliminate Technically Infeasible Options

Available emission reduction alternatives identified in Step 1 are evaluated for application to the ethane cracking furnaces and, if found to be technically infeasible in this application, eliminated.

Low-Carbon Fuels

The primary fuel combusted by the ethane cracking furnaces is tail gas, which typically contains at least 79 mole percent hydrogen, with the balance mostly comprised of methane. The secondary fuel combusted by the ethane cracking furnaces is natural gas. A review of the CO_2 emission factors in 40 CFR Part 98, Table C-1 indicates that natural gas emits the least CO_2 per unit of thermal energy production among the fuels that are available at SPM, except for the tail gas that is generated by SPM's ethylene manufacturing unit and recovered to be efficiently used as fuel at SPM. Thus, the use of low-carbon fuels is a technically feasible alternative to reduce GHG emissions from the ethane cracking furnaces. Furthermore, the combustion of tail gas (a very low-carbon fuel generated onsite) and natural gas in the ethane cracking furnaces is a highly effective technique to maximize energy efficiency and carbon minimization at SPM.

Energy Efficient Design

Energy efficiency was a fundamental design criterion for the ethane cracking furnaces. Therefore, energy efficient design is considered a technically feasible alternative to reduce GHG emissions from the furnaces.

Good Combustion Practices

The ethane cracking furnaces are designed and operated in accordance with good combustion practices. Therefore, good combustion practices are considered a technically feasible alternative to reduce GHG emissions from the furnaces.

CCS

There is broad consensus that the technology for safe and effective capture, transport, and storage or use of CO_2 currently exists, but CCS programs are not commercially available. For example, in January 2021, the Texas Commission on Environmental Quality issued a permit to the Phillips 66 Borger Refinery that determined GHG BACT for two crude charge heaters and a continuous catalytic reformer heater was energy efficient design, low-carbon fuels (i.e., refinery fuel gas and natural gas), and good combustion practices; CCS was not considered to be a technically feasible alternative in the GHG BACT evaluation. Nevertheless, for purposes of this BACT analysis, CCS using a post-combustion capture technology is considered to be a technically feasible control alternative for CO_2 emissions from the ethane cracking furnaces. Alternatively, pre-combustion capture technology is not considered technically feasible because the tail gas fuel is already hydrogen-rich and the pyrolysis or steam reforming of the methane portion of the tail gas and/or any added natural gas would significantly complicate SPM's operations and yield limited benefits. Additionally, oxy-fuel combustion is not considered a technically feasible combustion approach for this analysis because it has not advanced significantly beyond the research and pilot plant phase.

CCS is an add-on technology for the removal of CO_2 from a gas stream, and CO_2 emissions represent greater than 99.9 weight percent of the GHG emissions from the ethane cracking furnaces. Although add-on technologies to remove only methane or nitrous oxide from a gas stream are commercially available (e.g., thermal and catalytic oxidation, non-selective catalytic reduction), none have been employed for the specific purpose of removing these GHG compounds from combustion source exhaust gases. Furthermore, on a CO_2e basis, methane and nitrous oxide emissions combined comprise less than 0.15 weight percent of the CO_2e emissions from the ethane cracking furnaces; thus, application of one or more add-on technologies to reduce these specific GHGs from the ethane cracking furnaces would have a negligible effect on the furnaces' overall GHG emission rate, even if such an approach were found to be technically feasible. Therefore, no add-on technologies for the removal of only methane and/or nitrous oxide from the combustion exhaust gases of the ethane cracking furnaces were considered in this GHG BACT analysis.

1.4.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

The available GHG emission reduction alternatives for the ethane cracking furnaces are listed below from the highest to lowest potential GHG emission reduction relative to baseline emissions.

- CCS: Post-combustion technology can capture between 85 to 90 percent of the CO_2 in typical combustion exhaust gases.
- Low-Carbon Fuels: This control technology is used by the ethane cracking furnaces because they combust only tail gas and natural gas as fuels.
- Energy Efficient Design: This control technology is used by the ethane cracking furnaces because each furnace includes the following energy efficient design features.
  - Convection section process feedstock heater heat exchanger
  - Convection section boiler feedwater heater heat exchanger

- Convection section steam production heat exchanger
- Convection section steam superheater heat exchanger
- Excess air monitoring and control system

- Good Combustion Practices: This control technology is used by the ethane cracking furnaces because they are designed and operated pursuant to these principles.

1.4.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

EPA's March 2011 GHG Permitting Guidance[5] suggests that, instead of the traditional BACT evaluation approach where emission reduction alternatives are considered and either eliminated or adopted in decreasing order of effectiveness, the economic, energy, and environmental impacts of all options are considered. Considering this guidance, each technically feasible option was evaluated, regardless of the Step 3 ranking.

Low-Carbon Fuels

The primary fuel combusted by the ethane cracking furnaces is tail gas, which is a very low-carbon fuel because it contains a considerable amount of hydrogen that does not generate GHGs when combusted. Additionally, the natural gas that is also combusted in the ethane cracking furnaces as fuel is a low-carbon fuel because it is primarily comprised of methane, a single carbon atom compound that results in lower CO_2 emissions per unit of thermal energy production than other hydrocarbon compounds that may be used as fuel.

Energy Efficient Design

The ethane cracking furnaces include design features that optimize the amount of heat recovered from the combustion process that occurs in the furnaces, which reduces the amount of hydrocarbon fuel combustion required to occur in the furnaces, as well as the requirement to have additional hydrocarbon fuel combustion sources (e.g., boilers) at SPM.

Good Combustion Practices

The ethane cracking furnace heaters are designed, operated, and maintained as recommended by the manufacturer to ensure good combustion practices are followed.

CCS

This CCS evaluation considers 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, and an associated pipeline that would be used to transport captured CO_2 from the ethane cracking furnace, CVTO, and SCTO combustion exhaust gases to an offsite location. Costs associated with combining the exhaust gases from the ethane cracking furnaces, CVTO, and SCTO are

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[5] EPA. Office of Air Quality Planning and Standards. Air Quality Policy Division. *PSD and Title V Permitting Guidance for Greenhouse Gases*. EPA-457/B-11-001. March 2011.

not considered, which means the costs presented in this analysis underestimate the actual costs that would occur to install and operate a CCS system on the ethane cracking furnaces, CVTO, and SCTO.

There are several possible methods to capture CO_2 from post-combustion exhaust gases, but only amine-based absorption systems are considered to be currently commercially available. Amine absorption systems have been employed to treat exhaust gases with CO_2 concentrations of between 9 and 12.5 volume percent. The combustion exhaust gases from the ethane cracking furnaces, which would comprise approximately 84 percent of the total combined exhaust volume, contain less than 5 volume percent CO_2 due to the combustion of tail gas in the furnaces, which is considerably less than typical amine-based CO_2 capture system applications and would reduce the cost-effectiveness of the overall CCS system.

In a study published in 2022,[6] the cost of an amine-based CO_2 capture system[7] was estimated for Unit 3 of PacifiCorp's Hunter Power Plant in Emery County, Utah ("Hunter Unit 3"). Hunter Unit 3 is a large coal-fired unit, and the analysis did not include the cost to reduce SO_2 and SO_3 concentrations in the unit's combustion exhaust gases to levels that would not react with and contaminate the amine solution in an amine-based CO_2 capture system. The volume of Hunter Unit 3's combustion exhaust gases is approximately 40 percent more than the total volume of the combustion exhaust gases of SPM's seven ethane cracking furnaces, CVTO, and SCTO.[8] Additionally, the CO_2 concentration in Hunter Unit 3's combustion exhaust gases was estimated to be approximately 12.3 volume percent, which is more than twice the CO_2 concentration in the combined combustion exhaust gases from the ethane cracking furnaces, CVTO, and SCTO.

The costs of a 90 percent effective CO_2 capture system for Hunter Unit 3 were scaled linearly[9] using the exhaust gas flow rate of Hunter Unit 3 and the combined exhaust gas flow rate of the ethane cracking furnaces, CVTO, and SCTO, which ignores any favorable economies of scale realized by the larger Hunter Unit 3. On this basis, the estimated annualized capital cost for a CO_2 capture system for the combined exhaust gases from the ethane cracking furnaces, CVTO, and SCTO is approximately $45.5 million,[10] and the annual operating cost is estimated to be approximately $49.7 million, for a total annual cost of approximately $95.2 million. Operating costs include the energy required to operate the amine-based capture system and to compress and condition the desorbed CO_2 for use or transport, as well as the cost of water treatment, makeup solvent, spent solvent disposal, and operating labor.

Captured CO_2 is a potentially valuable commodity that is used in various chemical and oil extraction industries, such as enhanced oil recovery (EOR). However, there are no operations at or near SPM

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[6] Palash Panja, Brian McPherson, and Milind Deo. Techno-Economic Analysis of Amine-based CO_2 Capture Technology: Hunter Plant Case Study. Carbon Capture Science & Technology 3 (2022).

[7] The "capture system" includes the separation of CO_2 from combustion exhaust gases using an amine solvent, desorbing the captured CO_2 from the amine solvent, amine solvent recovery, dehydration of the desorbed CO_2, and compression of the captured CO_2 for delivery to a pipeline for transport to an offsite location.

[8] 1,574,000 acfm vs. 1,017,336 acfm.

[9] Note that a linear scaling approach is more conservative than the generally accepted "sixth-tenths rule" or "0.6 rule" that is often used in engineering cost analyses to estimate costs for comparable equipment of different sizes or capacities.

[10] The capital cost was annualized using a capital recovery factor of 0.0806, which assumes an equipment life of 30 years and an interest rate of 7.0 percent.

capable of utilizing the captured CO_2, meaning it would have to be transported to another location to be used or stored. In the United States, CO_2 transportation is primary accomplished using pipelines, and the predominant end use is EOR. The technology used to design, construct, and operate a CO_2 pipeline is similar to those used for natural gas and oil pipelines.

The United States Department of Energy (DOE) National Energy Technology Laboratory (NETL) has developed a spreadsheet-based model to estimate the cost of a single point-to-point pipeline to transport liquid phase CO_2.[11] An online NETL CCS database[12] was used to identify potential CO_2 storage facilities near SPM to minimize the cost of the pipeline that would be needed to transport CO_2 captured from the ethane cracking furnace, CVTO, and SCTO combustion exhaust gases. Using the NETL cost model and the nearest storage location,[13] the capital cost of the pipeline would be approximately $26.5 million, which is equivalent to an annualized capital cost of $2.1 million.[14] The annual operating costs for a pipeline to this location would be approximately $1 million, for a total annual pipeline cost of approximately $3.1 million. A more realistic, but more distant, alternative storage location scenario based on a planned CO_2 storage facility[15] was calculated using the NETL cost model to have a pipeline capital cost of approximately $115.5 million, which is equivalent to an annualized capital cost of $9.3 million.[16] The annual operating costs for this pipeline would be approximately $2.9 million, for a total annual pipeline cost of approximately $12.2 million. The estimated total annual cost of the combined CO_2 capture system and transport pipeline ranged from $98.2 million to $107.4 million for the two storage location scenarios.

These considerable costs, which are documented in Attachment 7-2, 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 for the installation and operation of a CCS system to reduce CO_2 emissions to the atmosphere from the ethane cracking furnaces, CVTO, and SCTO. Also, the increased energy requirements of a CCS system would result in the generation of additional emissions of criteria pollutants, hazardous air pollutants (HAPs), and GHGs, which represents an unacceptable collateral environmental impact that would potentially offset the environmental benefits of CO_2 CCS in this specific case. Furthermore, a considerable amount of time would be required to acquire all necessary property rights and obtain regulatory authority approvals before the lengthy CCS CO_2 transportation pipeline construction process could begin. As a result of these numerous disqualifying factors, a CCS system was removed from consideration as BACT for GHG emissions from the ethane cracking furnaces, CVTO, and SCTO.

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[11] https://netl.doe.gov/energy-analysis/search?search=CO2TransportCostModel
[12] https://netl.doe.gov/carbon-management/carbon-storage/worldwide-ccs-database
[13] The assumed location is a terminated CO_2 storage project near Wellsville, Ohio, which is approximately 21 miles from SPM. This scenario assumes that the storage project could resume development.
[14] The capital cost was annualized using a capital recovery factor of 0.0806, which assumes an equipment life of 30 years and an interest rate of 7.0 percent.
[15] The assumed location is a planned CO_2 storage project near Coshocton, Ohio, which is approximately 94 miles from SPM.
[16] The capital cost was annualized using a capital recovery factor of 0.0806, which assumes an equipment life of 30 years and an interest rate of 7.0 percent.

1.4.1.5 Step 5: Select BACT

Shell 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 ethane cracking furnaces. Accordingly, Shell will comply with the following GHG BACT requirements for the ethane cracking furnaces.

- Combust only tail gas and natural gas in the ethane cracking furnaces.
- Include energy efficient design features in the ethane cracking furnaces such that the exhaust gas temperature from each of the ethane cracking furnace stacks does not exceed 350°F on a monthly 12-month rolling average, excluding periods of startup, shutdown, hot steam standby, and decoking.
- Operate the ethane cracking furnaces in accordance with good combustion practices, including performing a tune-up of each furnace at a minimum of once every 5 years.
- Comply with a GHG BACT limit of 1,112,927 tpy CO_2e combined (12-month rolling period) for the ethane cracking furnaces.

1.5 Cogeneration Plant Cooling Tower BACT Determinations

As presented below, Shell has reevaluated the PM and PM_{10} BACT determinations that were previously made for the Cogeneration Plant Cooling Tower at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BACT determination reevaluations for the Cogeneration Plant Cooling Tower is documented in Attachment 7-1.

1.5.1 PM and PM_{10}

The Cogeneration Plant Cooling Tower is a counter-flow mechanical draft recirculating cooling tower that provides cooling water to the three cogeneration units (Cogen Units) at SPM. In a wet cooling tower, the cooling water circulating through the tower makes direct contact with the air passing through the tower. The air exiting the tower contains a certain amount of entrained cooling water, and these cooling water droplets are referenced as "drift." This drift contains the same TDS as the water circulating in the tower. PM and PM_{10} emissions result from the drift when the water comprising the water droplet evaporates, and the TDS contained in the water droplet remain suspended in the atmosphere. However, the Cogeneration Plant Cooling Tower is equipped with high-efficiency drift eliminators to minimize the amount of drift from the cooling tower.

The Cogeneration Plant Cooling Tower is currently subject to the following PM and PM_{10} BACT requirements.

- The cooling tower shall be equipped with drift/mist eliminators designed not to exceed 0.0005% drift loss.
- The cooling tower water TDS shall not exceed 2,000 ppmw on a monthly 12-month rolling average.

1.5.1.1 Step 1: Identify Control Technologies

The following are available PM and PM_{10} emission control technologies for the Cogeneration Plant Cooling Tower.

- High-efficiency drift eliminator
- Low cooling water TDS levels
- Air-cooled heat exchanger

These technologies are generally described below. As previously noted, the Cogeneration Plant Cooling Tower is currently required to be equipped with high-efficiency drift eliminators, and the cooling tower's recirculating water TDS levels are limited to 2,000 ppmw on a monthly 12-month rolling average.

High-Efficiency Drift Eliminator

Wet cooling towers primarily rely on the latent heat of water evaporation to cool a process. Cooling water is pumped between an indirect contact process heat exchanger and the direct contact cooling tower. The cooling water absorbs heat in the indirect contact process heat exchanger and the heated cooling water then transfers heat via direct contact to an air stream passing through the cooling tower. Specifically, the cooling water temperature is lowered in the cooling tower due to the temperature gradient driven transfer of heat from the higher temperature cooling water to the lower temperature air stream, as well as the evaporation of some of the circulating cooling water into the air stream flowing through the cooling tower. A portion of the circulating water becomes entrained in the air stream and is carried out of the tower as drift droplets.

Drift eliminators reduce the amount of drift droplets from a wet cooling tower, thereby reducing the PM and PM_{10} emissions from this type of cooling tower. Drift eliminators are placed where the air flow exits the cooling tower, and these devices rely on inertial separation caused by direction changes to remove entrained water from the exiting air stream. Current day drift eliminators are typically recognized as "high-efficiency" drift eliminators.

Low Cooling Water TDS Levels

As previously indicated, the TDS contained in cooling tower drift droplets will result in PM and PM_{10} emissions when certain size smaller droplets completely evaporate. TDS levels increase in a cooling water circuit due to the evaporation of a portion of the recirculated cooling water in the cooling tower. However, cooling tower water TDS levels can be managed by periodically removing a portion of the water from the tower's recirculating cooling water circuit. This "blowdown" is concentrated cooling tower water containing higher TDS levels, and it is removed from the cooling water circuit and replaced with "makeup water" that contains lower levels of TDS to manage the overall cooling tower water TDS levels.

Air-Cooled Heat Exchanger

An air-cooled heat exchanger is an indirect contact process heat exchanger that provides for the transfer of heat from a higher temperature process fluid to a lower temperature ambient air stream. The technical feasibility of an air-cooled heat exchanger is dependent on the peak ambient air temperature anticipated for the location where the exchanger will be installed and the temperature to which the process fluid in the exchanger must be cooled. Air-cooled heat exchangers are not feasible for scenarios in which a process fluid must be cooled to a temperature less than approximately 25 °F above the ambient air temperature. For example, if the ambient air temperature is 80 °F, then an air-cooled heat exchanger would likely not be able to cool a process fluid to a temperature below 105 °F.

Additionally, the size of an air-cooled heat exchanger can be significantly larger than a comparable duty heat exchanger using cooling water, which can limit the application of an air-cooled heat exchanger when faced with available space constraints or practical equipment layout constrictions. Furthermore, as the required amount of cooling or number of cooling exchangers increases for a process, the capital cost of air-cooled heat exchangers can become considerably greater than a wet cooling tower system (i.e., combination of water-cooled heat exchangers and a wet cooling tower).

1.5.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the PM and PM_{10} emission control technologies determined to be available for the Cogeneration Plant Cooling Tower is evaluated below.

High-Efficiency Drift Eliminator

This option is technically feasible for the cooling tower.

Low Cooling Water TDS Levels

This option is technically feasible for the cooling tower.

Air-Cooled Heat Exchanger

The use of air-cooled heat exchangers in place of water-cooled heat exchangers in the Cogen Units is not technically feasible because air-cooled heat exchangers would not provide adequate cooling, especially during summer months, to effectively operate the Cogen Units. In fact, the Cogen Units include water-cooled condensing steam turbine generators to avoid the operating limitations and inefficiencies associated with air-cooled steam condensers, which are known to considerably limit electricity production by steam units. Additionally, air-cooled heat exchangers for the Cogen Units would occupy significantly more space and cost considerably more to install and operate, all the while limiting the overall efficiency, operational reliability, and operating capability of the Cogen Units. In summary, air-cooled heat exchangers are not technically feasible for the Cogen Units because they would result in fundamental cooling capability deficiencies for the units.

1.5.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the two emission control technologies determined to be available for the Cogeneration Plant Cooling Tower to control its PM and PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.5.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the two emission control technologies determined to be available for the Cogeneration Plant Cooling Tower to control its PM and PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.5.1.5 Step 5: Select BACT

Shell determined that high-efficiency drift eliminators and managing cooling water TDS levels represent BACT for the Cogeneration Plant Cooling Tower's PM and PM_{10} emissions. Accordingly, Shell proposes the following PM and PM_{10} BACT requirements for the Cogeneration Plant Cooling Tower, which are the same PM and PM_{10} BACT 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.

1.6 CVTO BACT Determinations

As presented below, Shell has reevaluated the CO, NOx, PM, PM_{10}, and GHG BACT determinations that were previously made for the CVTO at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BACT determination reevaluations for the CVTO is documented in Attachment 7-1.

1.6.1 CO

CO is emitted by the CVTO due to the partial oxidation of hydrocarbons present in the fuel and vent gases combusted in the thermal oxidizer. However, the fuel combusted in the CVTO is pipeline quality natural gas, which is comprised of easily combustible light hydrocarbons. Additionally, the vent gases combusted in the CVTO, which are generated by SPM's three polyethylene manufacturing units and equipment associated with SPM's ethylene manufacturing unit, are primarily comprised of easily combustible light hydrocarbons.

The combustion efficiency of a thermal oxidizer is a measure of the amount of hydrocarbon present in the fuel and vent gases combusted in the thermal oxidizer that oxidizes completely to CO_2 and water. A thermal oxidizer's combustion efficiency is primarily affected by vent gas characteristics (e.g., Btu content, composition), thermal oxidizer burner design, residence time at the proper operating temperature in the thermal oxidizer, and oxygen levels in the thermal oxidizer's combustion chamber. A properly designed and operated thermal oxidizer emits CO at very low levels.

The CVTO is currently subject to the following CO BACT emission limitation.

- The thermal oxidizer's CO emissions shall not exceed 0.0824 lb/MMBtu.

1.6.1.1 Step 1: Identify Control Technologies

The following are available CO emission control technologies for the CVTO.

- Good combustion practices
- Catalytic oxidation

These technologies are generally described below.

Good Combustion Practices

Good combustion practices for a thermal oxidizer require an appropriate supply of fuel and oxygen to the thermal oxidizer and proper combustion chamber residence time, temperature, and turbulence conditions. Partial combustion of fuel and vent gas hydrocarbons in a thermal oxidizer may result from poor design, operation, and/or maintenance of the thermal oxidizer. However, a thermal oxidizer is designed to achieve very high combustion efficiency because its primary purpose is to destroy via efficient oxidation (combustion) combustible waste materials (typically hydrocarbon-based waste materials) at an elevated temperature. As a result, a properly designed and operated thermal oxidizer emits CO, PM, PM_{10}, $PM_{2.5}$, VOC, HAP, and methane at very low levels. In general, good combustion practices are achieved by following a combustion device manufacturer's operating procedures and guidelines, as well as the manufacturer's routine maintenance procedures and programs.

Catalytic Oxidation

Catalytic oxidation uses catalysts comprised of precious metals such as platinum, palladium, or rhodium to reduce the temperature at which CO oxidizes to CO_2. The CO removal effectiveness of catalytic oxidation is dependent on an exhaust stream's temperature, the concentration of CO in the stream, and the presence of potentially poisoning contaminants in the stream. The amount of catalyst required for a particular application is dependent upon a stream's flow rate, composition, and temperature, as well as the desired CO removal efficiency. The catalyst in a catalytic oxidation system will experience activity loss over time due to physical deterioration and/or chemical deactivation. Therefore, periodic testing of the catalyst is necessary to monitor its activity (i.e., oxidation promoting effectiveness) and predict its remaining useful life. As needed, the catalyst will require periodic replacement. Catalyst life varies from manufacturer-to-manufacturer, but a three to six-year window is not uncommon.

1.6.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for the CVTO is evaluated below.

Good Combustion Practices

This option is technically feasible for the CVTO.

Catalytic Oxidation

The CVTO is a thermal oxidizer, and the fundamental purpose of a thermal oxidizer is to achieve very high combustion efficiency, which results in thermal oxidizers emitting CO at very low levels. In fact, source testing results indicate the CO concentration in the CVTO's exhaust stream (< 2 parts per million by volume on a dry basis (ppmvd) at 15% oxygen) is typically below the concentrations seen in exhaust streams from oxidation catalysts, indicating it would not be feasible to design an oxidation catalyst system to install on the CVTO for CO emissions reduction purposes. Furthermore, the flue gas temperature in the CVTO's stack is typically greater than 1,300 to 1,400 °F, which is greater than the acceptable operating range for oxidation catalysts. These factors indicate it would not be technically feasible to use an oxidation catalyst to control CO emissions from the CVTO, which is further supported by the fact that EPA's RBLC database indicates oxidation catalysts have not been used to control CO emissions from thermal oxidizers.

1.6.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes using the only emission control technology determined to be available for the CVTO to control its CO emissions. Therefore, no additional analysis is necessary under this step.

1.6.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes using the only emission control technology determined to be available for the CVTO to control its CO emissions. Therefore, no additional analysis is necessary under this step.

1.6.1.5 Step 5: Select BACT

Shell determined that good combustion practices represent BACT for the CO emissions from the CVTO. Shell proposes a CO BACT limit of 0.0824 lb/MMBtu (3-hour average) for the CVTO, which is the same CO BACT limit that is currently applicable to the thermal oxidizer.

1.6.2 NOx

Shell reevaluated the NOx LAER determination that was previously made for the CVTO, as presented separately. LAER for a specific pollutant emitted by an emission source is at least as stringent as BACT for the same pollutant from the emission source. Therefore, the NOx LAER determination reevaluation completed for the CVTO serves as the NOx BACT determination reevaluation for the thermal oxidizer.

1.6.3 PM and PM_{10}

PM and PM_{10} are emitted by the CVTO due to metals that may be present in trace amounts 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 CVTO is pipeline quality natural gas, which is comprised of easily combustible light hydrocarbons and a negligible amount of metals. Additionally, the vent gases combusted in the thermal oxidizer have the same characteristics – they contain easily combustible light hydrocarbons and a negligible amount of metals. Furthermore, the vent gases do not contain compounds (e.g., sulfur-containing compounds, chloride-containing compounds) that would result in the generation of acid gases (condensable PM) when combusted. Therefore, the CVTO emits PM and PM_{10} at very low levels.

The CVTO is currently subject to the following PM_{10} BACT emission limitation.

- The thermal oxidizer's PM_{10} emissions shall not exceed 0.0075 lb/MMBtu.

1.6.3.1 Step 1: Identify Control Technologies

The following are available PM and PM_{10} emission control technologies for the CVTO.

- Good combustion practices
- Electrostatic Precipitator (ESP)
- Filter
- Wet scrubber
- Cyclone

These technologies are generally described below.

Good Combustion Practices

Please see Section 1.6.1.1 herein for a discussion of this technology.

ESP

An ESP uses an electric field and collection plates to remove PM and PM_{10} from a flowing gaseous stream. The PM and PM_{10} contained in the gaseous stream are given an electric charge by passing the stream through a corona discharge. The resulting negatively charged PM and PM_{10} are collected on grounded collection plates, which are periodically cleaned without re-entraining the PM and PM_{10} into the flowing gaseous stream that is being treated by the ESP. In a dry ESP, the collection plate cleaning process can be accomplished mechanically by knocking the PM and PM_{10} loose from the plates. Alternatively, in a wet ESP, a washing technique is used to remove the collected PM and PM_{10} from the collection plates. ESPs can be configured in several ways, including a plate-wire ESP, a flat-plate ESP, and a tubular ESP. As the diameter of the PM decreases, the removal efficiency of an ESP decreases.

Filter

A filter is a porous media that removes PM and PM_{10} from a gaseous stream as the stream passes through the filter. For an emission source with an appreciable exhaust rate, the filter system typically contains multiple filter elements. Filters can be used to treat exhaust streams containing dry or liquid PM and PM_{10}.

Filters handling dry PM and PM_{10} become coated with collected PM and PM_{10} during operation and this coating ("cake") contributes to the filtration mechanism. A dry PM and PM_{10} filter system commonly used in industrial scale applications is a "baghouse." A baghouse is comprised of multiple cylindrical bags, and the number of bags is dependent on the exhaust rate requiring treatment, the PM and PM_{10} loading of the exhaust stream, and the baghouse design. The two most common baghouse designs today are the reverse-air and pulse-jet designs. These design references indicate the type of bag cleaning system used in the baghouse.

Filters handling liquid PM and PM_{10} rely on the impingement of the entrained liquid PM and PM_{10} on the surface of the filter media and the retention of these liquid particles on the surface until multiple particles coalesce into particles of sufficient size capable of falling back against the flowing gas stream and collecting at a location below the filter. For the high-efficiency removal of submicron liquid particles from a gaseous stream, Brownian diffusion filters are used. “Brownian diffusion” is the random movement of submicron particles in a gaseous stream as these particles collide with gas molecules. Liquid PM and PM_{10} filter systems can be comprised of pad or candle filter elements. These filter elements require little operation and maintenance attention.

Wet Scrubber

A wet scrubber uses impaction, diffusion, interception and/or absorption to remove PM and PM_{10} from a gaseous stream. Impaction is the primary mechanism and occurs when a particle impacts a liquid surface or droplet in a wet scrubber. Wet scrubbers are ideal for hygroscopic PM, PM in exhaust streams containing soluble gases, and PM in exhaust streams with high moisture content. Water is commonly used as the scrubbing liquid in a wet scrubber used for PM and PM_{10} emission control. There are several types of wet scrubber designs, including spray towers, packed-bed counterflow scrubbers, packed-bed cross-flow scrubbers, bubble plate scrubbers, and tray scrubbers.

Cyclone

A cyclone is the most common type of inertial separator used to collect medium-sized and coarse PM from gaseous streams. The PM and PM_{10} contained in a gaseous stream treated in a cyclone move outward under the influence of centrifugal force until it contacts the wall of the cyclone. The PM and PM_{10} are then carried downward by gravity along the wall of the cyclone and collected in a hopper located at the bottom of the cyclone. Although cyclones provide a relatively low cost, mechanically simple option for the removal of larger diameter PM from gaseous streams, alone they do not typically provide adequate PM removal, especially when the gaseous stream contains smaller diameter PM. Instead, these devices are typically used to preclean a gaseous stream by removing larger diameter PM upstream of PM emission control devices that are more effective at removing smaller diameter PM.

1.6.3.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the PM and PM_{10} emission control technologies determined to be available for the CVTO is evaluated below.

Good Combustion Practices

This option is technically feasible for the CVTO.

ESP

The CVTO is estimated to emit only PM with an aerodynamic diameter less than or equal to 10 micrometers, which would greatly limit the effectiveness of an ESP. Additionally, the PM_{10} concentration in the CVTO’s exhaust stream (< 0.01 gr/dscf) is well below the concentrations seen in exhaust streams from ESPs, indicating it would not be feasible to design an ESP to install on the CVTO for PM_{10} emissions reduction purposes. These factors indicate it would not be technically feasible to use an ESP to control PM_{10} emissions from the CVTO, which is further supported by the fact that EPA’s RBLC database indicates ESPs have not been used to control PM and PM_{10} emissions from thermal oxidizers.

Filter

The PM_{10}-only profile of the CVTO's PM emissions would limit the potential control effectiveness of a filter on the thermal oxidizer. Additionally, the PM_{10} concentration in the CVTO's exhaust stream, as noted above, is well below the concentrations seen in exhaust streams from filters, indicating it would not be feasible to design a filter to install on the CVTO for PM_{10} emissions reduction purposes. These factors indicate it would not be technically feasible to use a filter to control PM_{10} emissions from the CVTO, which is further supported by the fact that EPA's RBLC database indicates filters have not been used to control PM and PM_{10} emissions from thermal oxidizers.

Wet Scrubber

The PM_{10}-only profile of the CVTO's PM emissions indicates a wet scrubber would require an excessively high pressure drop to attempt to achieve any measurable reduction in the thermal oxidizer's PM emissions. Additionally, the PM_{10} concentration in the CVTO's exhaust stream, as noted above, is well below the concentrations seen in exhaust streams from wet scrubbers, indicating it would not be feasible to design a wet scrubber to install on the CVTO for PM_{10} emissions reduction purposes. Moreover, liquid carryover in the exhaust stream from a wet scrubber would contain dissolved and suspended solids, which would result in a new PM emissions mechanism, likely nullifying any negligible PM_{10} control effectiveness of a wet scrubber in this application. These factors indicate it would not be technically feasible to use a wet scrubber to control PM_{10} emissions from the CVTO, which is further supported by the fact that EPA's RBLC database indicates wet scrubbers have not been used to control PM and PM_{10} emissions from thermal oxidizers.

Cyclone

The PM_{10}-only profile of the CVTO's PM emissions would severely limit the potential control effectiveness of a cyclone on the thermal oxidizer. Additionally, the PM_{10} concentration in the CVTO's exhaust stream, as noted above, is well below the concentrations seen in exhaust streams from cyclones, indicating it would not be feasible to design a cyclone to install on the CVTO for PM_{10} emissions reduction purposes. These factors indicate it would not be technically feasible to use a cyclone to control PM_{10} emissions from the CVTO, which is further supported by the fact that EPA's RBLC database indicates cyclones have not been used to control PM and PM_{10} emissions from thermal oxidizers.

1.6.3.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes using the only emission control technology determined to be available for the CVTO to control its PM and PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.6.3.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes using the only emission control technology determined to be available for the CVTO to control its PM and PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.6.3.5 Step 5: Select BACT

Shell determined that good combustion practices represent BACT for the PM and PM_{10} emissions from the CVTO. Shell proposes a PM (filterable only) BACT limit of 0.0019 lb/MMBtu (3-hour average) for the CVTO and a PM_{10} BACT limit of 0.0075 lb/MMBtu (3-hour average) for the CVTO. This proposed PM_{10} BACT limit is the same as the PM_{10} BACT limit that is currently applicable to the thermal oxidizer.

1.6.4 GHGs

The CVTO combusts hydrocarbon-containing vent gases to minimize VOC emissions to the atmosphere from certain polyethylene manufacturing unit and ethylene manufacturing unit-related equipment and activities at SPM, as well as pipeline quality natural gas to achieve and maintain appropriate CVTO temperatures due to varying ambient conditions and vent gas rates and characteristics. CVTO combustion products include the following GHGs: CO_2, methane, and nitrous oxide. Despite having greater GWP than CO_2, the small quantities of methane and nitrous oxide generated by the CVTO make their contribution to the thermal oxidizer's total GHG emissions insignificant, and they are therefore not considered in this analysis.

1.6.4.1 Step 1: Identify Control Technologies

The following are available GHG emission control technologies for the CVTO.

- Low-carbon fuels
- Good combustion practices
- CCS

These technologies are generally described below.

Low-Carbon Fuels

Please see Section 1.4.1.1 herein for a discussion of this technology.

Good Combustion Practices

Please see Section 1.6.1.1 herein for a discussion of this technology.

CCS

Please see Section 1.4.1.1 herein for a discussion of this technology.

1.6.4.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the GHG emission control technologies determined to be available for the CVTO is evaluated below.

Low-Carbon Fuels

This option is technically feasible for the CVTO.

Good Combustion Practices

This option is technically feasible for the CVTO.

CCS

For purposes of this BACT analysis, CCS using a post-combustion capture technology is considered to be a technically feasible control alternative for CO_2 emissions from the CVTO. Alternatively, pre-combustion capture technology is not considered technically feasible because of the variability of the rate and composition of the vent gases that may be routed to the CVTO. Additionally, oxy-fuel combustion is not considered a technically feasible combustion approach for this analysis because it has not advanced significantly beyond the research and pilot plant phase.

1.6.4.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

The available GHG emission reduction alternatives for the CVTO are listed below from the highest to lowest potential GHG emission reduction relative to baseline emissions.

- CCS: Post-combustion technology can capture between 85 to 90 percent of the CO_2 in typical combustion exhaust gases.
- Low-Carbon Fuels: This control technology is used by the CVTO because it combusts only natural gas as fuel.
- Good Combustion Practices: This control technology is used by the CVTO because it is inherently designed and operated pursuant to these principles to achieve the very high combustion efficiencies that are necessary for it to comply with applicable regulatory requirements as a hydrocarbon emission control device.

1.6.4.4 Step 4: Evaluate Most Effective Control Options and Document Results

As previously discussed in the GHG BACT analysis completed for the ethane cracking furnaces at SPM, each technically feasible GHG control technology option for the CVTO was evaluated, regardless of the Step 3 ranking.

Low-Carbon Fuels

The fuel combusted by the CVTO is natural gas, which is a low-carbon fuel because it is primarily comprised of methane, a single carbon atom compound that results in lower CO_2 emissions per unit of thermal energy production than other hydrocarbon compounds that may be used as a gaseous fuel or included in a gaseous fuel.

Good Combustion Practices

The CVTO is designed, operated, and maintained as recommended by the manufacturer to ensure good combustion practices are followed.

CCS

As previously documented in Section 1.4.1.4 herein, Shell determined that the considerable costs and additional energy requirements that would be necessary to install and operate a CCS system to reduce

CO_2 emissions to the atmosphere from the ethane cracking furnaces, CVTO, and SCTO resulted in the elimination of CCS as BACT for the GHG emissions from the ethane cracking furnaces, CVTO, and SCTO.

1.6.4.5 Step 5: Select BACT

Shell determined that combusting low-carbon fuels and operating in accordance with good combustion practices represent BACT for the GHG emissions from the CVTO. Accordingly, Shell will comply with the following GHG BACT requirements for the CVTO.

- Combust only natural gas as fuel in the CVTO.
- Operate the CVTO in accordance with good combustion practices, as recommended by the manufacturer of the thermal oxidizer.

1.7 MPGF BACT Determinations

As presented below, Shell has reevaluated the CO, NOx, PM, PM_{10}, and GHG BACT determinations that were previously made for the MPGF at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BACT determination reevaluations for the MPGF is documented in Attachment 7-1.

1.7.1 CO

CO is emitted by the MPGF due to the partial oxidation of hydrocarbons present in the flare vent gas combusted at the flare. The combustion efficiency of a flare is a measure of the amount of hydrocarbon present in the flare vent gas that oxidizes completely to CO_2 and water at the flare tip. The combustion efficiency of a flare is affected by flare vent gas characteristics (e.g., Btu content, composition), flare tip velocity, and oxygen levels at the flare's combustion zone.

The MPGF is currently subject to the following CO BACT requirements.

- The flare must be operated in accordance with a flare minimization plan.
- The flare must be operated in accordance with good combustion practices.

1.7.1.1 Step 1: Identify Control Technologies

The following are available CO emission control technologies for the MPGF.

- Flare minimization
- Good combustion practices

These technologies are generally described below. As previously noted, the MPGF is currently required to operate in accordance with a flare minimization plan and good combustion practices.

Flare Minimization

A facility typically develops a flare minimization plan to document and guide its flare minimization design features, procedures, and practices. In general, a flare minimization plan is used to minimize flaring at a facility without compromising its safe operations and practices, especially during planned startup, shutdown, and maintenance events. A flare minimization plan results in reduced emissions of combustion pollutants such as CO, NOx, PM, PM_{10}, $PM_{2.5}$, SO_2, and CO_2, as well as VOC and HAPs, from a flare because it promotes a reduction in the occurrence of certain flaring events, the amount of waste gas generated during flaring events, and the duration of flaring events. Key components of an effective flare minimization plan are careful planning to minimize flaring events, measuring and monitoring flaring events when they occur, and investigative evaluation of the causes of flaring events, especially large or unplanned flaring events. Regarding unplanned flaring events, a flare minimization plan usually includes procedures to evaluate the events and their causes to develop strategies and measures to minimize the likelihood for the reoccurrence of the same or similar events.

Good Combustion Practices

Good combustion practices for a flare promote appropriate flame zone residence time, temperature, and turbulence to achieve low CO, NOx, PM, PM_{10}, $PM_{2.5}$, VOC, HAP, and methane emission levels. The following are design and operating parameters that are typically used to measure or indicate good combustion practices for a flare: flare vent gas heating value, flare vent gas flow rate, assist gas flow rate, and visible emissions. A flare is generally recognized as achieving and demonstrating good combustion practice operations when it follows the design, operating, and monitoring requirements specified in 40 CFR 63 Subpart CC, which are specifically referenced and required to be met by 40 CFR 63 Subpart YY and 40 CFR 63 Subpart FFFF with minor revisions.

1.7.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for the MPGF is evaluated below.

Flare Minimization

This option is technically feasible for the flare.

Good Combustion Practices

This option is technically feasible for the flare.

1.7.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the two emission control technologies determined to be available for the MPGF to control its CO emissions. Therefore, no additional analysis is necessary under this step.

1.7.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the two emission control technologies determined to be available for the MPGF to control its CO emissions. Therefore, no additional analysis is necessary under this step.

1.7.1.5 Step 5: Select BACT

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents BACT for the CO emissions from the MPGF, which is the same as the CO BACT that is currently applicable to the flare. Accordingly, Shell will operate the MPGF in accordance with a flare minimization plan that will include the following:

- Procedures for operating and maintaining the flare during periods of process unit startup, shutdown, and unforeseeable events;
- A program of corrective action for malfunctioning process equipment;
- Procedures to minimize discharges to the flare during the planned and unplanned startup or shutdown of process equipment;
- Procedures for conducting root cause analyses; and
- Procedures for taking identified corrective actions.

Also, Shell will operate the MPGF in accordance with the good combustion practice requirements in 40 CFR 60 Subpart Kb, 40 CFR 63 Subpart YY, and 40 CFR 63 Subpart FFFF, as applicable, which include design requirements, minimum flare combustion zone gas heating value requirements, and extensive monitoring requirements for the flare.

1.7.2 NOx

Shell reevaluated the NOx LAER determination that was previously made for the MPGF, as presented separately. LAER for a specific pollutant emitted by an emission source is at least as stringent as BACT for the same pollutant from the emission source. Therefore, the NOx LAER determination reevaluation completed for the MPGF serves as the NOx BACT determination reevaluation for the flare.

1.7.3 PM and PM_{10}

PM and PM_{10} are emitted by the MPGF due to the incomplete combustion of hydrocarbons present in the flare vent gas combusted at the flare. However, the flare combusts mostly low molecular weight hydrocarbons (e.g., methane, ethane, ethylene, and butane) that combust relatively easily, minimizing the generation of carbon particles. Additionally, the MPGF is designed to use assist air to promote proper air and flare vent gas mixing in the flame zone at its flare tips, which results in smokeless flare operation (i.e., negligible carbon particles escaping oxidation to CO and CO_2).

The MPGF is currently subject to the following PM and PM_{10} BACT requirements.

- The flare must be operated in accordance with a flare minimization plan.
- The flare must be operated in accordance with good combustion practices.

1.7.3.1 Step 1: Identify Control Technologies

The following are available PM and PM_{10} emission control technologies for the MPGF.

- Flare minimization
- Good combustion practices

These technologies are generally described below. As previously noted, the MPGF is currently required to operate in accordance with a flare minimization plan and good combustion practices.

Flare Minimization

Please see Section 1.7.1.1 herein for a discussion of this technology.

Good Combustion Practices

Please see Section 1.7.1.1 herein for a discussion of this technology.

1.7.3.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the PM and PM_{10} emission control technologies determined to be available for the MPGF is evaluated below.

Flare Minimization

This option is technically feasible for the MPGF.

Good Combustion Practices

This option is technically feasible for the MPGF.

1.7.3.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the two emission control technologies determined to be available for the MPGF to control its PM and PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.7.3.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the two emission control technologies determined to be available for the MPGF to control its PM and PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.7.3.5 Step 5: Select BACT

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents BACT for the PM and PM_{10} emissions from the MPGF, which is the same as the PM and PM_{10} BACT that is currently applicable to the flare. Accordingly, Shell will operate the MPGF in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.7.1.5.

1.7.4 GHGs

The primary GHG emitted by the MPGF is CO_2, which is emitted due to the complete oxidation of hydrocarbons present in the flare vent gas to CO_2. However, that is the purpose of the MPGF – to safely combust (oxidize) vent gas streams that contain hydrocarbons, including VOC and HAPs, to minimize the uncontrolled release of those compounds to the atmosphere. Additionally, the MPGF emits small amounts of methane and nitrous oxide, which are also GHGs. The flare emits methane because some of the methane in the flare vent gas does not react as part of the combustion reactions that occur at the flare and is therefore emitted to the atmosphere as methane, while some of the non-methane hydrocarbons in the flare vent gas may react to form methane as part of the combustion reactions at the flare. The MPGF emits nitrous oxide due to certain reactions that occur during the combustion process at the flare.

The MPGF is currently subject to the following GHG BACT requirements.

- The flare must be operated in accordance with a flare minimization plan.
- The flare must be operated in accordance with good combustion practices.

1.7.4.1 Step 1: Identify Control Technologies

The following are available GHG emission control technologies for the MPGF.

- Flare minimization
- Low-carbon fuels
- Good combustion practices

These technologies are generally described below. As previously noted, the MPGF is currently required to operate in accordance with a flare minimization plan and good combustion practices.

Flare Minimization

Please see Section 1.7.1.1 herein for a discussion of this technology.

Low-Carbon Fuels

Please see Section 1.4.1.1 herein for a discussion of this technology.

Good Combustion Practices

Please see Section 1.7.1.1 herein for a discussion of this technology.

1.7.4.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the GHG emission control technologies determined to be available for the MPGF is evaluated below.

Flare Minimization

This option is technically feasible for the MPGF.

Low-Carbon Fuels

This option is technically feasible for the MPGF.

Good Combustion Practices

This option is technically feasible for the MPGF.

1.7.4.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

The technically feasible GHG emission control technologies for the MPGF are listed below from the highest to lowest potential emission control.

- Flare minimization
- Low-carbon fuels
- Good combustion practices

1.7.4.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the three emission control technologies determined to be available for the MPGF to control its GHG emissions. Therefore, no additional analysis is necessary under this step.

1.7.4.5 Step 5: Select BACT

Shell determined that operating in accordance with a flare minimization plan and good combustion practices and combusting low-carbon fuels represent BACT for the GHG emissions from the MPGF, which is the same as the GHG BACT that is currently applicable to the flare. Accordingly, Shell will operate the MPGF in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.7.1.5; use natural gas as the supplemental gas combusted at the flare; and, use natural gas as the pilot fuel combusted at the flare.

1.8 TEGF A, TEGF B, and HP Elevated Flare BACT Determinations

As presented below, Shell has reevaluated the CO, NOx, PM, PM_{10}, and GHG BACT determinations that were previously made for the TEGF A, TEGF B, and HP Elevated Flare at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BACT determination reevaluations for the TEGF A, TEGF B, and HP Elevated Flare is documented in Attachment 7-1.

1.8.1 CO

CO is emitted by the TEGF A, TEGF B, and HP Elevated Flare due to the partial oxidation of hydrocarbons present in the flare vent gas combusted at the flares. The combustion efficiency of a flare is a measure of the amount of hydrocarbon present in the flare vent gas that oxidizes completely to CO_2 and water at the flare tip. The combustion efficiency of a flare is affected by flare vent gas characteristics (e.g., Btu content, composition), flare tip velocity, and oxygen levels at the flare's combustion zone.

The TEGF A, TEGF B, and HP Elevated Flare are currently subject to the following CO BACT requirements.

- Each flare must be operated in accordance with a flare minimization plan.
- Each flare must be operated in accordance with good combustion practices.

1.8.1.1 Step 1: Identify Control Technologies

The following are available CO emission control technologies for the TEGF A, TEGF B, and HP Elevated Flare.

- Flare minimization
- Good combustion practices

These technologies are generally described below.

Flare Minimization

Please see Section 1.7.1.1 herein for a discussion of this technology.

Good Combustion Practices

Please see Section 1.7.1.1 herein for a discussion of this technology.

1.8.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare is evaluated below.

Flare Minimization

This option is technically feasible for the flares.

Good Combustion Practices

This option is technically feasible for the flares.

1.8.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the two emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their CO emissions. Therefore, no additional analysis is necessary under this step.

1.8.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the two emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their CO emissions. Therefore, no additional analysis is necessary under this step.

1.8.1.5 Step 5: Select BACT

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents BACT for the CO emissions from the TEGF A, TEGF B, and HP Elevated Flare, which is the same as the CO BACT that is currently applicable to the flares. Accordingly, Shell will operate the TEGF A, TEGF B, and HP Elevated Flare in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.7.1.5.

1.8.2 NOx

Shell reevaluated the NOx LAER determinations that were previously made for the TEGF A, TEGF B, and HP Elevated Flare, as presented separately. LAER for a specific pollutant emitted by an emission source is at least as stringent as BACT for the same pollutant from the emission source. Therefore, the NOx LAER determination reevaluation completed for the TEGF A, TEGF B, and HP Elevated Flare serves as the NOx BACT determination reevaluation for the flares.

1.8.3 PM and PM_{10}

PM and PM_{10} are emitted by the TEGF A, TEGF B, and HP Elevated Flare due to the incomplete combustion of hydrocarbons present in the flare vent gas combusted at the flares. However, these flares combust mostly low molecular weight hydrocarbons (e.g., methane, ethane, and ethylene) that combust relatively easily, minimizing the generation of carbon particles. Additionally, the TEGF A and TEGF B are designed to use high pressure upstream of their flare tips, while the HP Elevated Flare uses assist steam, to draw air into the flame zone at the tips of the flares to promote proper air and flare vent gas mixing in the flame zone, which results in smokeless flare operation (i.e., negligible carbon particles escaping oxidation to CO and CO_2).

The TEGF A, TEGF B, and HP Elevated Flare are currently subject to the following PM and PM_{10} BACT requirements.

- Each flare must be operated in accordance with a flare minimization plan.
- Each flare must be operated in accordance with good combustion practices.

1.8.3.1 Step 1: Identify Control Technologies

The following are available PM and PM_{10} emission control technologies for the TEGF A, TEGF B, and HP Elevated Flare.

- Flare minimization
- Good combustion practices

These technologies are generally described below.

Flare Minimization

Please see Section 1.7.1.1 herein for a discussion of this technology.

Good Combustion Practices

Please see Section 1.7.1.1 herein for a discussion of this technology.

1.8.3.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the PM and PM_{10} emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare is evaluated below.

Flare Minimization

This option is technically feasible for the flares.

Good Combustion Practices

This option is technically feasible for the flares.

1.8.3.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the two emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their PM and PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.8.3.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the two emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their PM and PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.8.3.5 Step 5: Select BACT

Shell determined that operating in accordance with a flare minimization plan and good combustion practices represents BACT for the PM and PM_{10} emissions from the TEGF A, TEGF B, and HP Elevated Flare, which is the same as the PM and PM_{10} BACT that is currently applicable to the flares. Accordingly, Shell will operate the TEGF A, TEGF B, and HP Elevated Flare in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.7.1.5.

1.8.4 GHGs

The primary GHG emitted by the TEGF A, TEGF B, and HP Elevated Flare is CO_2, which is emitted due to the complete oxidation of hydrocarbons present in the flare vent gas to CO_2. However, that is the purpose of the TEGF A, TEGF B, and HP Elevated Flare – to safely combust (oxidize) vent gas streams that contain hydrocarbons, including VOC and HAPs, to minimize the uncontrolled release of those compounds to the atmosphere. Additionally, the TEGF A, TEGF B, and HP Elevated Flare emit small amounts of methane and nitrous oxide, which are also GHGs. The flares emit methane because some of the methane in the flare vent gas does not react as part of the combustion reactions that occur at the flares and is therefore emitted to the atmosphere as methane, while some of the non-methane hydrocarbons in the flare vent gas may react to form methane as part of the combustion reactions at the flares. The TEGF A, TEGF B, and HP Elevated Flare emit nitrous oxide due to certain reactions that occur during the combustion process at the flares.

The TEGF A, TEGF B, and HP Elevated Flare are currently subject to the following GHG BACT requirements.

- Each flare must be operated in accordance with a flare minimization plan.
- Each flare must be operated in accordance with good combustion practices.

1.8.4.1 Step 1: Identify Control Technologies

The following are available GHG emission control technologies for the TEGF A, TEGF B, and HP Elevated Flare.

- Flare minimization
- Low-carbon fuels

- Good combustion practices

These technologies are generally described below.

Flare Minimization

Please see Section 1.7.1.1 herein for a discussion of this technology.

Low-Carbon Fuels

Please see Section 1.4.1.1 herein for a discussion of this technology.

Good Combustion Practices

Please see Section 1.7.1.1 herein for a discussion of this technology.

1.8.4.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the GHG emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare is evaluated below.

Flare Minimization

This option is technically feasible for the flares.

Low-Carbon Fuels

This option is technically feasible for the flares.

Good Combustion Practices

This option is technically feasible for the flares.

1.8.4.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

The technically feasible GHG emission control technologies for the TEGF A, TEGF B, and HP Elevated Flare are listed below from the highest to lowest potential emission control.

- Flare minimization
- Low-carbon fuels
- Good combustion practices

1.8.4.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the three emission control technologies determined to be available for the TEGF A, TEGF B, and HP Elevated Flare to control their GHG emissions. Therefore, no additional analysis is necessary under this step.

1.8.4.5 Step 5: Select BACT

Shell determined that operating in accordance with a flare minimization plan and good combustion practices and combusting low-carbon fuels represent BACT for the GHG emissions from the TEGF A, TEGF B, and HP Elevated Flare, which is the same as the GHG BACT that is currently applicable to the flares. Accordingly, Shell will operate the TEGF A, TEGF B, and HP Elevated Flare in accordance with a flare minimization plan and good combustion practices, as previously described in Section 1.7.1.5; use natural gas and/or tail gas as the supplemental gas combusted at the flares; and, use natural gas as the pilot fuel combusted at the flares.

1.9 SCTO BACT Determinations

As presented below, Shell has reevaluated the CO, NOx, PM_{10}, and GHG BACT determinations that were previously made for the SCTO at SPM contemporaneous with the construction of the facility. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BACT determination reevaluations for the SCTO is documented in Attachment 7-1.

1.9.1 CO

CO is emitted by the SCTO due to the partial oxidation of hydrocarbons present in the fuel and vent gases combusted in the thermal oxidizer. However, the fuel combusted in the SCTO is pipeline quality natural gas, which is comprised of easily combustible light hydrocarbons. Additionally, the vent gases combusted in the SCTO, which are generated by SPM's spent caustic storage tank, SPM's spent caustic oxidation treatment operation, and SPM's Wastewater Treatment Plant-related equipment, are primarily comprised of easily combustible hydrocarbons.

The combustion efficiency of a thermal oxidizer is a measure of the amount of hydrocarbon present in the fuel and vent gases combusted in the thermal oxidizer that oxidizes completely to CO_2 and water. A thermal oxidizer's combustion efficiency is primarily affected by vent gas characteristics (e.g., Btu content, composition), thermal oxidizer burner design, residence time at the proper operating temperature in the thermal oxidizer, and oxygen levels in the thermal oxidizer's combustion chamber. A properly designed and operated thermal oxidizer emits CO at very low levels.

The SCTO is currently subject to the following CO BACT requirement.

- The thermal oxidizer's CO emissions shall not exceed 0.0824 lb/MMBtu.

1.9.1.1 Step 1: Identify Control Technologies

The following are available CO emission control technologies for the SCTO.

- Good combustion practices
- Catalytic oxidation

These technologies are generally described below.

Good Combustion Practices

Please see Section 1.6.1.1 herein for a discussion of this technology.

Catalytic Oxidation

Please see Section 1.6.1.1 herein for a discussion of this technology.

1.9.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for the SCTO is evaluated below.

Good Combustion Practices

This option is technically feasible for the SCTO.

Catalytic Oxidation

The SCTO is a thermal oxidizer, and the fundamental purpose of a thermal oxidizer is to achieve very high combustion efficiency, which results in thermal oxidizers emitting CO at very low levels. In fact, the CO concentration in the SCTO's exhaust stream (< 4 ppmvd at 15% oxygen) is typically near the concentrations seen in exhaust streams from oxidation catalysts, indicating it would not be feasible to design an oxidation catalyst system to install on the SCTO for CO emissions reduction purposes. This fundamental limitation indicates it would not be technically feasible to use an oxidation catalyst to control CO emissions from the SCTO, which is further supported by the fact that EPA's RBLC database indicates oxidation catalysts have not been used to control CO emissions from thermal oxidizers.

1.9.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes using the only emission control technology determined to be available for the SCTO to control its CO emissions. Therefore, no additional analysis is necessary under this step.

1.9.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes using the only emission control technology determined to be available for the SCTO to control its CO emissions. Therefore, no additional analysis is necessary under this step.

1.9.1.5 Step 5: Select BACT

Shell determined that good combustion practices represent BACT for the CO emissions from the SCTO. Shell proposes a CO BACT limit of 0.0824 lb/MMBtu (3-hour average) for the SCTO, which is the same CO BACT limit that is currently applicable to the thermal oxidizer.

1.9.2 NOx

Shell reevaluated the NOx LAER determination that was previously made for the SCTO, as presented separately. LAER for a specific pollutant emitted by an emission source is at least as stringent as BACT for the same pollutant from the emission source. Therefore, the NOx LAER determination reevaluation completed for the SCTO serves as the NOx BACT determination reevaluation for the thermal oxidizer.

1.9.3 PM_{10}

PM_{10} is emitted by the SCTO due to metals that may be present in trace amounts 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 a negligible amount of metals. Additionally, the vent gases combusted in the thermal oxidizer have the same characteristics – they contain easily combustible hydrocarbons and a negligible amount of metals. Furthermore, the composite vent gas stream combusted in the SCTO, which is comprised of vent gases generated by SPM's spent caustic storage tank, SPM's spent caustic oxidation treatment operation, and SPM's Wastewater Treatment Plant-related equipment, does not contain appreciable amounts of compounds (e.g., sulfur-containing compounds, chloride-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 would have the potential to 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, though, the SCTO emits PM_{10} at relatively low levels.

The SCTO is currently subject to the following PM_{10} BACT requirement.

- The thermal oxidizer's PM_{10} emissions shall not exceed 0.0075 lb/MMBtu.

1.9.3.1 Step 1: Identify Control Technologies

The following are available PM_{10} emission control technologies for the SCTO.

- Good combustion practices
- ESP
- Filter
- Wet scrubber
- Cyclone

These technologies are generally described below.

Good Combustion Practices

Please see Section 1.6.1.1 herein for a discussion of this technology.

ESP

Please see Section 1.6.3.1 herein for a discussion of this technology.

Filter

Please see Section 1.6.3.1 herein for a discussion of this technology.

Wet Scrubber

Please see Section 1.6.3.1 herein for a discussion of this technology.

Cyclone

Please see Section 1.6.3.1 herein for a discussion of this technology.

1.9.3.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the PM_{10} emission control technologies determined to be available for the SCTO is evaluated below.

Good Combustion Practices

This option is technically feasible for the SCTO.

ESP

The SCTO is estimated to emit only PM with an aerodynamic diameter less than or equal to 10 micrometers, which would greatly limit the effectiveness of an ESP. Additionally, the PM_{10} concentration in the SCTO's exhaust stream (< 0.01 gr/dscf) is well below the concentrations seen in exhaust streams from ESPs, indicating it would not be feasible to design an ESP to install on the SCTO for PM_{10} emissions reduction purposes. These factors indicate it would not be technically feasible to use an ESP to control PM_{10} emissions from the SCTO, which is further supported by the fact that EPA's RBLC database indicates ESPs have not been used to control PM_{10} emissions from thermal oxidizers.

Filter

The PM_{10}-only profile of the SCTO's PM emissions would limit the potential control effectiveness of a filter on the thermal oxidizer. Additionally, the PM_{10} concentration in the SCTO's exhaust stream, as noted above, is well below the concentrations seen in exhaust streams from filters, indicating it would not be feasible to design a filter to install on the SCTO for PM_{10} emissions reduction purposes. These factors indicate it would not be technically feasible to use a filter to control PM_{10} emissions from the SCTO, which is further supported by the fact that EPA's RBLC database indicates filters have not been used to control PM_{10} emissions from thermal oxidizers.

Wet Scrubber

The PM_{10}-only profile of the SCTO's PM emissions indicates a wet scrubber would require an excessively high pressure drop to attempt to achieve any measurable reduction in the thermal oxidizer's PM emissions. Additionally, the PM_{10} concentration in the SCTO's exhaust stream, as noted above, is well below the concentrations seen in exhaust streams from wet scrubbers, indicating it would not be feasible to design a wet scrubber to install on the SCTO for PM_{10} emissions reduction purposes. Moreover, liquid carryover in the exhaust stream from a wet scrubber would contain dissolved and suspended solids, which would result in a new PM emissions mechanism, likely nullifying any negligible PM_{10} control effectiveness of a wet scrubber in this application. These factors indicate it would not be technically feasible to use a wet scrubber to control PM_{10} emissions from the SCTO, which is further supported by the fact that EPA's RBLC database indicates wet scrubbers have not been used to control PM_{10} emissions from thermal oxidizers.

Cyclone

The PM_{10}-only profile of the SCTO's PM emissions would severely limit the potential control effectiveness of a cyclone on the thermal oxidizer. Additionally, the PM_{10} concentration in the SCTO's exhaust stream, as noted above, is well below the concentrations seen in exhaust streams from cyclones, indicating it would not be feasible to design a cyclone to install on the SCTO for PM_{10} emissions reduction purposes. These factors indicate it would not be technically feasible to use a cyclone to control PM_{10} emissions from the SCTO, which is further supported by the fact that EPA's RBLC database indicates cyclones have not been used to control PM_{10} emissions from thermal oxidizers.

1.9.3.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes using the only emission control technology determined to be available for the SCTO to control its PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.9.3.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes using the only emission control technology determined to be available for the SCTO to control its PM_{10} emissions. Therefore, no additional analysis is necessary under this step.

1.9.3.5 Step 5: Select BACT

Shell determined that good combustion practices represent BACT for the SCTO's PM_{10} emissions. Shell proposes a PM_{10} BACT limit of 0.012 lb/MMBtu (3-hour average) for the SCTO.

1.9.4 GHGs

The SCTO combusts hydrocarbon-containing vent gases to minimize VOC emissions to the atmosphere from spent caustic storage tank, spent caustic oxidation treatment operation, and Wastewater Treatment Plant-related equipment at SPM, as well as pipeline quality natural gas to achieve and maintain appropriate SCTO temperatures due to varying ambient conditions and vent gas rates and characteristics. SCTO combustion products include the following GHGs: CO_2, methane, and nitrous oxide. Despite having greater GWP than CO_2, the small quantities of methane and nitrous oxide generated by the SCTO make their contribution to the thermal oxidizer's total GHG emissions insignificant, and they are therefore not considered in this analysis.

1.9.4.1 Step 1: Identify Control Technologies

The following are available GHG emission control technologies for the SCTO.

- Low-carbon fuels
- Good combustion practices
- CCS

These technologies are generally described below.

Low-Carbon Fuels

Please see Section 1.4.1.1 herein for a discussion of this technology.

Good Combustion Practices

Please see Section 1.6.1.1 herein for a discussion of this technology.

CCS

Please see Section 1.4.1.1 herein for a discussion of this technology.

1.9.4.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the GHG emission control technologies determined to be available for the SCTO is evaluated below.

Low-Carbon Fuels

This option is technically feasible for the SCTO.

Good Combustion Practices

This option is technically feasible for the SCTO.

CCS

For purposes of this BACT analysis, CCS using a post-combustion capture technology is considered to be a technically feasible control alternative for CO_2 emissions from the SCTO. Alternatively, pre-combustion capture technology is not considered technically feasible because of the variability of the rate and composition of the vent gases that may be routed to the SCTO. Additionally, oxy-fuel combustion is not considered a technically feasible combustion approach for this analysis because it has not advanced significantly beyond the research and pilot plant phase.

1.9.4.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

The available GHG emission reduction alternatives for the SCTO are listed below from the highest to lowest potential GHG emission reduction relative to baseline emissions.

- CCS: Post-combustion technology can capture between 85 to 90 percent of the CO_2 in typical combustion exhaust gases.
- Low-Carbon Fuels: This control technology is used by the SCTO because it combusts only natural gas as fuel.
- Good Combustion Practices: This control technology is used by the SCTO because it is inherently designed and operated pursuant to these principles to achieve the very high combustion efficiencies that are necessary for it to comply with applicable regulatory requirements as a hydrocarbon emission control device.

1.9.4.4 Step 4: Evaluate Most Effective Control Options and Document Results

As previously discussed in the GHG BACT analysis completed for the ethane cracking furnaces at SPM, each technically feasible GHG control technology option for the SCTO was evaluated, regardless of the Step 3 ranking.

Low-Carbon Fuels

The fuel combusted by the SCTO is natural gas, which is a low-carbon fuel because it is primarily comprised of methane, a single carbon atom compound that results in lower CO_2 emissions per unit of thermal energy production than other hydrocarbon compounds that may be used as a gaseous fuel or included in a gaseous fuel.

Good Combustion Practices

The SCTO is designed, operated, and maintained as recommended by the manufacturer to ensure good combustion practices are followed.

CCS

As previously documented in Section 1.4.1.4 herein, Shell determined that the considerable costs and additional energy requirements that would be necessary to install and operate a CCS system to reduce CO_2 emissions to the atmosphere from the ethane cracking furnaces, CVTO, and SCTO resulted in the elimination of CCS as BACT for the GHG emissions from the ethane cracking furnaces, CVTO, and SCTO.

1.9.4.5 Step 5: Select BACT

Shell determined that combusting low-carbon fuels and operating in accordance with good combustion practices represent BACT for the GHG emissions from the SCTO. Accordingly, Shell will comply with the following GHG BACT requirements for the SCTO.

- Combust only natural gas as fuel in the SCTO.
- Operate the SCTO in accordance with good combustion practices, as recommended by the manufacturer of the thermal oxidizer.

1.10 Equipment Components BACT Determinations

The BACT determinations made for the Equipment Components are presented below, by pollutant. The EPA RBLC database control technology and emission limitation information that Shell used to support the below BACT determinations for the Equipment Components is documented in Attachment 7-1.

1.10.1 CO

Some of SPM’s piping components (valves and connectors) will handle material that contains CO. These piping components are primarily associated with the polyethylene manufacturing units because the primary CO-containing material that is handled in piping at SPM is a gas that is referenced as “Kill Gas,” which is comprised of CO and nitrogen, that is periodically used to stop polyethylene reactions at SPM. The referenced piping components will have the potential to emit CO if they develop a leak to the atmosphere. For example, valves can develop leaks because of the degradation or failure of valve stem seal systems that are designed to prevent material handled by these components from leaking to the atmosphere.

1.10.1.1 Step 1: Identify Control Technologies

The following are available CO emission control technologies for the Equipment Components.

- Equipment design
- LDAR

These technologies are generally described below.

Equipment Design

Equipment can be designed and/or configured in a manner to reduce the probability that the equipment will develop a leak and/or reduce the amount of material that may leak from the equipment. In fact, certain equipment can be designed to essentially eliminate the mechanism(s) and/or interface(s) that result in leaks to the atmosphere, except for a catastrophic failure of the equipment. The following are examples of design features that can minimize leaks from the noted types of equipment.

- A cap, plug, or second valve on an open-ended line
- A dual mechanical seal on a pump
- A rupture disk assembly on a pressure relief valve

LDAR

LDAR programs are used to identify equipment leaking material at a level warranting repair (or replacement), and the effectiveness of these programs has been well established throughout many different industries over several decades. The primary features of an LDAR program are leak monitoring frequency, leak detection level, and timely leak repair requirements. Equipment may be checked for leakage by using only visual, audible, olfactory, or instrument techniques. For example, audio/olfactory/visual (AVO) inspections may be used to identify leaks of hydrocarbon-containing heavy liquid materials from connectors, valves, and pumps because heavy liquid material leaks from these components may result in hydrocarbon emissions below the detection level of conventional portable hydrocarbon detection instruments. Similarly, AVO inspections can be used to identify leaks of inert materials or non-hydrocarbon materials that cannot be detected using portable hydrocarbon detection instruments. Alternatively, a portable hydrocarbon detection instrument is typically used to identify (and measure) leaks of hydrocarbon-containing gaseous and light liquid materials from equipment. After a leak is detected using AVO or instrument techniques, then the leak must typically be repaired within a specific period, followed by a subsequent leak inspection to ensure the leaking equipment was properly repaired.

1.10.1.2 Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for the Equipment Components is evaluated below.

Equipment Design

This option is technically feasible for the Equipment Components.

LDAR

This option is technically feasible for the Equipment Components.

1.10.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Shell proposes to use the two emission control technologies determined to be available for the Equipment Components to control their CO emissions. Therefore, no additional analysis is necessary under this step.

1.10.1.4 Step 4: Evaluate Most Effective Control Options and Document Results

Shell proposes to use the two emission control technologies determined to be available for the Equipment Components to control their CO emissions. Therefore, no additional analysis is necessary under this step.

1.10.1.5 Step 5: Select BACT

Shell determined that equipment design and LDAR represent BACT for the CO emissions from the Equipment Components emission source. Accordingly, Shell proposes to use equipment design features (e.g., a cap, plug, or second valve on an open-ended line) that are reasonably available for the Equipment Components in Kill Gas service and the following LDAR practices for Equipment Components in Kill Gas service as BACT for the CO emissions from the Equipment Components emission source.

- Complete quarterly AVO checks of the Equipment Components in Kill Gas service for leaks. Every reasonable effort shall be made to repair or replace a leaking component identified during a quarterly AVO check within 15 days after the leak is found. If the repair or replacement of a leaking component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired or replaced until a scheduled shutdown shall be identified in a list to be made available to DEP upon request. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to DEP upon request.

Attachment 7-1

Request No. 5 EPA RBLC Database Information

11.310 - Gaseous Fuel & Gaseous Fuel Mixtures (>250 MMBtu/hr) - Natural Gas (Includes Propane and LPG)
Pollutant: GHGs
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	01/06/2015	Primary Reformer Furnace	1350	MMBtu/hr	CO2e		59.61	tons/MMcf	BACT-PSD	
AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	Three (3) Building Heat Medium Heaters	275	MMBtu/hr	CO2e	Good combustion practices and clean burning fuel (NG).	117.1	lb/MMBtu	BACT-PSD	Potential CO2e emissions of 140,914 tpy per heater. The 117.1 lb/MMBtu emission rate is the CO2e emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO2e emissions rate is calculated with the equation CO2(1) + CH4(25) + N2O(298).
AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	03/26/2021	Primary Reformer	1350	MMBtu/hr	CO2e	Good combustion practices and burning clean fuel.	60.4	tons/MMscf	BACT-PSD	GHG emissions from EU 12 shall not exceed 60.4 tons/MMscf averaged over a 3-hour period (AP-42 Table 1-4.2, CO2, N2O (uncontrolled), and methane).
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Reformer Furnace	1096	MMBtu/hr	CO2e				BACT-PSD	See limit for GHG for Ammonia Plant.
KY-0111	PHOENIX PAPER WICKLIFFE LLC	PHOENIX PAPER WICKLIFFE LLC	12/18/2019	#1 Power Boiler	325	MMBtu/hr	CO2e	i. Use of natural gas only; ii. Good combustion practices; and iii. Follow manufacturer's procedures for start-up and shutdown	119,099	lb/MMscf	N/A	The permittee is also required to install, operate, and maintain a continuous oxygen trim system on the #1 Power Boiler that ensures an optimum air to fuel ratio.
KY-0111	PHOENIX PAPER WICKLIFFE LLC	PHOENIX PAPER WICKLIFFE LLC	12/18/2019	#2 Power Boiler	325	MMBtu/hr	CO2e	i. Use of natural gas only; ii. Good combustion practices; and iii. Follow manufacturer's procedures for start-up and shutdown	119,099	lb/MMscf	N/A	The permittee is also required to install, operate, and maintain a continuous oxygen trim system on the #2 Power Boiler that ensures an optimum air to fuel ratio.
*LA-0306	TOPCHEM POLLOCK, LLC	TOPCHEM POLLOCK, LLC	12/20/2016	Primary Reformer Stack RS-16-1 (EQT029)	337	MMBtu/hr	CO2e	Energy efficiency measures.	363,287	tpy	BACT-PSD	111.72 kg/MMBtu of CO2, 0.001 kg/MMBtu of CH4, and 0.0001 kg/MMBtu of N2O
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	RV-13 - Reformer Vent (EQT0001)	3148	MMBtu/hr	CO2e	Energy efficiency measures.	1.05	ton CO2e/metric ton	BACT-PSD	1.05 Ton CO2e/Metric Ton of MeOH produced.
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	RV-13-SUSD - Reformer Vent Startup/Shutdown (EQT0002)	492	MMBtu/hr	CO2e	Follow manufacturer's procedures for startup/shutdown.	3,284	tpy	BACT-PSD	
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	B1-13 - Boiler 1 (EQT0003)	350	MMBtu/hr	CO2e	Energy efficiency measures.	179,511	tpy	BACT-PSD	1.05 Ton CO2e/Metric Ton of MeOH produced.
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	B2-13 - Boiler 2 (EQT0004)	350	MMBtu/hr	CO2e	Energy efficiency measures.	179,511	tpy	BACT-PSD	1.05 Ton CO2e/Metric Ton of MeOH produced.
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	B2-13-SUSD - Boiler 2 Startup/Shutdown (EQT0006)	515	MMBtu/hr	CO2e	Follow manufacturer's procedures for startup/shutdown.	4,339	tpy	BACT-PSD	
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	06/30/2017	B1-13-SUSD - Boiler 1 Startup/Shutdown (EQT0005)	515	MMBtu/hr	CO2e	Follow manufacturer's procedures for startup/shutdown.	4,339	tpy	BACT-PSD	
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	12/22/2016	Steam methane reformers (I-H-101, II-H-101)	2364	MMBtu/hr	CO2e	Energy efficiency measures with the installation of heat recovery steam generators.			BACT-PSD	
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	01/09/2017	No. 9 Boiler - Natural Gas Fired	325	MMBtu/hr	CO2e	Good combustion practices and energy efficient operation.	0.167	lb/lb steam	BACT-PSD	Units are lb of CO2e/lb of steam generated.
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	01/09/2017	No. 10 Boiler - Natural Gas Fired	325	MMBtu/hr	CO2e	Good combustion practices and energy efficient operation.	0.167	lb/lb steam	BACT-PSD	Units are lb of CO2e/lb of steam generated.
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	PR Reactor Charge Heater	277	MMBtu/hr	CO2e	Use of fuel gas as fuel, energy-efficient design options, and operational/maintenance practices.	171,980	tpy	BACT-PSD	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	Boilers	1200	MMBtu/hr	CO2e	Use of natural gas or fuel gas as fuel, energy-efficient design options, and operational/maintenance practices.	615,294	tpy	BACT-PSD	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	Pyrolysis Furnaces	372	MMBtu/hr	CO2e	Use of low carbon fuel, energy-efficient design options, and operational/maintenance practices.			BACT-PSD	
LA-0385	GARYVILLE REFINERY	MARATHON PETROLEUM COMPANY LP	02/11/2021	FCCU Charge Heater (EQT0163)	315	MMBtu/hr	CO2e	Comply with work practice standards of 40 CFR 63 Subpart DDDDD.			BACT-PSD	
LA-0385	GARYVILLE REFINERY	MARATHON PETROLEUM COMPANY LP	02/11/2021	Crude Heaters (EQT0292)	745	MMBtu/hr	CO2e	Comply with work practice standards of 40 CFR 63 Subpart DDDDD.			BACT-PSD	
*LA-0394	GEISMAR PLANT	SHELL CHEMICAL LP	12/12/2023	01-22 - AO-5 Boiler	350	MMBtu/hr	CO2e	Use of low carbon fuels, good combustion practices, good operating and maintenance practices, and energy efficient design.			BACT-PSD	

11.310 - Gaseous Fuel & Gaseous Fuel Mixtures (>250 MMBtu/hr) - Natural Gas (Includes Propane and LPG)
Pollutant: GHGs
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	05/22/2019	EUSTMBOILER	300	MMBtu/hr	CO2e	Utilize low-carbon fuels and implement energy efficiency measures and preventative maintenance pursuant to manufacturer's recommendations.	214,988	tpy	BACT-PSD	Carbon capture and sequestration is not economically feasible.
*ND-0033	GRAND FORKS FERTILIZER PLANT	NORTHERN PLAINS NITROGEN	08/10/2015	Ammonia Plant Primary Reformer	1006	MMBtu/hr	CO2e	Energy efficiency measures.	515,778	tpy	BACT-PSD	
NE-0065	CARGILL, INCORPORATED	CARGILL, INCORPORATED	12/28/2018	Boiler L	299	MMBtu/hr	CO2e	Good combustion practices.	153,354	tpy	BACT-PSD	
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	04/19/2017	Primary Reformer Heater (B002)	740	MMBtu/hr	CO2e	Use of low-carbon fuels (natural gas and/or tail gas) and periodic burner tuning and heater inspection.	383,584	tpy	BACT-PSD	
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	04/19/2017	Package Boilers (2 identical, B003 and B004)	265	MMBtu/hr	CO2e	Thermal efficiency of 80%, based on HHV in addition to good design, good combustion practices, and energy efficient operation.	137,364	tpy	BACT-PSD	
TX-0774	BISHOP FACILITY	TICONA POLYMERS, INC.	11/12/2015	Reformer	1190	MMBtu/hr	CO2e	Firing of pipeline quality natural gas and high hydrogen process gas. CO2eq (CH4, N2O, and CO2) emissions are controlled through heat integration and best management practices.	533,629	tpy	BACT-PSD	
TX-0806	PORT ARTHUR ETHANE SIDE CRACKER	TOTAL PETROCHEMICALS AND REFINING USA INC.	07/22/2016	Pyrolysis Furnaces (7)	4,000,000,000	scf/yr	CO2e	Low carbon fuel, good combustion practices.	192,399	tpy	BACT-PSD	Emissions information per furnace.
TX-0814	AMMONIA AND UREA PLANT	AGRIUM US, INC	01/05/2017	Reformer Furnace 101-B	9,636,000	MMBtu/yr	CO2e	Agrium uses good engineering practices to minimize CO2e emissions.	564,019	tpy	BACT-PSD	
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	04/23/2020	Boilers	250	MMBtu/hr	CO2e	Good combustion practice and proper design.			BACT-PSD	
WI-0267	GREEN BAY PACKAGING, INC. - MILL DIVISION	GREEN BAY PACKAGING, INC.	09/06/2018	Two Natural Gas-Fired Boilers (Boilers B34 and B35)	285	MMBtu/hr	CO2e	Good combustion practices, only fire natural gas.	160	lb/1,000 lb steam	BACT-PSD	

11.390 - Gaseous Fuel & Gaseous Fuel Mixtures (>250 MMBtu/hr) - Other Gaseous Fuel & Gaseous Fuel Mixtures
Pollutant: GHGs
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
IL-0115	WOOD RIVER REFINERY	PHILLIPS 66 COMPANY	01/23/2015	Boiler 19	405	MMBtu/hr	CO2e	Good combustion practices.	0.168	lb/lb steam produced	BACT-PSD	
IL-0128	CITGO PETROLEUM CORPORATION	CITGO PETROLEUM CORPORATION	04/11/2018	Two RFG-fired Boilers	340	MMBtu/hr	CO2e	Energy efficient design, good combustion practices, boiler maintenance and annual tune-ups.	230	lb/lb steam	BACT-PSD	BACT limits for each boiler: Boiler 430B-24: 230 lbs per 1,000 lbs steam produced, 12-month rolling average. Boiler 431B-25: 189 lbs per 1,000 lbs steam produced, 12-month rolling average.
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	05/06/2022	Reformer Furnace EU-001	780	MMBtu/hr	CO2e	Good combustion practices and proper design, shall combust natural gas and/or process off gas streams, shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet steam flows, shall be designed to achieve a thermal efficiency of 80% (HHV).	59.61	lb/MMcf	BACT-PSD	
KY-0105	MARATHON PETROLEUM COMPANY LP;CATLETTSBURG REFINING, LLC	MARATHON PETROLEUM COMPANY LP;CATLETTSBURG REFININ	09/01/2015	Boiler #15 (#15 package boiler)	0.35	MMscf/hr	CO2e	The use of low-carbon RFG as a fuel, the use of good combustion practices, and the use of an energy efficient design.	179,000	CO2e	BACT-PSD	
*LA-0395	VALERO REFINING NEW ORLEANS - ST. CHARLES REFINERY	VALERO REFINING NEW ORLEANS, LLC	10/24/2023	Boiler 401-J	462	MMBtu/hr	CO2e	Maintain good combustion practices by meeting the work practice standards of 40 CFR 63 Subpart DDDDD.	215,413	tpy	BACT-PSD	
*LA-0396	MARATHON GARYVILLE REFINERY	MARATHON PETROLEUM CO LP	12/04/2023	Vacuum Tower Heaters 210-1403 and 210-1404	338.77	MMBtu/hr	CO2e	Use of clean fuels and compliance with work practice standards of 40 CFR 63 Subpart DDDDD.			BACT-PSD	There was no emission limit for GHG in the PSD permit.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Ethane Cracking Furnaces, 6 identical (B001 - B006)	552	MMBtu/hr	CO2e	Use of low carbon gaseous fuels, good combustion and operating practices, and pollution prevention means by improving energy efficiency.	1,673,240	tpy	BACT-PSD	1,673,240 tons of carbon dioxide equivalents (CO2e) per rolling, 12-month period for B001-B006, combined.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Natural Gas and Ethane-Fired Steam Boilers (B007 - B009)	400	MMBtu/hr	CO2e	Low carbon intensity gaseous fuels, good combusting and operating practices, and efficiency improvement measures to maximize overall unit energy efficiency.	102,500	tpy	BACT-PSD	102,500 tons of carbon dioxide equivalents (CO2e) per rolling, 12-month period for B007-B009, combined.
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	09/04/2015	Utility and Industrial Boiler greater than 250 million British thermal units (MMBtu) firing	560	MMBtu/hr	CO2		130	lb/MMBtu	BACT-PSD	
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	09/04/2015	Utility and Industrial Boiler greater than 250 million British thermal units (MMBtu)	462.3	MMBtu/hr	CO2		130	lb/MMBtu	BACT-PSD	
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	09/04/2015	Utility and Industrial Boiler greater than 250 million British thermal units (MMBtu)	364.6	MMBtu/hr	CO2		130	lb/MMBtu	BACT-PSD	
TX-0776	BISHOP FACILITY	TICONA POLYMERS, INC.	11/12/2015	Boiler	452	MMBtu/hr	CO2e	Low carbon fuel, good combustion practices, efficient boiler design.	235,156	tpy	BACT-PSD	77 Percent Thermal efficiency on a monthly average
TX-0801	PL PROPYLENE HOUSTON OLEFINS PLANT	FLINT HILLS RESOURCES HOUSTON CHEMICAL LLC	06/24/2016	Charge Gas Heater	463	MMBtu/hr	CO2e	Work practices such as regular maintenance also required.	500	°F	BACT-PSD	30 TAC Chapter 117 Subchapter B
TX-0801	PL PROPYLENE HOUSTON OLEFINS PLANT	FLINT HILLS RESOURCES HOUSTON CHEMICAL LLC	06/24/2016	Waste Heat Boiler	1690	MMBtu/hr	CO2e	Work practices such as regular maintenance also required.	500	°F	BACT-PSD	NSPS Subpart Db, MACT Subpart DDDDD, 30 TAC Chapter 117 Subchapter B
TX-0832	EXXONMOBIL BEAUMONT REFINERY	EXXONMOBIL OIL CORPORATION	01/09/2018	F-1001 Crude Charge Furnace	630.8	MMBtu/hr	CO2e	Control of maximum stack exhaust temperature, performing preventative maintenance as necessary, and inspecting and tuning burners and conducting a visual inspection of the heater components annually.	500	°F	BACT-PSD	NSPS Ja, MACT CC, DDDDD
TX-0906	PORT ARTHUR REFINERY	THE PREMCOR REFINING GROUP INC.	10/30/2020	Boiler	250	MMBtu/hr	CO2e	Good combustion practices.			BACT-PSD	
*TX-0938	VALERO CORPUS CHRISTI REFINERY WEST PLANT	VALERO REFINING-TEXAS, L.P.	05/03/2024	Boiler	462	MMBtu/hr	CO2e	Good combustion practices and the use of gaseous fuel.			BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: PM-PM_{10}
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
NE-0059	AGP SOY	AG PROCESSING INC., A COOPERATIVE	3/25/2015	Cooling Tower	360,000	gal/hr	PM	Drift loss design specification and TDS concentration limit.	0.0005	%	BACT-PSD	
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	4/1/2015	Cooling tower	40,000	gpm	PM	Drift eliminator is 0.0005% efficient.	0.35	lb/hr	OTHER CASE-BY-CASE	
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	4/1/2015	Cooling tower	40,000	gpm	PM10	Drift eliminator is 0.0005% efficient.	0.31	lb/hr	OTHER CASE-BY-CASE	
OH-0364	OREGON ENERGY CENTER	OREGON ENERGY CENTER	5/20/2015	Cooling Towers #1 & #2 (P009 & P010)	115,037	gpm	PM	Advanced drift eliminators with a drift rate of less than 0.0005% and maintain the TDS content of the circulating cooling water at 5,130 mg/L or less as a 24-hour rolling average.	1.48	lb/hr	BACT-PSD	
OH-0364	OREGON ENERGY CENTER	OREGON ENERGY CENTER	5/20/2015	Cooling Towers #1 & #2 (P009 & P010)	115,037	gpm	PM10	Advanced drift eliminators with a drift rate of less than 0.0005% and maintain the TDS content of the circulating cooling water at 5,130 mg/L or less as a 24-hour rolling average.	1.48	lb/hr	BACT-PSD	
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	6/4/2015	Cooling Towers			PM10	Drift eliminators.	0.0005	% drift rate	BACT-PSD	
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	Mechanical draft cooling tower			PM10	High efficiency drift eliminators (integral part of the design).	0.0005	% drift rate	BACT-PSD	
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	Mechanical draft cooling tower			PM	High efficiency drift eliminators (integral part of the design).	0.0005	% drift rate	BACT-PSD	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	8/25/2015	Wet Cooling Tower (P005)	165,470	gpm	PM10	Drift eliminator with a maximum drift rate of 0.0005% and TDS concentration of the cooling water less than or equal to 3,075 mg/L.	1.27	lb/hr	BACT-PSD	
TX-0774	BISHOP FACILITY	TICONA POLYMERS, INC.	11/12/2015	Cooling Tower	10,400		PM10	Drift eliminators meeting 0.001% drift.	3.07	tpy	BACT-PSD	
LA-0318	FLOPAM FACILITY	FLOPAM, INC.	1/7/2016	Cooling towers			PM10	Integrated drift eliminators.			BACT-PSD	
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	Mechanical draft cooling tower	465,815	gpm	PM	Must have certified drift rate no more than 0.0005%.			BACT-PSD	
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	6/30/2016	Cooling Towers			PM10	Drift eliminators.	0.0005	%	BACT-PSD	
TX-0803	PL PROPYLENE HOUSTON OLEFINS PLANT	FLINT HILLS RESOURCES HOUSTON CHEMICAL LLC	7/12/2016	Cooling Tower			PM10	Drift eliminators.	0.001	% drift	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Cooling towers - 007	86,500	gpm	PM10	Drift eliminators.	0.0005	%	BACT-PSD	
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	9/23/2016	Cooling Towers (2 identical, P005 and P006)	118,441	gpm	PM10	High efficiency drift eliminators and minimize TDS.	1.33	lb/hr	BACT-PSD	Advanced drift eliminators with a drift rate of less than 0.0005% and maintain the TDS concentration of the cooling water less than or equal to 4,500 mg/L.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	EUCOOLTWR (Cooling Tower--Wet Mechanical Draft)			PM10	Mist/drift eliminators.	2.37	tpy	BACT-PSD	Mist/drift eliminator with a maximum drift rate of 0.0005%.
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	12/22/2016	Cooling towers (I-CT-621, II-CT-621)	66,000	gpm (each)	PM10	Drift eliminators.	0.001	%	BACT-PSD	
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	1/9/2017	Cooling Water Tower	18,000	gpm	PM10	Drift eliminators with drift factor of 0.003%.	0.003	%	BACT-PSD	Drift eliminators with drift factor of 0.003%.
TX-0815	PORT ARTHUR ETHANE SIDE CRACKER	TOTAL PETROCHEMICALS & REFINING USA, INC.	1/17/2017	Cooling Tower			FPM10	Drift eliminators.			BACT-PSD	
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	4/19/2017	Cooling Towers #1 & #2 (P010 & P011)	79,800	gpm	PM10	Drift eliminators with a maximum drift rate specification of 0.0005% or less and TDS concentration of the cooling water less than or equal to 5,000 mg/L.	0.3	lb/hr	BACT-PSD	
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	4/19/2017	Wastewater Treatment Plant Cooling Water Tower (P012)	1,000	gpm	PM10	Drift eliminators with a maximum drift rate specification of 0.0005% or less and TDS concentration of the cooling water less than or equal to 5,000 mg/L.	5	X10-4 lb/hr	BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: PM-PM_{10}
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	6/30/2017	ECT-14 - Econamine Cooling Tower (EQT0018)	29,120	gpm	FPM10	High efficiency drift eliminators.	0.44	tpy	BACT-PSD	Use high efficiency drift eliminators with a maximum drift rate of 0.0005%; a cooling Water Circulation Rate <= 29,100 gpm; and a TDS Concentration <= 2,660 ppm for PM/PM10/PM2.5 control. The permittee shall determine and record the concentration of TDS in the cooling water at least once per week using Standard Method 2540C or EPA Method 160.1.
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	6/30/2017	CT-13 - Cooling Tower (EQT0007)	231,000	gpm	FPM10	High efficiency drift eliminators.	0.96	lb/hr	BACT-PSD	Use high efficiency drift eliminators with a maximum drift rate of 0.0005%; a cooling Water Circulation Rate <= 231,000 gpm; and a TDS Concentration <= 2,660 ppm for PM/PM10/PM2.5 control. The permittee shall determine and record the concentration of TDS in the cooling water at least once per week using Standard Method 2540C or EPA Method 160.1.
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	9/7/2017	Wet Cooling Tower (P005)	155,083	gpm	PM10	Drift eliminator with a maximum drift rate of 0.0005% and TDS concentration of the cooling water less than or equal to 3,500 mg/L.	1.36	lb/hr	BACT-PSD	
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	9/27/2017	Wet Cooling Tower (P005)	155,083	gpm	PM10	Drift eliminator with a maximum drift rate of 0.0005% and TDS concentration of the cooling water less than or equal to 3,500 mg/L.	0.93	lb/hr	BACT-PSD	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Wet Mechanical Draft Cooling Tower (P003)	120,000	gpm	PM	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and TDS content not to exceed 5,000 mg/l.	6.58	tpy	BACT-PSD	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	11/7/2017	Wet Mechanical Draft Cooling Tower (P003)	120,000	gpm	PM10	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and TDS content not to exceed 5,000 mg/l.	4.24	tpy	BACT-PSD	
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	EUCOOLTWR (Cooling Tower--Wet Mechanical Drift)			FPM	Mist/drift eliminators.	0.0006	%	BACT-PSD	Emission limit 1 above is 0.0006%, vendor-certified maximum drift rate. Emission limit 2 above is 7700 ppmw, maximum TDS in cooling water. The estimated efficiency is to reduce drift loss to 0.0006%. There are no BACT emission limits in the permit, but there is a requirement for the permittee to equip and maintain EUCOOLTWR with mist/drift eliminators with a vendor-certified maximum drift rate of 0.0006% or less, and there is also a limit of 7700 ppmw maximum TDS in cooling water.
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	EUCOOLTWR (Cooling Tower--Wet Mechanical Drift)			PM10	Mist/drift eliminators.	0.0006	%	BACT-PSD	Emission limit 1 above is 0.0006% with vendor-certified maximum drift rate. Emission limit 2 above is 7700 ppmw, maximum TDS in cooling water. The estimated efficiency is to reduce drift loss to 0.0006%. There are no BACT emission limits in the permit, but there is a requirement for the permittee to equip and maintain EUCOOLTWR with mist/drift eliminators with a vendor-certified maximum drift rate of 0.0006% or less, and there is also a limit of 7700 ppmw maximum TDS in cooling water.
FL-0363	DANIA BEACH ENERGY CENTER	FLORIDA POWER AND LIGHT COMPANY	12/4/2017	Mechanical draft cooling system			FPM	Certified drift rate < 0.0005%	0.0005	% drift rate	BACT-PSD	
TX-0832	EXXONMOBIL BEAUMONT REFINERY	EXXONMOBIL OIL CORPORATION	1/9/2018	Cooling Towers			PM	Drift eliminators.			BACT-PSD	
TX-0832	EXXONMOBIL BEAUMONT REFINERY	EXXONMOBIL OIL CORPORATION	1/9/2018	Cooling Towers			PM10	Drift eliminators.			BACT-PSD	
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	2/9/2018	Wet Cooling Tower (P005)	24,766	gpm	PM10	Drift eliminator with a maximum drift rate of 0.0005% and TDS concentration of the cooling water less than or equal to 1,100 parts per million by weight (ppmw).	0.02	lb/hr	BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: PM-PM_{10}
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	3/30/2018	Cooling Tower	9,864,000	gal/hr	PM	Drift eliminators.			BACT-PSD	
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	3/30/2018	Cooling Tower	9,864,000	gal/hr	PM10	Drift eliminators.			BACT-PSD	
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT		4/24/2018	P02A-P & P03A-P Cooling Towers			PM	Drift eliminator & cooling additive control system.			BACT-PSD	BACT is: Use of a drift eliminator with a design drift rate of no more than 0.0005% of circulating water flow; Total cooling water circulation rate for each cooling tower may not exceed 18,000 gpm; and Use of a cooling additive control system that results in a TDS concentration of not more than 2,500 ppm.
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT		4/24/2018	P02A-P & P03A-P Cooling Towers			PM10	Drift eliminator & cooling additive control system.			BACT-PSD	BACT is: Use of a drift eliminator with a design drift rate of no more than 0.0005% of circulating water flow; Total cooling water circulation rate for each cooling tower may not exceed 18,000 gpm; and Use of a cooling additive control system that results in a TDS concentration of not more than 2,500 ppm.
VA-0328	C4GT, LLC	NOVI ENERGY	4/26/2018	Cooling Tower			FPM10	Drift rate of 0.00050% of the circulating water flow with mist eliminators and a TDS content of the cooling water, not to exceed 6250 mg/L.			BACT-PSD	
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	6/29/2018	EUCOOLTOWER (North Plant): Cooling Tower	170,000	gpm	FPM	High efficiency drift/mist eliminators	5.59	tpy	BACT-PSD	There is a third emission limit in the permit: Maximum TDS in circulating water = 3000 PPMW; monthly as determined based upon weekly and monthly parameter monitoring. The estimated efficiency is to reduce drift loss to 0.0005%.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	6/29/2018	EUCOOLTOWER (North Plant): Cooling Tower	170,000	gpm	PM10	High efficiency drift/mist eliminators	2.85	tpy	BACT-PSD	There is a third emission limit in the permit which is the Maximum TDS in circulating water = 3000 PPMW; monthly as determined based upon weekly and monthly parameter monitoring. The estimated efficiency is to reduce drift loss to 0.0005%.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	6/29/2018	EUCOOLTOWER (South Plant): Cooling Tower	170,000	gpm	FPM	High efficiency drift/mist eliminators.	5.59	tpy	BACT-PSD	There is a third emission limit in the permit, as follows: Maximum TDS in circulating water = 3000 ppmw, monthly as determined based upon weekly and monthly parameter monitoring.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	6/29/2018	EUCOOLTOWER (South Plant): Cooling Tower	170,000	gpm	PM10	High efficiency drift/mist eliminators.	2.85	tpy	BACT-PSD	There is a third emission limit as follows: Maximum TDS in circulating water = 3000 ppmw; monthly as determined based upon weekly and monthly parameter monitoring. Estimated efficiency of add on controls is to reduce drift loss to 0.0005%.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	7/16/2018	EUCOOLINGTWR: Cooling Tower			FPM	High efficiency drift/mist eliminators.	4.03	lb/hr	BACT-PSD	There is a third emission limit in the permit as follows: Maximum TDS in circulating water = 3000 ppmw; monthly as determined based upon weekly and monthly parameter monitoring. The estimated efficiency of the add on controls is to reduce drift loss to 0.0005%.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	7/16/2018	EUCOOLINGTWR: Cooling Tower			PM10	High efficiency drift/mist eliminators.	0.48	lb/hr	BACT-PSD	There is a third emission limit in the permit as follows: Maximum TDS in circulating water = 3000 ppmw; monthly as determined based upon weekly and monthly parameter monitoring. The estimated efficiency of the add on controls is to reduce drift loss to 0.0005%.
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	7/27/2018	Mechanical Draft Auxiliary Cooling System			FPM	Certified drift rate < 0.0005%.	0.0005	% drift rate	BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers

Pollutant: PM-PM_{10}

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Cooling Tower (P011)	13.88	MMgal/hr	PM	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a TDS content not to exceed 2,000 ppm in the circulating cooling water based on a rolling 12-month average.	5.07	tpy	BACT-PSD	
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Cooling Tower (P011)	13.88	MMgal/hr	PM10	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a TDS content not to exceed 2,000 ppm in the circulating cooling water based on a rolling 12-month average.	3.22	tpy	BACT-PSD	
FL-0368	NUCOR STEEL FLORIDA FACILITY	NUCOR STEEL FLORIDA, INC.	2/14/2019	Two Cooling Towers	19650	gpm	PM	Drift eliminators.	0.001	% drift rate	BACT-PSD	
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	6/11/2019	Cooling tower EU-6001	32,000	gal/hr	PM	Drift eliminators.	2,395	mg/L	BACT-PSD	
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	6/11/2019	Cooling tower EU-6001	32,000	gal/hr	PM10	Drift eliminators.	2,395	mg/L	BACT-PSD	
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	8/21/2019	FGCOOLTWR	92,500	gpm	PM	Particulate in water droplets will be controlled with high efficiency drift/mist eliminators.	4.1	tpy	BACT-PSD	As part of normal operation, some of the circulating water may become entrained in the air leaving the cool tower. This water is in droplet form (also known as "drift" droplets) and contains the same impurities as the circulating water. Therefore, any particulate matter that is dissolved in the circulating water may be emitted as PM, PM10 and PM2.5. No other pollutants will be emitted from the cooling towers. High efficiency drift eliminators were proposed by Thomas Township Energy as BACT with a drift rate of 0.0005%. The dissolved solids content of the circulating water also contributes to the emissions; therefore, there is also a proposed material limit of 2,000 ppmw dissolved solids content in the circulating water.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	8/21/2019	FGCOOLTWR	92,500	gpm	PM10	Particulate in water droplets will be controlled with high efficiency drift/mist eliminators	2.6	tpy	BACT-PSD	As part of normal operation, some of the circulating water may become entrained in the air leaving the cool tower. This water is in droplet form (also known as "drift" droplets) and contains the same impurities as the circulating water. Therefore, any particulate matter that is dissolved in the circulating water may be emitted as PM, PM10 and PM2.5. No other pollutants will be emitted from the cooling towers. High efficiency drift eliminators were proposed by Thomas Township Energy as BACT with a drift rate of 0.0005%. The dissolved solids content of the circulating water also contributes to the emissions; therefore, there is also a proposed material limit of 2,000 ppmw dissolved solids content in the circulating water.
MN-0094	CHS OILSEED PROCESSING - FAIRMONT	CHS INC	8/22/2019	Cooling Towers	12,000	gpm	PM		0.005	%	N/A	
TX-0863	POLYETHYLENE 7 FACILITY	THE DOW CHEMICAL COMPANY	9/3/2019	Cooling Tower			PM10	Drift eliminators.	0		BACT-PSD	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Cooling Tower			PM	Drift eliminators.	0.005	% drift	BACT-PSD	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Cooling Tower			PM10	Drift eliminators.	0.005	% drift	BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Cooling Tower			PM	Drift eliminators.	6,000	ppmw	BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Cooling Tower			PM10	Drift eliminators.	6,000	ppmw	BACT-PSD	
AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	9/23/2019	Cooling Towers			FPM	Drift eliminators. Low TDS.	0.0005	% drift loss	BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: PM-PM_{10}
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	9/23/2019	Cooling Towers			PM10	Drift eliminators. Low TDS.	0.0005	% drift loss	BACT-PSD	
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	9/27/2019	Contact Cooling Towers - Melt Shop 2 (P027)	2.7	MMgal/hr	FPM	i. Use of drift eliminator(s) designed to achieve a 0.001% drift rate; ii. Maintenance of a TDS content (for the 5 individual cooling towers) not to exceed the ppm in the circulating cooling water based on a rolling 12-month average as indicated in the table below: Cooling Tower - TDS (ppm) Meltshop 2 Cooling Tower - 1000 Caster Mold Water Cooling Tower - 800 Tunnel Furnace Cooling Tower - 800 Caster Non-Contact 2 Cooling Tower - 800 Caster Contact 2 Cooling Tower - 1400	1.17	tpy	BACT-PSD	
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	9/27/2019	Contact Cooling Towers - Melt Shop 2 (P027)	2.7	MMgal/hr	FPM10	i. Use of drift eliminator(s) designed to achieve a 0.001% drift rate; ii. Maintenance of a TDS content (for the 5 individual cooling towers) not to exceed the ppm in the circulating cooling water based on a rolling 12-month average as indicated in the table below: Cooling Tower - TDS (ppm) Meltshop 2 Cooling Tower - 1000 Caster Mold Water Cooling Tower - 800 Tunnel Furnace Cooling Tower - 800 Caster Non-Contact 2 Cooling Tower - 800 Caster Contact 2 Cooling Tower - 1400	0.93	tpy	BACT-PSD	
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	9/27/2019	Contact Cooling Towers (P014)	6.41	MMgal/hr	FPM	i. Use of drift eliminator(s) designed to achieve a 0.003% drift rate; ii. Maintenance of a TDS content (for the 5 individual cooling towers) not to exceed the ppm in the circulating cooling water based on a rolling 12-month average as indicated in the table below: Cooling Tower - TDS (ppm) Meltshop Cooling Tower (501) - 800 Caster Non-Contact Cooling Tower (6 Cell) - 800 Caster Contact Cooling Tower (503) - 1100 Mill Contact Cooling Tower (505) - 2000 Laminar Flow Cooling Tower (506) - 1400	8.7	tpy	BACT-PSD	
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	9/27/2019	Contact Cooling Towers (P014)	6.41	MMgal/hr	FPM10	i. Use of drift eliminator(s) designed to achieve a 0.003% drift rate; ii. Maintenance of a TDS content (for the 5 individual cooling towers) not to exceed the ppm in the circulating cooling water based on a rolling 12-month average as indicated in the table below: Cooling Tower - TDS (ppm) Meltshop Cooling Tower (501) - 800 Caster Non-Contact Cooling Tower (6 Cell) - 800 Caster Contact Cooling Tower (503) - 1100 Mill Contact Cooling Tower (505) - 2000 Laminar Flow Cooling Tower (506) - 1400	6.95	tpy	BACT-PSD	
WI-0311	SUPERIOR REFINING COMPANY LLC	SUPERIOR REFINING COMPANY LLC	9/27/2019	Cooling Tower No.1 (P80)	10,000	gpm	PM	Drift eliminator, cooling additive control system that results in a TDS concentration of not more than 3,000 ppm.	0.0005	% drift	BACT-PSD	Total cooling water circulation rate may not exceed 10,000 gpm, on an hourly average basis. Use of a cooling additive control system that results in a TDS concentration of not more than 3,000 ppm. May demonstrate compliance with the TDS limitation through measurement of cooling water conductivity.

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: PM-PM_{10}
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
WI-0311	SUPERIOR REFINING COMPANY LLC	SUPERIOR REFINING COMPANY LLC	9/27/2019	Cooling Tower No.1 (P80)	10,000	gpm	PM10	Drift eliminator, cooling additive control system that results in a TDS concentration of not more than 3,000 ppm.	0.0005	% drift	BACT-PSD	Total cooling water circulation rate may not exceed 10,000 gpm, on an hourly average basis. May demonstrate compliance with the TDS limitation through measurement of cooling water conductivity.
KS-0040	JOHNS MANVILLE AT MCPHERSON	JOHNS MANVILLE	12/3/2019	Cooling Towers			PM	Drift rate control.	0.001	%	BACT-PSD	Drift rate from each cooling tower shall be 0.001% or less.
TX-0873	PORT ARTHUR REFINERY	MOTIVA ENTERPRISES LLC	2/4/2020	Cooling Tower	35,000	gpm	PM	Drift eliminators.			BACT-PSD	
TX-0873	PORT ARTHUR REFINERY	MOTIVA ENTERPRISES LLC	2/4/2020	Cooling Tower	35,000	gpm	PM10	Drift eliminators.			BACT-PSD	
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	2/6/2020	Cooling Tower			FPM	Drift eliminators.	1,200	ppm	BACT-PSD	
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	2/6/2020	Cooling Tower			FPM10	Drift eliminators.	1,200	ppm	BACT-PSD	
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	4/23/2020	Cooling Towers			PM	Drift eliminators.			BACT-PSD	
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	4/23/2020	Cooling Towers			PM10	Drift eliminators.			BACT-PSD	
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-01 - Melt Shop ICW Cooling Tower	52,000	gpm	FPM	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.36	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,365 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-01 - Melt Shop ICW Cooling Tower	52,000	gpm	PM10	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.27	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,365 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-02 - Melt Shop DCW Cooling Tower	5,900	gpm	FPM	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.04	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-02 - Melt Shop DCW Cooling Tower	5,900	gpm	PM10	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.03	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-03 - Rolling Mill ICW Cooling Tower	8,500	gpm	FPM	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.06	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,365 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-03 - Rolling Mill ICW Cooling Tower	8,500	gpm	PM10	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.04	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,365 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-04 - Rolling Mill DCW Cooling Tower	22,750	gpm	FPM	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.17	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-04 - Rolling Mill DCW Cooling Tower	22,750	gpm	PM10	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.12	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-05 - Rolling Mill Quench/ACC Cooling Tower	90,000	gpm	FPM	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.78	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,729 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-05 - Rolling Mill Quench/ACC Cooling Tower	90,000	gpm	PM10	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.54	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,729 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-06 - Light Plate Quench DCW Cooling Tower	8,000	gpm	FPM	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.06	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-06 - Light Plate Quench DCW Cooling Tower	8,000	gpm	PM10	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.04	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.

Process Type: 99.009 - Industrial Process Cooling Towers

Pollutant: PM-PM_{10}

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-07 - Heavy Plate Quench DCW Cooling Tower	3,000	gpm	FPM	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.02	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-07 - Heavy Plate Quench DCW Cooling Tower	3,000	gpm	PM10	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.02	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-08 - Air Separation Plant Cooling Tower	14,000	gpm	FPM	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.1	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	7/23/2020	EP 09-08 - Air Separation Plant Cooling Tower	14,000	gpm	PM10	High efficiency mist eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.	0.08	lb/hr	BACT-PSD	TDS concentration shall not exceed 1,495 ppm.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		9/9/2020	Cooling Tower			PM	Non-contact design and drift eliminators.	1,200	ppmw	BACT-PSD	
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		9/9/2020	Cooling Tower			PM10	Non-contact design and drift eliminators.	1,200	ppmw	BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	Cooling Tower			PM	Drift eliminators 0.001%.			BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	Cooling Tower			PM10	Drift eliminators 0.001%.			BACT-PSD	
TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	3/17/2021	Cooling Tower			PM	Drift eliminators at 0.0005%.	60,000	ppm	BACT-PSD	
TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	3/17/2021	Cooling Tower			PM10	Drift eliminators at 0.0005%.	60,000	ppm	BACT-PSD	
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Laminar Cooling Tower - Hot Mill Cells (EP 03-09)	35,000	gpm	FPM	Mist eliminator, 0.001% drift loss.	0.27	lb/hr	BACT-PSD	TDS limited to 1729 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Laminar Cooling Tower - Hot Mill Cells (EP 03-09)	35,000	gpm	PM10	Mist eliminator, 0.001% drift loss.	0.19	lb/hr	BACT-PSD	TDS limited to 1729 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Direct Cooling Tower-Caster Roughing Mill Cells (EP 03-10)	26,300	gpm	FPM	Mist eliminator, 0.001% drift loss.	0.17	lb/hr	BACT-PSD	TDS limited to 1495 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Direct Cooling Tower-Caster Roughing Mill Cells (EP 03-10)	26,300	gpm	PM10	Mist eliminator, 0.001% drift loss.	0.12	lb/hr	BACT-PSD	TDS limited to 1495 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Melt Shop #2 Cooling Tower (indirect) (EP 03-11)	59,500	gpm	FPM	Mist eliminator, 0.001% drift loss.	0.39	lb/hr	BACT-PSD	TDS limited to 1365 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: PM-PM_{10}
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Melt Shop #2 Cooling Tower (indirect) (EP 03-11)	59,500	gpm	PM10	Mist eliminator, 0.001% drift loss.	0.29	lb/hr	BACT-PSD	TDS limited to 1365 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Cold Mill Cooling Tower (EP 03-12)	20,000	gpm	FPM	Mist eliminator, 0.001% drift loss.	0.14	lb/hr	BACT-PSD	TDS limited to 1365 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Cold Mill Cooling Tower (EP 03-12)	20,000	gpm	PM10	Mist eliminator, 0.001% drift loss.	0.094	lb/hr	BACT-PSD	TDS limited to 1365 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Air Separation Plant Cooling Tower (EP 03-13)	15,000	gpm	FPM	Mist eliminator, 0.001% drift loss.	0.08	lb/hr	BACT-PSD	TDS limited to 1125 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	Air Separation Plant Cooling Tower (EP 03-13)	15,000	gpm	PM10	Mist eliminator, 0.001% drift loss.	0.07	lb/hr	BACT-PSD	TDS limited to 1125 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	DCW Auxiliary Cooling Tower (EP 03-14)	9,250	gpm	FPM	Mist eliminator, 0.001% drift loss.	0.06	lb/hr	BACT-PSD	TDS limited to 1309 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	4/19/2021	DCW Auxiliary Cooling Tower (EP 03-14)	9,250	gpm	PM10	Mist eliminator, 0.001% drift loss.	0.05	lb/hr	BACT-PSD	TDS limited to 1309 ppm. Emission calculations are based on a technical paper about calculating particulates from cooling towers by Reisman and Frisbie. ("Calculating Realistic PM10 Emissions From Cooling Towers" Reisman-Frisbie. Environmental Progress 21 (July 2002)).
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	6/7/2021	Mechanical Draft Auxiliary Cooling System			FPM	Certified drift rate < 0.0005%.	0.0005	% drift rate	BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Cooling Tower			PM	Drift eliminators required. Maximum drift 0.0005%. TDS limit of 3,500 ppmw in the cooling water. Daily sampling for TDS required, or weekly TDS sampling is allowed if conductivity is monitored daily and a TDS to conductivity ratio is established.			BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Cooling Tower			PM10	Drift eliminators required. Maximum drift 0.0005%. TDS limit of 3,500 ppmw in the cooling water. Daily sampling for TDS required, or weekly TDS sampling is allowed if conductivity is monitored daily and a TDS to conductivity ratio is established.			BACT-PSD	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Cooling Tower			PM	Drift eliminators with 0.001% drift.			BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers
Pollutant: PM-PM_{10}
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Cooling Tower			PM10	Drift eliminators with 0.001% drift.			BACT-PSD	
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	MAGNOLIA POWER LLC	6/3/2022	Cooling Tower	8,400	gpm	PM10	High-efficiency drift eliminators.	0.0005	%	BACT-PSD	Equipped with high-efficiency drift eliminators <= 0.0005% drift rate.
TX-0922	HOUSTON PLANT - 46307	TPC GROUP LLC	6/13/2022	Cooling Tower			PM	Drift eliminators with 0.0005% drift.			BACT-PSD	
TX-0922	HOUSTON PLANT - 46307	TPC GROUP LLC	6/13/2022	Cooling Tower			PM10	Drift eliminators with 0.0005% drift.			BACT-PSD	
KY-0116	NOVELIS CORPORATION - GUTHRIE	NOVELIS CORPORATION	7/25/2022	EU 043 - Cooling Tower #1	0.15	MMgal/hr	FPM	Mist eliminator (0.001% drift loss), TDS concentration limit of 1000 ppm.	0.013	lb/hr	BACT-PSD	Initial compliance demonstration with BACT will be shown by properly installing mist eliminators on EU043 and using parametric monitoring for the cooling tower to ensure the TDS remains below 1000 ppm. Emissions calculated using the vendor design specification for the mist eliminator of 0.001% drift loss and 1,000 ppm TDS.
KY-0116	NOVELIS CORPORATION - GUTHRIE	NOVELIS CORPORATION	7/25/2022	EU 043 - Cooling Tower #1	0.15	MMgal/hr	PM10	Mist eliminator (0.001% drift loss), TDS concentration limit of 1000 ppm.	0.006	lb/hr	BACT-PSD	Initial compliance demonstration with BACT will be shown by properly installing mist eliminators on EU043 and using parametric monitoring for the cooling tower to ensure the TDS remains below 1000 ppm. Emissions calculated using the vendor design specification for the mist eliminator of 0.001% drift loss and 1,000 ppm TDS, and Reisman-Frisbie interpolation.
TX-0940	FIBERGLASS MANUFACTURING FACILITY	KNAUF INSULATION, INC.	9/6/2022	Cooling Tower	2,175	gpm	PM	Drift eliminators.	0.001	%	BACT-PSD	
TX-0940	FIBERGLASS MANUFACTURING FACILITY	KNAUF INSULATION, INC.	9/6/2022	Cooling Tower	2,175	gpm	PM10	Drift eliminators.	0.001	%	BACT-PSD	
OH-0387	INTEL OHIO SITE	INTEL OHIO SITE	9/20/2022	Cooling Towers: P054 through P178			PM	Drift eliminators.	0.0005	%	BACT-PSD	
OH-0387	INTEL OHIO SITE	INTEL OHIO SITE	9/20/2022	Cooling Towers: P054 through P178			PM10	Drift eliminators.	0.0005	%	BACT-PSD	
*NE-0064	NORFOLK CRUSH, LLC	NORFOLK CRUSH, LLC	11/21/2022	Cooling Tower	480,060	gal/hr	PM	There is a drift loss design specification and a TDS concentration limit.	0.0005	%	BACT-PSD	The drift loss % is guaranteed by the manufacturer.
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	ENTERGY TEXAS, INC.	3/13/2023	Cooling Tower	13,734,000	gal/hr	PM	0.001% drift eliminators.			BACT-PSD	
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	ENTERGY TEXAS, INC.	3/13/2023	Cooling Tower	13,734,000	gal/hr	PM10	0.001% drift eliminators.			BACT-PSD	
*NE-0068	AG PROCESSING INC - DAVID CITY	AG PROCESSING INC., A COOPERATIVE	6/27/2023	Cooling Tower 1	759,600	gal/hr	PM	There is a drift loss design specification with the mist eliminator (CE-8000) and a TDS concentration limit.	0.0005	%	BACT-PSD	The drift loss of 0.0005% is guaranteed by the manufacturer and TDS concentration of 3000 ppm is verified by monthly samples and tests.
*NE-0068	AG PROCESSING INC - DAVID CITY	AG PROCESSING INC., A COOPERATIVE	6/27/2023	Cooling Tower 2	303,840	gal/hr	PM	There is a drift loss design specification with the mist eliminator (CE-8001) and a TDS concentration limit.	0.0005	%	BACT-PSD	The drift loss of 0.0005% is guaranteed by the manufacturer and TDS concentration of 3000 ppm is verified by monthly samples and tests.
*TX-0964	NEDERLAND FACILITY	LINDE, INC	10/5/2023	Cooling Towers			FPM	Drift eliminators with 0.001% drift.	2,000	ppmw	BACT-PSD	
*TX-0964	NEDERLAND FACILITY	LINDE, INC	10/5/2023	Cooling Towers			FPM10	Drift eliminators with 0.001% drift.	2,000	ppmw	BACT-PSD	
*OH-0391	VALENCIA PROJECT LLC	VALENCIA PROJECT LLC	10/27/2023	Cooling Towers (P023, P024, P025)			PM	A drift eliminator achieving drift loss equal to or less than 0.0005%.	0.05	lb/hr	BACT-PSD	A drift eliminator achieving drift loss equal to or less than 0.0005%.
*OH-0391	VALENCIA PROJECT LLC	VALENCIA PROJECT LLC	10/27/2023	Cooling Towers (P023, P024, P025)			PM10	A drift eliminator achieving drift loss equal to or less than 0.0005%.	0.04	lb/hr	BACT-PSD	A drift eliminator achieving drift loss equal to or less than 0.0005%.
*SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD PLANT	SCOUT MOTORS INC A DELAWARE CORPORATION	10/31/2023	Cooling Towers			FPM	Drift eliminators.	0.001	% drift rate	BACT-PSD	
*SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD PLANT	SCOUT MOTORS INC A DELAWARE CORPORATION	10/31/2023	Cooling Towers			PM10	Drift eliminators.	0.001	% drift rate	BACT-PSD	
*LA-0394	GEISMAR PLANT	SHELL CHEMICAL LP	12/12/2023	04-22 - AO-5 Cooling Water Tower, W-S5401	47,410	gpm	PM10		0.18	lb/hr	BACT-PSD	

Process Type: 99.009 - Industrial Process Cooling Towers

Pollutant: PM-PM_{10}

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
*LA-0402	DESTREHAN OIL PROCESSING FACILITY	BUNGE CHEVRON AG RENEWABLES, LLC	12/13/2023	HLK40 - Cooling Towers (EQT0095)	125,856	gpm	FPM10	Drift elimination system.	0.06	lb/hr	BACT-PSD	Employ a drift elimination system with a maximum design drift rate of 0.0005%.
*LA-0401	KOCH METHANOL (KME) FACILITY	KOCH METHANOL ST. JAMES, LLC	12/20/2023	CWT - Cooling Water Tower	200,000	gpm	PM10	Use of high efficiency drift eliminators.			BACT-PSD	
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Cooling Tower	145,310	gpm	PM10	High efficiency drift eliminators.	0.0005	%	BACT-PSD	Monthly sampling to determine TDS content of water circulated in the cooling tower.
*TX-0967	QUAIL RUN CARBON CAPTURE PLANT	QUAIL RUN CARBON, LLC	2/5/2024	Cooling Towers	142,700	gpm	PM	Drift eliminators 0.0005%.			BACT-PSD	
*TX-0967	QUAIL RUN CARBON CAPTURE PLANT	QUAIL RUN CARBON, LLC	2/5/2024	Cooling Towers	142,700	gpm	PM10	Drift eliminators 0.0005%.			BACT-PSD	
*TX-0938	VALERO CORPUS CHRISTI REFINERY WEST PLANT	VALERO REFINING-TEXAS, L.P.	5/3/2024	Cooling Tower			PM	Drift eliminators 0.001% drift.			BACT-PSD	
*TX-0938	VALERO CORPUS CHRISTI REFINERY WEST PLANT	VALERO REFINING-TEXAS, L.P.	5/3/2024	Cooling Tower			PM10	Drift eliminators 0.001% drift.			BACT-PSD	
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4C-4 - C/A Cooling Tower	64,600	gpm	PM10	High efficiency drift eliminators.	0.23	lb/hr	BACT-PSD	
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4M-7 - VCM Cooling Tower 1	122,269	gpm	PM10	Drift eliminators.	0.36	lb/hr	BACT-PSD	
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4M-18 - VCM Cooling Tower 2	28,620	gpm	PM10	Drift eliminators.	0.08	lb/hr	BACT-PSD	
*IN-0382	DUKE ENERGY INDIANA, INC.- CAYUGA GENERATING STATION	DUKE ENERGY INDIANA, INC.	2/14/2025	Cooling Towers	280,000	gpm	PM	Drift eliminator system.			BACT-PSD	

Process Type: 19.200 - Emission Control Afterburners & Incinerators (Combustion Gases Only) (SOCMI, Including Ethylene and Polyethylene Operations)

Pollutant: CO

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0815	PORT ARTHUR ETHANE SIDE CRACKER	TOTAL PETROCHEMICALS & REFINING USA, INC.	1/17/2017	Thermal Oxidizer	5.3	MMBtu/hr	CO	Good combustion practices and design.	1.9	tpy	BACT-PSD	
TX-0858	GULF COAST GROWTH VENTURES PROJECT	GCGV ASSET HOLDING LLC	6/12/2019	Thermal Oxidizers			CO	Best combustion practices and natural gas supplemental fuel.			BACT-PSD	
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	SHELL CHEMICAL LP	12/12/2019	Thermal Oxidizer 13-19 (EQT0913)	35	MMBtu/hr	CO	Good combustion practices.	0.08	lb/MMBtu	BACT-PSD	
TX-0889	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	8/8/2020	Thermal Oxidizer			CO	Use natural gas as assist gas and good combustion practices.	0.06	lb/MMBtu	BACT-PSD	
TX-0928	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	10/15/2021	Thermal Oxidizer			CO	Good combustion practices.	0.06	lb/MMBtu	BACT-PSD	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Thermal Oxidizer			CO	Good combustion practices and use of gaseous fuel.			BACT-PSD	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Vapor Combustor			CO	Good combustion practices and use of gaseous fuel.			BACT-PSD	
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	3M-5 - Gas Thermal Oxidizer A	72	MMBtu/hr	CO	Good operating practices.	6.09	lb/hr	BACT-PSD	0.085 lb/MMBtu
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	3M-6 - Gas Thermal Oxidizer B	72	MMBtu/hr	CO	Good operating practices.	6.09	lb/hr	BACT-PSD	0.085 lb/MMBtu
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	2P-35 - PVC Plant Thermal Oxidizer A	5.37	MMBtu/hr	CO	Good combustion practices.	0.53	lb/hr	BACT-PSD	0.099 lb/MMBtu
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	2P-36 - PVC Plant Thermal Oxidizer B	5.37	MMBtu/hr	CO	Good combustion practices.	0.53	lb/hr	BACT-PSD	0.099 lb/MMBtu
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4M-5 - Gas Thermal Oxidizer A	72	MMBtu/hr	CO	Good combustion practices.	6.09	lb/hr	BACT-PSD	0.085 lb/MMBtu
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4M-6 - Gas Thermal Oxidizer B	72	MMBtu/hr	CO	Good combustion practices.	6.09	lb/hr	BACT-PSD	0.085 lb/MMBtu

Process Type: 19.200 - Emission Control Afterburners & Incinerators (Combustion Gases Only) (SOCMI, Including Ethylene and Polyethylene Operations)
Pollutant: PM (filterable only)
Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Thermal Oxidizer			FPM	Good combustion practices and use of gaseous fuel.			BACT-PSD	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Vapor Combustor			FPM	Good combustion practices and use of gaseous fuel.			BACT-PSD	

Process Type: 19.200 - Emission Control Afterburners & Incinerators (Combustion Gases Only) (SOCMI, Including Ethylene and Polyethylene Operations)

Pollutant: PM_{10}

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	3M-5 - Gas Thermal Oxidizer A	72	MMBtu/hr	PM10	Good operating practices.	0.54	lb/hr	BACT-PSD	0.0075 lb/MMBtu
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	3M-6 - Gas Thermal Oxidizer B	72	MMBtu/hr	PM10	Good operating practices.	0.54	lb/hr	BACT-PSD	0.0075 lb/MMBtu
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	2P-35 - PVC Plant Thermal Oxidizer A	5.37	MMBtu/hr	PM10	Good combustion practices.	0.2	lb/hr	BACT-PSD	0.0372 lb/MMBtu
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	2P-36 - PVC Plant Thermal Oxidizer B	5.37	MMBtu/hr	PM10	Good combustion practices.	0.2	lb/hr	BACT-PSD	0.0372 lb/MMBtu
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4M-5 - Gas Thermal Oxidizer A	72	MMBtu/hr	PM10	Good combustion practices.	0.54	lb/hr	BACT-PSD	0.0075 lb/MMBtu
*LA-0403	SHINTECH PLAQUEMINE PLANT 4	SHINTCH LOUISIANA, LLC	12/16/2024	4M-6 - Gas Thermal Oxidizer B	72	MMBtu/hr	PM10	Good combustion practices.	0.54	lb/hr	BACT-PSD	0.0075 lb/MMBtu

Process Type: 19.200 - Emission Control Afterburners & Incinerators (Combustion Gases Only) (SOCMI, Including Ethylene and Polyethylene Operations)

Pollutant: GHGs

Permit Date Range: 1/1/2015 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0858	GULF COAST GROWTH VENTURES PROJECT	GCGV ASSET HOLDING LLC	6/12/2019	Thermal Oxidizers			CO2e	Best combustion practices and natural gas supplemental fuel.			BACT-PSD	
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	SHELL CHEMICAL LP	12/12/2019	Thermal Oxidizer 1-19 (EQT0903)			CO2e	Good combustion, operating, and maintenance practices. Efficient equipment design.			BACT-PSD	
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	SHELL CHEMICAL LP	12/12/2019	Thermal Oxidizer 13-19 (EQT0913)			CO2e	Good combustion, operating, and maintenance practices. Efficient equipment design.			BACT-PSD	
TX-0889	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	8/8/2020	Thermal Oxidizer			CO2e	Use natural gas as assist gas and good combustion practices.			BACT-PSD	
TX-0928	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	10/15/2021	Thermal Oxidizer			CO2e	Good combustion practices.			BACT-PSD	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Thermal Oxidizer			CO2e	Good combustion practices and use of gaseous fuel.			BACT-PSD	
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	Vapor Combustor			CO2e	Good combustion practices and use of gaseous fuel.			BACT-PSD	
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	2P-35 - PVC Plant Thermal Oxidizer A	5.37	MMBtu/hr	CO2e	Energy efficiency measures.			BACT-PSD	
LA-0389	SHINTECH PLAQUEMINE PLANT 3	SHINTECH LOUISIANA LLC	10/20/2022	2P-36 - PVC Plant Thermal Oxidizer B	5.37	MMBtu/hr	CO2e	Energy efficiency measures.			BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: CO

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0697	ETHYLENE PRODUCTION PLANT	THE DOW CHEMICAL COMPANY	3/27/2014	Low Pressure Flare	10,000	Btu/scf	CO	Good combustion.	0.3503	lb/MMBtu	OTHER CASE-BY-CASE	
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Multi-Point Ground Flares (EQT 836 & 837)			CO	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subparts FFFF and SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987; minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	5,837.62	lb/hr	BACT-PSD	
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	LLPDE/LDPE Multi-Point Ground Flare (EQT 640)			CO	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.	947.25	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. BACT is also determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.
LA-0299	LAKE CHARLES CHEMICAL COMPLEX ETHOXYLATION UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	ETO/Guerbet Elevated Flare (EQT 1079)			CO	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart PPP.	46.32	lb/hr	BACT-PSD	The permittee shall continuously monitor and record the volume of vent gas routed to the following flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips.
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 981)			CO	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	67,378.78	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.

Process Type: 19.310 - Chemical Plant Flares

Pollutant: CO

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Ground Flare (EQT 982)			CO	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	46,605.38	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare and Ground Flare (EQTs 1012 & 1013)			CO	Compliance with 40 CFR 63.11(b) and the closed vent system requirements of 40 CFR 63.148; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	13.23	lb/hr	BACT-PSD	Pound per hour CO limitations are per flare. *Annual CO emissions from both flares are limited to the TPY value reported.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 133)			CO	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	300.93	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Emission Combustion Unit #3 Ground Flare (EQT 500)			CO	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	270.32	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	CO	Natural gas pilot and flare minimization practices.	0.37	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	CO	Natural gas pilot and flare minimization practices.	0.37	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	CO	Natural gas pilot and flare minimization practices.	0.37	lb/MMBtu	BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: CO

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	CO	Natural gas pilot and flare minimization practices.	0.37	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	CO	Natural gas pilot and flare minimization practices.	0.37	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	CO	Natural gas pilot and flare minimization practices.	0.37	lb/MMBtu	BACT-PSD	
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	1/6/2015	Three (3) Flares	1.25	MMBtu/hr	CO	Work practice requirements and limited use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events).	0.37	lb/MMBtu	BACT-PSD	
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	1/23/2015	Drilling, HP, and LP Flares	50	MMscf/yr	CO		0.37	lb/MMBtu	BACT-PSD	
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	4/1/2015	ammonia flare	106,396	MMBtu/yr	CO	Good combustion practices.	950.41	lb/hr	OTHER CASE-BY-CASE	Emission rates provided are for worst-case MSS scenarios.
TX-0795	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	4/18/2016	PARAXYLENE FLARE	5,351	MMscf/hr	CO	VOC emissions are controlled by the flare. Increasing clean supplemental fuel (natural gas) improves reliability and effectiveness of the primary function of this control device. The increase in natural gas yields the CO emissions increase.	50	tpy	BACT-PSD	40 CFR 60.18
TX-0795	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	4/18/2016	East Low Pressure Flare and West High Pressure Flare	8,464	MMscf/hr	CO	VOC emissions are controlled by the flares. Increasing clean supplemental fuel (natural gas) improves reliability and effectiveness of the primary function of these control devices. The increase in natural gas yields the CO emissions increase.	188	tpy	BACT-PSD	40 CFR 60.18
TX-0795	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	4/18/2016	Udex Flare	2,914	MMscf/hr	CO	VOC emissions are controlled by the flare. Increasing clean supplemental fuel (natural gas) improves reliability and effectiveness of the primary function of this control device. The increase in natural gas yields the CO emissions increase.	40	tpy	BACT-PSD	40 CFR 60.18
TX-0795	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	4/18/2016	C&S FLARE	746	MMscf/hr	CO	VOC emissions are controlled by the flare. Increasing clean supplemental fuel (natural gas) improves reliability and effectiveness of the primary function of this control device. The increase in natural gas yields the CO emissions increase.	55	tpy	BACT-PSD	40 CFR 60.18
TX-0796	BEAUMONT POLYETHYLENE PLANT	EXXONMOBIL OIL CORPORATION	4/20/2016	High Pressure Flare	4,988	MMscf/hr	CO	VOC emissions are controlled by the flare. Increasing clean supplemental fuel (natural gas) improves reliability and effectiveness of the primary function of this control device. The increase in natural gas yields the CO emissions increase.	155	tpy	BACT-PSD	40 CFR 60.18
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	6/30/2016	Flares	1,008	MMBtu/hr	CO	Good flare design.			BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Flare No. 1 - 008	85,097	MMBtu/yr	CO	Complying with 40 CFR 60.18 and good combustion practices (including establishment of flare minimization practices).	0.31	lb/MMBtu	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Pyrolysis Gasoline Tank Flare - 009	0.66	MMBtu/hr	CO	Complying with 40 CFR 60.18 and 63.11 and good combustion practices (including establishment of flare minimization practices).	0.31	lb/MMBtu	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	vessel evacuation flare - 018	3.04	MMBtu/hr	CO	Good combustion practices (including establishment of flare minimization practices).	0.31	lb/MMBtu	BACT-PSD	
*LA-0306	TOPCHEM POLLOCK, LLC	TOPCHEM POLLOCK, LLC	12/20/2016	Process Flare FL-16-1 (EQT034)	2.17	MMBtu/hr	CO	Compliance with the Louisiana non-NSPS flare requirements.	0.87	lb/hr	BACT-PSD	Correct flare design and proper combustion.
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	12/22/2016	flares (I-X-703, II-X-703)	3,723	MMBtu/hr	CO	Complying with 40 CFR 63.11.			BACT-PSD	
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	1/9/2017	Emergency Flare	0.4	MMBtu/hr	CO	Proper design and operation.			BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares
Pollutant: CO
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0815	PORT ARTHUR ETHANE SIDE CRACKER	TOTAL PETROCHEMICALS & REFINING USA, INC.	1/17/2017	Multi Point Ground Flare			CO	Good combustion practices and design.	375.46	tpy	BACT-PSD	Emission rate of 375.46 tpy is the sum of 142.82 tpy CO for routine operations and 232.64 tpy CO for MSS operations.
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	1/4/2018	Flares (4)	6.6	MMBtu/hr	CO	Complying with 40 CFR 63.11(b).			BACT-PSD	
LA-0348	GEISMAR SYNGAS SEPARATION UNIT	PRAXAIR INC.	2/18/2018	Hot Flare - T2	501	MMBtu/hr	CO	Good flare design, good operating and combustion practices, and flare minimization practices.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	High and Low Pressure Flare cap			CO	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	NSPS YY
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	UDEX FLARE			CO	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	PARAXYLENE FLARE			CO	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	C & S FLARE			CO	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	High Pressure Ground Flare (P003)	1.8	MMBtu/hr	CO	Use of natural gas as pilot light fuel.	2.9171	tpy	BACT-PSD	The high pressure (HP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the HP ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The HP flare controls VOC emissions from units P801, P802, P803, P804, and P805.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Low Pressure Ground Flare (P004)	0.78	MMBtu/hr	CO	Use of natural gas as pilot light fuel.	1.26	tpy	BACT-PSD	The low pressure (LP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the ECU ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The LP flare controls VOC emissions from units P804 and P805.
TX-0857	LIGHT HYDROCARBON 7	THE DOW CHEMICAL COMPANY	4/16/2019	Large Flare			CO	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
TX-0857	LIGHT HYDROCARBON 7	THE DOW CHEMICAL COMPANY	4/16/2019	Small Flare			CO	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	4/25/2019	Flares (EQT0012, EQT0039, EQT0040)			CO	Comply with requirements of 40 CFR 63.11(b).			BACT-PSD	
TX-0863	POLYETHYLENE 7 FACILITY	THE DOW CHEMICAL COMPANY	9/3/2019	FLARE			CO	Good combustion practices.			BACT-PSD	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Multi Point Ground Flare			CO	Good combustion practices, design, and natural gas fuel.			BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	MULTIPOINT GROUND FLARE			CO	Good combustion practices and proper design and operation.			BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	MEROX ELEVATED FLARE			CO	Good combustion practices and proper design and operation.			BACT-PSD	
TX-0893	HYDOW DROCARBONS FACILITIES	THE DOW CHEMICAL COMPANY	8/7/2020	Flare			CO	Good combustion practices.	0.2755	lb/MMBtu	BACT-PSD	
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		9/9/2020	FLARE			CO	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	FLARE			CO	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
KY-0113	WESTLAKE CHEMICAL OPCO, LP	WESTLAKE CHEMICAL OPCO, LP	9/21/2020	Ethylene Flare EU#007 (EPN321)	5,979	MMBtu/hr	CO	Employ good flare design, minimize the amount of gases going to flare and use the appropriate instrumentation, control and best operational practices as best available control options for reducing CO emissions from flare.			BACT-PSD	The flare must be operated in compliance with 40 CFR 60.18 and 40 CFR 63.11 in order to meet BACT.

Process Type: 19.310 - Chemical Plant Flares
Pollutant: CO
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	3/26/2021	Three (3) Flares	1.25	MMBtu/hr	CO	Work practice requirements and limited use.	0.31	lb/MMBtu	BACT-PSD	Limited to 168 hours per year for each flare.
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	FLARE			CO	Good combustion practices and use of gaseous fuel.			BACT-PSD	
LA-0388	LACC LLC US - ETHYLENE PLANT	LACC, LLC US	2/25/2022	Ethylene Plant Flares Emissions Cap			CO		180.38	tpy	BACT-PSD	
TX-0945	FORMOSA POINT COMFORT PLANT OL3	FORMOSA PLASTICS CORPORATION, TEXAS	4/6/2023	FLARES			CO	Clean fuel and good combustion practices.			BACT-PSD	
*TX-0957	LINDE GAS LA PORTE SYNGAS PLANT	LYONDELLBASELL ACETYLS, LLC	5/25/2023	FLARES			CO	Clean fuel supplements waste stream Btu.			BACT-PSD	
*TX-0956	ENTERPRISE MONT BELVIEU COMPLEX	ENTERPRISE PRODUCTS OPERATING LLC	6/8/2023	FLARE			CO	Good design and combustion practices.			BACT-PSD	
*TX-0964	NEDERLAND FACILITY	LINDE, INC	10/5/2023	FLARE			CO	40 CFR 60.18 and good combustion practices.			BACT-PSD	
*LA-0401	KOCH METHANOL (KME) FACILITY	KOCH METHANOL ST. JAMES, LLC	12/20/2023	FLR - Flare			CO	Use of good operating practices and compliance with 40 CFR 60.18 and 40 CFR 63.11.			BACT-PSD	
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Front End Flare	2.22	MMBtu/hr	CO	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.08	lb/MMBtu	BACT-PSD	Also 43.28 tons/year (both Pilot and SSM) and 43.28 tons/bi-month period during commissioning/shakedown period.
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Flare	2.22	MMBtu/hr	CO	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.08	lb/MMBtu	BACT-PSD	Also 35.87 tons/year (Pilot and SSM) and 35.87 tons/bi-month period (Pilot and SSM) during commissioning/shakedown period.
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Storage Flare	0.4	MMBtu/hr	CO	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.08	lb/MMBtu	BACT-PSD	Also 8.36 tons/year (pilot and boil-off).
*TX-0965	ORANGE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	12/29/2023	FLARE			CO	Good combustion practices.			BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: PM (filterable only)

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	FPM	Natural gas pilot and flare minimization practices.	1.9	lb/MMcf	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	FPM	Natural gas pilot and flare minimization practices.	0.0019	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	FPM	Natural gas pilot and flare minimization practices.	0.0019	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	FPM	Natural gas pilot and flare minimization practices.	1.9	lb/MMcf	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	FPM	Natural gas pilot and flare minimization practices.	0.0019	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	FPM	Natural gas pilot and flare minimization practices.	0.0019	lb/MMBtu	BACT-PSD	
KY-0113	WESTLAKE CHEMICAL OPCO, LP	WESTLAKE CHEMICAL OPCO, LP	9/21/2020	Ethylene Flare EU#007 (EPN321)	5,979	MMBtu/hr	FPM	Employ natural gas as a pilot fuel, good flare design, and the use of appropriate instrumentation, control and best operational practices as BACT for reducing PM/PM10/PM2.5 emissions from the pilot flame of the flare.			BACT-PSD	The flare must be operated in compliance with 40 CFR 60.18 and 40 CFR 63.11 in order to meet BACT. The permittee shall conduct a visible emission test by EPA Test Method 22, with a 2 hour observation period within 5 years of the previous test approved by the Division. Final design could be elevated flare or ground flare.

Process Type: 19.310 - Chemical Plant Flares

Pollutant: PM_{10}

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Multi-Point Ground Flares (EQT 836 & 837)			PM10	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subparts FFFF and SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987; minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	170.84	lb/hr	BACT-PSD	
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	LLPDE/LDPE Multi-Point Ground Flare (EQT 640)			PM10	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.	37.51	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. BACT is also determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.
LA-0299	LAKE CHARLES CHEMICAL COMPLEX ETHOXYLATION UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	ETO/Guerbet Elevated Flare (EQT 1079)			PM10	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart PPP.	0.23	lb/hr	BACT-PSD	The permittee shall continuously monitor and record the volume of vent gas routed to the following flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips.
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 981)			PM10	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	562.23	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.

Process Type: 19.310 - Chemical Plant Flares
Pollutant: PM_{10}
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Ground Flare (EQT 982)			PM10	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	1,041.94	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare and Ground Flare (EQTs 1012 & 1013)			PM10	Compliance with 40 CFR 63.11(b) and the closed vent system requirements of 40 CFR 63.148; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	0.18	lb/hr	BACT-PSD	Pound per hour PM10 limitations are per flare. *Annual PM10 emissions from both flares are limited to the TPY value reported.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 133)			PM10	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	0.9	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Emission Combustion Unit #3 Ground Flare (EQT 500)			PM10	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	1.52	lb/hr	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	PM10	Natural gas pilot and flare minimization practices.	7.6	lb/MMcf	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	PM10	Natural gas pilot and flare minimization practices.	0.0075	lb/MMBtu	BACT-PSD	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	PM10	Natural gas pilot and flare minimization practices.	0.0075	lb/MMBtu	BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares
Pollutant: PM_{10}
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	FRONT END FLARE	4	MMBtu/hr	PM10	Natural gas pilot and flare minimization practices.	7.6	lb/MMcf	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	BACK END FLARE	4	MMBtu/hr	PM10	Natural gas pilot and flare minimization practices.	0.0075	lb/MMBtu	BACT-PSD	
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	6/4/2014	AMMONIA STORAGE FLARE	1.5	MMBtu/hr	PM10	Natural gas pilot and flare minimization practices.	0.0075	lb/MMBtu	BACT-PSD	
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	1/6/2015	Three (3) Flares	1.25	MMBtu/hr	PM10	Work practice requirements and limited use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events).	0.0074	lb/MMBtu	BACT-PSD	
LA-0275	LINEAR ALKYL BENZENE (LAB) UNIT	SASOL CHEMICALS (USA) LLC	4/29/2016	LF-1 - LAB Unit Flare			PM10	Steam assisted.	0.4	lb/hr	BACT-PSD	
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	6/30/2016	Flares	1,008	MMBtu/hr	PM10	Good flare design.			BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Flare No. 1 - 008	85,097	MM BTU/yr	PM10	Complying with 40 CFR 60.18 and good combustion practices (including establishment of flare minimization practices).	0.007	lb/MMBtu	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Pyrolysis Gasoline Tank Flare - 009	0.66	MMBtu/hr	PM10	Complying with 40 CFR 60.18 and 63.11 and good combustion practices (including establishment of flare minimization practices).	0.007	lb/MMBtu	BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	vessel evacuation flare - 018	3.04	MMBtu/hr	PM10	Good combustion practices (including establishment of flare minimization practices).	0.007	lb/MMBtu	BACT-PSD	
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	12/22/2016	flares (I-X-703, II-X-703)	3,723	MMBtu/hr	PM10	Complying with 40 CFR 63.11.			BACT-PSD	
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	1/9/2017	Emergency Flare	0.4	MMBtu/hr	PM10	Proper design and operation.			BACT-PSD	
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	1/4/2018	Flares (4)	6.6	MMBtu/hr	PM10	Complying with 40 CFR 63.11(b).			BACT-PSD	
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	High Pressure Ground Flare (P003)	1.8	MMBtu/hr	PM10	Use of natural gas as pilot light fuel.	0.059	tpy	BACT-PSD	The high pressure (HP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the HP ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The HP flare controls VOC emissions from units P801, P802, P803, P804, and P805.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Low Pressure Ground Flare (P004)	0.78	MMBtu/hr	PM10	Use of natural gas as pilot light fuel.	0.026	tpy	BACT-PSD	The low pressure (LP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the ECU ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The LP flare controls VOC emissions from units P804 and P805.
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	4/25/2019	Flares (EQT0012, EQT0039, EQT0040)			PM10	Comply with requirements of 40 CFR 63.11(b).			BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	FLARE			PM10	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
KY-0113	WESTLAKE CHEMICAL OPCO, LP	WESTLAKE CHEMICAL OPCO, LP	9/21/2020	Ethylene Flare EU#007 (EPN321)	5,979	MMBtu/hr	PM10	Employ natural gas as a pilot fuel, good flare design, and the use of appropriate instrumentation, control and best operational practices as BACT for reducing PM/PM10/PM2.5 emissions from the pilot flame of the flare.			BACT-PSD	The flare must be operated in compliance with 40 CFR 60.18 and 40 CFR 63.11 in order to meet BACT. The permittee shall conduct a visible emission test by EPA Test Method 22, with a 2 hour observation period within 5 years of the previous test approved by the Division. Final design could be elevated flare or ground flare.

Process Type: 19.310 - Chemical Plant Flares

Pollutant: PM_{10}

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	3/26/2021	Three (3) Flares	1.25	MMBtu/hr	PM10	Work practice requirements and limited use.	0.0075	lb/MMBtu	BACT-PSD	Limited to 168 hours per year for each flare.
LA-0388	LACC LLC US - ETHYLENE PLANT	LACC, LLC US	2/25/2022	Ethylene Plant Flares Emissions Cap			PM10	Minimize flaring.	4.33	tpy	BACT-PSD	
*TX-0956	ENTERPRISE MONT BELVIEU COMPLEX	ENTERPRISE PRODUCTS OPERATING LLC	6/8/2023	FLARE			PM10	Good design and combustion practices.			BACT-PSD	
*LA-0401	KOCH METHANOL (KME) FACILITY	KOCH METHANOL ST. JAMES, LLC	12/20/2023	FLR - Flare			PM10	Use of good operating practices and compliance with 40 CFR 60.18 and 40 CFR 63.11.			BACT-PSD	
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Front End Flare	2.22	MMBtu/hr	PM10	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.0075	lb/MMBtu	BACT-PSD	Also 0.10 tons/year and 0.10 ton/bi-month period during commissioning/shakedown period
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Flare	2.22	MMBtu/hr	PM10	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.0075	lb/MMBtu	BACT-PSD	Also 0.07 tons/year and 0.07 tons/bi-month period during commissioning/shakedown period
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Storage Flare	0.4	MMBtu/hr	PM10	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	0.01	tpy	BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: GHGs

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Multi-Point Ground Flares (EQT 836 & 837)			CO2e	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subparts FFFF and SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987; minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	115,911	tpy	BACT-PSD	CO2e limits are based on a CH4 global warming potential (GWP) of 21 and a N2O GWP of 310. In the event any GWP is revised, the CO2e limits shall be revised accordingly without the need to modify the permit.
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	LLPDE/LDPE Multi-Point Ground Flare (EQT 640)			CO2e	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas.	68,285	tpy	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. BACT is also determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's startup, shutdown, and malfunction plan (SSMP) developed in accordance with 40 CFR 63.6(e)(3); continuously monitoring the volume of vent gas routed to the flare, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tip; and the use of natural gas as pilot gas. The CO2e limits are based on a CH4 global warming potential (GWP) of 21 and a N2O GWP of 310. In the event any GWP is revised, the CO2e limits shall be revised accordingly without the need to modify the permit.
LA-0299	LAKE CHARLES CHEMICAL COMPLEX ETHOXYLATION UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	ETO/Guerbet Elevated Flare (EQT 1079)			CO2e	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart PPP.	3,986	tpy	BACT-PSD	The permittee shall continuously monitor and record the volume of vent gas routed to the following flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips. The CO2e limits are based on a CH4 global warming potential (GWP) of 21 and a N2O GWP of 310. In the event any GWP is revised, the CO2e limits shall be revised accordingly without the need to modify the permit.

Process Type: 19.310 - Chemical Plant Flares

Pollutant: GHGs

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 981)			CO2e	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	44,516	tpy	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas. The CO2e limits are based on a CH4 global warming potential (GWP) of 21 and a N2O GWP of 310. In the event any GWP is revised, the CO2e limits shall be revised accordingly without the need to modify the permit.
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Ground Flare (EQT 982)			CO2e	Compliance with 40 CFR 63.11(b) and 40 CFR 63 Subpart SS; minimization of flaring through adherence to Sasol's SSMP; monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	100,085	tpy	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987, and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas. The CO2e limits are based on a CH4 global warming potential (GWP) of 21 and a N2O GWP of 310. In the event any GWP is revised, the CO2e limits shall be revised accordingly without the need to modify the permit.
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare and Ground Flare (EQTs 1012 & 1013)			CO2e	Compliance with 40 CFR 63.11(b) and the closed vent system requirements of 40 CFR 63.148; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	1,998	tpy*	BACT-PSD	*Annual CO2e emissions from both flares are limited to the TPY value reported. The CO2e limits are based on a CH4 global warming potential (GWP) of 21 and a N2O GWP of 310. In the event any GWP is revised, the CO2e limits shall be revised accordingly without the need to modify the permit.

Process Type: 19.310 - Chemical Plant Flares

Pollutant: GHGs

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Elevated Flare (EQT 133)			CO2e	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	94,386	tpy	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas. The CO2e limits are based on a CH4 global warming potential (GWP) of 21 and a N2O GWP of 310. In the event any GWP is revised, the CO2e limits shall be revised accordingly without the need to modify the permit.
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	SASOL CHEMICALS (USA) LLC	5/23/2014	Emission Combustion Unit #3 Ground Flare (EQT 500)			CO2e	Compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS; minimization of flaring through adherence to the SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas.	24,567	tpy	BACT-PSD	BACT is compliance with 40 CFR 63.11(b) and the applicable provisions of 40 CFR 63 Subpart SS, including, but not limited to, the closed vent system requirements of 40 CFR 63.983, the flare compliance assessment requirements of 40 CFR 63.987 and 40 CFR 63.2450(f), and the flame monitoring requirements of 40 CFR 63.987. In addition, BACT is determined to be minimization of flaring through adherence to the Lake Charles Chemical Complex's SSMP developed in accordance with 40 CFR 63.6(e)(3); monitoring the volume of vent gas routed to the flares, the lower heating value or composition of the vent gas, the fuel gas flow rate, and for steam-assisted flares, the flow of steam to the flare tips; and the use of natural gas as pilot gas. The CO2e limits are based on a CH4 global warming potential (GWP) of 21 and a N2O GWP of 310. In the event any GWP is revised, the CO2e limits shall be revised accordingly without the need to modify the permit.
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	1/6/2015	Three (3) Flares	1.25	MMBtu/hr	CO2e	Work practice requirements and limited use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events).	59.61	ton/MMcf	BACT-PSD	
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	6/30/2016	Flares	1,008	MMBtu/hr	CO2e	Good equipment design and good combustion practices.			BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Flare No. 1 - 008	85,097	MMBtu/yr	CO2e	Good management practices, good combustion practices, and proper flare design			BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	Pyrolysis Gasoline Tank Flare - 009	0.66	MMBtu/hr	CO2e	Good management practices, good combustion practices, and proper flare design			BACT-PSD	
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	8/3/2016	vessel evacuation flare - 018	3.04	MMBtu/hr	CO2e	Insulation, gaseous fuels, good combustion practices, and proper operation and maintenance.			BACT-PSD	
*LA-0306	TOPCHEM POLLOCK, LLC	TOPCHEM POLLOCK, LLC	12/20/2016	Process Flare FL-16-1 (EQT034)	2.17	MMBtu/hr	CO2e	Compliance with the Louisiana non-NSPS flare requirements.	370	tpy	BACT-PSD	Correct flare design and proper combustion.
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	12/22/2016	flares (I-X-703, II-X-703)	3,723	MMBtu/hr	CO2e	Complying with 40 CFR 63.11.			BACT-PSD	
TX-0814	AMMONIA AND UREA PLANT	AGRIUM US, INC	1/5/2017	Ammonia Emergency Flare	0.31	MMBtu/hr	CO2e	Agrium uses good engineering practices to minimize CO2e emissions.	157	tpy	BACT-PSD	
TX-0814	AMMONIA AND UREA PLANT	AGRIUM US, INC	1/5/2017	Urea Emergency Flare	2.76	MMBtu/hr	CO2e	Good engineering practices to minimize CO2e emissions.	1,418	tpy	BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: GHGs

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
TX-0814	AMMONIA AND UREA PLANT	AGRIUM US, INC	1/5/2017	Process Name: Urea Emergency Flare (maintenance)			CO2e	Good engineering practices to minimize CO2e emissions.	5.9	tpy	BACT-PSD	
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	1/9/2017	Emergency Flare	0.4	MMBtu/hr	CO2e	Proper design and operation.			BACT-PSD	
LA-0348	GEISMAR SYNGAS SEPARATION UNIT	PRAXAIR INC.	2/18/2018	Hot Flare - T2	501	MMBtu/hr	CO2e	Good design and operational practices.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	High and Low Pressure Flare cap			CO2e	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	MACT YY
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	UDEX FLARE			CO2e	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	PARAXYLENE FLARE			CO2e	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
TX-0838	BEAUMONT CHEMICAL PLANT	EXXONMOBIL OIL CORPORATION	6/13/2018	C & S FLARE			CO2e	Meet the design and operating requirements of 40 CFR 60.18.			BACT-PSD	
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	High Pressure Ground Flare (P003)	1.8	MMBtu/hr	CO2e	Use of natural gas as pilot light fuel.	923	tpy	BACT-PSD	The high pressure (HP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the HP ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The HP flare controls VOC emissions from units P801, P802, P803, P804, and P805.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Low Pressure Ground Flare (P004)	0.78	MMBtu/hr	CO2e	Use of natural gas as pilot light fuel.	400	tpy	BACT-PSD	The low pressure (LP) ground flare is used to meet control requirements associated with BACT, NSPS, BAT, and MACT for affected facility operations and process vents. For efficient permitting structure, the ECU ground flare has been permitted as a separate and individual emissions unit to contain limitations, operational restrictions, monitoring, record keeping, reporting, and testing associated with control requirements. The LP flare controls VOC emissions from units P804 and P805.
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Multi Point Ground Flare			CO2e	Good combustion practices, design, and natural gas fuel.			BACT-PSD	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	Elevated Flare			CO2e	Good combustion practices, design, and natural gas fuel.			BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	MULTIPOINT GROUND FLARE			CO2e	Good combustion practices and proper design and operation.			BACT-PSD	
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EQUISTAR CHEMICALS, LP	9/9/2019	MEROX ELEVATED FLARE			CO2e	Good combustion practices and proper design and operation.			BACT-PSD	
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		9/9/2020	FLARE			CO2e	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	9/16/2020	FLARE			CO2e	Good combustion practices and the use of gaseous fuel.			BACT-PSD	
KY-0113	WESTLAKE CHEMICAL OPCO, LP	WESTLAKE CHEMICAL OPCO, LP	9/21/2020	Ethylene Flare EU#007 (EPN321)	5,979	MMBtu/hr	CO2e	Employ low carbon assist gas, good flare design, minimize the amount of gases going to flare, and use the appropriate instrumentation, control and best operational practices as best available control options for reducing flare GHGs.			BACT-PSD	Good Combustion Practices include: 1. Good air/fuel mixing, residence time, fuel supply, optimum temperature and oxygen levels will be controlled as required to maintain efficiency and guaranteed performance. 2. Preventative maintenance of the flares includes calibration of fuel gas flow meters and cleaning of burner tips.
AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	3/26/2021	Three (3) Flares	1.25	MMBtu/hr	CO2e	Work practice requirements and limited use.	60.2	ton/MMscf	BACT-PSD	Limited to 168 hours per year for each flare.
TX-0931	ROEHM AMERICA BAY CITY SITE	ROEHM AMERICA LLC	12/16/2021	FLARE			CO2e	Good combustion practices and use of gaseous fuel.			BACT-PSD	

Process Type: 19.310 - Chemical Plant Flares

Pollutant: GHGs

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0388	LACC LLC US - ETHYLENE PLANT	LACC, LLC US	2/25/2022	Ethylene Plant Flares Emissions Cap			CO2e		72,927	tpy	BACT-PSD	
TX-0945	FORMOSA POINT COMFORT PLANT OL3	FORMOSA PLASTICS CORPORATION, TEXAS	4/6/2023	FLARES			CO2e	Clean fuel and good combustion practices.			BACT-PSD	
*TX-0956	ENTERPRISE MONT BELVIEU COMPLEX	ENTERPRISE PRODUCTS OPERATING LLC	6/8/2023	FLARE			CO2e	Good design and combustion practices.			BACT-PSD	
*TX-0964	NEDERLAND FACILITY	LINDE, INC	10/5/2023	FLARE			CO2e	Good combustion practices and fire low carbon natural gas.			BACT-PSD	
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Front End Flare	2.22	MMBtu/hr	CO2e	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	18,603	tpy	BACT-PSD	
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Flare	2.22	MMBtu/hr	CO2e	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	16,093	tpy	BACT-PSD	
*IL-0134	CRONUS CHEMICALS	CRONUS CHEMICALS, LLC	12/21/2023	Ammonia Storage Flare	0.4	MMBtu/hr	CO2e	Flare minimization plan and root cause analysis, steam-assist flare design, work practices in accordance with 40 CFR 63.11(b), GCP, and use of nitrogen as purge gas.	3,305	tpy	BACT-PSD	

Process Type: 19.330 - Refinery Flares
Pollutant: CO
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
NM-0052	ZIA II GAS PLANT	DCP MIDSTREAM L.P.	4/25/2014	Units FL1 & FL2: Refinery Flares (Inlet Gas Flare & Acid Gas Flare)	2.3	MMBtu/hr	CO	NOx, CO, PM10, PM2.5, and SO2 controlled through good combustion practices (GCP), pipeline quality natural gas for pilot, and limits on flaring events. VOC and CO2e controlled through GCP, limits on flaring, and meeting 40 CFR 60.18.	3,782.5	lb/hr	BACT-PSD	
TX-0832	EXXONMOBIL BEAUMONT REFINERY	EXXONMOBIL OIL CORPORATION	1/9/2018	No.12 Flare			CO	Meets 40 CFR 60.18 and MACT CC design requirements.	94	tpy	BACT-PSD	NSPS Ja, MACT CC
TX-0872	CONDENSATE SPLITTER FACILITY	MAGELLAN PROCESSING, L.P.	10/31/2019	Flare (Routine and MSS)	12,000		CO	Use of natural gas. Good combustion practices will be used to reduce CO including maintaining proper air-to-fuel ratio, necessary residence time, temperature and turbulence.	0.2755	lb/MMBtu	BACT-PSD	
TX-0873	PORT ARTHUR REFINERY	MOTIVA ENTERPRISES LLC	2/4/2020	Flare			CO	Steam-assisted flare equipped with CPMS and flow meter, hourly net heating value calculated, continuous pilot flame, and limited hourly and yearly tank degassing.			BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Main Flare			CO	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.	0.3465	lb/MMBtu	BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Butane (Rail Car) Flare			CO	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.	0.3465	lb/MMBtu	BACT-PSD	

Process Type: 19.330 - Refinery Flares
Pollutant: PM (filterable only)
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
None												

Process Type: 19.330 - Refinery Flares
Pollutant: PM_{10}
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
KS-0032	CHS MCPHERSON REFINERY, INC.	CHS MCPHERSON REFINERY, INC.	12/14/2015	Main Flare and Alky Flare			PM10				BACT-PSD	BACT for sulfur dioxide and PM/PM10 consists of design and workplace standards since there is no currently feasible method to measure emissions exiting the flares. BACT is using a flare design that meets the requirements of 40 CFR 60.18 and API recommended practice 520 and 521. Workplace standards include continuously monitoring the pilot flame with infrared sensors, maintaining a natural gas/refinery gas purge so that the heating value of gases to the flares is not less than 300 Btu/scf, and using steam assisted mixing at the flare tip for smokeless operation.

Process Type: 19.330 - Refinery Flares
Pollutant: GHGs
Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
NM-0052	ZIA II GAS PLANT	DCP MIDSTREAM L.P.	4/25/2014	Units FL1 & FL2: Refinery Flares (Inlet Gas Flare & Acid Gas Flare)	2.3	MMBtu/hr	CO2e	NOx, CO, PM10, PM2.5, and SO2 controlled through good combustion practices (GCP), pipeline quality natural gas for pilot, and limits on flaring events. VOC and CO2e controlled through GCP, limits on flaring, and meeting 40 CFR 60.18.	5,626	lb/hr	BACT-PSD	The emission limits represent CO2e from SSM for Units FL1 & FL2. Additional limits for CO2e from pilot & purge are 1331.0 pph from unit FL1 and 1331.0 pph from Unit FL2.
TX-0832	EXXONMOBIL BEAUMONT REFINERY	EXXONMOBIL OIL CORPORATION	1/9/2018	No.12 Flare			CO2e	Meets 40 CFR 60.18 and MACT CC design requirements.	2,716	tpy	BACT-PSD	NSPS Ja, MACT CC
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	BUCKEYE TEXAS PROCESSING, LLC	8/29/2019	Flare			CO2e	Good combustion practices.			BACT-PSD	
TX-0872	CONDENSATE SPLITTER FACILITY	MAGELLAN PROCESSING, L.P.	10/31/2019	Flare (Routine and MSS)	12,000		CO2e	Use of natural gas and good combustion practices will be used to reduce CO2e, including maintaining proper air-to-fuel ratio, necessary residence time, temperature, and turbulence.			BACT-PSD	
TX-0873	PORT ARTHUR REFINERY	MOTIVA ENTERPRISES LLC	2/4/2020	Flare			CO2e	Steam-assisted flare equipped with CPMS and flow meter, hourly net heating value calculated, continuous pilot flame, and limited hourly and yearly tank degassing.			BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Main Flare			CO2e	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.			BACT-PSD	
TX-0930	CENTURION BROWNSVILLE	JUPITER BROWNSVILLE, LLC	10/19/2021	Butane (Rail Car) Flare			CO2e	Use of natural gas or fuel gas as supplemental fuel and good combustion practices, including maintaining proper air-to-fuel ratio and necessary residence time, temperature, and turbulence.			BACT-PSD	

Process Type: 64.002 - Equipment Leaks (Valves, compressors, pumps, etc.)

Pollutant: CO

Permit Date Range: 1/1/2014 - 4/2025

RBLC ID	Facility Name	Corporate/Company Name	Permit Issuance Date	Process Name	Throughput	Unit	Pollutant	Control Method Description	Emission Limit	Unit	Basis	Compliance Notes
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	06/30/2016	Fugitives			CO				BACT-PSD	
LA-0388	LACC LLC US - ETHYLENE PLANT	LACC, LLC US	02/25/2022	Ethylene Plant Fugitive Emissions			CO		0.27	tpy	BACT-PSD	
*LA-0401	KOCH METHANOL (KME) FACILITY	KOCH METHANOL ST. JAMES, LLC	12/20/2023	FUG - Fugitive Emissions - KMe Facility			CO	Koch shall implement a CO LDAR program for those components in CO service that are not subject to VVa and that contain >5% CO. The CO LDAR program shall include relevant elements from Subpart VVa such as calendar-based leak monitoring, 5/15 day repair requirements, delay of repair (DOR), etc., and be adjusted to appropriately accommodate requirements for CO. The CO LDAR plan shall be submitted to LDEQ within 60 days of permit issuance. The CO LDAR program will be implemented within 180 days following LDEQ approval of the plan.			BACT-PSD	
TX-0827	PRAXAIR CLEAR LAKE PLANT	PRAXAIR INC	10/19/2017	HyCO FUGITIVES			CO		51.1	tpy	BACT-PSD	
TX-0830	PRAXIAR CLEAR LAKE	PRAXIAR INC	10/20/2017	HYCO FUGITIVES			CO		51.1	tpy	BACT-PSD	

Attachment 7-2

Request No. 5 GHG BACT Cost Information

SPM Ethane Cracking Furnace and Thermal Oxidizer CO2 Emissions

Ethane Cracking Furnaces:

Ethane Cracking Furnace	Annual Emissions (tpy)
Ethane Cracking Furnace #1	158,764
Ethane Cracking Furnace #2	158,764
Ethane Cracking Furnace #3	158,764
Ethane Cracking Furnace #4	158,764
Ethane Cracking Furnace #5	158,764
Ethane Cracking Furnace #6	158,764
Ethane Cracking Furnace #7	158,764
Total =	**1,111,348**

Thermal Oxidizers (TOs):

TO	Annual Emissions (tpy)
Continuous Vent TO (CVTO)	109,133
Spent Caustic TO (SCTO)	6,039
Total =	**115,172**

Total Annual Emissions from Ethane Cracking Furnaces and TOs	1,226,520	tpy
CO2 Capture Rate	90	%
Captured CO2	1,103,868	tpy

Ethane Cracking Furnace and TO Exhaust Parameters

Emission Unit	Exit Velocity (m/s)	Exit Velocity (ft/s)	Stack Diameter (m)	Stack Diameter (ft)	Stack Temperature (°F)	Exhaust Flow Rate (acfm)
Ethane Cracking Furnace	12.25	40.2	2.59	8.5	253.13	136,751
CVTO	56.76	186.2	1.37	4.5	1,599.53	177,288
SCTO	13.71	45.0	0.61	2.0	1,599.53	8,490

Ethane Cracking Furnace and TO Exhaust Flow Rates at Stack Temperature and Pressure

Emission Unit	Exhaust Flow Rate (acfm)
Ethane Cracking Furnaces (7 units)	957,260
CVTO	177,288
SCTO	8,490
Total =	**1,143,038**

Note: The stack pressure was assumed to be at atmospheric pressure (i.e., 14.69595 psia).

Ethane Cracking Furnace and TO Exhaust Flow Rates at 123°F and 12.063 psia

Emission Unit	Exhaust Flow Rate (acfm)
Ethane Cracking Furnaces (7 units)	953,295
CVTO	61,115
SCTO	2,927
Total =	**1,017,336**

Note: The Ethane Cracking Furnace and TO exhaust flow rates were converted to be at the same temperature (123°F) and pressure (12.063 psia) indicated for the Hunter Unit 3's exhaust gas in the case study to provide a consistent exhaust flow rate basis to use in the cost scaling analysis.

SPM Amine-Based CO2 Capture System Cost Analysis

Hunter Unit 3 Case 2 Amine-Based CO2 Capture System Cost Information (2017$ Cost Basis)

Cost Type	Cost Description	Cost Amount (2017$)
Capital Cost ($)	Total Capital Investment	666,222,700
O&M Costs ($/yr)	Total Annual O&M Cost	85,840,000
	Total Annual CO2 Transportation, Storage and Monitoring Cost	27,138,000
	Total Annual O&M Cost without Total Annual CO2 Transportation, Storage and Monitoring Cost	58,702,000

USD Inflation from 2017 to 2025
1.31

Hunter Unit 3 Case 2 Amine-Based CO2 Capture System Cost Information (2025$ Cost Basis)

Cost Type	Cost Description	Cost Amount (2025$)
Capital Cost ($)	Total Capital Investment	872,751,737
O&M Cost ($/yr)	Total Annual O&M Cost without Total Annual CO2 Transportation, Storage and Monitoring Cost	76,899,620

Ratio of SPM Ethane Cracking Furnace and TO Total Exhaust Flow Rate to Hunter Unit 3 Case 2 Exhaust Flow Rate

SPM Exhaust Flow Rate (acfm)	1,017,336
Hunter Unit 3 Case 2 Exhaust Flow Rate (acfm)	1,574,000
SPM/Hunter	64.6%

Capital Recovery Factor

i	n	(1+i)^n	CRF
0.07	30.00	7.61	0.0806

SPM Amine-Based CO2 Capture System Cost (2025$ Cost Basis)

Cost Type	Cost Description	Cost Amount (2025$)
Capital Cost ($)	Total Capital Investment	564,092,668
Annualized Capital Cost ($/yr)	Total Annualized Capital Cost	45,458,199
O&M Cost ($/yr)	Total Annual O&M Cost without Total Annual CO2 Transportation, Storage and Monitoring Cost	49,703,152
Total Annual Costs ($/yr)	Total Annualized Capital Cost + Total Annual O&M Cost without Total Annual CO2 Transportation, Storage and Monitoring Cost	95,161,351

SPM CO2 Transport Pipeline

FECM/NETL CO2 Transport Cost Model

Blue cells are model outputs

FECM/NETL CO2 Transport Cost Model Escalation Factors

From 2011 to 2028	1.58
From 2011 to 2025	1.47
2025/2028	0.93

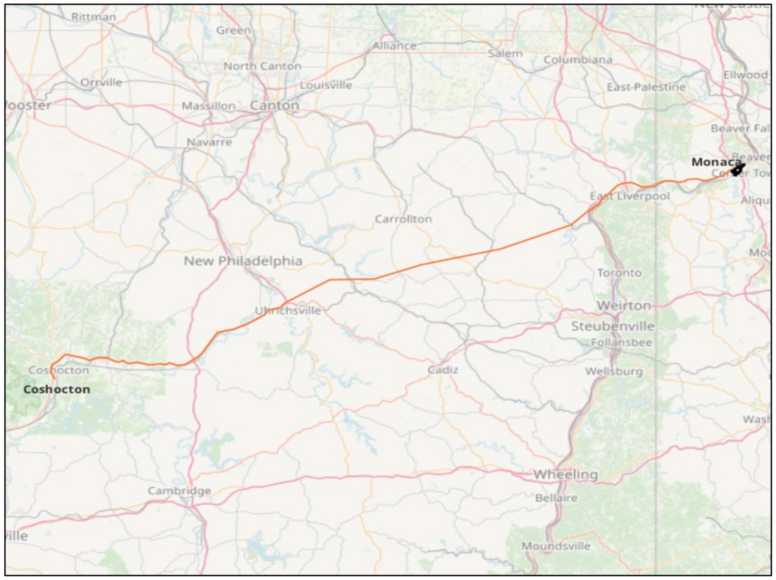
Note: Outputs from sheet 'Main' row 109

Destination	Coshocton, Ohio
Distance to destination (mi)	94
Year construction begins	2028
Years of construction	3
Years of operation	30
Total Capital Investment (2028$)	123,672,867
Total O&M Costs (2028$)	92,753,270

Note: Outputs from sheet 'Main' cells C150:C151

Cost Type	Cost Amount (2025$)
Capital Costs ($)	115,517,432
Equivalent annual cost of capital ($/yr)	9,309,134
Total O&M Costs ($)	86,636,785
O&M Costs ($/yr)	2,887,893
Total Annual Costs ($/yr)	12,197,027

Summary (2025$)	Total Annual Costs ($/yr)	$/ton CO2 Captured
SPM Amine-Based CO2 Capture System	95,161,351	86.2
Pipeline to Coshocton, Ohio	12,197,027	11.0
Total with Coshocton, Ohio	107,358,378	97.3



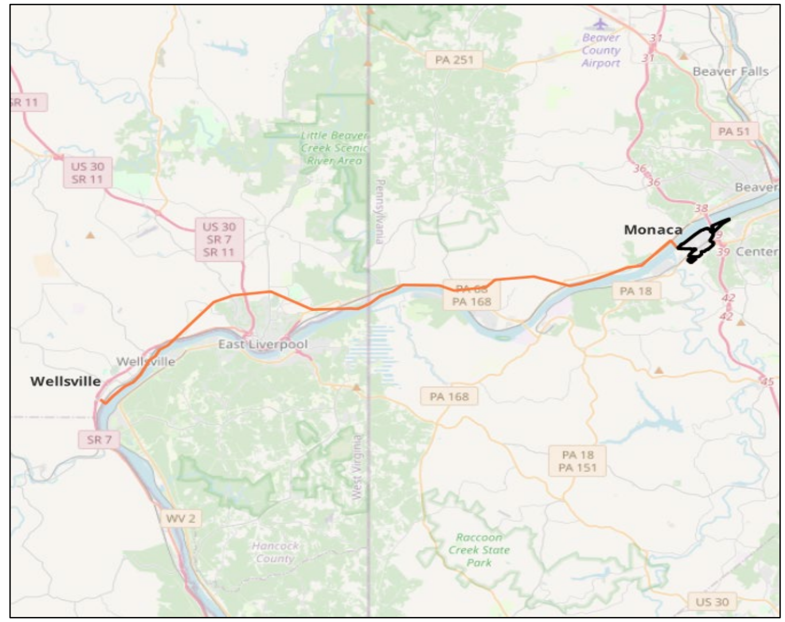
Destination	Wellsville, Ohio (Terminated)
Distance to destination (mi)	21
Year construction begins	2028
Years of construction	3
Years of operation	30
Total Capital Investment (2028$)	28,342,501
Total O&M Costs (2028$)	30,581,293

Note: Outputs from sheet 'Main' cells C150:C151

Cost Type	Cost Amount (2025$)
Capital Costs ($)	26,473,495
Equivalent annual cost of capital ($/yr)	2,133,404
Total O&M Costs ($)	28,564,652
O&M Costs ($/yr)	952,155
Total Annual Costs ($/yr)	3,085,559

Summary (2025$)	Total Annual Costs ($/yr)	$/ton CO2 Captured
SPM Amine-Based CO2 Capture System	95,161,351	86.2
Pipeline to Wellsville, Ohio	3,085,559	2.8
Total with Wellsville, Ohio	98,246,910	89.0

Note: Wellsville project is Terminated



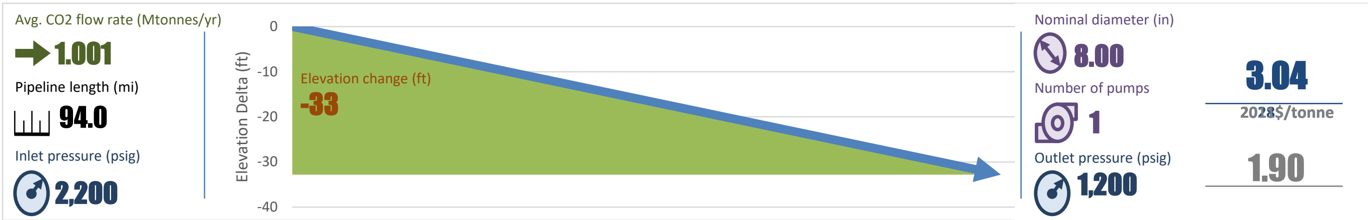


Table 1 **Summary** **A. Key Inputs and Results for Basic Analysis**

	2011$/tonne	2028$/tonne	2031$/tonne
		first yr of proj	first yr of transp
First-year Price to Transport CO2 by Pipeline	1.90	3.04	3.25
Annual Average CO2 Mass Flow Rate (qav)	1.001	Mtonnes/yr (Mtonnes = megatonnes [million tonnes]; tonne = 1,000 kg)	
Capacity Factor (fraction of time when flow is at equivalent of maximum flow rate)	85%		
Maximum CO2 Flow Rate on annualized basis	1.18	Mtonnes/yr	
Length of pipeline	94.0	mi	
Number of booster pumps (Optimal Pump Number will set the optimal pump number)	1	Optimal number of pumps	
Change in Elevation (Positive if pipeline outlet is at a higher elevation than inlet)	-33	ft	

Key Outputs		
Calculated Minimum Inner Diameter for Pipe	7.13	in
Nominal Pipe Diameter or Pipe Size	8.00	in
Net Present Value (NPV) of Cash to Owners	-115,045,096	Present Value$
Rate of Return on Weighted Debt and Equity	NA	

Note: A pipe size of 2,000 inches indicates a nominal pipe diameter greater than 48 inches was needed. 48 inches is largest pipe size allowed by model.

Summary of Costs	Real* 2011$	Real* 2028$	Nominal Escalated$	Present Value Present Value$
Capital Costs	77,337,740	123,672,867	127,626,428	114,417,144
Operating Expenses	58,002,442	92,753,270	140,777,193	38,524,548
Total Costs	135,340,183	216,426,137	268,403,621	152,941,692
Total tonnes of CO2 transported	30,030,000	30,030,000	30,030,000	30,030,000
Costs per tonne	4.51	7.21	8.94	5.09
Capital Costs per mile of pipeline	822,742	1,315,669	1,357,728	1,217,204
Operating Expenses per mile of pipeline	617,047	986,737	1,497,630	409,836
Operating Expenses per mile of pipeline per year of operation	20,568	32,891	49,921	13,661
Total Costs per mile of pipeline	1,439,789	2,302,406	2,855,358	1,627,039

Revenues	Real 2011$	Real 2028$	Nominal Escalated$	Present Value Present Value$
Revenue	57,057,000	91,291,200	138,482,518	37,896,596
Revenue per tonne	1.90	3.04	4.61	1.26
Revenue per mile of pipeline	606,989	971,183	1,473,218	403,155

Table 2	Inputs	Category	Value	Unit	Note
		Financial Inputs			
		Capitalization (fequity)	45.0%		Percent equity; see Appendix A of User's Manual
		Cost of Equity (minimum internal rate of return on equity or IRROEmin)	13.00%	/yr	10.77% default when calculating real$, 13% default when calculating nominal$; see Appendix A in User's Manual
		Cost of Debt (id)	6.00%	/yr	interest rate; 3.91% default when calculating real$, 6% default when calculating nominal$; see Appendix A in User's Manual
		Tax Rate (rtax)	25.7%	/yr	Effective tax rate (21% federal corporate income tax, 4.74% state & local tax); see Appendix A in User's Manual
		Escalation rate from 2011 to starting year of project	2.8%	/yr	Representative regional or national value from Table 2A at right if project start year is 2018. For any other start year, the user needs to calculate a project-specific value.
		Escalation factor from 2011 to starting year of project	1.599		
		Escalation rate beyond starting year of project	2.3%	/yr	0% default when calculating real$, 2.3% default when
		Project Contingency Factor	15%		
		Depreciation method - recovery period for depreciation	DB150 - 15 years		DB150 - 15 years is default
		DB150 - 150% declining balance or SL - straight line			
		Tax affected cost of debt (idtax)	4.5%	/yr	idtax = id * (1-rtax)
		Weighted average cost of capital (WACC)	8.30%	/yr	WACC = fequity * IRROEmin + (1 - fequity) * idtax
		Base year for capital and O&M costs	2011		If this year is changed from 2011 all the capital costs and O&M costs in other sheets must be modified. This would require substantial effort on the user's part.
		Starting Calendar Year for Project	2028	year	
		Duration of Construction in years	3	years	1 to 5 years — **Note**: See Table 3 below for distribution of capital costs over the period of construction.
		Duration of Operation in years	30	years	
		Starting Project Year for Operations	4	year number	
		Ending Project Year for Operations	33	year number	
		Last Project Year for Depreciation	33	year number	
		Last Project Year for Lending	33	year number	
		Other Quantities and Inputs			
		Annual Tonnes of CO2 Transported (on average)	1,001,000	tonne/yr	These are annual CO2 mass flow rates from Table 1A
			30,030,000	tonnes/project	
		Maximum CO2 transported each day	1.18	Mtonne/yr	Maximum CO2 mass flow rate on annualized basis (average
			3,226	tonnes/day	Maximum CO2 mass flow rate on daily basis
		Number of pumps	1		See Table 1A
		Length of pipeline	94.0	mi	See Table 1A
			151.3	km	
		Input Pressure	2,200	psig	Pressure leaving source or at exit of booster pump
			15.3	MPa	
		Outlet Pressure	1,200	psig	Pressure entering booster pump or exiting pipeline at storage
			8.4	MPa	
		Change in Elevation	-10.0	m	These are the unit conversion values
		Indicate equations to use for capital cost of natural gas pipelines	PARKER		PARKER=Parker (2004), MCCOY=McCoy and Rubin (2008), RUI=Rui et al. (2011), BROWN=Brown et al. (2022); see "Eng
		Region of US for McCoy equations	Avg		
		Region of US or Canada for Rui equations	Avg		Avg=average of all US regions; see Figure 2A at right for states
		Region of US for Brown equations	Avg		Avg=average of all US regions; see Table 2B at right for states

Table 3	Engineering Cost Inputs	Capital Costs	Total Real Costs 2011$	Percent in Year 1	Percent in Year 2	Percent in Year 3	cent in Year 4	cent in Year 5	Check
		Materials	10,206,628	5%	40%	55%	0%	0%	100%
		Labor	39,806,180	5%	40%	55%	0%	0%	100%
		ROW-Damages	4,200,434	55%	30%	15%	0%	0%	100%
		Miscellaneous	11,102,856	30%	35%	35%	0%	0%	100%
		CO2 Surge Tanks	1,244,744	0%	10%	90%	0%	0%	100%
		Pipeline Control system	111,907	0%	10%	90%	0%	0%	100%
		Pumps	577,461	0%	40%	60%	0%	0%	100%
		Total capital expenses (before contingencies)	67,250,209	**Note:** Fill in the percentage of capital costs incurred in each year in tables to the right.					
		Operating Expenses	**Real Annual Costs 2011$/yr**						
		Pipeline O&M	1,666,819						
		Pipeline related equipment and pumps O&M	77,364						
		Electricity costs for pumps	189,232						
		Total annual operating expenses	1,933,415						

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where								
	Calendar Year	2028	2029	2030	2031	2032	2033	2034
	Project Year	1	2	3	4	5	6	7
	Escalation schedule from base year of 2011	1.60	1.64	1.67	1.71	1.75	1.79	1.83
	Factor for dividing escal. quantities to yield pres. value using WACC	1.00	1.08	1.17	1.27	1.38	1.49	1.61

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where								
	Calendar Year	2035	2036	2037	2038	2039	2040	2041
	Project Year	8	9	10	11	12	13	14
	Escalation schedule from base year of 2011	1.88	1.92	1.96	2.01	2.05	2.10	2.15
	Factor for dividing escal. quantities to yield pres. value using WACC	1.75	1.89	2.05	2.22	2.40	2.60	2.82

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where							
	Calendar Year	2042	2043	2044	2045	2046	2047
	Project Year	15	16	17	18	19	20
	Escalation schedule from base year of 2011	2.20	2.25	2.30	2.35	2.41	2.46
	Factor for dividing escal. quantities to yield pres. value using WACC	3.05	3.31	3.58	3.88	4.20	4.55

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where							
	Calendar Year	2048	2049	2050	2051	2052	2053
	Project Year	21	22	23	24	25	26
	Escalation schedule from base year of 2011	2.52	2.58	2.64	2.70	2.76	2.82
	Factor for dividing escal. quantities to yield pres. value using WACC	4.93	5.34	5.78	6.26	6.78	7.34

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where		2054	2055	2056	2057	2058	2059	2060
	Calendar Year	2054	2055	2056	2057	2058	2059	2060
	Project Year	27	28	29	30	31	32	33
	Escalation schedule from base year of 2011	2.89	2.95	3.02	3.09	3.16	3.24	3.31
	Factor for dividing escal. quantities to yield pres. value using WACC	7.95	8.61	9.33	10.10	10.94	11.85	12.83

Table 5 **Operating Expenses, Capital Expenses and Depreciation and Amortization**

This column contains row sums, where		2028	2029	2030	2031	2032	2033	2034
		0.934056396						
	Calendar Year	2028	2029	2030	2031	2032	2033	2034
	Project Year	1	2	3	4	5	6	7
	Real Costs in 2011$							
	Capital Costs in Real 2011$							
10,206,628	Materials	510,331	4,082,651	5,613,645	0	0	0	0
39,806,180	Labor	1,990,309	15,922,472	21,893,399	0	0	0	0
4,200,434	ROW-Damages	2,310,239	1,260,130	630,065	0	0	0	0
11,102,856	Miscellaneous	3,330,857	3,886,000	3,886,000	0	0	0	0
1,244,744	CO2 Surge Tanks	0	124,474	1,120,269	0	0	0	0
111,907	Pipeline Control System	0	11,191	100,716	0	0	0	0
577,461	Pumps	0	230,984	346,476	0	0	0	0
10,087,531	Contingency	1,221,260	3,827,685	5,038,586	0	0	0	0
	Operating Expenses in Real 2011$							
50,004,561	Pipeline fixed O&M	0	0	0	1,666,819	1,666,819	1,666,819	1,666,819
2,320,934	Pipeline related equipment and pumps fixed O&M	0	0	0	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	0	0	0	189,232	189,232	189,232	189,232
77,337,740	Total Investment (capital expenses or Capex) in real 2011$	9,362,996	29,345,587	38,629,157	0	0	0	0
58,002,442	Project Expenses (operating expenses or Opex) in real 2011$	0	0	0	1,933,415	1,933,415	1,933,415	1,933,415
	Real Costs in 2028$							
	Capital Costs in Real 2028$							
16,321,693	Materials	816,085	6,528,677	8,976,931	0	0	0	0
63,655,136	Labor	3,182,757	25,462,054	35,010,325	0	0	0	0
6,717,027	ROW-Damages	3,694,365	2,015,108	1,007,554	0	0	0	0
17,754,877	Miscellaneous	5,326,463	6,214,207	6,214,207	0	0	0	0
1,990,503	CO2 Surge Tanks	0	199,050	1,791,453	0	0	0	0
178,954	Pipeline Control System	0	17,895	161,058	0	0	0	0
923,433	Pumps	0	369,373	554,060	0	0	0	0
16,131,243	Contingency	1,952,950	6,120,955	8,057,338	0	0	0	0
	Operating Expenses in Real 2028$							
79,963,643	Pipeline fixed O&M	0	0	0	2,665,455	2,665,455	2,665,455	2,665,455
3,711,468	Pipeline related equipment and pumps fixed O&M	0	0	0	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	0	0	0	302,605	302,605	302,605	302,605
123,672,867	Total Investment (capital expenses or Capex) in real 2028$	14,972,620	46,927,321	61,772,926	0	0	0	0
92,753,270	Project Expenses (operating expenses or Opex) in real 2028$	0	0	0	3,091,776	3,091,776	3,091,776	3,091,776

Table 5 **Operating Expenses, Capital Expenses and Depreciation and Amortization**

This column contains row sums, where	Calendar Year	2035	2036	2037	2038	2039	2040	2041
	Project Year	8	9	10	11	12	13	14
	Real Costs in 2011$							
	Capital Costs in Real 2011$							
10,206,628	Materials	0	0	0	0	0	0	0
39,806,180	Labor	0	0	0	0	0	0	0
4,200,434	ROW-Damages	0	0	0	0	0	0	0
11,102,856	Miscellaneous	0	0	0	0	0	0	0
1,244,744	CO2 Surge Tanks	0	0	0	0	0	0	0
111,907	Pipeline Control System	0	0	0	0	0	0	0
577,461	Pumps	0	0	0	0	0	0	0
10,087,531	Contingency	0	0	0	0	0	0	0
	Operating Expenses in Real 2011$							
50,004,561	Pipeline fixed O&M	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819
2,320,934	Pipeline related equipment and pumps fixed O&M	77,364	77,364	77,364	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	189,232	189,232	189,232	189,232	189,232	189,232	189,232
77,337,740	Total Investment (capital expenses or Capex) in real 2011$	0	0	0	0	0	0	0
58,002,442	Project Expenses (operating expenses or Opex) in real 2011$	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415
	Real Costs in 2028$							
	Capital Costs in Real 2028$							
16,321,693	Materials	0	0	0	0	0	0	0
63,655,136	Labor	0	0	0	0	0	0	0
6,717,027	ROW-Damages	0	0	0	0	0	0	0
17,754,877	Miscellaneous	0	0	0	0	0	0	0
1,990,503	CO2 Surge Tanks	0	0	0	0	0	0	0
178,954	Pipeline Control System	0	0	0	0	0	0	0
923,433	Pumps	0	0	0	0	0	0	0
16,131,243	Contingency	0	0	0	0	0	0	0
	Operating Expenses in Real 2028$							
79,963,643	Pipeline fixed O&M	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455
3,711,468	Pipeline related equipment and pumps fixed O&M	123,716	123,716	123,716	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	302,605	302,605	302,605	302,605	302,605	302,605	302,605
123,672,867	Total Investment (capital expenses or Capex) in real 2028$	0	0	0	0	0	0	0
92,753,270	Project Expenses (operating expenses or Opex) in real 2028$	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776

Table 5 **Operating Expenses, Capital Expenses and Depreciation and Amortization**

This column contains row sums, where	Calendar Year	2042	2043	2044	2045	2046	2047
	Project Year	15	16	17	18	19	20
	Real Costs in 2011$						
	Capital Costs in Real 2011$						
10,206,628	Materials	0	0	0	0	0	0
39,806,180	Labor	0	0	0	0	0	0
4,200,434	ROW-Damages	0	0	0	0	0	0
11,102,856	Miscellaneous	0	0	0	0	0	0
1,244,744	CO2 Surge Tanks	0	0	0	0	0	0
111,907	Pipeline Control System	0	0	0	0	0	0
577,461	Pumps	0	0	0	0	0	0
10,087,531	Contingency	0	0	0	0	0	0
	Operating Expenses in Real 2011$						
50,004,561	Pipeline fixed O&M	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819
2,320,934	Pipeline related equipment and pumps fixed O&M	77,364	77,364	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	189,232	189,232	189,232	189,232	189,232	189,232
77,337,740	Total Investment (capital expenses or Capex) in real 2011$	0	0	0	0	0	0
58,002,442	Project Expenses (operating expenses or Opex) in real 2011$	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415
	Real Costs in 2028$						
	Capital Costs in Real 2028$						
16,321,693	Materials	0	0	0	0	0	0
63,655,136	Labor	0	0	0	0	0	0
6,717,027	ROW-Damages	0	0	0	0	0	0
17,754,877	Miscellaneous	0	0	0	0	0	0
1,990,503	CO2 Surge Tanks	0	0	0	0	0	0
178,954	Pipeline Control System	0	0	0	0	0	0
923,433	Pumps	0	0	0	0	0	0
16,131,243	Contingency	0	0	0	0	0	0
	Operating Expenses in Real 2028$						
79,963,643	Pipeline fixed O&M	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455
3,711,468	Pipeline related equipment and pumps fixed O&M	123,716	123,716	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	302,605	302,605	302,605	302,605	302,605	302,605
123,672,867	Total Investment (capital expenses or Capex) in real 2028$	0	0	0	0	0	0
92,753,270	Project Expenses (operating expenses or Opex) in real 2028$	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776

Table 5	Operating Expenses, Capital Expenses and Depreciation and Amortization						
This column contains row sums, where	Calendar Year	2048	2049	2050	2051	2052	2053
	Project Year	21	22	23	24	25	26
	Real Costs in 2011$						
	Capital Costs in Real 2011$						
10,206,628	Materials	0	0	0	0	0	0
39,806,180	Labor	0	0	0	0	0	0
4,200,434	ROW-Damages	0	0	0	0	0	0
11,102,856	Miscellaneous	0	0	0	0	0	0
1,244,744	CO2 Surge Tanks	0	0	0	0	0	0
111,907	Pipeline Control System	0	0	0	0	0	0
577,461	Pumps	0	0	0	0	0	0
10,087,531	Contingency	0	0	0	0	0	0
	Operating Expenses in Real 2011$						
50,004,561	Pipeline fixed O&M	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819
2,320,934	Pipeline related equipment and pumps fixed O&M	77,364	77,364	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	189,232	189,232	189,232	189,232	189,232	189,232
77,337,740	Total Investment (capital expenses or Capex) in real 2011$	0	0	0	0	0	0
58,002,442	Project Expenses (operating expenses or Opex) in real 2011$	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415
	Real Costs in 2028$						
	Capital Costs in Real 2028$						
16,321,693	Materials	0	0	0	0	0	0
63,655,136	Labor	0	0	0	0	0	0
6,717,027	ROW-Damages	0	0	0	0	0	0
17,754,877	Miscellaneous	0	0	0	0	0	0
1,990,503	CO2 Surge Tanks	0	0	0	0	0	0
178,954	Pipeline Control System	0	0	0	0	0	0
923,433	Pumps	0	0	0	0	0	0
16,131,243	Contingency	0	0	0	0	0	0
	Operating Expenses in Real 2028$						
79,963,643	Pipeline fixed O&M	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455
3,711,468	Pipeline related equipment and pumps fixed O&M	123,716	123,716	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	302,605	302,605	302,605	302,605	302,605	302,605
123,672,867	Total Investment (capital expenses or Capex) in real 2028$	0	0	0	0	0	0
92,753,270	Project Expenses (operating expenses or Opex) in real 2028$	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776

Table 5 **Operating Expenses, Capital Expenses and Depreciation and Amortization**

This column contains row sums, where	Calendar Year	2054	2055	2056	2057	2058	2059	2060
	Project Year	27	28	29	30	31	32	33
	Real Costs in 2011$							
	Capital Costs in Real 2011$							
10,206,628	Materials	0	0	0	0	0	0	0
39,806,180	Labor	0	0	0	0	0	0	0
4,200,434	ROW-Damages	0	0	0	0	0	0	0
11,102,856	Miscellaneous	0	0	0	0	0	0	0
1,244,744	CO2 Surge Tanks	0	0	0	0	0	0	0
111,907	Pipeline Control System	0	0	0	0	0	0	0
577,461	Pumps	0	0	0	0	0	0	0
10,087,531	Contingency	0	0	0	0	0	0	0
	Operating Expenses in Real 2011$							
50,004,561	Pipeline fixed O&M	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819	1,666,819
2,320,934	Pipeline related equipment and pumps fixed O&M	77,364	77,364	77,364	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	189,232	189,232	189,232	189,232	189,232	189,232	189,232
77,337,740	Total Investment (capital expenses or Capex) in real 2011$	0	0	0	0	0	0	0
58,002,442	Project Expenses (operating expenses or Opex) in real 2011$	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415	1,933,415
	Real Costs in 2028$							
	Capital Costs in Real 2028$							
16,321,693	Materials	0	0	0	0	0	0	0
63,655,136	Labor	0	0	0	0	0	0	0
6,717,027	ROW-Damages	0	0	0	0	0	0	0
17,754,877	Miscellaneous	0	0	0	0	0	0	0
1,990,503	CO2 Surge Tanks	0	0	0	0	0	0	0
178,954	Pipeline Control System	0	0	0	0	0	0	0
923,433	Pumps	0	0	0	0	0	0	0
16,131,243	Contingency	0	0	0	0	0	0	0
	Operating Expenses in Real 2028$							
79,963,643	Pipeline fixed O&M	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455	2,665,455
3,711,468	Pipeline related equipment and pumps fixed O&M	123,716	123,716	123,716	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	302,605	302,605	302,605	302,605	302,605	302,605	302,605
123,672,867	Total Investment (capital expenses or Capex) in real 2028$	0	0	0	0	0	0	0
92,753,270	Project Expenses (operating expenses or Opex) in real 2028$	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776	3,091,776

Table 5 (continued)	Operating Expenses, Capital Expenses and Depreciation and Amortization							
	Escalated Costs							
	Capital Costs in escalated $							
16,889,541	Materials	816,085	6,678,837	9,394,619	0	0	0	0
65,869,759	Labor	3,182,757	26,047,682	36,639,320	0	0	0	0
6,810,255	ROW-Damages	3,694,365	2,061,456	1,054,435	0	0	0	0
18,186,945	Miscellaneous	5,326,463	6,357,134	6,503,348	0	0	0	0
2,078,436	CO2 Surge Tanks	0	203,628	1,874,807	0	0	0	0
186,859	Pipeline Control System	0	18,307	168,552	0	0	0	0
957,708	Pumps	0	377,869	579,840	0	0	0	0
16,646,925	Contingency	1,952,950	6,261,737	8,432,238	0	0	0	0
	Operating Expenses in escalated $							
121,365,609	Pipeline fixed O&M	0	0	0	2,853,634	2,919,267	2,986,410	3,055,098
5,633,117	Pipeline related equipment and pumps fixed O&M	0	0	0	132,450	135,496	138,613	141,801
13,778,467	Electricity costs for pumps (variable O&M)	0	0	0	323,969	331,420	339,043	346,841
127,626,428	Total Investment (capital expenses or Capex) in escalated $	14,972,620	48,006,649	64,647,159	0	0	0	0
140,777,193	Project Expenses (operating expenses or Opex) in escalated $	0	0	0	3,310,052	3,386,184	3,464,066	3,543,739
	Escalated and Discounted Costs (only used for reporting purposes)							
114,417,144	Total Investment (capital expenses or Capex) in present value $	14,972,620	44,327,232	55,117,293	0	0	0	0
38,524,548	Project Expenses (operating expenses or Opex) in present value $	0	0	0	2,605,809	2,461,429	2,325,050	2,196,226
	Depreciation							
127,626,428	Total Capital Costs in escalated dollars	14,972,620	48,006,649	64,647,159	0	0	0	0
127,626,428	Total Capital Costs in escalated $ before pipeline operations begin	14,972,620	48,006,649	64,647,159	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	0.00%	0.00%	0.00%	5.00%	9.50%	8.55%	7.70%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	0.00%	0.00%	0.00%	3.33%	6.67%	6.67%	6.67%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	0.00%	0.00%	0.00%	2.27%	4.55%	4.55%	4.55%
127,626,428	Depreciation Schedule (150% declining balance, 15 year recov. per.)	0	0	0	6,381,321	12,124,511	10,912,060	9,827,235

Table 5 (continued)	Operating Expenses, Capital Expenses and Depreciation and Amortization							
	Escalated Costs							
	Capital Costs in escalated $							
16,889,541	Materials	0	0	0	0	0	0	0
65,869,759	Labor	0	0	0	0	0	0	0
6,810,255	ROW-Damages	0	0	0	0	0	0	0
18,186,945	Miscellaneous	0	0	0	0	0	0	0
2,078,436	CO2 Surge Tanks	0	0	0	0	0	0	0
186,859	Pipeline Control System	0	0	0	0	0	0	0
957,708	Pumps	0	0	0	0	0	0	0
16,646,925	Contingency	0	0	0	0	0	0	0
	Operating Expenses in escalated $							
121,365,609	Pipeline fixed O&M	3,125,365	3,197,248	3,270,785	3,346,013	3,422,972	3,501,700	3,582,239
5,633,117	Pipeline related equipment and pumps fixed O&M	145,062	148,399	151,812	155,303	158,875	162,529	166,268
13,778,467	Electricity costs for pumps (variable O&M)	354,818	362,979	371,328	379,868	388,605	397,543	406,687
127,626,428	Total Investment (capital expenses or Capex) in escalated $	0	0	0	0	0	0	0
140,777,193	Project Expenses (operating expenses or Opex) in escalated $	3,625,245	3,708,626	3,793,924	3,881,185	3,970,452	4,061,772	4,155,193
	Escalated and Discounted Costs (only used for reporting purposes)							
114,417,144	Total Investment (capital expenses or Capex) in present value $	0	0	0	0	0	0	0
38,524,548	Project Expenses (operating expenses or Opex) in present value $	2,074,541	1,959,597	1,851,022	1,748,463	1,651,587	1,560,078	1,473,639
	Depreciation							
127,626,428	Total Capital Costs in escalated dollars	0	0	0	0	0	0	0
127,626,428	Total Capital Costs in escalated $ before pipeline operations begin	0	0	0	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	6.93%	6.23%	5.90%	5.90%	5.91%	5.90%	5.91%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	6.67%	6.67%	6.67%	6.66%	6.67%	6.66%	6.67%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%
127,626,428	Depreciation Schedule (150% declining balance, 15 year recov. per.)	8,844,511	7,951,126	7,529,959	7,529,959	7,542,722	7,529,959	7,542,722

Table 5 (continued)	**Operating Expenses, Capital Expenses and Depreciation and Amortization**						
	Escalated Costs						
	Capital Costs in escalated $						
16,889,541	Materials	0	0	0	0	0	0
65,869,759	Labor	0	0	0	0	0	0
6,810,255	ROW-Damages	0	0	0	0	0	0
18,186,945	Miscellaneous	0	0	0	0	0	0
2,078,436	CO2 Surge Tanks	0	0	0	0	0	0
186,859	Pipeline Control System	0	0	0	0	0	0
957,708	Pumps	0	0	0	0	0	0
16,646,925	Contingency	0	0	0	0	0	0
	Operating Expenses in escalated $						
121,365,609	Pipeline fixed O&M	3,664,630	3,748,917	3,835,142	3,923,350	4,013,587	4,105,900
5,633,117	Pipeline related equipment and pumps fixed O&M	170,092	174,004	178,006	182,100	186,288	190,573
13,778,467	Electricity costs for pumps (variable O&M)	416,040	425,609	435,398	445,412	455,657	466,137
127,626,428	Total Investment (capital expenses or Capex) in escalated $	0	0	0	0	0	0
140,777,193	Project Expenses (operating expenses or Opex) in escalated $	4,250,763	4,348,530	4,448,546	4,550,863	4,655,533	4,762,610
	Escalated and Discounted Costs (only used for reporting purposes)						
114,417,144	Total Investment (capital expenses or Capex) in present value $	0	0	0	0	0	0
38,524,548	Project Expenses (operating expenses or Opex) in present value $	1,391,989	1,314,864	1,242,011	1,173,196	1,108,193	1,046,791
	Depreciation						
127,626,428	Total Capital Costs in escalated dollars	0	0	0	0	0	0
127,626,428	Total Capital Costs in escalated $ before pipeline operations begin	0	0	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	5.90%	5.91%	5.90%	5.91%	2.95%	0.00%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	6.66%	6.67%	6.66%	6.67%	3.33%	0.00%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%
127,626,428	Depreciation Schedule (150% declining balance, 15 year recov. per.)	7,529,959	7,542,722	7,529,959	7,542,722	3,764,980	0

Table 5 (continued)	**Operating Expenses, Capital Expenses and Depreciation and Amortization**						
	Escalated Costs						
	Capital Costs in escalated $						
16,889,541	Materials	0	0	0	0	0	0
65,869,759	Labor	0	0	0	0	0	0
6,810,255	ROW-Damages	0	0	0	0	0	0
18,186,945	Miscellaneous	0	0	0	0	0	0
2,078,436	CO2 Surge Tanks	0	0	0	0	0	0
186,859	Pipeline Control System	0	0	0	0	0	0
957,708	Pumps	0	0	0	0	0	0
16,646,925	Contingency	0	0	0	0	0	0
	Operating Expenses in escalated $						
121,365,609	Pipeline fixed O&M	4,200,336	4,296,943	4,395,773	4,496,876	4,600,304	4,706,111
5,633,117	Pipeline related equipment and pumps fixed O&M	194,956	199,440	204,027	208,720	213,521	218,432
13,778,467	Electricity costs for pumps (variable O&M)	476,858	487,826	499,046	510,524	522,266	534,278
127,626,428	Total Investment (capital expenses or Capex) in escalated $	0	0	0	0	0	0
140,777,193	Project Expenses (operating expenses or Opex) in escalated $	4,872,150	4,984,209	5,098,846	5,216,120	5,336,090	5,458,821
	Escalated and Discounted Costs (only used for reporting purposes)						
114,417,144	Total Investment (capital expenses or Capex) in present value $	0	0	0	0	0	0
38,524,548	Project Expenses (operating expenses or Opex) in present value $	988,792	934,006	882,256	833,373	787,199	743,583
	Depreciation						
127,626,428	Total Capital Costs in escalated dollars	0	0	0	0	0	0
127,626,428	Total Capital Costs in escalated $ before pipeline operations begin	0	0	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	4.55%	4.55%	4.55%	4.55%	4.55%	2.27%
127,626,428	Depreciation Schedule (150% declining balance, 15 year recov. per.)	0	0	0	0	0	0

Table 5 (continued)	**Operating Expenses, Capital Expenses and Depreciation and Amortization**							
	Escalated Costs							
	Capital Costs in escalated $							
16,889,541	Materials	0	0	0	0	0	0	0
65,869,759	Labor	0	0	0	0	0	0	0
6,810,255	ROW-Damages	0	0	0	0	0	0	0
18,186,945	Miscellaneous	0	0	0	0	0	0	0
2,078,436	CO2 Surge Tanks	0	0	0	0	0	0	0
186,859	Pipeline Control System	0	0	0	0	0	0	0
957,708	Pumps	0	0	0	0	0	0	0
16,646,925	Contingency	0	0	0	0	0	0	0
	Operating Expenses in escalated $							
121,365,609	Pipeline fixed O&M	4,814,351	4,925,082	5,038,358	5,154,241	5,272,788	5,394,062	5,518,126
5,633,117	Pipeline related equipment and pumps fixed O&M	223,455	228,595	233,853	239,231	244,734	250,362	256,121
13,778,467	Electricity costs for pumps (variable O&M)	546,567	559,138	571,998	585,154	598,612	612,380	626,465
127,626,428	Total Investment (capital expenses or Capex) in escalated $	0	0	0	0	0	0	0
140,777,193	Project Expenses (operating expenses or Opex) in escalated $	5,584,373	5,712,814	5,844,209	5,978,626	6,116,134	6,256,805	6,400,712
	Escalated and Discounted Costs (only used for reporting purposes)							
114,417,144	Total Investment (capital expenses or Capex) in present value $	0	0	0	0	0	0	0
38,524,548	Project Expenses (operating expenses or Opex) in present value $	702,383	663,466	626,706	591,982	559,182	528,200	498,934
	Depreciation							
127,626,428	Total Capital Costs in escalated dollars	0	0	0	0	0	0	0
127,626,428	Total Capital Costs in escalated $ before pipeline operations begin	0	0	0	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
127,626,428	Depreciation Schedule (150% declining balance, 15 year recov. per.)	0	0	0	0	0	0	0

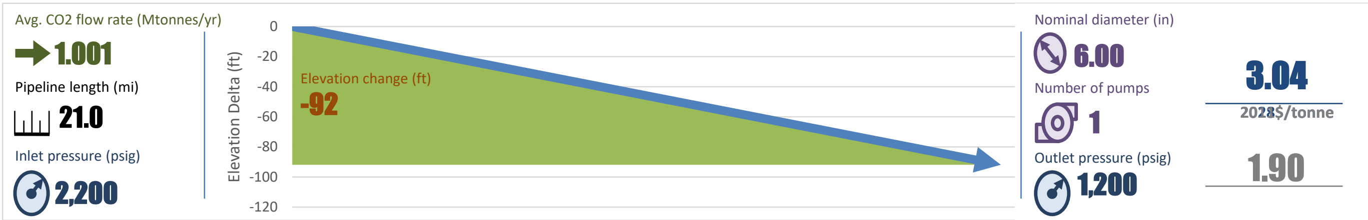


Table 1 **Summary** **A. Key Inputs and Results for Basic Analysis**

	2011$/tonne	2028$/tonne	2031$/tonne
		first yr of proj	first yr of transp
First-year Price to Transport CO2 by Pipeline	1.90	3.04	3.25
Annual Average CO2 Mass Flow Rate (qav)	1.001	Mtonnes/yr (Mtonnes = megatonnes [million tonnes]; tonne = 1,000 kg)	
Capacity Factor (fraction of time when flow is at equivalent of maximum flow rate)	85%		
Maximum CO2 Flow Rate on annualized basis	1.18	Mtonnes/yr	
Length of pipeline	21.0	mi	
Number of booster pumps (Optimal Pump Number will set the optimal pump number)	1	Optimal number of pumps	
Change in Elevation (Positive if pipeline outlet is at a higher elevation than inlet)	-92	ft	

Key Outputs

Calculated Minimum Inner Diameter for Pipe	5.32	in
Nominal Pipe Diameter or Pipe Size	6.00	in
Net Present Value (NPV) of Cash to Owners	-3,815,700	Present Value$
Rate of Return on Weighted Debt and Equity	NA	

Note: A pipe size of 2,000 inches indicates a nominal pipe diameter greater than 48 inches was needed. 48 inches is largest pipe size allowed by model.

Summary of Costs	**Real* 2011$**	**Real* 2028$**	**Nominal Escalated$**	**Present Value Present Value$**
Capital Costs	17,723,734	28,342,501	29,278,727	26,152,597
Operating Expenses	19,123,743	30,581,293	46,415,059	12,701,768
Total Costs	36,847,477	58,923,794	75,693,786	38,854,365
Total tonnes of CO2 transported	30,030,000	30,030,000	30,030,000	30,030,000
Costs per tonne	1.23	1.96	2.52	1.29
Capital Costs per mile of pipeline	843,987	1,349,643	1,394,225	1,245,362
Operating Expenses per mile of pipeline	910,654	1,456,252	2,210,241	604,846
Operating Expenses per mile of pipeline per year of operation	30,355	48,542	73,675	20,162
Total Costs per mile of pipeline	1,754,642	2,805,895	3,604,466	1,850,208

Revenues	**Real 2011$**	**Real 2028$**	**Nominal Escalated$**	**Present Value Present Value$**
Revenue	57,057,000	91,291,200	138,482,518	37,896,596
Revenue per tonne	1.90	3.04	4.61	1.26
Revenue per mile of pipeline	2,717,000	4,347,200	6,594,406	1,804,600

Table 2	Inputs	Category	Value	Unit	Note
		Financial Inputs			
		Capitalization (fequity)	45.0%		Percent equity; see Appendix A of User's Manual
		Cost of Equity (minimum internal rate of return on equity or IRROEmin)	13.00%	/yr	10.77% default when calculating real$, 13% default when calculating nominal$; see Appendix A in User's Manual
		Cost of Debt (id)	6.00%	/yr	interest rate; 3.91% default when calculating real$, 6% default when calculating nominal$; see Appendix A in User's Manual
		Tax Rate (rtax)	25.7%	/yr	Effective tax rate (21% federal corporate income tax, 4.74% state & local tax); see Appendix A in User's Manual
		Escalation rate from 2011 to starting year of project	2.8%	/yr	Representative regional or national value from Table 2A at right if project start year is 2018. For any other start year, the user needs to calculate a project-specific value.
		Escalation factor from 2011 to starting year of project	1.599		
		Escalation rate beyond starting year of project	2.3%	/yr	0% default when calculating real$, 2.3% default when
		Project Contingency Factor	15%		
		Depreciation method - recovery period for depreciation	DB150 - 15 years		DB150 - 15 years is default
		DB150 - 150% declining balance or SL - straight line			
		Tax affected cost of debt (idtax)	4.5%	/yr	idtax = id * (1-rtax)
		Weighted average cost of capital (WACC)	8.30%	/yr	WACC = fequity * IRROEmin + (1 - fequity) * idtax
		Base year for capital and O&M costs	2011		If this year is changed from 2011 all the capital costs and O&M costs in other sheets must be modified. This would require substantial effort on the user's part.
		Starting Calendar Year for Project	2028	year	
		Duration of Construction in years	3	years	1 to 5 years; **Note**: See Table 3 below for distribution of capital costs over the period of construction.
		Duration of Operation in years	30	years	
		Starting Project Year for Operations	4	year number	
		Ending Project Year for Operations	33	year number	
		Last Project Year for Depreciation	33	year number	
		Last Project Year for Lending	33	year number	
		Other Quantities and Inputs			
		Annual Tonnes of CO2 Transported (on average)	1,001,000	tonne/yr	These are annual CO2 mass flow rates from Table 1A
			30,030,000	tonnes/project	
		Maximum CO2 transported each day	1.18	Mtonne/yr	Maximum CO2 mass flow rate on annualized basis (average
			3,226	tonnes/day	Maximum CO2 mass flow rate on daily basis
		Number of pumps	1		See Table 1A
		Length of pipeline	21.0	mi	See Table 1A
			33.8	km	
		Input Pressure	2,200	psig	Pressure leaving source or at exit of booster pump
			15.3	MPa	
		Outlet Pressure	1,200	psig	Pressure entering booster pump or exiting pipeline at storage
			8.4	MPa	
		Change in Elevation	-28.0	m	These are the unit conversion values
		Indicate equations to use for capital cost of natural gas pipelines	PARKER		PARKER=Parker (2004), MCCOY=McCoy and Rubin (2008), RUI=Rui et al. (2011), BROWN=Brown et al. (2022); see "Eng
		Region of US for McCoy equations	Avg		
		Region of US or Canada for Rui equations	Avg		Avg=average of all US regions; see Figure 2A at right for states
		Region of US for Brown equations	Avg		Avg=average of all US regions; see Table 2B at right for states

Table 3	Engineering Cost Inputs	Capital Costs	Total Real Costs 2011$	Percent in Year 1	Percent in Year 2	Percent in Year 3	cent in Year 4	cent in Year 5	Check
		Materials	1,885,937	5%	40%	55%	0%	0%	100%
		Labor	8,600,958	5%	40%	55%	0%	0%	100%
		ROW-Damages	947,157	55%	30%	15%	0%	0%	100%
		Miscellaneous	2,043,779	30%	35%	35%	0%	0%	100%
		CO2 Surge Tanks	1,244,744	0%	10%	90%	0%	0%	100%
		Pipeline Control system	111,907	0%	10%	90%	0%	0%	100%
		Pumps	577,461	0%	40%	60%	0%	0%	100%
		Total capital expenses (before contingencies)	15,411,943	**Note:** Fill in the percentage of capital costs incurred in each year in tables to the right.					
		Operating Expenses	**Real Annual Costs 2011$/yr**						
		Pipeline O&M	370,862						
		Pipeline related equipment and pumps O&M	77,364						
		Electricity costs for pumps	189,232						
		Total annual operating expenses	637,458						

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where		2028	2029	2030	2031	2032	2033	2034
	Calendar Year	2028	2029	2030	2031	2032	2033	2034
	Project Year	1	2	3	4	5	6	7
	Escalation schedule from base year of 2011	1.60	1.64	1.67	1.71	1.75	1.79	1.83
	Factor for dividing escal. quantities to yield pres. value using WACC	1.00	1.08	1.17	1.27	1.38	1.49	1.61

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where								
	Calendar Year	2035	2036	2037	2038	2039	2040	2041
	Project Year	8	9	10	11	12	13	14
	Escalation schedule from base year of 2011	1.88	1.92	1.96	2.01	2.05	2.10	2.15
	Factor for dividing escal. quantities to yield pres. value using WACC	1.75	1.89	2.05	2.22	2.40	2.60	2.82

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where		2042	2043	2044	2045	2046	2047
	Calendar Year	2042	2043	2044	2045	2046	2047
	Project Year	15	16	17	18	19	20
	Escalation schedule from base year of 2011	2.20	2.25	2.30	2.35	2.41	2.46
	Factor for dividing escal. quantities to yield pres. value using WACC	3.05	3.31	3.58	3.88	4.20	4.55

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where	**Calendar Year**	2048	2049	2050	2051	2052	2053
	Project Year	21	22	23	24	25	26
	Escalation schedule from base year of 2011	2.52	2.58	2.64	2.70	2.76	2.82
	Factor for dividing escal. quantities to yield pres. value using WACC	4.93	5.34	5.78	6.26	6.78	7.34

Table 4 **Escalation and Discounting Factors**

This column contains row sums, where		2054	2055	2056	2057	2058	2059	2060
	Calendar Year	2054	2055	2056	2057	2058	2059	2060
	Project Year	27	28	29	30	31	32	33
	Escalation schedule from base year of 2011	2.89	2.95	3.02	3.09	3.16	3.24	3.31
	Factor for dividing escal. quantities to yield pres. value using WACC	7.95	8.61	9.33	10.10	10.94	11.85	12.83

Table 5	Operating Expenses, Capital Expenses and Depreciation and Amortization							
		0.934056396						
This column contains row sums, where	**Calendar Year**	2028	2029	2030	2031	2032	2033	2034
	Project Year	1	2	3	4	5	6	7
	Real Costs in 2011$							
	Capital Costs in Real 2011$							
1,885,937	Materials	94,297	754,375	1,037,265	0	0	0	0
8,600,958	Labor	430,048	3,440,383	4,730,527	0	0	0	0
947,157	ROW-Damages	520,936	284,147	142,074	0	0	0	0
2,043,779	Miscellaneous	613,134	715,323	715,323	0	0	0	0
1,244,744	CO2 Surge Tanks	0	124,474	1,120,269	0	0	0	0
111,907	Pipeline Control System	0	11,191	100,716	0	0	0	0
577,461	Pumps	0	230,984	346,476	0	0	0	0
2,311,791	Contingency	248,762	834,132	1,228,898	0	0	0	0
	Operating Expenses in Real 2011$							
11,125,862	Pipeline fixed O&M	0	0	0	370,862	370,862	370,862	370,862
2,320,934	Pipeline related equipment and pumps fixed O&M	0	0	0	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	0	0	0	189,232	189,232	189,232	189,232
17,723,734	Total Investment (capital expenses or Capex) in real 2011$	1,907,177	6,395,009	9,421,548	0	0	0	0
19,123,743	Project Expenses (operating expenses or Opex) in real 2011$	0	0	0	637,458	637,458	637,458	637,458
	Real Costs in 2028$							
	Capital Costs in Real 2028$							
3,015,852	Materials	150,793	1,206,341	1,658,719	0	0	0	0
13,754,024	Labor	687,701	5,501,610	7,564,713	0	0	0	0
1,514,625	ROW-Damages	833,044	454,387	227,194	0	0	0	0
3,268,262	Miscellaneous	980,479	1,143,892	1,143,892	0	0	0	0
1,990,503	CO2 Surge Tanks	0	199,050	1,791,453	0	0	0	0
178,954	Pipeline Control System	0	17,895	161,058	0	0	0	0
923,433	Pumps	0	369,373	554,060	0	0	0	0
3,696,848	Contingency	397,802	1,333,882	1,965,163	0	0	0	0
	Operating Expenses in Real 2028$							
17,791,665	Pipeline fixed O&M	0	0	0	593,056	593,056	593,056	593,056
3,711,468	Pipeline related equipment and pumps fixed O&M	0	0	0	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	0	0	0	302,605	302,605	302,605	302,605
28,342,501	Total Investment (capital expenses or Capex) in real 2028$	3,049,818	10,226,431	15,066,252	0	0	0	0
30,581,293	Project Expenses (operating expenses or Opex) in real 2028$	0	0	0	1,019,376	1,019,376	1,019,376	1,019,376

Table 5 **Operating Expenses, Capital Expenses and Depreciation and Amortization**

This column contains row sums, where	Calendar Year	2035	2036	2037	2038	2039	2040	2041
	Project Year	8	9	10	11	12	13	14
	Real Costs in 2011$							
	Capital Costs in Real 2011$							
1,885,937	Materials	0	0	0	0	0	0	0
8,600,958	Labor	0	0	0	0	0	0	0
947,157	ROW-Damages	0	0	0	0	0	0	0
2,043,779	Miscellaneous	0	0	0	0	0	0	0
1,244,744	CO2 Surge Tanks	0	0	0	0	0	0	0
111,907	Pipeline Control System	0	0	0	0	0	0	0
577,461	Pumps	0	0	0	0	0	0	0
2,311,791	Contingency	0	0	0	0	0	0	0
	Operating Expenses in Real 2011$							
11,125,862	Pipeline fixed O&M	370,862	370,862	370,862	370,862	370,862	370,862	370,862
2,320,934	Pipeline related equipment and pumps fixed O&M	77,364	77,364	77,364	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	189,232	189,232	189,232	189,232	189,232	189,232	189,232
17,723,734	Total Investment (capital expenses or Capex) in real 2011$	0	0	0	0	0	0	0
19,123,743	Project Expenses (operating expenses or Opex) in real 2011$	637,458	637,458	637,458	637,458	637,458	637,458	637,458
	Real Costs in 2028$							
	Capital Costs in Real 2028$							
3,015,852	Materials	0	0	0	0	0	0	0
13,754,024	Labor	0	0	0	0	0	0	0
1,514,625	ROW-Damages	0	0	0	0	0	0	0
3,268,262	Miscellaneous	0	0	0	0	0	0	0
1,990,503	CO2 Surge Tanks	0	0	0	0	0	0	0
178,954	Pipeline Control System	0	0	0	0	0	0	0
923,433	Pumps	0	0	0	0	0	0	0
3,696,848	Contingency	0	0	0	0	0	0	0
	Operating Expenses in Real 2028$							
17,791,665	Pipeline fixed O&M	593,056	593,056	593,056	593,056	593,056	593,056	593,056
3,711,468	Pipeline related equipment and pumps fixed O&M	123,716	123,716	123,716	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	302,605	302,605	302,605	302,605	302,605	302,605	302,605
28,342,501	Total Investment (capital expenses or Capex) in real 2028$	0	0	0	0	0	0	0
30,581,293	Project Expenses (operating expenses or Opex) in real 2028$	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376

Table 5 **Operating Expenses, Capital Expenses and Depreciation and Amortization**

This column contains row sums, where		2042	2043	2044	2045	2046	2047
	Calendar Year	2042	2043	2044	2045	2046	2047
	Project Year	15	16	17	18	19	20
	Real Costs in 2011$						
	Capital Costs in Real 2011$						
1,885,937	Materials	0	0	0	0	0	0
8,600,958	Labor	0	0	0	0	0	0
947,157	ROW-Damages	0	0	0	0	0	0
2,043,779	Miscellaneous	0	0	0	0	0	0
1,244,744	CO2 Surge Tanks	0	0	0	0	0	0
111,907	Pipeline Control System	0	0	0	0	0	0
577,461	Pumps	0	0	0	0	0	0
2,311,791	Contingency	0	0	0	0	0	0
	Operating Expenses in Real 2011$						
11,125,862	Pipeline fixed O&M	370,862	370,862	370,862	370,862	370,862	370,862
2,320,934	Pipeline related equipment and pumps fixed O&M	77,364	77,364	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	189,232	189,232	189,232	189,232	189,232	189,232
17,723,734	Total Investment (capital expenses or Capex) in real 2011$	0	0	0	0	0	0
19,123,743	Project Expenses (operating expenses or Opex) in real 2011$	637,458	637,458	637,458	637,458	637,458	637,458
	Real Costs in 2028$						
	Capital Costs in Real 2028$						
3,015,852	Materials	0	0	0	0	0	0
13,754,024	Labor	0	0	0	0	0	0
1,514,625	ROW-Damages	0	0	0	0	0	0
3,268,262	Miscellaneous	0	0	0	0	0	0
1,990,503	CO2 Surge Tanks	0	0	0	0	0	0
178,954	Pipeline Control System	0	0	0	0	0	0
923,433	Pumps	0	0	0	0	0	0
3,696,848	Contingency	0	0	0	0	0	0
	Operating Expenses in Real 2028$						
17,791,665	Pipeline fixed O&M	593,056	593,056	593,056	593,056	593,056	593,056
3,711,468	Pipeline related equipment and pumps fixed O&M	123,716	123,716	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	302,605	302,605	302,605	302,605	302,605	302,605
28,342,501	Total Investment (capital expenses or Capex) in real 2028$	0	0	0	0	0	0
30,581,293	Project Expenses (operating expenses or Opex) in real 2028$	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376

Table 5	Operating Expenses, Capital Expenses and Depreciation and Amortization						
This column contains row sums, where	**Calendar Year**	2048	2049	2050	2051	2052	2053
	Project Year	21	22	23	24	25	26
	Real Costs in 2011$						
	Capital Costs in Real 2011$						
1,885,937	Materials	0	0	0	0	0	0
8,600,958	Labor	0	0	0	0	0	0
947,157	ROW-Damages	0	0	0	0	0	0
2,043,779	Miscellaneous	0	0	0	0	0	0
1,244,744	CO2 Surge Tanks	0	0	0	0	0	0
111,907	Pipeline Control System	0	0	0	0	0	0
577,461	Pumps	0	0	0	0	0	0
2,311,791	Contingency	0	0	0	0	0	0
	Operating Expenses in Real 2011$						
11,125,862	Pipeline fixed O&M	370,862	370,862	370,862	370,862	370,862	370,862
2,320,934	Pipeline related equipment and pumps fixed O&M	77,364	77,364	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	189,232	189,232	189,232	189,232	189,232	189,232
17,723,734	Total Investment (capital expenses or Capex) in real 2011$	0	0	0	0	0	0
19,123,743	Project Expenses (operating expenses or Opex) in real 2011$	637,458	637,458	637,458	637,458	637,458	637,458
	Real Costs in 2028$						
	Capital Costs in Real 2028$						
3,015,852	Materials	0	0	0	0	0	0
13,754,024	Labor	0	0	0	0	0	0
1,514,625	ROW-Damages	0	0	0	0	0	0
3,268,262	Miscellaneous	0	0	0	0	0	0
1,990,503	CO2 Surge Tanks	0	0	0	0	0	0
178,954	Pipeline Control System	0	0	0	0	0	0
923,433	Pumps	0	0	0	0	0	0
3,696,848	Contingency	0	0	0	0	0	0
	Operating Expenses in Real 2028$						
17,791,665	Pipeline fixed O&M	593,056	593,056	593,056	593,056	593,056	593,056
3,711,468	Pipeline related equipment and pumps fixed O&M	123,716	123,716	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	302,605	302,605	302,605	302,605	302,605	302,605
28,342,501	Total Investment (capital expenses or Capex) in real 2028$	0	0	0	0	0	0
30,581,293	Project Expenses (operating expenses or Opex) in real 2028$	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376

Table 5	Operating Expenses, Capital Expenses and Depreciation and Amortization							
This column contains row sums, where	**Calendar Year**	2054	2055	2056	2057	2058	2059	2060
	Project Year	27	28	29	30	31	32	33
	Real Costs in 2011$							
	Capital Costs in Real 2011$							
1,885,937	Materials	0	0	0	0	0	0	0
8,600,958	Labor	0	0	0	0	0	0	0
947,157	ROW-Damages	0	0	0	0	0	0	0
2,043,779	Miscellaneous	0	0	0	0	0	0	0
1,244,744	CO2 Surge Tanks	0	0	0	0	0	0	0
111,907	Pipeline Control System	0	0	0	0	0	0	0
577,461	Pumps	0	0	0	0	0	0	0
2,311,791	Contingency	0	0	0	0	0	0	0
	Operating Expenses in Real 2011$							
11,125,862	Pipeline fixed O&M	370,862	370,862	370,862	370,862	370,862	370,862	370,862
2,320,934	Pipeline related equipment and pumps fixed O&M	77,364	77,364	77,364	77,364	77,364	77,364	77,364
5,676,947	Electricity costs for pumps (variable O&M)	189,232	189,232	189,232	189,232	189,232	189,232	189,232
17,723,734	Total Investment (capital expenses or Capex) in real 2011$	0	0	0	0	0	0	0
19,123,743	Project Expenses (operating expenses or Opex) in real 2011$	637,458	637,458	637,458	637,458	637,458	637,458	637,458
	Real Costs in 2028$							
	Capital Costs in Real 2028$							
3,015,852	Materials	0	0	0	0	0	0	0
13,754,024	Labor	0	0	0	0	0	0	0
1,514,625	ROW-Damages	0	0	0	0	0	0	0
3,268,262	Miscellaneous	0	0	0	0	0	0	0
1,990,503	CO2 Surge Tanks	0	0	0	0	0	0	0
178,954	Pipeline Control System	0	0	0	0	0	0	0
923,433	Pumps	0	0	0	0	0	0	0
3,696,848	Contingency	0	0	0	0	0	0	0
	Operating Expenses in Real 2028$							
17,791,665	Pipeline fixed O&M	593,056	593,056	593,056	593,056	593,056	593,056	593,056
3,711,468	Pipeline related equipment and pumps fixed O&M	123,716	123,716	123,716	123,716	123,716	123,716	123,716
9,078,160	Electricity costs for pumps (variable O&M)	302,605	302,605	302,605	302,605	302,605	302,605	302,605
28,342,501	Total Investment (capital expenses or Capex) in real 2028$	0	0	0	0	0	0	0
30,581,293	Project Expenses (operating expenses or Opex) in real 2028$	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376	1,019,376

Table 5 (continued)	Operating Expenses, Capital Expenses and Depreciation and Amortization							
	Escalated Costs							
	Capital Costs in escalated $							
3,120,777	Materials	150,793	1,234,087	1,735,897	0	0	0	0
14,232,540	Labor	687,701	5,628,147	7,916,692	0	0	0	0
1,535,647	ROW-Damages	833,044	464,838	237,765	0	0	0	0
3,347,796	Miscellaneous	980,479	1,170,201	1,197,116	0	0	0	0
2,078,436	CO2 Surge Tanks	0	203,628	1,874,807	0	0	0	0
186,859	Pipeline Control System	0	18,307	168,552	0	0	0	0
957,708	Pumps	0	377,869	579,840	0	0	0	0
3,818,964	Contingency	397,802	1,364,562	2,056,600	0	0	0	0
	Operating Expenses in escalated $							
27,003,476	Pipeline fixed O&M	0	0	0	634,925	649,528	664,467	679,750
5,633,117	Pipeline related equipment and pumps fixed O&M	0	0	0	132,450	135,496	138,613	141,801
13,778,467	Electricity costs for pumps (variable O&M)	0	0	0	323,969	331,420	339,043	346,841
29,278,727	Total Investment (capital expenses or Capex) in escalated $	3,049,818	10,461,639	15,767,270	0	0	0	0
46,415,059	Project Expenses (operating expenses or Opex) in escalated $	0	0	0	1,091,344	1,116,444	1,142,123	1,168,391
	Escalated and Discounted Costs (only used for reporting purposes)							
26,152,597	Total Investment (capital expenses or Capex) in present value $	3,049,818	9,659,818	13,442,961	0	0	0	0
12,701,768	Project Expenses (operating expenses or Opex) in present value $	0	0	0	859,150	811,548	766,582	724,109
	Depreciation							
29,278,727	Total Capital Costs in escalated dollars	3,049,818	10,461,639	15,767,270	0	0	0	0
29,278,727	Total Capital Costs in escalated $ before pipeline operations begin	3,049,818	10,461,639	15,767,270	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	0.00%	0.00%	0.00%	5.00%	9.50%	8.55%	7.70%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	0.00%	0.00%	0.00%	3.33%	6.67%	6.67%	6.67%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	0.00%	0.00%	0.00%	2.27%	4.55%	4.55%	4.55%
29,278,727	Depreciation Schedule (150% declining balance, 15 year recov. per.)	0	0	0	1,463,936	2,781,479	2,503,331	2,254,462

Table 5 (continued)	Operating Expenses, Capital Expenses and Depreciation and Amortization							
	Escalated Costs							
	Capital Costs in escalated $							
3,120,777	Materials	0	0	0	0	0	0	0
14,232,540	Labor	0	0	0	0	0	0	0
1,535,647	ROW-Damages	0	0	0	0	0	0	0
3,347,796	Miscellaneous	0	0	0	0	0	0	0
2,078,436	CO2 Surge Tanks	0	0	0	0	0	0	0
186,859	Pipeline Control System	0	0	0	0	0	0	0
957,708	Pumps	0	0	0	0	0	0	0
3,818,964	Contingency	0	0	0	0	0	0	0
	Operating Expenses in escalated $							
27,003,476	Pipeline fixed O&M	695,384	711,378	727,740	744,478	761,601	779,117	797,037
5,633,117	Pipeline related equipment and pumps fixed O&M	145,062	148,399	151,812	155,303	158,875	162,529	166,268
13,778,467	Electricity costs for pumps (variable O&M)	354,818	362,979	371,328	379,868	388,605	397,543	406,687
29,278,727	Total Investment (capital expenses or Capex) in escalated $	0	0	0	0	0	0	0
46,415,059	Project Expenses (operating expenses or Opex) in escalated $	1,195,265	1,222,756	1,250,879	1,279,649	1,309,081	1,339,190	1,369,991
	Escalated and Discounted Costs (only used for reporting purposes)							
26,152,597	Total Investment (capital expenses or Capex) in present value $	0	0	0	0	0	0	0
12,701,768	Project Expenses (operating expenses or Opex) in present value $	683,988	646,091	610,293	576,478	544,538	514,367	485,867
	Depreciation							
29,278,727	Total Capital Costs in escalated dollars	0	0	0	0	0	0	0
29,278,727	Total Capital Costs in escalated $ before pipeline operations begin	0	0	0	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	6.93%	6.23%	5.90%	5.90%	5.91%	5.90%	5.91%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	6.67%	6.67%	6.67%	6.66%	6.67%	6.66%	6.67%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%
29,278,727	Depreciation Schedule (150% declining balance, 15 year recov. per.)	2,029,016	1,824,065	1,727,445	1,727,445	1,730,373	1,727,445	1,730,373

Table 5 (continued)	Operating Expenses, Capital Expenses and Depreciation and Amortization						
	Escalated Costs						
	Capital Costs in escalated $						
3,120,777	Materials	0	0	0	0	0	0
14,232,540	Labor	0	0	0	0	0	0
1,535,647	ROW-Damages	0	0	0	0	0	0
3,347,796	Miscellaneous	0	0	0	0	0	0
2,078,436	CO2 Surge Tanks	0	0	0	0	0	0
186,859	Pipeline Control System	0	0	0	0	0	0
957,708	Pumps	0	0	0	0	0	0
3,818,964	Contingency	0	0	0	0	0	0
	Operating Expenses in escalated $						
27,003,476	Pipeline fixed O&M	815,369	834,123	853,307	872,933	893,011	913,550
5,633,117	Pipeline related equipment and pumps fixed O&M	170,092	174,004	178,006	182,100	186,288	190,573
13,778,467	Electricity costs for pumps (variable O&M)	416,040	425,609	435,398	445,412	455,657	466,137
29,278,727	Total Investment (capital expenses or Capex) in escalated $	0	0	0	0	0	0
46,415,059	Project Expenses (operating expenses or Opex) in escalated $	1,401,501	1,433,736	1,466,712	1,500,446	1,534,956	1,570,260
	Escalated and Discounted Costs (only used for reporting purposes)						
26,152,597	Total Investment (capital expenses or Capex) in present value $	0	0	0	0	0	0
12,701,768	Project Expenses (operating expenses or Opex) in present value $	458,947	433,518	409,498	386,809	365,378	345,133
	Depreciation						
29,278,727	Total Capital Costs in escalated dollars	0	0	0	0	0	0
29,278,727	Total Capital Costs in escalated $ before pipeline operations begin	0	0	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	5.90%	5.91%	5.90%	5.91%	2.95%	0.00%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	6.66%	6.67%	6.66%	6.67%	3.33%	0.00%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%
29,278,727	Depreciation Schedule (150% declining balance, 15 year recov. per.)	1,727,445	1,730,373	1,727,445	1,730,373	863,722	0

Table 5 (continued)	**Operating Expenses, Capital Expenses and Depreciation and Amortization**						
	Escalated Costs						
	Capital Costs in escalated $						
3,120,777	Materials	0	0	0	0	0	0
14,232,540	Labor	0	0	0	0	0	0
1,535,647	ROW-Damages	0	0	0	0	0	0
3,347,796	Miscellaneous	0	0	0	0	0	0
2,078,436	CO2 Surge Tanks	0	0	0	0	0	0
186,859	Pipeline Control System	0	0	0	0	0	0
957,708	Pumps	0	0	0	0	0	0
3,818,964	Contingency	0	0	0	0	0	0
	Operating Expenses in escalated $						
27,003,476	Pipeline fixed O&M	934,562	956,057	978,046	1,000,541	1,023,554	1,047,095
5,633,117	Pipeline related equipment and pumps fixed O&M	194,956	199,440	204,027	208,720	213,521	218,432
13,778,467	Electricity costs for pumps (variable O&M)	476,858	487,826	499,046	510,524	522,266	534,278
29,278,727	Total Investment (capital expenses or Capex) in escalated $	0	0	0	0	0	0
46,415,059	Project Expenses (operating expenses or Opex) in escalated $	1,606,376	1,643,323	1,681,119	1,719,785	1,759,340	1,799,805
	Escalated and Discounted Costs (only used for reporting purposes)						
26,152,597	Total Investment (capital expenses or Capex) in present value $	0	0	0	0	0	0
12,701,768	Project Expenses (operating expenses or Opex) in present value $	326,011	307,947	290,885	274,768	259,544	245,164
	Depreciation						
29,278,727	Total Capital Costs in escalated dollars	0	0	0	0	0	0
29,278,727	Total Capital Costs in escalated $ before pipeline operations begin	0	0	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	4.55%	4.55%	4.55%	4.55%	4.55%	2.27%
29,278,727	Depreciation Schedule (150% declining balance, 15 year recov. per.)	0	0	0	0	0	0

Table 5 (continued)	**Operating Expenses, Capital Expenses and Depreciation and Amortization**							
	Escalated Costs							
	Capital Costs in escalated $							
3,120,777	Materials	0	0	0	0	0	0	0
14,232,540	Labor	0	0	0	0	0	0	0
1,535,647	ROW-Damages	0	0	0	0	0	0	0
3,347,796	Miscellaneous	0	0	0	0	0	0	0
2,078,436	CO2 Surge Tanks	0	0	0	0	0	0	0
186,859	Pipeline Control System	0	0	0	0	0	0	0
957,708	Pumps	0	0	0	0	0	0	0
3,818,964	Contingency	0	0	0	0	0	0	0
	Operating Expenses in escalated $							
27,003,476	Pipeline fixed O&M	1,071,178	1,095,816	1,121,019	1,146,803	1,173,179	1,200,162	1,227,766
5,633,117	Pipeline related equipment and pumps fixed O&M	223,455	228,595	233,853	239,231	244,734	250,362	256,121
13,778,467	Electricity costs for pumps (variable O&M)	546,567	559,138	571,998	585,154	598,612	612,380	626,465
29,278,727	Total Investment (capital expenses or Capex) in escalated $	0	0	0	0	0	0	0
46,415,059	Project Expenses (operating expenses or Opex) in escalated $	1,841,200	1,883,548	1,926,870	1,971,188	2,016,525	2,062,905	2,110,352
	Escalated and Discounted Costs (only used for reporting purposes)							
26,152,597	Total Investment (capital expenses or Capex) in present value $	0	0	0	0	0	0	0
12,701,768	Project Expenses (operating expenses or Opex) in present value $	231,580	218,749	206,629	195,180	184,366	174,151	164,501
	Depreciation							
29,278,727	Total Capital Costs in escalated dollars	0	0	0	0	0	0	0
29,278,727	Total Capital Costs in escalated $ before pipeline operations begin	0	0	0	0	0	0	0
100.00%	Depreciation factors (MACRS GDS 150% Declining Balance; 15 year recov. Per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100.00%	Depreciation factors (MACRS GDS Straight Line; 15 year recov. per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100.00%	Depreciation factors (MACRS ADS Straight Line; 22 year recov. per.)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29,278,727	Depreciation Schedule (150% declining balance, 15 year recov. per.)	0	0	0	0	0	0	0