Statement of Basis
Greenhouse Gas Prevention of Significant Deterioration Pre-Construction Permit
for the Sinclair Wyoming Refining Company,
Sinclair Refinery

Permit Number: PSD-WY-000002-2011.001

March 21, 2013

This document serves as the Statement of Basis (SOB) required by 40 CFR 124.7. This document sets forth the legal and factual basis for permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, and 40 CFR 52.37 (Federal Implementation Plan (FIP) to issue permits under the Prevention of Significant Deterioration (PSD) requirements to sources that emit greenhouse gases). This document is intended for use by all parties interested in the permit.

I.   Executive Summary

On October 18, 2011, Sinclair Wyoming Refining Company (Sinclair) submitted to the Environmental Protection Agency Region 8 (EPA) a PSD permit application for Greenhouse Gas (GHG) emissions associated with the modification and construction of their oil refinery located in Sinclair, Wyoming. In connection with the same proposed project, Sinclair submitted a PSD permit application for non-GHG pollutants to the Wyoming Department of Environmental Quality (WDEQ) Air Quality Division (AQD) on October 10, 2011. The proposed modifications of existing emission units include modifying the existing 581 Crude Unit, 583 Vacuum Unit, the Coker Unit Flare, the #1 HDS Heater, the Naphtha Splitter Heater, and the Hydrocracker H5 Heater. The action would also permit the installation of a new BSI Heater, New Emergency Air Compressor, and additional fugitive emission components through increased crude oil throughput. After reviewing the application, EPA prepared the following SOB and New Source Review (NSR)/PSD pre-construction air permit to authorize construction of GHG air emission sources at the Sinclair refinery.

In addition to the original October 18, 2011 submittal, Sinclair submitted supplemental information dated December 23, 2011 and May 21, 2012 (document is mis-dated as May 21, 2011 but was received by EPA on May 29, 2012).

This SOB documents the information and analysis EPA used to support decisions made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA concludes that Sinclair's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable PSD air permit regulations for GHGs. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Sinclair, and EPA's own technical analysis. EPA is making all of this information available as part of the public record.

II.   Applicant

Sinclair Wyoming Refining Company
P.O. Box 277
Sinclair, Wyoming 82334

Physical Location:
Sinclair Wyoming Refining Company
Section 21, Township 21 North, Range 86 West (100 East Lincoln Highway, Sinclair, Wyoming)
Latitude: 41° 46' 36.2" North
Longitude: 107° 06' 28.0" West
Sinclair, Carbon County, Wyoming

Operator: Sinclair Wyoming Refining Company
Owner: Sinclair Wyoming Refining Company
Responsible Official: Mike Achacoso, Refinery Manager, 307-324-3404
Alternate: John Pfeffer, Environmental Manager, 307-328-3548
Permit Contact: John Pfeffer, Environmental Manager, 307-328-3548

III.   Permitting Authority

On December 30, 2010, EPA published a FIP making EPA the GHG PSD permitting authority for states that do not have the authority to implement GHG PSD permitting. 75 FR 82246 (promulgating 40 CFR 52.37). Wyoming still retains approval of its State Implementation Plan (SIP) PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD permitting authority for the state of Wyoming is:

EPA, Region 8
1595 Wynkoop St.
Denver, CO 80202

Permit Author:
Donald Law
Air Permitting Monitoring and Modeling Unit (8P-AR)
(303) 312-7015

The non-GHG PSD permitting authority for the state of Wyoming is:

Air Quality Division
Wyoming Dept. of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

IV.   Public Notice, Comment, Hearings and Appeals

Public notice for the draft PSD GHG permit was published on September 1, 2012, in the Rawlins Daily Times. The public comment period began on September 1, 2012 and closed on October 1, 2012. During the public comment period, the public was given the opportunity to review a copy of the permit application, the draft permit prepared by EPA, the SOB, and permit-related correspondence. The draft permit, SOB, and Administrative Record for the draft permit were available for review at EPA Region 8's office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). The permit application, draft permit and SOB was also available for review on EPA's website at http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading. A hardcopy of these documents was available for review at the Carbon County Clerk's Office in Rawlins, Wyoming, Monday through Friday from 8:00 a.m. to 5:00 p.m. until the close of the public comment period.

In accordance with 40 CFR 52.21(q), *Public participation*, any interested person is afforded the opportunity to submit written comments on the draft permit during the public comment period and to request a hearing. A public hearing was held for this action on September 17, 2012 from 7:00 p.m. to 8:30 p.m. in the Council Chambers at the Sinclair Town Clerk. The purpose of the hearing was to gather comments concerning the issuance of the EPA GHG PSD permit. The scope of the hearing was limited to such issues in order for the EPA to determine whether or not the applicable PSD Regulations have been appropriately applied to the modification, construction and operation of the proposed oil refinery. Oral statements were accepted at the time of the hearing. Since the EPA was not the permitting authority for the remainder of the NSR pollutants there was a hearing held prior to the EPA GHG permit hearing from 5:00 p.m. to 7:30 p.m. on September 17, 2012 in the Council Chambers at the Sinclair Town Clerk regarding the WDEQ draft PSD permit. All comments regarding pollutants other than GHGs from the proposed facility had to be submitted to the WDEQ.

In accordance with 40 CFR 124.15, *Issuance and Effective Date of Permit*, the permit shall become effective immediately upon issuance as a final permit. Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice of the final permit decision.

In accordance with 40 CFR 124.19, *Appeal of RCRA, UIC, NPDES and PSD Permits*, any person who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board, within 30 days after the final permit decision, to review any condition of the permit decision. Any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review only to the extent of changes from the draft to the final permit decision.

V.   Facility Location

The Sinclair refinery is located in Carbon County, Wyoming, which is currently considered to be in attainment for all of the National Ambient Air Quality Standards (NAAQS). The nearest federal Class 1 area is Rocky Mountain National Park, which is located approximately 60 miles southeast from the proposed site. Savage Run Wilderness Area is a Class I area recognized by the state of Wyoming located

approximately 83 miles west from the proposed site. The geographic coordinates for this facility are as follows:

> Latitude: 41° 46' 36.2" North
> Longitude: 107° 06' 28.0" West

VI. Applicability of Prevention of Significant Deterioration (PSD) Regulations

Under EPA's Clean Air Act permitting rules, the term "greenhouse gas" means an air pollutant consisting of the aggregate of six gases with atmospheric warming potential: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). GHG emissions can be measured using a "CO_2-equivalent" (CO_2e), which is determined by multiplying the mass emissions of each of these gases, in tons per year (tpy), by its respective Global Warming Potential (GWP) and summing the result. See 40 CFR 52.21(b)(49)(ii). The GWPs used in developing and issuing this permit are 1.0 for CO_2, 21 for CH_4, 310 for N_2O, and 23,900 for SF_6 (from 40 CFR 98, Table A-1, as of the date of permit issuance). No emissions of HFCs, SF_6, or PFCs are expected from this project.

EPA concludes that Sinclair's application is subject to PSD review for GHG, because the project would lead to a net increase of GHG emissions as described at 40 CFR 52.21(b)(23) and (49)(iv) and (v). The proposed project emissions would result in increased GHG emissions above the PSD modification threshold of zero tpy on a mass basis and 75,000 tpy on a CO_2e basis. Sinclair has presented CO_2e potential emissions from modified and new emission sources of 359,915 tpy CO_2e. The potential GHG emissions from these sources on a mass basis are 358,524 tpy.

EPA is the permitting authority responsible for implementing a GHG PSD FIP for Wyoming under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). See 40 CFR 52.37. As the permitting authority for regulated NSR pollutants other than GHGs, WDEQ has determined the proposed new source is subject to PSD review for non-GHG pollutants. Specifically, the PSD application submitted to WDEQ explains the proposed facility will be a major modification to an existing source. Accordingly, WDEQ will issue the non-GHG portion of the PSD permit and EPA will issue the GHG portion.[1]

EPA applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) (Guidance), available on EPA website at: www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf. Consistent with the Guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, since there are no ambient air quality standards for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the Best Available Control Technology (BACT) analysis is the best technique that can be employed, at present, to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from WDEQ.

---

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting authorities (April 19, 2011).
Available online at: http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf.

For a description of the five-step process involved in making a PSD BACT determination for GHGs, please refer to the aforementioned Guidance. EPA has followed those steps in making the GHG BACT determination for this project.

VII. Project Description

Sinclair proposes to increase the crude refining capacity and implement other miscellaneous projects, as described below, at its Sinclair, Wyoming oil refinery. The crude optimization project consists of the following: 1) removal of the 581 Crude unit heater firing limit rate and replacement of the 581 Crude Unit atmospheric distillation tower; 2) modification of the 283 Vacuum Tower to accommodate an increase in reduced crude feedstock from the debottlenecked 581 Crude Unit; and 3) allowing the combustion of sweetened refinery fuel gas in the Coker Flare to accommodate potential periods when the refinery may have to operate in a fuel gas imbalance condition. In addition and unrelated to the increase in crude oil refining capacity, the following projects will be covered by this permit: 1) removal of the firing limits for the #1 HDS heater, Naphtha Splitter heater and Hydrocracker H5 heater so that these units will be able to fire at their design maximum rates; 2) installation of a new Naphtha Splitter and BSI Unit to provide capacity to reduce benzene content in gasoline product to meet the specification of the February 2007 Mobile Sources Air Toxics II rule; 3) upgrade of the refinery's sour water stripping system which includes increasing the capacity of the existing system and installation of an additional sour water stripper; and 4) installation of a new emergency air compressor to supply instrument air to the refinery in the event of a power failure.

Table 1 – Potential to Emit for Sinclair New Emission Sources

Operating Unit	Description	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
BSI	BSI Heater – 50.0 MMBtu/hr	31,842.6	1.4	0.3	31,962.6
Tank Farm	100 Mbbl tank	N/A	Insignificant	N/A	Insignificant
Boilerhouse	New Emergency Air Compressor	114.1	<0.1	<0.1	114.5
Equipment Leaks	Fugitive Emission Sources	N/A	1.9	N/A	40.8
TOTALS		31,956.7	3.3	0.3	32,177.9

Table 2 – Potential to Emit for Sinclair Modified Emission Sources

Operating Unit	Description	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
581 Crude Unit	581 Crude Heater – 233 MMBtu/hr	148,386.5	6.7	1.3	148,945.6
583 Vacuum Unit	583 Vacuum Heater – 64.2 MMBtu/hr	40,885.9	1.9	0.4	41,039.9
Coker	Coker Unit Flare– 100.0 MMBtu/hr	57,921.1	2.9	0.6	58,161.1[1]
781 Reformer	Naphtha Splitter Heater– 46.3 MMBtu/hr	29,486.2	1.3	0.3	29,597.3
Hydrocracker	Hydrocracker H5 Heater– 44.9 MMBtu/hr	28,594.7	1.3	0.3	28,702.4
#1 HDS	#1 HDS Heater - 33.4 MMBtu/hr	21,270.9	1.0	0.2	21,351.0
TOTALS		326,545.3	15.1	3.1	327,797.3

1. Emissions from the Coker Unit Flare are based upon emissions from assist gas and pilot emissions only.

Table 3 – Potential to Emit for Sinclair Non-Modified Emission Sources

Operating Unit	Description	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
781 Reformer	LEF Heater – 24 MMBtu/hr	15,284.4	0.7	0.1	15,342.0
	#1 Reformer Heater – 44.6 MMBtu/hr	28,403.6	1.3	0.3	28,510.6
	#2 Reformer Heater – 74.8 MMBtu/hr	47,636.5	2.2	0.4	47,816.0
	#3 Reformer Heater – 11.1 MMBtu/hr	14,265.5	0.6	0.1	14,319.2
	Stabilizer Heater – 74.8 MMBtu/hr	7,069.1	0.3	<0.1	7,095.7
Hydrocracker	Heater H1/H2 – 38.0 MMBtu/hr	24,200.4	1.1	0.2	24,291.6
	Heater H3 – 56.0 MMBtu/hr	35,633.7	1.6	0.3	35,798.1
	Heater H4 – 57.0 MMBtu/hr	36,300.6	1.6	0.3	36,473.3
Coker	Coker Heater – 145.0 MMBtu/hr	92,343.5	4.2	0.8	92,691.4
	Coker (Material Handling)	N/A	N/A	N/A	N/A
780 FCCU	780 FCCU Heater B3 – 10 MMBtu/hr	6,368.5	0.3	<0.1	6,392.5
	780 FCCU Heater H2 – 19.4 MMBtu/hr	12,354.9	0.6	0.1	12,401.5
	780 FCCU Regenerator – N/A	235,738.0	25.3	3.7	237,411.5
#2 HDS	Charge Heater – 28.0 MMBtu/hr	17,831.9	0.8	0.2	17,899.0
#3 HDS	Charge Heater – 18.0 MMBtu/hr	11,463.3	0.5	0.1	11,506.5
#4 HDS	H2 Heater (25-HT-101) – 22.0 MMBtu/hr	14,010.7	0.6	0.2	14,063.5
	H2 Heater (25-HT-101) – 24.0 MMBtu/hr	15,284.4	0.7	0.2	15,342.0
#1 H2 Plant	#1 H2 Plant Heater – 288.0 MMBtu/hr	183,413.4	8.3	8.3	184,104.4
#2 H2 Plant	#2 H2 Plant Heater – 288.0 MMBtu/hr	183,413.4	8.3	1.7	184,104.4
#1, #2, #3, #4 SRU	#1, #3, #4 TGTU	17,086.7	0.9	0.2	17,158.7
Asphalt Loading	Asphalt Heater #1 – 8 MMBtu/hr	5,094.8	0.2	<0.1	5,114.0

Tank Farm	Working Losses - aggregate	N/A	N/A	Insignificant	Insignificant
Light Oil Loading	Loading rack Flare	733.4	1.2	<0.1	762.9
TOTALS		1,003,960.8	61.4	17.3	1,008,562.9

VIII. BACT Analysis

The BACT analysis provided by the applicant included the assumptions described below, which have been considered and adopted, with some modifications, by EPA in its own BACT analysis.

1. Tables 1, 2, and 3 above present estimated Sinclair GHG emissions in terms of CO_2e emissions, and only include emissions of CO_2, CH_4, and N_2O. The project is not expected to emit HFCs, PFCs, or SF6.

2. Emission units 581 Crude Heater, 583 Vacuum Heater, #1 HDS Heater, Naphtha Splitter Heater, Hydrocracker H5 Heater, BSI Heater, for the discussion of BACT, are grouped into a process heater subcategory.

A. Process Heaters CO_2 Emissions

Step 1 Identify Potential Control Technologies

CO_2 will be emitted from the 581 Crude Heater, 583 Vacuum Heater, #1 HDS Heater, Naphtha Splitter Heater, Hydrocracker H5 Heater, and BSI Heater (process heaters) because it is a combustion product of any carbon-containing fuel. All fossil fuels contain significant amounts of carbon, but the refinery fuel gas and natural gas combusted in these heaters are low carbon fuels. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because full combustion releases more useful energy within the process. CO_2 emissions are generated and emitted from the process heaters and exhausted to the atmosphere from a stack at the refinery.

The following technologies were identified as CO_2 control options for refinery process heaters based on available information and data sources. Review of the RACT/BACT/LAER Clearinghouse (RBLC) did not reveal any additional control options.

- Post-Combustion Carbon Capture and Storage (CCS),
- Pre-Combustion CCS,
- Energy efficient design,
- Use of good combustion practices, and
- Use of low carbon fuels.

Post-Combustion Carbon Capture and Storage

Post-combustion carbon capture for fuel gas combustion is applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases. Because the air used for combustion contains approximately 79% nitrogen and because the refinery fuel gas is a lower-carbon fuel, the CO_2 concentration in the exhaust gases is approximately 10%. There are a number of methods and processes that could be used to capture CO_2 from the dilute exhaust gases produced by the process heaters. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO_2, and membrane separation technologies. In order to provide effective reduction of CO_2 emissions methods of compression, transport, and storage would also be required. This would require transporting the captured CO_2 to a suitable geological storage formation including the following: depleted oil and gas reservoirs, unmineable coal seams, Saline formations, basalt formations, and terrestrial ecosystems.

Separation With Solvent Scrubbers

There are many solvents under development for the separation of CO_2 from combustion of flue gases through chemical absorption. The most commercially developed of these processes use monoethanolamine (MEA) as the solvent. MEA has the advantage of fast reaction with CO_2 at low partial pressure. The primary concern with MEA is corrosion in the presence of O_2 and other impurities, high solvent degradation rates due to reactions with SO_2 and NOx, and the energy requirements for solvent regeneration. To minimize the issue of reacting with SO_2 and NOx, these impurities must be removed from the exhaust gas prior to separation.

Separation With Physical Absorption Media

Available physical absorption processes include carbonaceous sorbents such as activated carbon, charcoal, or coal materials, as well as aluminosilicate materials such as Zeolite13X. The use of physical absorption for CO_2 capture would entail significant gas compression, resulting in high energy use. These separation technologies have not yet been tested or demonstrated in a large scale project such as the process heaters at an oil refinery.

Extensive research work is ongoing evaluating the use of solid sorbents for post-combustion CO_2 capture that may have lower costs relative to other systems. For example, the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has developed research into the use of solid sorbents in post-combustion CO_2 capture. Possible configurations include fixed, moving, and fluidized beds.

Cryogenic Separation

The cryogenic CO_2 capture process includes the following steps: dry and cool the combustion flue gas, compress the flue gas, further cool the compressed flue gas by expansion which precipitates the CO_2 as a solid, pressurize the CO_2 to a liquid; and reheat the CO_2 and remaining flue gas by cooling the incoming flue gases.

9

The final result is the CO_2 in a liquid phase and a gaseous nitrogen stream that can be vented through a gas turbine for power generation. Currently, Sinclair does not have a gas turbine for power generation at the Wyoming facility.

Membrane Separation

This method is commonly used for CO_2 removal from natural gas at high pressure and high CO_2 concentration. Membrane-based capture uses permeable or semi-permeable materials that allow for selective transport/separation of CO_2 from flue gas.

Pre-Combustion Carbon Capture and Storage

Pre-combustion carbon capture for fuel gas combustion involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO_2 exhaust stream. The oxygen may be isolated from air using a number of technologies, including cryogenic separation and membrane separation. This "oxyfuel" process has not yet been tested or demonstrated in a large-scale project such as the process heaters at a petroleum refinery. In order to provide effective reduction of CO_2 emissions methods of compression, transport, and storage would also be required. This would require transporting the captured CO_2 to a suitable geological storage formation including the following: depleted oil and gas reservoirs, unmineable coal seams, saline formations, basalt formations, and terrestrial ecosystems.

Energy Efficient Design

Sinclair cited the use of combustion air preheat, use of process heat to generate steam, process integration and heat recovery and use of excess combustion air monitoring and control and using cogeneration as ways to use energy efficient design for process heaters. These techniques and applications of technology would minimize the required fuel combustion for process heat.

Use of Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas cited in the BACT analysis include the following: good air/fuel mixing in the combustion zone, sufficient residence time to complete combustion, proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality, good burner maintenance and operation, high temperatures and low oxygen levels in the primary combustion zone, and overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

10

Use of Low Carbon Fuels

The following table presents the amount of CO_2 formed when combusting fossil fuels, including some of the fuels that will be used by the new and modified heaters at Sinclair.

Table 4 – Default CO_2 Emission Factors by Fuel Type
(extracted from 40 CFR part 98, Subpart C, Table C-1)

Fuel type	Default CO_2 emission factor (Kg/MMBtu)
Coke Oven Gas	46.85
Biogas (Captured methane)	52.07
Natural Gas (Weighted U.S. Average)	53.02
Fuel Gas	59
Propane	61.46
Propane Gas	61.46
Ethane	62.64
Liquefied petroleum gases (LPG)	62.98
Isobutane	64.91
Butane	65.15
Propylene	65.95
Natural Gasoline	66.83
Ethylene	67.43
Butylene	67.73
Isobutylene	67.74
Naphtha (<401 deg F)	68.02
Ethanol	68.44
Ethanol	68.44
Aviation Gasoline	69.25
Pentanes Plus	70.02
Motor Gasoline	70.22
Petrochemical Feedstocks	70.97
Rendered Animal Fat	71.06
Kerosene-Type Jet Fuel	72.22
Special Naphtha	72.34
Residual Fuel Oil No. 5	72.93
Distillate Fuel Oil No. 1	73.25
Biodiesel	73.84

11

Biodiesel (100%)	73.84
Distillate Fuel Oil No. 2	73.96
Used Oil	74
Lubricants	74.27
Unfinished Oils	74.49
Crude Oil	74.49
Heavy Gas Oils	74.92
Plastics	75
Distillate Fuel Oil No. 4	75.04
Residual Fuel Oil No. 6	75.1
Kerosene	75.2
Asphalt and Road Oil	75.36
Other Oil (>401 deg F)	76.22
Vegetable Oil	81.55
Tires	85.97
Municipal Solid Waste	90.7
Bituminous - Coal	93.4
Mixed (Industrial coking) - Coal and coke	93.65
Wood and Wood Residuals - solid fuel	93.8
Mixed (Industrial sector) - Coal and coke	93.91
Mixed (Electric Power sector) - Coal and coke	94.38
Mixed (Commercial sector) - Coal and coke	95.26
Lignite – Coal	96.36
Subbituminous – Coal	97.02
Coke	102
Petroleum Coke	102.4
Petroleum Coke	102.4
Anthracite Coal	103.5
Biomass Solid Byproducts	105.5
Peat - solid fuel	111.8
Agricultural Byproducts - solid fuel	118.2
Blast Furnace Gas	274.3

As shown in table 4, the use of refinery fuel gas (listed as fuel gas – 59 kg/MMBtu) generates lower quantities of CO_2 from combustion relative to burning solid fuels (e.g. bituminous coal – 93.4 kg/MMBtu or petroleum coke -102.4 kg/MMBtu) and liquid fuels (i.e., distillate fuel oil no. 4 – 75.04 kg/MMBtu or residual fuel oil no. 5 – 72.93 kg/MMBtu).

Step 2 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration technically infeasible options. EPA does not generally consider a control technology to be technically feasible unless it is either (1) demonstrated and operated on the source type under review, or (2) both available and applicable to the source type under review (PSD and Title V Permitting Guidance for Greenhouse Gases, at Page 33 (March 2011)). To be considered "available," a technology should be able to be obtained through commercial channels. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration.

A number of the processes in the following sections have not yet been tested or demonstrated in a large-scale project such as the process heaters at a petroleum refinery. However, for the purpose of this BACT analysis it is assumed that these technologies would be technically feasible and the following descriptions are provided for additional background.

Post-Combustion CO₂ Capture for New and Modified Process Heaters

There are a number of methods and processes that could be used to capture CO_2 from the dilute exhaust gases produced by the process heaters. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO_2, and membrane separation technologies. These technologies are discussed below.

Separation with Solvent Scrubbers -Technically Feasible

There are many solvents under development for the separation of CO_2 from combustion of flue gases through chemical absorption. The most commercially developed of these processes uses MEA as the solvent. MEA has the advantage of fast reaction with CO_2 at low partial pressure. The primary concern with MEA is corrosion in the presence of O_2 and other impurities, high solvent degradation rates due to reactions with SO_2 and NOx, and the energy requirements for solvent regeneration. To minimize the issue of reacting with SO_2 and NOx, these impurities must be removed from the exhaust gas prior to separation.

Because the Sinclair process heaters are fired exclusively with refinery fuel gas, it is anticipated that MEA-based systems are technically feasible.

Separation with Physical Absorption Media -Technically Infeasible

Available physical absorption processes include carbonaceous sorbents such as activated carbon, charcoal, or coal materials, as well as aluminosilicate materials such as Zeolite 13X. The use of physical absorption for CO_2 capture would entail significant gas compression, resulting in high energy use. These separation technologies have not yet been tested or demonstrated in a large scale project such as the

process heaters at a petroleum refinery and therefore this option is considered technically infeasible for this analysis.

Extensive research work is ongoing evaluating the use of solid sorbents for post-combustion CO_2 capture that may have lower costs relative to other systems. For example, the DOE NETL has developed research into the use of solid sorbents in post-combustion CO_2 capture. Possible configurations include fixed, moving, and fluidized beds. However, these processes are the subject of current research, and have not been commercially developed. To date, there is insufficient data available to accurately complete cost analyses for this developmental technology, and therefore this option is considered technically infeasible for this analysis.

Cryogenic Separation -Technically Infeasible

The cryogenic CO_2 capture process includes the following steps: dry and cool the combustion flue gas, compress the flue gas, further cool the compressed flue gas by expansion which precipitates the CO_2 as a solid, pressurize the CO_2 to a liquid; and reheat the CO_2 and remaining flue gas by cooling the incoming flue gases.

The final result is the CO_2 in a liquid phase and a gaseous nitrogen stream that can be vented through a gas turbine for power generation. This process has not been commercially demonstrated on gas streams with low CO_2 concentrations such as the process heaters at a petroleum refinery, and therefore this option is considered technically infeasible for this analysis.

Membrane Separation -Technically Infeasible

This method is commonly used for CO_2 removal from natural gas at high pressure and high CO_2 concentration. Membrane-based capture uses permeable or semi-permeable materials that allow for selective transport/separation of CO_2 from flue gas. Membrane technology is not fully developed for CO_2 concentration and gas flow such as the process heaters at a petroleum refinery, and therefore this option is considered technically infeasible for this analysis.

Pre-Combustion CO_2 Capture for New and Modified Process Heaters - Technically Feasible

The pre-combustion technique for CO_2 separation involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO_2 exhaust stream. The oxygen may be isolated from air using a number of technologies, including cryogenic separation and membrane separation. This "oxyfuel" process has not yet been tested or demonstrated in a large-scale project such as the process heaters at a petroleum refinery. However, in its proposed BACT analysis, Sinclair assumed for the sake of the analysis that the oxyfuel technology would be technically feasible.

Carbon Transport and Storage -Technically Feasible

There are available technically feasible methods for compression, transport, and storage of concentrated CO_2 streams. Options for capturing emissions from process heaters fired with refinery fuel gas, which would be required as an element of CCS as a GHG emission control option, were discussed in the preceding sections.

14

For the purpose of this BACT analysis, it is assumed that carbon transport and storage technologies are technically feasible.

Energy Efficient Design - Technically Infeasible for 581 Crude Unit, 781 Reformer, and BSI Heater/Technically Feasible for 583 Vacuum Unit Heater, Hydrocracker Heater H5, and #1HDS Heater

Sinclair cited the use of combustion air preheat, use of process heat to generate steam, process integration and heat recovery, use of excess combustion air monitoring and control and using cogeneration as ways to use energy efficient design for process heaters. These techniques and applications of technology would minimize the required fuel combustion for process heat. Energy efficient design has been demonstrated on process heaters fired with refinery fuel gas and is available at the 583 Vacuum Unit Heater, Hydrocracker Heater H5, and #1HDS Heater.

The 581 Crude Heater is the largest of the new and modified heaters and the flue gas from the 581 Crude Heater is currently used to generate steam from waste heat of combustion. The use of the flue gas to generate steam significantly reduces the flue gas temperature after steam generation such that the further use of the flue gas in an air preheater is technically infeasible. Recovering heat from the flue gas to generate steam also accomplishes the same GHG emission minimization goal as recovering heat to preheat combustion air in that the steam generated from recovered heat will result in a decrease in steam production (and GHG emissions) at the Sinclair refinery boilerhouse. Therefore, combustion air preheat is technically infeasible at the 581 Crude Heater.

Flue gas temperatures between 1000 °F and 1600 °F are generally the best candidates for combustion air preheat design as they provide the necessary temperature approach for efficient heat exchange. At very low flue gas temperatures there is a tendency to condense moisture and acids present in the flue gas which leads to equipment corrosion problems. Typically a minimum stack temperature in the 300 °F range is acceptable to avoid these problems. However, because the wintertime ambient temperature at Sinclair can drop as low as -40 °F, Sinclair's internal practice is to maintain a minimum flue gas temperature in the 400 °F range. This practice has been established because there is a potential for surfaces in the stack which contact flue gas to approach the condensation temperatures, particularly in stagnant non-uniformly heated zones. Sinclair believes this practice is necessary to avoid these unnecessary corrosion problems.

In order to evaluate the technical feasibility of combustion air preheat for the 781 Reformer Naphtha Splitter Heater and BSI Heater, Sinclair reviewed recent stack testing results including flue gas temperatures measured. The stack temperature for the 781 Reformer Naphtha Splitter Heater was measured to be in the 350 degree °F range which makes it technically infeasible for combustion air preheat. Moreover, attempting to remove additional heat from the 781 Reformer Naphtha Splitter Heater flue gas would further reduce the stack temperature and could result in other operational problems including flue gas condensation and equipment corrosion rendering it technically infeasible for a flue gas of this temperature. The stack temperature for the New BSI Heater was estimated to be less than 400 °F due a low 25 °F process fluid delta temperature across the heater. Moreover, attempting to remove additional heat from the New BSI Heater flue gas would further reduce the stack temperature

and could result in other operational problems including flue gas condensation and equipment corrosion rendering it technically infeasible for a flue gas of this temperature.

Therefore, combustion air preheat is technically infeasible at the 781 Reformer Heater and New BSI Heater.

Use of Good Combustion Practices -Technically Feasible

Good combustion practices for process heaters fired with refinery fuel gas cited in the BACT analysis include the following: good air/fuel mixing in the combustion zone, sufficient residence time to complete combustion, proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality, good burner maintenance and operation, high temperatures and low oxygen levels in the primary combustion zone, and overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency. Use of good combustion practices has been demonstrated on process heaters fired with refinery fuel gas and is available at this facility.

Use of Other Lower Carbon Fuels for New and Modified Process Heaters – Technically Infeasible

The process heaters at the refinery combust refinery fuel gas, which is a low carbon fuel. The only identified fuels with lower CO_2 formation rates are syngas, pressure swing adsorption ("PSA") tail gas, and natural gas. Production of additional syngas or PSA tail gas would lead to overall increases in GHG emissions from the refinery and do not represent options for reducing GHG emission. Natural gas is commercially available and would yield slightly reduced CO_2 emission rates from the process heaters, but displacing refinery fuel gas from use as fuel in the process heaters would necessitate disposal of this fuel gas by combustion elsewhere at the refinery, such as by flaring, which would increase overall refinery CO_2 emissions. Thus there are no control options involving the use of lower carbon fuels in process heaters that are technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

The following technologies and control efficiencies (where applicable) were identified as CO_2 control options for refinery process heaters based on available information and data sources.

- Post-Combustion CCS (assumed 93% control efficiency),
- Pre-Combustion CCS (assumed 87% control efficiency),
- Energy efficient design (% control efficiency is variable), and
- Use of good combustion practices (% control efficiency is variable).

Step 4 Evaluate the Most Effective Controls and Document Results

Post-Combustion Carbon Capture

For the purposes of the following analysis of CCS, chemical absorption using MEA based solvents is assumed to represent the best post-combustion CO_2 capture option, and the use of depleted oil and gas reservoirs with enhanced oil recovery (EOR) potential are assumed to represent the best option for long-term storage. This control option is assumed to be 93% effective. The CO_2 emissions increase from the new and modified process heaters are 268,717.3 tpy. The refinery process heaters are located throughout the refinery and as a result, multiple scrubbers would be installed in order to implement CO_2 separation with solvent scrubbers as it would be more cost effective than attempting to duct all of the flue gases into a single MEA scrubbing system. The CO_2 rich solvent from the scrubbers would then be pumped to a regeneration system for CO_2 removal and reuse. The CO_2 would need to be dried, compressed from low pressure up to 2,000 psi and transported by pipeline to an appropriate storage site.

The estimated capital cost for Post-Combustion Carbon Capture and Storage (post-CCS) including the equipment needed for capture, compression, pipeline transportation, and injection/storage is approximately $42.9 million. These estimated costs for post-CCS would represent greater than 71% of the $60,000,000 total estimated budgetary project cost for entire refinery modification project. EPA believes post-CCS is financially prohibitive for this project due to its overall cost as a GHG control strategy. Therefore, post-CCS does not represent BACT for the new and modified process heaters at Sinclair.

Pre-Combustion Carbon Capture ("Oxfuel")

The CO_2 emissions increases from the new a modified process heaters are 268,717.3 tons per year. The pre-combustion technique for CO_2 separation involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO_2 exhaust stream. The oxygen may be isolated from air using a number of technologies, including cryogenic separation and membrane separation. The concentrated CO_2 streams would then need to be dried, compressed from low pressure up to 2,000 psi and transported by pipeline to an appropriate storage site.

The estimated capital cost for Pre-Combustion Carbon Capture and Storage (pre-CCS) including the equipment needed for capture, compression, pipeline transportation, and injection/storage is approximately $54.1 million. These estimated costs for pre-CCS would represent greater than 90% of the $60,000,000 total estimated budgetary project cost for entire refinery modification project. EPA believes pre-CCS is financially prohibitive for this project due to its overall cost as a GHG control strategy. Therefore, pre-CCS does not represent BACT for the new and modified process heaters at Sinclair.

EPA believes CCS is financially prohibitive due to its overall cost as a GHG control strategy. Therefore, CCS does not represent BACT for the new and modified process heaters at Sinclair.

17

Impacts of Both CCS Options

In addition to the substantial economic impacts that show CCS is not a viable option for this project, the use of either Post-CCS or Pre-CCS for the process heaters at Sinclair would entail significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In order to capture, dry, compress, and transport to a suitable EOR site the CO_2 available for capture from the new and modified process heaters would require excessive amounts of additional electric power and steam generation capacity. The generation of the steam and electric power required by the project would itself increase GHG emissions, which would offset some of the GHG reduction achieved by capturing and storing the CO_2 from the process heaters. In addition, both types of CCS would entail a significant amount of gas compression capacity resulting in high energy use. This additional energy use could require additional electricity generation, and in turn increase emissions of GHG (and other emissions) from the local power provider, which would result in additional energy and environmental impacts.

Given the overall economic, energy, and environmental impacts, both Post and Pre-Combustion CCS are eliminated as BACT for new and modified process heaters at Sinclair.

Use of Low Carbon Fuels, Good Combustion Practices, and Energy Efficient Design

The use of low carbon refinery fuel gas and good combustion practices are inherent in the operation of all process heaters at Sinclair. These practices are used at Sinclair in order to provide the required heat/energy demand needed in the refining process while maximizing fuel efficiency and minimizing operating costs. Energy efficient design can be incorporated as feasible depending on heater and refinery design. Specifically, the use of process heat to generate steam, process integration and heat recovery in the process heaters, and excess combustion air monitoring and control are utilized for the process heaters. These technologies are not eliminated as BACT (see more detail in step 5, below).

A Cogeneration Unit as a part of this process would not offset any proposed emission increases associated with this project. The use of a Cogeneration Unit would not decrease any of the proposed emission increases associated with the proposed new and modified emission sources (581 Crude Heater, 583 Vacuum Heater, Naphtha Splitter Heater, Hydrocracker Heater H5, #1HDS Heater, New BSI Heater, New Emergency Air Compressor, Coker Flare, and Fugitive emissions) and is therefore eliminated as BACT.

Additionally, the addition of a Cogeneration Unit as part of this project would not result in any emission decreases from the current refinery steam boilers. Steam demand at the refinery is such that the installation of a Cogeneration Unit would not result in a direct reduction of firing in the existing boilers because additional steam at the refinery is often needed, and is thus eliminated as BACT based on the resulting environmental impact.

For the 583 Vacuum Unit Heater, Hydrocracker Heater H5, and #1 HDS Heater, stack temperatures as measured during historical stack testing indicate the technology is technically feasible for these natural draft heaters. Thus, an economic analysis was conducted for each of these heaters to determine the

18

economic feasibility for installing a combustion air preheat system. The estimated capital costs for the equipment needed to retrofit these natural draft heaters to mechanical draft is provided below.

• 583 Vacuum Unit Heater Total Capital Cost= $1,404,408
• Hydrocracker Heater H5 Total Capital Cost= $1,162,581
• #1 HDS Heater Total Capital Cost= $998,193

For this cost, the estimated GHG emission reductions are not substantial. Specifically, the potential emission reductions that could be attributed to the use of air preheat for these heaters was estimated from the flue gas parameters measured during historical testing. The potential estimated GHG emissions reductions are summarized in the following table.

Table 5 – Estimated Emissions Reductions with Air Preheat

Operating Unit	Emission Source	Reduced Firing Rate With Air Preheat Estimated Emissions	CH_4 Estimated Emissions	N_2O Estimated Emissions	CO_2 Estimated Emissions	CO_2e Estimated Emissions
		(MMBtu/hr)	TPY	TPY	TPY	TPY
583 Vacuum Unit	583 Vacuum Heater	1.6	<0.1	<0.1	911.3	915.1
Hydrocracker	H5 Heater	1.4	<0.1	<0.1	797.4	800.7
#1 HDS	#1 HDS Heater	1.7	<0.1	<0.1	968.2	972.3

It is also important to note that the scope of the refinery's Crude Oil Optimization Project does not include any physical modifications to any of these three heaters. The project will remove firing rate limits on heaters so that these writs will able to fire at their design maximum firing rates. There is no planned capital expenditure for these heaters and the installation of air preheat to any one of these heaters would add at a minimum near one (1) million dollars of expense to the project while adding air preheat to all three heaters would add over 3.5 million dollars of expense to the project. Sinclair contends that this is not economically feasible and GHG BACT should be as proposed for the new and modified heaters. A detailed economic analysis of the estimated air preheat costs for each of these heaters is provided in the May 19, 2012 Sinclair submittal.

Step 5 Select BACT

Sinclair will incorporate the use of low carbon fuels (refinery fuel gas), good combustion practices, and energy efficient design for the affected process heaters to meet BACT for CO_2. Specifically, proposed BACT for the process heaters (581 Crude Heater, 583 Vacuum Heater, #1 HDS Heater, Naphtha Splitter Heater, Hydrocracker H5 Heater, and BSI Heater) includes:

For the 581 Crude Heater:

- Use of good combustion and maintenance practices to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. SWRC operations will also make daily visual observations of the 581 Crude Unit Heater burners to verify proper combustion;

- Use of lower-carbon content gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CO_2e emissions per unit of energy generated via combustion;

- Use of a process waste heat recovery steam generator to improve energy efficiency and reduce the quantity of fuel burned per unit of production;

- Use of process heat integration between, and/or internal to, the 581 Crude unit to improve energy efficiency and reduce the quantity of fuel burned per unit of production. This is accomplished by feed/effluent heat exchange systems in the 581 Crude Unit; and

- Use of continuous O_2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Continuous O_2 monitoring will be conducted using the existing monitors in the 581 flue gas emission stack. Note that if the continuous monitoring system is off-line, daily O_2 monitoring in the stack will be conducted using an existing insitu or hand-held monitor.

For the 583 Vacuum Heater, # 1 HDS Heater, Naphtha Splitter Heater, and Hydrocracker H5 Heater:

- Use of good combustion and maintenance practices to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Refinery operations will also make daily visual observations of the burners to verify proper combustion;

- Use of lower-carbon content gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CO_2e emissions per unit of energy generated via combustion;

- Use of process heat integration between, and/or internal to, the BSI Unit to improve energy efficiency and reduce the quantity of fuel burned per unit of production. This is accomplished by feed/effluent heat exchange systems in each process unit; and

- Use of O_2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. O_2 monitoring will be conducted daily using the existing in situ monitors in the individual emission stacks for each heater.

For the BSI:

- Use of good combustion and maintenance practices to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Refinery

operations will also make daily visual observations of the BSI burners to verify proper combustion;

- Use of lower-carbon content gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CO_2e emissions per unit of energy generated via combustion;

- Use of process heat integration between, and/or internal to, the BSI Unit to improve energy efficiency and reduce the quantity of fuel burned per unit of production. This is accomplished by feed/effluent heat exchange systems in BSI unit; and

- Use of O2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. O2 monitoring will be conducted daily using the existing insitu monitors in the BSI Heater stack.

A GHG emission limit, including CO_2 emissions of 146 lb CO_2e/MMBtu will be established for each of the process heaters. This GHG emission limit is calculated from the CO_2e emissions for the process heaters based on the emission factors provided in May 21, 2012 information submitted by Sinclair. This value is based upon data gathered by Sinclair for carbon content of various refinery fuel gas mixtures potentially used at the Sinclair refinery.

In addition, yearly "ton per yr" limits will be established for each individual process heater. These limits are based upon the 146 lb CO_2e/MMBtu BACT limit and the individual process heaters maximum rated combustion rate.

Table 6 – Process heaters and associated BACT limits

Equipment	Limitations
581 Crude Heater – 233 MMBtu/hr	• 146 lb CO_2e /MMBtu • 148,946 ton CO_2e /yr
583 Vacuum Heater – 64.2 MMBtu/hr	• 146 lb CO_2e /MMBtu • 41,040 ton CO_2e /yr
#1 HDS Heater – 33.4 MMBtu/hr	• 146 lb CO_2e /MMBtu • 21,351 ton CO_2e /yr
Naphtha Splitter Heater– 46.3 MMBtu/hr	• 146 lb CO_2e /MMBtu • 29,598 ton CO_2e /yr
Hydrocracker H5 Heater– 44.9 MMBtu/hr	• 146 lb CO_2e /MMBtu • 28,703 ton CO_2e /yr
BSI Heater– 50.0 MMBtu/hr	• 146 lb CO_2e /MMBtu • 31,963 ton CO_2e /yr

B.   Process Heater CH₄ Emissions

Step 1 Identify Potential Control Technologies

CH_4 will be emitted from the new and modified process heaters as a result of any incomplete combustion of refinery fuel gas and/or natural gas. Fuel costs represent one of the highest operating costs for a petroleum refinery and as such, process heaters are designed to achieve the highest combustion efficiencies practicable. Although CH_4 emissions can be slightly reduced by operating combustion devices at higher flame temperatures, higher excess oxygen levels, and longer furnace residence times, these techniques for reducing CH_4 emissions can result in an undesirable increase in NOx emissions.

The following technologies were identified as CH_4 control options for refinery process heaters based on available information and data sources

- Energy efficient design,
- Use of good combustion practices,
- Use of low carbon fuels, and
- Oxidation catalysts.

Energy Efficient Design

When possible based on existing refinery design and operation, the use of the following can provide an energy efficient design for process heaters minimizing the required fuel combustion for process heat.

- Combustion Air Preheat,
- Use of Process Heat to Generate Steam,
- Process Integration and Heat Recovery, and
- Excess Combustion Air Monitoring and Control.

Use of Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas include the following: good air/fuel mixing in the combustion zone, sufficient residence time to complete combustion, proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality, good burner maintenance and operation, high temperatures and low oxygen levels in the primary combustion zone, and overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

Use of Low Carbon Fuels

The following table presents the amount of CH_4 formed when combusting fossil fuels, including some of the fuels that will be used by the new and modified heaters at Sinclair.

22

**Table 7 – Default CH₄ Emission Factors by Fuel Type
(extracted from 40 CFR part 98, Subpart C, Table C-2)**

Fuel type	Default CH_4 emission factor (kg CH_4/MMBtu)
Blast Furnace Gas	2.2E-05
Coke Oven Gas	4.8E-04
Natural Gas	1.0E-03
Biomass Fuels—Liquid	1.1E-03
Petroleum (all fuel types)	3.0E-03
Biogas	3.2E-03
Coal and Coke	1.1E-02
Municipal Solid Waste	3.2E-02
Tires	3.2E-02
Biomass Fuels—Solid	3.2E-02

As shown in the table, the use of gaseous fuels creates lower emissions of CH_4 from combustion of gaseous fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels.

Oxidation Catalysts

Oxidation catalyst has been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle gas turbines and would also provide reduction in CH_4 emissions. This technology utilizes excess air present in the combustion exhaust and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. No chemical reagent addition is required and reactants are introduced into a catalytic bed. The optimum temperature range for these systems is approximately 850 °F to 1,100 °F.

Step 2 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration technically infeasible options. EPA does not generally consider a control technology to be technically feasible unless it is either (1) demonstrated and operated on the source type under review, or (2) both available and applicable to the source type under review (PSD and Title V Permitting Guidance for Greenhouse Gases, at Page 3 (March 2011)). To be considered "available," a technology should be able to be obtained through commercial channels.. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration.

Energy Efficient Design -Technically Feasible

When possible based on existing refinery design and operation, the use of the following can provide an energy efficient design for process heaters minimizing the required fuel combustion for process heat.

- Combustion Air Preheat,
- Use of Process Heat to Generate Steam,
- Process Integration and Heat Recovery,
- Excess Combustion Air Monitoring and Control, and
- Cogeneration as a CH_4 Reduction Technique.

Use of Good Combustion Practices -Technically Feasible

Good combustion practices for process heaters fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone,
- Sufficient residence time to complete combustion,
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality,
- Good burner maintenance and operation,
- High temperatures and low oxygen levels in the primary combustion zone, and
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

Use of Other Lower Carbon Fuels for New and Modified Process Heaters-Technically Infeasible

The process heaters at the refinery combust refinery fuel gas which is a lower carbon fuel. The only identified fuels with lower CH_4 formation rates are syngas, PSA tail gas, and natural gas. Production of additional syngas or PSA tail gas would lead to overall increases in GHG emissions from the refinery and do not represent options for reducing GHG emission. Natural gas is commercially available and would yield slightly reduced CH_4 emission rates from the process heaters, but displacing refinery fuel gas from use as fuel in the process heaters would necessitate disposal of this fuel gas by combustion elsewhere at the refinery, such as by flaring, which would increase overall refinery CH_4 emissions. Thus there are no control options involving the use of lower-carbon fuels in process heaters that are technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas.

Oxidation Catalysts for New and Modified Process Heaters -Technically Infeasible

Oxidation catalysts are not technically feasible. The typical oxidation catalyst for CH_4-containing exhaust gases is rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is installed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates.

24

Acceptable catalyst operating temperatures range from 400 °F to 1250 °F, with the optimal range being 850 °F to 1,100 °F. Below approximately 600 °F, a greater catalyst volume would be required to achieve the same reductions. To achieve this temperature range in process heaters fired with refinery fuel gas, the catalyst would need to be installed in the heater upstream of any waste heat recovery or air preheat equipment. This would require extensive rebuild of the heater firebox, heat exchange systems and ductwork.

Additionally, installation of oxidation catalyst in flue gas containing more than trace levels of SO_2 will result in poisoning and deactivation of the catalyst by sulfur-containing compounds, as well as increasing the conversion for SO_2 to SO_3. The increased conversion of SO_2 to SO_3 will increase condensable particulate matter emissions and increase flue gas system corrosion rates. Flue gas from the refinery heaters will contain sulfur compounds (e.g. SO_2 and SO_3) that would result in poisoning and deactivation of the catalyst. Sulfur compounds in the flue gas would form strong bonds with metals in the oxidation catalyst. Sulfur chemisorbs onto and reacts with the active catalyst sites on the catalyst and prevents reactant access to the catalyst for CH_4 reduction. Furthermore, the stable metal sulfur bonds can lead to non-selective side reactions which modify the surface chemistry and reduce the effectiveness of the catalyst for control of carbon containing compounds. For these reasons, catalytic oxidation of CH_4 is not considered technically feasible for the refinery fuel gas fired process heaters.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

The following technologies and control efficiencies (where applicable) were identified as CH_4 control options for refinery process heaters based on available information and data sources.

- Energy efficient design (% control efficiency is variable),
- Use of good combustion practices (% control efficiency is variable), and
- Use of lower carbon refinery fuel gas (% control efficiency is variable).

Step 4 Evaluate the Most Effective Controls and Document Results

The use of low carbon fuels and good combustion practices are inherent in the operation of all process heaters at Sinclair. These practices are used at Sinclair in order to provide the required heat/energy demand needed in the refining process while maximizing fuel efficiency and minimizing operating costs. Energy efficient design can be incorporated as feasible depending on heater and refinery design. Specifically, the use of process heat to generate steam, process integration and heat recovery in the process heaters, and excess combustion air monitoring and control are utilized.

Additionally, the addition of a Cogeneration Unit as part of this project would not result in any emission decreases from the current refinery steam boilers. Steam demand at the refinery is such that the installation of a Cogeneration Unit would not result in a direct reduction of firing in the existing boilers because additional steam at the refinery is often needed. Thus, the installation of a Cogeneration Unit would result in greater emissions beyond those from just the existing refinery boilers.

Step 5 Select BACT

Sinclair will incorporate the use of low carbon fuels (refinery fuel gas and natural gas) good combustion practices, and energy efficient design for the affected process heaters to meet BACT for CH_4. Specifically, proposed BACT for the process heaters (581 Crude Heater, 583 Vacuum Heater, #1 HDS Heater, Naphtha Splitter Heater, Hydrocracker H5 Heater, and BSI Heater) includes:

- Use of good combustion and maintenance practices to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Sinclair operations will also make daily visual observations of all process heater burners to verify proper combustion;

- Use of lower-carbon content gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CO_2 emissions per unit of energy generated via combustion;

- Use of a process waste heat recovery steam generator to improve energy efficiency and reduce the quantity of fuel burned per unit of production;

- Use of process heat integration between, and/or internal to, the process heaters to improve energy efficiency and reduce the quantity of fuel burned per unit of production. This is accomplished by feed/effluent heat exchange systems in the process heater. Feed/effluent heat exchange is the practice of pre-heating feed streams, by indirect heat exchange with the hotter intermediate streams exiting a process unit, prior to being heated by a fired heater. This practice ultimately reduces the need to fire the heater at higher rates, reducing the generation of GHG emissions; and

- Use of continuous O_2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Continuous O_2 monitoring will be conducted using the existing monitors in the relevant process heater flue gas emission stack. Note that if the continuous monitoring system is off-line (due to malfunction, maintenance, repair, etc.), daily O_2 monitoring in the stack will be conducted using existing in situ or hand-held monitors.

A GHG emission limit, which includes CH_4 emissions, of 146 lb CO_2e /MMBtu must be established for each of the process heaters. This GHG emission limit is calculated from the CO_2e emissions for the process heaters based on the emission factors provided in May 21, 2012 information submitted by Sinclair. This value is based upon data gathered by Sinclair for carbon content of various refinery fuel gas mixtures potentially used at the Sinclair refinery.

In addition, yearly "ton per yr" limits will be established for each individual process heater. These limits are based upon the 146 lb CO_2e /MMBtu BACT limit and the individual process heaters maximum rated combustion rate. (See Table 5, page 19 of this document.)

C.   Process Heater N_2O Emissions

Step 1 Identify Potential Control Technologies

N_2O will be emitted from the new and modified process heaters in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process. Fuel costs

represent one of the highest operating costs for a petroleum refinery and as such, process heaters are designed to achieve the highest combustion efficiencies practicable.

The following technologies were identified as N_2O control options for refinery process heaters based on available information and data sources.

- Energy efficient design,
- Use of good combustion practices (because N_2O is a partially oxidized molecule), and
- Use of low carbon fuels.

Energy Efficient Design

When possible based on existing refinery design and operation, the use of the following can provide an energy efficient design for process heaters minimizing the required fuel combustion for process heat.

- Combustion Air Preheat,
- Use of Process Heat to Generate Steam,
- Process Integration and Heat Recovery, and
- Excess Combustion Air Monitoring and Control.

Use of Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone,
- Sufficient residence time to complete combustion,
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality,
- Good burner maintenance and operation,
- High temperatures and low oxygen levels in the primary combustion zone, and
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

Use of Low Carbon Fuels

The following table presents the amount of N_2O formed when combusting fossil fuels, including some of the fuels that will be used by the new and modified heaters at Sinclair.

Table 8 – Default N$_2$O Emission Factors by Fuel Type
(extracted from 40 CFR part 98, Subpart C, Table C-2)

Fuel type	Default N$_2$O emission factor (kg N$_2$O/MMBtu)
Natural Gas	1.0E-04
Blast Furnace Gas	1.0E-04
Coke Oven Gas	1.0E-04
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1E-04
Petroleum (All fuel types in Table C–1)	6.0E-04
Biogas	6.3E-04
Coal and Coke (All fuel types in Table C–1)	1.6E-03
Municipal Solid Waste	4.2E-03
Tires	4.2E-03
Biomass Fuels—Solid (All fuel types in Table C–1)	4.2E-03

As shown in the table, the use of gaseous fuels reduces the production of N$_2$O from combustion of gaseous fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels.

Step 2 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration technically infeasible options. EPA does not generally consider a control technology to be technically feasible unless it is either (1) demonstrated and operated on the source type under review, or (2) both available and applicable to the source type under review (PSD and Title V Permitting Guidance for Greenhouse Gases, at Page 3 (March 2011)). To be considered "available," a technology should be able to be obtained through commercial channels.. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration.

Energy Efficient Design -Technically Feasible

When possible based on existing refinery design and operation, the use of the following can provide an energy efficient design for process heaters minimizing the required fuel combustion for process heat.

- Combustion Air Preheat,
- Use of Process Heat to Generate Steam,
- Process Integration and Heat Recovery,
- Excess Combustion Air Monitoring and Control, and
- Cogeneration as a N_2O Reduction Technique.

Use of Good Combustion Practices -Technically Feasible

Good combustion practices for process heaters fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone,
- Sufficient residence time to complete combustion,
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality,
- Good burner maintenance and operation,
- High temperatures and low oxygen levels in the primary combustion zone, and
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

Use of Other Lower Carbon Fuels for New and Modified Process Heaters – Technically Infeasible

The process heaters at the refinery combust refinery fuel gas which is a lower carbon fuel. The only identified fuels with lower N_2O formation rates are syngas, PSA tail gas, and natural gas. Production of additional syngas or PSA tail gas would lead to overall increases in GHG emissions from the refinery and do not represent options for reducing GHG emission. Natural gas is commercially available and would yield slightly reduced N_2O emission rates from the process heaters, but displacing refinery fuel gas from use as fuel in the process heaters would necessitate disposal of this fuel gas by combustion elsewhere at the refinery, such as by flaring, which would increase overall refinery N_2O emissions. Thus there are no control options involving the use of lower-carbon fuels in process heaters that are technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

The following technologies and control efficiencies (where applicable) were identified as N_2O control options for refinery process heaters based on available information and data sources.

- Energy efficient design (% control efficiency is variable),
- Use of good combustion practices (% control efficiency is variable), and
- Use of low carbon refinery fuel gas (% control efficiency is variable).

29

Step 4 Evaluate The Most Effective Controls and Document Results

The use of low carbon fuels and good combustion practices are inherent in the operation of all process heaters at Sinclair. These practices are used at Sinclair in order to provide the required heat/energy demand needed in the refining process while maximizing fuel efficiency and minimizing operating costs. Energy efficient design can be incorporated as feasible depending on heater and refinery design. Specifically, the use of process heat to generate steam, process integration and heat recovery in the process heaters, and excess combustion air monitoring and control are utilized.

Additionally, the addition of a Cogeneration Unit as part of this project would not result in any emission decreases from the current refinery steam boilers. Steam demand at the refinery is such that the installation of a Cogeneration Unit would not result in a direct reduction of firing in the existing boilers because additional steam at the refinery is often needed. Thus, the installation of a Cogeneration Unit would result in greater emissions beyond those from just the existing refinery boilers.

Step 5 Select BACT

Sinclair will incorporate the use of low carbon fuels (refinery fuel gas) good combustion practices, and energy efficient design for the affected process heaters to meet BACT. Specifically, proposed BACT for the process heaters (581 Crude Heater, 583 Vacuum Heater, #1 HDS Heater, Naphtha Splitter Heater, Hydrocracker H5 Heater, and BSI Heater) includes:

- Use of good combustion and maintenance practices to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Sinclair operations will also make daily visual observations of all process heater burners to verify proper combustion;

- Use of lower-carbon content gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CO_2 emissions per unit of energy generated via combustion;

- Use of a process waste heat recovery steam generator to improve energy efficiency and reduce the quantity of fuel burned per unit of production;

- Use of process heat integration between, and/or internal to, the process heaters to improve energy efficiency and reduce the quantity of fuel burned per unit of production. This is accomplished by feed/effluent heat exchange systems in the process heater. Feed/effluent heat exchange is the practice of pre-heating feed streams, by indirect heat exchange with the hotter intermediate streams exiting a process unit, prior to being heated by a fired heater. This practice ultimately reduces the need to fire the heater at higher rates, reducing the generation of GHG emissions; and

- Use of continuous O_2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Continuous O_2 monitoring will be conducted using the existing monitors in the relevant process heater flue gas emission stack. Note that if the continuous monitoring system is off-line (due to malfunction, maintenance, repair, etc.), daily O_2 monitoring in the stack will be conducted using existing in situ or hand-held monitors.

A GHG emission limit, which includes N_2O emissions, of 146 lb CO_2e/MMBtu, will be established for each of the process heaters. This GHG emission limit is calculated from the CO_2e emissions for the process heaters based on the emission factors provided in May 21, 2012 information submitted by Sinclair. This value is based upon data gathered by Sinclair for carbon content of various refinery fuel gas mixtures potentially used at the Sinclair refinery.

In addition, yearly "ton per yr" limits will be established for each individual process heater. These limits are based upon the 146 lb CO_2e/MMBtu BACT limit and the individual process heaters maximum rated combustion rate. (See Table 5, page 19 of this document.)

D. New Emergency Air Compressor CO_2, CH_4, N_2O Emissions

Step 1 Identify Potential Control Technologies

As previously identified for new and modified process heaters, CO_2 will be emitted from the new emergency air compressor because it is a combustion product of any carbon-containing fuel. The following technologies were identified as CO_2 control options for the new emergency air compressor based on available information and data sources:

- Energy efficient design,
- Use of good combustion practices, and
- Use of low carbon fuels.

Energy Efficient Design

When possible based on existing refinery design and operation, the use of the following can provide an energy efficient design for engines minimizing the required fuel combustion for process heat.

- Combustion Air Preheat,
- Use of Process Heat to Generate Steam,
- Process Integration and Heat Recovery,
- Combustion Air Monitoring and Control,
- Optimal fuel compression ratio (Air to Fuel Ratio (AFR) controls),
- Low weight high strength rotating assembly (pistons, rods, crank, valves and rockers).

Use of Good Combustion Practices

Good combustion practices for diesel engines include the following:

- Good air/fuel mixing in the combustion zone,
- Sufficient residence time to complete combustion,
- Proper fuel supply system design and operation in order to minimize fluctuations in fuel quality,
- Good engine maintenance and operation, and
- Overall oxygen level control to ensure complete combustion while maximizing thermal efficiency.

31

Use of Low Carbon Fuels

As previously shown above, the use of diesel fuel reduces the production of CO_2 from combustion of fuel relative to burning solid fuels (e.g. coal or coke).

Step 2 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration technically infeasible options. EPA does not generally consider a control technology to be technically feasible unless it is either (1) demonstrated and operated on the source type under review, or (2) both available and applicable to the source type under review (PSD and Title V Permitting Guidance for Greenhouse Gases, at Page 33 (March 2011)). To be considered "available," a technology should be able to be obtained through commercial channels.. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration.

Energy Efficient Design -Technically Feasible

When possible based on existing refinery design and operation, the use of the following can provide an energy efficient design for engines minimizing the required fuel combustion for process heat.

- Combustion Air Preheat,
- Use of Process Heat to Generate Steam,
- Process Integration and Heat Recovery,
- Combustion Air Monitoring and Control,
- Optimal fuel compression ratio (Air to Fuel Ratio (AFR) controls),
- Low weight high strength rotating assembly (pistons, rods, crank, valves and rockers).

Use of Good Combustion Practices -Technically Feasible

Good combustion practices for diesel engines include the following:

- Good air/fuel mixing in the combustion zone,
- Sufficient residence time to complete combustion,
- Proper fuel supply system design and operation in order to minimize fluctuations in fuel quality,
- Good engine maintenance and operation, and
- Overall oxygen level control to ensure complete combustion while maximizing thermal efficiency.

Use of Other Low Carbon Fuels - Technically Infeasible

As previously shown above, the use of diesel fuel reduces the production of CO_2 from combustion of fuel relative to burning solid fuels (e.g. coal or coke).

The new emergency air compressor at the refinery will provide instrument air to critical instruments in the event of a power failure and will reduce the potential for excess emissions at the refinery as a result

of a power failure. It is essential that the intermittent operation of this emergency compressor is reliable, and a diesel fuel source provides Sinclair with the most reliable resource. The only identified fuels with lower CO_2 formation rates are syngas, PSA tail gas, refinery fuel gas, and natural gas but could result in reduced reliability of the engine and in turn greater emissions from the entire refinery due to unplanned power failures. This engine will not be operated continuously and will be limited to 500 hours of non emergency operation. Thus, due to the infrequent nature of its operation and multiple potential startups and shutdowns, diesel fuel has been identified as the fuel type that will provide the necessary combustion fuel reliability for the intermittent operation of the emergency air compressor. Thus there are no control options involving the use of lower-carbon fuels for the emergency air compressor that are technically feasible for reducing GHG emissions relative to the proposed use of diesel.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

The following technologies and control efficiencies (where applicable) were identified as CO_2 control options for the emergency air compressor based on available information and data sources.

- Energy efficient design
- Use of good combustion practices, and
- Use of diesel fuel.

Step 4 Evaluate the Most Effective Controls and Document Results

The use of low carbon fuel and good combustion practices are inherent in the operation of new emergency air compressor. These practices are of the utmost importance to Sinclair in order to provide the required heat/energy demand needed in the refining process while maximizing fuel efficiency and minimizing operating costs. Energy efficient design can be incorporated as feasible depending on compressor and refinery design. Specifically, the use of combustion air preheat, process heat to generate steam, process integration and heat recovery, excess combustion air monitoring and control, optimal fuel compression ratio (Air to Fuel Ratio (AFR) controls), low weight high strength rotating assembly (pistons, rods, crank, valves, rockers), and recent developments to reduce soot and hydrocarbon emissions during startup are utilized where possible but can be limited for smaller sources, such as the emergency air compressor, that do not utilize a large amount of fuel or generate a large amount of waste heat. As such, the small size and intermittent operation of the new emergency air compressor do not present a practical opportunity to utilize combustion air preheat, process heat to generate steam, nor process integration and heat recovery.

The new emergency air compressor will be constructed to meet all of the most recent EPA specifications for emergency diesel engines including the applicable provisions of 40 CFR Part 89.112 for Tier III engines.

Step 5 Select BACT

Sinclair will incorporate the use of low carbon diesel fuel and good combustion practices for the new emergency air compressor to meet BACT. Specifically, proposed BACT for the new emergency air compressor includes:

- Use of good combustion and maintenance practices to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production;
- Use of lower-carbon content diesel fuel (diesel fuel rather than coal or coke) to reduce CO_2 emissions per unit of energy generated via combustion;
- Use of AFR controller on the new emergency engine to provide the optimal fuel compression ratio; and
- Limiting the use of the new emergency air compressor to 500 hours of operation or less per 12 month rolling period.

The installation of the new emergency air compressor will reduce the potential for excess GHG emissions from the entire refinery as a result of unplanned power failures.

A single GHG emission limit will be established for the new emergency generator. The proposed emission limit is 114.5 tons CO_2e per year. Sinclair shall install, maintain and operate a non-resettable elapsed time meter for the new emergency air compressor. The new emergency air compressor shall be limited to 500 hours of operation or less per 12 month rolling period.

E.   Coker Flare CO_2, CH_4, and N_2O Emissions

Step 1 Identify Potential Control Technologies

Operation of the Coker Flare results in CO_2 emissions from the combustion of gas supplied to the flare. Based on available information and data sources there is no technology for CO_2 control options post combustion for refinery flares. Thus, the only potential BACT control for the flare is to minimize all potential flaring events and maximize flare combustion efficiency during unavoidable flaring events.

Sinclair operates the flare to minimize emissions when there is an unavoidable flaring event. During unavoidable flaring events, to minimize emissions, Sinclair maximizes flare gas destruction efficiency by using the following control, measurement and ancillary devices:

- Natural gas piping, flow control and igniter systems to maintain the continuous presence of pilot lights installed at the flare tip to assure that any flare gas vapors sent to the flare will have combustion initiated by the pilot to control these flare gas vapors.
- A system of thermocouples to continuously monitor the presence of the flare pilot.
- A video camera system to continuously display an image of the flare tip and combustion zone in the control room, allowing visual adjustment of the air rate for smokeless operation.
- A Panametrics ultrasonic flow meter located downstream of the seal drum to measure the flare gas flow being combusted.
- The air assist configuration and operation includes an air blower with a variable frequency drive to change blower speed and air rate. The air flow rate is adjusted from the control room in auto or manual mode. In auto mode, the air flow rate is controlled in proportion to the flare gas flow rate as measured by the Panametrics flare gas flow meter. In manual mode, air addition is adjusted by the control board operator based on camera observation of the flare flame. Sinclair has found that manual mode has provided better smokeless operating performance the majority of the time.

Step 2 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration technically infeasible options. EPA does not generally consider a control technology to be technically feasible unless it is either (1) demonstrated and operated on the source type under review, or (2) both available and applicable to the source type under review (PSD and Title V Permitting Guidance for Greenhouse Gases, at Page 33 (March 2011)). To be considered "available," a technology should be able to be obtained through commercial channels.. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration. Sinclair investigated the use of a turbine or microturbine to combust the flare gas usually routed to flares at petroleum refineries. There are numerous obstacles which make the use of a turbine or microturbine technically infeasible for this project. Sinclair seeks to minimize all possible flaring at the refinery and is upgrading the flare gas recovery system to comply with the provisions of a Consent Decree to answer previous alleged violations at the Sinclair, Wyoming refinery. These upgrades include several provisions to reduce the generation of refinery gas vented to the flare. However, there will not be a consistent known volume or content of gas that is sent to the Coker Flare during normal refinery operation.

Sinclair also reviewed historical records for flaring and identified that there has not been a consistent volume or content of gas that is sent to the Coker Flare over the course of a year. Without having the key design specification such as combustion fuel volume and content, Sinclair asserts it is technically infeasible to design and operate a turbine or microturbine for energy efficiency purposes. In contrast, attempting to use a turbine or microturbine is likely to produce more GHG emissions in comparison to flaring as a significant volume ofsupplemental fuel would need to be used in the turbine or microturbine to keep them operating when there is no flare gas to be used. Attempting to operate the turbine or microturbine only when potential flare gas is available is also not feasible because the startup of a turbine or microturbine has not been shown to always be an adequately quick and reliable process.

The use of microturbines or turbines at the Sinclair refinery for the purposes of combusting flare gas normally routed to the Coker Flare unit is not technically feasible.

Step 5 Select BACT

Based on available information and data sources there is no technology for CO_2 control options post combustion for refinery flares. Thus, the only potential BACT control for the flare is to minimize all potential flaring events and maximize flare combustion efficiency during unavoidable flaring events.

Sinclair proposes the use of its FGR system in order to minimize flaring as BACT. Additionally, Sinclair will continue to operate the flare to maximize combustion efficiency during unavoidable flaring events.

Due to the infrequent, unplanned, and undesired nature of emissions from flaring it is not feasible to propose a numeric CO_2e emission limit under which the Coker Flare can operate. Rather, the use of the flare gas recovery system in order to minimize flaring will represent BACT.

F.   Fugitive Emission Components CH₄ Emissions

Step 1 Identify Potential Control Technologies

Fugitive emission sources at the refinery include valves, pumps, connectors, compressors, and similar components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of CH_4 emissions due to fugitive emission leaks from equipment handling materials containing CH_4. Sinclair's design is to minimize these potential emissions. For example, Sinclair utilizes instrument air with no pollutant emissions for pneumatic valve operation rather than product fluids, as is often done in the oil and gas production industry. Sinclair also implements a Leak Detection and Repair (LDAR) program that incorporates both the applicable Federal and company specific provisions for monitoring and repairing fugitive emission leaks.

Based on available information and data sources, the only potential BACT control for these CH_4 fugitive emissions would involve enhancements (listed in detail in Step 5) to the applicable LDAR program currently in place at the refinery.

Step 2 Eliminate Technically Infeasible Options

None of the enhancements listed in detail in Step 5 are technically infeasible.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

Based on available information and data sources the only potential BACT control of CH_4 fugitive emissions would involve enhancements to the applicable LDAR program currently in place at the refinery.

Step 4 Evaluate The Most Effective Controls and Document Results

Based on available information and data sources the only potential BACT control for these CH_4 fugitive emissions would involve enhancements to the applicable LDAR program currently in place at the refinery.

Step 5 Select BACT

BACT control for CH_4 fugitive emissions involves enhancements to the applicable LDAR program currently in place at the refinery. Fugitive emission sources at the refinery are currently regulated under the requirements of New Source Performance Standards Subpart GGG (NSPS GGG). Additionally, Sinclair is subject to additional fugitive emission source requirements under their Federal CD (Civil Action No. 08CV 020-D). These CD provisions require that in addition to the requirements of NSPS GGG that Sinclair conduct the following:

- Develop a written refinery-wide LDAR program,
- Implement an LDAR training program,
- Conduct internal and external refinery-wide LDAR audits,

36

- Implement a 500 ppm VOC internal leak definition for valves (excluding pressure relief devices),
- Implement a 2,000 ppm VOC internal leak definition for pumps,
- Meet enhanced initial repair and remonitoring deadlines,
- Implement enhanced monitoring frequencies for pumps, valves, and after turnarounds,
- Maintain electronic LDAR database records,
- Conduct enhanced QA/QC of LDAR records,
- Implement enhanced tracking program for maintenance records to ensure that valves and pumps added during maintenance and construction are integrated into the LDAR program,
- Conduct enhanced instrument calibration requirements,
- Meet enhanced Delay or Repair (DOR) requirements,
- Implement chronic leaker repair program, and
- Conduct enhanced LDAR program reporting and certification.

Sinclair will continue to implement all of the applicable Federal and company specific requirements for fugitive emissions. To the extent that conditions of any active CD apply to the modified or constructed emission units, Sinclair will comply with those conditions for the applicable process units for the time that the CD remains active. Sinclair is proposing to meet BACT control for CH_4 fugitive emissions by conducting the following:

- Comply with the applicable Federal and company specific requirements for existing process units.
- Comply with the applicable Federal and company specific requirements for new BSI unit.
- Comply with the applicable Federal and company specific requirements if reconstruction or modification is triggered for any process unit.

Sinclair proposes utilizing these LDAR program requirements to limit fugitive emissions rather than proposing a numeric CO_2e emission limit. Due to the infrequent, unplanned, and undesired nature of these emissions it would be less effective to minimize fugitive emissions by proposing a numeric limit under which the refinery could operate than it is to follow the stringent LDAR program requirements outlined.

The FGR system used as a portion of the BACT for the Coker Unit Flare will also be required to be monitored by a LDAR program. Due to the nature of the composition of refinery fuel gas, fuel gas systems are not typically covered under refinery NSPS or MACT standard LDAR programs. As this LDAR program is part of BACT for GHG fugitive emissions, and GHG fugitive emission could reasonably be expected to be emitted from the FGR system, an LDAR program shall be required.

IX.   Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal PSD permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB

1999)]. This permitting action authorizes emissions of GHG, controlled by what we have determined is the BACT for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHG. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

X. Conclusion and Action

Based on the information supplied by Sinclair, our review of the analyses contained in the WDEQ PSD Permit Application and in the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed modification would employ BACT for GHG under the terms contained in the permit. Therefore, EPA is issuing Sinclair a PSD permit for GHG for the described project, subject to the PSD permit conditions specified therein.