Sinclair

October 16, 2012

Mr. Donald Law
Air Program (8P-AR)
United States Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, CO 80202

Re: Sinclair Wyoming Refining Company (SWRC)
Crude Oil Optimization Project
Transmittal of Comments for Statement of Basis and Draft Prevention of Significant Deterioration Greenhouse Gas Permit to Construct (PSD-WY-000002-2011.001)

Dear Mr. Law:

On August 30, 2012 the United States Environmental Protection Agency (EPA) issued the Statement of Basis (SOB) and the Draft Prevention of Significant Deterioration (PSD) Greenhouse Gas (GHG) Permit to Construct (PSD-WY-000002-2011.001) for the Sinclair Wyoming Refining Company (SWRC) Crude Oil Optimization Project. SWRC is providing the following comments after a complete review of these documents.

<u>Statement of Basis</u>

1. SWRC is providing the following redline comments to identify the carbon dioxide equivalent (CO_2e) limits that are applicable for this project. The ton per year (TPY) CO_2e emission limits that are included in the SOB and Draft Permit were based on a fuel gas limit lower than the 146 lb CO_2e/MMBtu limit that was supplied in the supplemental permit application documentation received by EPA May 29, 2012. As identified in the following, the revision to the CO_2e emission limits is limited to the new and modified heaters which combust refinery fuel gas.

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

   "Sinclair has presented CO_2e potential emissions from modified and new emission sources of ~~328,166~~ 359,915 tpy CO_2e. The potential GHG emissions from these sources on a mass basis are ~~326,775~~ 358,524 tpy"

   Section VII. Project Description

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	~~28,477.9~~ 31,842.6	1.4	0.3	~~28,597.9~~ 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

Table 1 - Potential to Emit for Sinclair New Emission Sources (continued)

Operating Unit	Description	CO_2 (tpy)	CH_4 (tpy)	N_2O(tpy)	CO_2e (tpy)
Equipment Leaks	Fugitive Emission Sources	N/A	1.9	N/A	40.8
TOTALS		~~28,592.0~~ 31,956.7	3.3	0.3	~~28,753.2~~ 32,117.9

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	~~132,706.9~~ 148,386.5	6.7	1.3	~~133,266.0~~ 148,945.6
583 Vacuum Unit	583 Vacuum Heater – 64.2 MMBtu/hr	~~36,565.6~~ 40,885.9	1.9	0.4	~~36,719.6~~ 41,039.9
~~Coker~~	~~Coker Unit Flare – 100.0 MMBtu/hr~~	~~57,921.1~~	~~2.9~~	~~0.6~~	~~58,161.1~~
781 Reformer	Naphtha Splitter Heater – 46.3 MMBtu/hr	~~26,370.5~~ 29,486.2	1.3	0.3	~~26,481.6~~ 29,597.3
Hydrocracker	Hydrocracker H5 Heater – 44.9 MMBtu/hr	~~25,573.1~~ 28,594.7	1.3	0.3	~~25,680.9~~ 28,702.4
#1 HDS	#1 HDS Heater – 33.4 MMBtu/hr	~~19,023.2~~ 21,270.9	1.0	0.2	~~19,103.4~~ 21,351.0
TOTALS		~~298,160.4~~ 326,545.3	15.1	3.1	~~299,412.6~~ 327,797.3

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	~~13,669.4~~ 15,284.4	0.7	0.1	~~13,727.0~~ 15,342.0
	#1 Reformer Heater – 44.6 MMBtu/hr	~~25,402.3~~ 28,403.6	1.3	0.3	~~25,509.3~~ 28,510.6
	#2 Reformer Heater – 74.8 MMBtu/hr	~~42,602.9~~ 47,636.5	2.2	0.4	~~42,782.4~~ 47,816.0
	#3 Reformer Heater – ~~11.1~~ 22.4 MMBtu/hr	~~25,573.1~~ 14,265.5	0.6	0.1	~~12,811.8~~ 14,319.2
	Stabilizer heater – 11.1 MMBtu/hr	~~6,322.1~~ 7,069.1	0.3	<0.1	~~6,348.7~~ 7,095.7

Table 3 - Potential to Emit for Sinclair Non-Modified Emission Sources (continued)

Operating Unit	Description	CO_2 (tpy)	CH_4 (tpy)	N_2O(tpy)	CO_2e (tpy)
Hydrocracker	Heater H1/H2 – 38.0 MMBtu/hr	~~21,643.2~~ 24,200.4	1.1	0.2	~~21,734.4~~ 24,291.6
	Heater H3 – 56.0 MMBtu/hr	~~31,895.2~~ 35,633.7	1.6	0.3	~~32,029.6~~ 35,798.1
	Heater H4 – 57.0 MMBtu/hr	~~32,464.8~~ 36,300.6	1.6	0.3	~~32,601.6~~ 36,473.3
Coker	Coker Heater – 145.0 MMBtu/hr	~~82,585.9~~ 92,343.5	4.2	0.8	~~82,933.8~~ 92,691.4
	Coker (Material Handling)	N/A	N/A	N/A	N/A
780 FCCU	780 FCCU Heater B3 – 10 MMBtu/hr	~~5,695.6~~ 6,368.5	0.3	<0.1	~~5,719.6~~ 6,392.5
	780 FCCU Heater H2 – 19.4 MMBtu/hr	~~11,049.4~~ 12,354.9	0.6	0.1	~~11,096.0~~ 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	~~15,947.6~~ 17,831.9	0.8	0.2	~~16,014.8~~ 17,899.0
#3 HDS	Charge Heater – 18.0 MMBtu/hr	~~10,252.0~~ 11,463.3	0.5	0.1	~~10,295.2~~ 11,506.5
#4 HDS	H2 Heater (25-HT-101) – 22.0 MMBtu/hr	~~12,530.3~~ 14,010.7	0.6	~~0.2~~ 0.1	~~12,583.1~~ 14,063.5
	H2 Heater (25-HT-10~~1~~2) – 24.0 MMBtu/hr	~~13,669.4~~ 15,284.4	0.7	~~0.2~~ 0.1	~~13,272.0~~ 15,342.0
#1 H2 Plant	#1 H2 Plant Heater – 288.0 MMBtu/hr	~~164,032.6~~ 183,413.4	8.3	~~8.3~~ 1.7	~~166,788.4~~ 184,104.4
#2 H2 Plant	#2 H2 Plant Heater – 288.0 MMBtu/hr	~~164,032.6~~ 183,413.4	8.3	1.7	~~164,723.6~~ 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 – 8.0 MMBtu/hr	~~4,556.5~~ 5,094.8	0.2	<0.1	~~4,575.7~~ 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		~~924,667.9~~ 1,003,960.8	61.4	~~17.3~~ 10.7	~~931,334.8~~ 1,008,562.9

Section VIII. BACT Analysis

Table 5 – Process heaters and associated BACT limits

Equipment	Limitations
581 Crude Heater – 233 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~133,266~~ 148,946 ton CO_2e/yr
583 Vacuum Heater – 64.2 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~36,720~~ 41,040 ton CO_2e/yr
#1 HDS Heater – 33.4 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~19,103~~ 21,351 ton CO_2e/yr
Naphtha Splitter Heater – 46.3 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~26,482~~ 29,598 ton CO_2e/yr
Hydrocracker H5 Heater – 44.9 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~25,681~~ 28,703 ton CO_2e/yr
BSI Heater – 50.0 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~28,598~~ 31,963 ton CO_2e/yr

2. SWRC contends that creating a numeric CO_2e emission limit for the Coker Flare is not required. SWRC operates the Coker Flare Gas Recovery System in order to minimize all potential flaring events at the refinery. Additionally, in the event of a malfunction, SWRC may need to utilize the Coker Flare as a safety device when depressurizing a unit. In the event of such a malfunction, attempting to put a numeric CO_2e emission limit on the flare being used as a safety device is not feasible and not a safe practice. As such, SWRC proposes to remove the following SOB text as identified in the redline text below.

Section VIII. BACT Analysis

> ~~"A CO_2e ton per year emission limit of 58,161 ton CO_2e/yr will be established for the Coker Unit Flare. This limit is based upon the firing rate of the Coker Unit Flare of 100.0 MMBtu/hr and an emission rate of 132.24 lb CO_2/MMBtu, 0.0066 lb CH_4/MMBtu, and 0.00132 lb N_2O/MMBtu."~~

Draft Permit to Construct PSD-WY-000002-2011.001

1. SWRC noted an administrative correction in the Introduction section of the draft permit as identified in the following redline text.

Section I. INTRODUCTION

> "The crude optimization project consists of the following: 1) removal of the 581 Crude Unite Heater firing limit rate and replacement of the 581 Crude Unit atmospheric distillation tower; 2) modification of the ~~283~~ 583 Vacuum Tower to accommodate an increase in reduced crude feedstock from the debottlenecked 581 Crude Unit;..."

2. SWRC is providing the following redline comments to identify the CO_2e limits that are applicable for this project. The TPY CO_2e emission limits that are included in the Draft Permit were based on a fuel gas limit lower than the 146 lb CO_2e/MMBtu limit that was

supplied in the supplemental permit application documentation received by EPA May 29, 2012. As identified in the following, the revision to the CO_2e emission limits is limited to the new and modified heaters which combust refinery fuel gas.

Section III. SPECIAL PERMIT CONDITIONS

A. POINT SOURCE EMISSION LIMITS

Table 1: Emission Limits

Equipment	Limitations
581 Crude Heater – 233 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~133,266~~ 148,946 ton CO_2e/yr • No Fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
583 Vacuum Heater – 64.2 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~36,720~~ 41,040 ton CO_2e/yr • No Fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
#1 HDS Heater – 33.4 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~19,103~~ 21,351 ton CO_2e/yr • No Fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
Naphtha Splitter Heater – 46.3 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~26,482~~ 29,598 ton CO_2e/yr • No Fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
Hydrocracker H5 Heater – 44.9 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~25,681~~ 28,703 ton CO_2e/yr • No Fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
BSI Heater – 50.0 MMBtu/hr	• 146 lb CO_2e/MMBtu • ~~28,598~~ 31,963 ton CO_2e/yr • No Fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
Emergency Air Compressor	• 114.5 ton CO_2e/yr • Diesel fuel only • Limited to 500 hours of operation per 12 month rolling period.
Coker Unit Flare – 100.0 MMBtu/hr	~~• 58,161 ton CO2e/yr~~ • Minimization of flaring events through use of Flare Gas Recovery (FGR) System. • In event of unavoidable flaring event, maximum flare combustion efficiency will be utilized.
Fugitive Emissions and Drains	• Use of existing LDAR program. • Addition of FGR as a source to be monitored under LDAR program.

3. SWRC contends that creating a numeric CO_2e emission limit for the Coker Flare is not required. SWRC operates the Coker Flare Gas Recovery System in order to minimize all potential flaring events at the refinery. Additionally, in the event of a malfunction, SWRC may need to utilize the Coker Flare as a safety device when depressurizing a unit. In the event of such a malfunction, attempting to put a numeric CO_2e emission limit on the flare being used as a safety device is not feasible and not a safe practice. As such, SWRC proposes to remove the following Draft Permit text as identified in the redline text below.

   Section III. SPECIAL PERMIT CONDITIONS

   C. REQUIREMENTS FOR COKER UNIT FLARE

   "3. Total CO_2e emissions from the Coker ~~Unit~~ Flare shall be calculated by using the equations stated in Special Conditions III.C.4. Annual total CO_2e emissions ~~shall not exceed 58,161 ton CO_2e/yr and~~ shall be calculated by Equation 3. "

4. SWRC requests that a clarification for the performance testing requirements is made as identified in the redline text below.

   Section VI. PERFORMANCE TESTING REQUIREMENTS

   B. "Each source tested by the Permittee shall be at or above 90.0% of the maximum normal load operations as **determined from the previous seven calendar days of emission source operation**. Tested source load shall be identified…."

SWRC is planning to perform the activities included in this construction permit application in the 2012 timeframe. Because permit issuance is required prior to commencing actual construction, SWRC is available at any time to discuss this project and permit application with the Agency. Please contact Mr. John Pfeffer, Environmental Manager, at (307) 328-3548 or myself at (801) 524-2729 with any questions or comments regarding this transmittal.

Respectfully,

SBGreene

Sam Greene P. E.
Environmental Engineer

SBG/sbg
attachment

cc:
M. Serres – Sinclair Wyoming Refining Company

cc: Electronic
Deirdre Rothery – EPA Region 8
J. Pfeffer – Sinclair Wyoming Refining Company
S. Greene– Sinclair Wyoming Refining Company
J. Maffuccio– Sinclair Wyoming Refining Company

PUBLIC NOTICE
OF A DRAFT PERMIT WHICH REGULATES
THE EMISSIONS OF AIR POLLUTANTS

The Region 8 office of the United States Environmental Protection Agency (EPA) is hereby providing opportunity through October 18 ,2012 8:30 p.m. Mountain Standard Time (MST), for public comment on a draft permit which would grant conditional approval, under Title I, Parts A and C, of the Federal Clean Air Act, as amended, and under Federal Prevention of Significant Deterioration of Air Quality (PSD) permitting rules at 40 CFR 52.21, to the following permit applicant, to construct a new facility:

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

Corporate Address:
Sinclair Wyoming Refining Company
P.O. Box 277
Sinclair, Wyoming 82334

The permit allows for construction and modification at the Sinclair Wyoming Refining Company's Sinclair, Wyoming oil refinery. Pursuant to a national Federal Implementation Plan (FIP), EPA is the PSD permitting authority for greenhouse gases (GHGs) in Wyoming. Pursuant to the Wyoming State Implementation Plan (SIP), the Wyoming Department of Environmental Quality (WDEQ) is the permitting authority implementing PSD requirements for all other regulated New Source Review (NSR) pollutants. Therefore, EPA will issue a PSD permit which covers only GHGs and WDEQ will issue a separate PSD permit covering all other NSR pollutants.

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. Potential GHG emissions from the construction and modification of the Sinclair refinery, on a mass basis, are estimated at 326,775 tons per year. The combined GHG emissions, taking into account global warming potentials for each pollutant, is estimated to be 328,166 tons per year of carbon dioxide equivalent. No emissions of the GHG pollutants, hydrofluorocarbons (HFCs), sulfur hexafluoride (SF6), and perfluorocarbons (PFCs), are anticipated from this source.

A copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection between 8:30 a.m. and 4:00 p.m. MST, through October 18, 2012, at:

US EPA Region 8 Air Program
Office (8P-AR) 1595 Wynkoop
Street Denver, Colorado
80202-1129 Permit Contact:
Donald Law email:
law.donald@epa.gov phone:
303-312-7015 toll-free:
800-227-8917 fax:
303-312-6064

All documents will be available for review at the U.S. EPA Region 8 office on Monday through Friday, from 8:30 a.m. to 4:00 p.m. MST (excluding federal holidays). A copy of the administrative record is also available for public inspection at the Carbon County Clerk's Office in Rawlins, Wyoming. A copy of the draft permit and draft Statement of Basis is also available on EPA website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

In accordance with 40 CFR 52.21(q), *Public participation,* any interested person may submit written or emailed comments on the draft permit during the public comment period and may request a public hearing. A public hearing will be held for this action on September 17, 2012 from 7:00 p.m. to 8:30 p.m. MST in the Council Chambers at the Sinclair Town Clerk located at 300 East Lincoln Highway, Sinclair, Wyoming. The purpose of the hearing is to gather comments concerning the issuance of the EPA GHG PSD permit. The scope of the hearing will be limited to such issues in order for the EPA to determine whether or not the applicable PSD Regulations have been appropriately applied to the construction and operation of the proposed generating station. All persons desiring to be heard on this matter are hereby notified to appear at the designated time and place. Oral statements will be accepted at the time of the hearing, but for accuracy of the record, written statements are encouraged and will be accepted at the time of the hearing or prior thereto. Since the EPA is not the permitting authority for the remainder of the NSR pollutants, WDEQ will hold a hearing regarding the WDEQ draft PSD permit prior to the EPA hearing for the draft GHG PSD permit at 5:30pm MST at the aforementioned date and location. All comments regarding from the WDEQ draft PSD permit for the proposed facility must be submitted to the WDEQ in accordance with WDEQ's concurrent public notice for its draft PSD permit for this facility.

All written and emailed comments received before the close of the public hearing will be considered as well as all verbal comments received during the public hearing. All comments, written and emailed, should be addressed to the Permit Contact at the U.S. EPA Region 8 address or email address listed above.

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, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective thirty days after issuance of a final permit decision, unless a later effective date is specified in the decision or review is requested on the permit under 40 CFR 124.19. 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.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. William Allison
Air Division Director
Air Pollution Control Division (APCD-SS-B1)
Colorado Department of Public Health & Environment
4300 Cherry Creek Drive South
Denver, CO 80246-1530

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
PSD-WY-000002-2011.001

Dear Mr. Allison:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice. A copy of these materials (in addition to the PSD application submitted to the EPA) are also being sent to the Carbon County Clerk's office. These documents are also available 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 copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection through October 18, 2012, at the Region 8 office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

The public notice will be published in the Rawlins Daily Times on Saturday, September 1, 2012. The public comment period will end on October 18, 2012, at 8:30 p.m. All written or emailed comments submitted by the close of the public comment period will be considered by the EPA in making its final permit decision. Please refer to the enclosed copy of the public notice for details on the public comment period.

The Wyoming Department of Environmental Quality (WDEQ) will issue a draft PSD permit for PSD pollutants other than GHGs for this facility. The WDEQ will conduct a public comment period concurrent with the EPA's for its draft PSD permit.

The conditions contained in the permit will become effective and enforceable if the permit is issued as a final permit. If you wish to comment on the proposed action please submit your written comments to:

Donald Law - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Law at (303) 312-7015.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Gwynn G. Bartlett
Carbon County Clerk
P.O. Box 6
Rawlins, WY 82301

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
PSD-WY-000002-2011.001

Dear Ms. Bartlett:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice, permit application and related correspondence (including supplemental information dated December 23, 2011, and May 21, 2011). Please make this information available to the public until the close of business on October 18, 2012. These documents are also available 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 copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection through October 18, 2012, at the Region 8 office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

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1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Law at (303) 312-7015.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (6)

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REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Bridget Hettger, R.N.
Wyoming Public Health Manager, Carbon County
PO Box 1013
Rawlins, WY 82301

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
PSD-WY-000002-2011.001

Dear Ms. Hettger:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

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Denver, Colorado 80202-1129

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Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
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Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Clark Smith
Permit Section Supervisor
Nebraska Department of Environmental Quality
1200 N. Street, Suite 400
Lincoln, NE 68508-8922

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
PSD-WY-000002-2011.001

Dear Mr. Smith:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice. A copy of these materials (in addition to the PSD application submitted to the EPA) are also being sent to the Carbon County Clerk's office. These documents are also available 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.

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The public notice will be published in the Rawlins Daily Times on Saturday, September 1, 2012. The public comment period will end on October 18, 2012, at 8:30 p.m. All written or emailed comments submitted by the close of the public comment period will be considered by the EPA in making its final permit decision. Please refer to the enclosed copy of the public notice for details on the public comment period.

The Wyoming Department of Environmental Quality (WDEQ) will issue a draft PSD permit for PSD pollutants other than GHGs for this facility. The WDEQ will conduct a public comment period concurrent with the EPA's for its draft PSD permit.

The conditions contained in the permit will become effective and enforceable if the permit is issued as a final permit. If you wish to comment on the proposed action please submit your written comments to:

Donald Law - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Law at (303) 312-7015.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Susan Johnson, Chief
Policy, Planning and Permit Review
Air Resources Division
National Park Service
12795 W. Alameda Pkwy.
Lakewood, CO 80228

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
PSD-WY-000002-2011.001

Dear Ms. Johnson:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

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Air Program

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DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Richard L. Currit
Senior Archaeologist
Wyoming State Historic Preservation Office
2301 Central Ave., Barrett Bldg. 3rd Floor
Cheyenne, WY 82002

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
PSD-WY-000002-2011.001

Dear Mr. Currit:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

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Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

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REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Jeff Sorkin
Air Program Manager
USDA Forest Service
Rocky Mountain Region
740 Simms Street
Golden, CO 80401

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
PSD-WY-000002-2011.001

Dear Mr. Sorkin:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

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Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

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Sincerely,

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Air Program

Enclosures (3)

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DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

<u>CERTIFIED MAIL</u>
<u>RETURN RECEIPT REQUESTED</u>

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
PSD-WY-000002-2011.001

Dear Ms. Silva:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

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Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

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Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

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REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Steven A. Dietrich
Air Quality Administrator
Air Quality Division
Wyoming Department of Environmental Quality
Herscher Building
122 West 25th Street
Cheyenne, WY 82002

Re: Greenhouse Gas Prevention of Significant
Deterioration Draft Permit
\# PSD-WY-000002-2011.001

Dear Mr. Dietrich:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Sinclair Wyoming Refining Company's permit application dated October 10, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction, modification, and operation of their Sinclair, Wyoming oil refinery.

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Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

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Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

United States Environmental Protection Agency
Region 8
Air Program
1595 Wynkoop Street
Denver, Colorado 80202-1129
August 30, 2012

Draft
Air Pollution Control
Prevention of Significant Deterioration (PSD)
Permit to Construct

PSD-WY-000002-2011.001

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

Permitted Facility:
Sinclair Refinery
Sinclair, Wyoming

Table of Contents

Table of Acronyms

BACT	Best Available Control Technology
bhp	Brake Horse Power
BSI	Benzene Saturation/Isomerization
Btu/hr	British Thermal Units per Hour
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
dscf	Dry Standard Cubic Foot
EP	Emission Point
FIP	Federal Implementation Plan
FGR	Flare Gas Recovery
FR	Federal Register
GHG	Greenhouse Gas
GCV	Gross Caloric Heating Value
gr	Grains
HHV	High Heating Value
hr	Hour
HRSG	Heat Recovery Steam Generator
lb	Pound
lbpy	Pounds Per Year
LDAR	Leak Detection and Repair
MMBtu/hr	Million British Thermal Units per Hour
N_2O	Nitrous Oxide
NSPS	New Source Performance Standards
NO_x	Nitrogen Oxides
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
QA/QC	Quality Assurance and/or Quality Control
RATA	Relative Accuracy Test Audit
Scf/hr	Standard Cubic Feet per Hour
SF_6	Sulfur Hexafluoride
tpy	Tons Per Year
VOC	Volatile Organic Compounds
%	Percent

I. INTRODUCTION

This Federal PSD permit is being issued under authority of 40 CFR 52.21 (PSD) and 52.37 (FIP to issue permits under the PSD requirements to sources that emit GHG). Sinclair Wyoming Refinery Company (hereinafter the "Permittee") proposes to increase the crude refining capacity and implement other miscellaneous projects, as described below, at its Sinclair, Wyoming Petroleum 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.

II. GENERAL PERMIT CONDITIONS

On the basis of findings set forth in Section III, Special Permit Conditions, of this permit, and pursuant to the authority (as delegated by the Administrator) of 52.21(u), EPA hereby conditionally authorizes Sinclair Wyoming Refining Company to construct or modify their petroleum refinery located in Sinclair, Wyoming. The authorization is expressly conditioned as follows:

A. PERMIT EFFECTIVE DATE AND EXPIRATION

As provided in 40 CFR 124.15(b), this PSD permit shall become effective 30 days after the service of notice of the permit decision, unless:

1. a later effective date is specified in the decision;

2. review is requested on the permit under 40 CFR 124.19; or

3. no comments requested a change in the draft permit, in which case the permit shall become effective immediately upon issuance

As provided in 40 CFR 52.21(r)(2), this PSD permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months after the approval takes effect; or

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

Under 40 CFR 52.21(r)(2), EPA may extend the 18 month period upon a satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

The Permittee shall notify EPA in writing of:

1. the date construction is commenced, postmarked within 30 days of such date;

2. the actual date of initial startup, postmarked within 15 days of such date. Startup is defined as the setting in operation of an affected facility for any purpose;

3. the date upon which initial performance tests will commence, in accordance with the provisions of Section V., Shakedown Periods, of this permit, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Section VI.B.; and

4. other events are required elsewhere in this permit.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, Permittee shall maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing GHG emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. The Permittee shall notify EPA by mail within 2 working days following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in CO_{2e} emissions above the allowable emission limits stated in Condition III.A., of this permit.

2. In addition, the Permittee shall notify EPA in writing within 15 calendar days of any such failure described under Section IV. Recordkeeping Requirements. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Condition III.A., and the methods utilized to mitigate emissions and restore normal operations.

3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,

4. to sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed under this PSD permit, this PSD permit is binding on all subsequent owners and operators. The Permittee shall notify, by letter, the succeeding owner and operator of the existence of this PSD permit and its conditions. A copy of the letter shall be provided to EPA within 30 days of the letter signature. Permit transfers shall be made in accordance with 40 CFR Part 122, Subpart D.

G. SEVERABILITY

The provisions of this PSD permit are severable, and, if any provision of the PSD permit is held invalid, the remainder of this PSD permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

The Permittee shall construct and operate this project in compliance with this PSD permit, the application on which this PSD permit is based, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. BINDING APPLICATION

This permit is issued in reliance upon the accuracy and completeness of the information set forth in the Permittee's application to EPA dated October 10, 2011, and subsequent information provided by the Permittee to EPA, as listed in the Administrative Record for issuance of this permit.

The Permittee shall abide by all representations, statements of intent and agreements contained in the permit application and subsequent submittals as listed in the Administrative Record. EPA shall be notified no less than 10 days in advance of any significant deviation from the permit application, and shall furnish any plans, specifications or supporting data regarding such deviation. The issuance of this PSD permit to Construct and Operate may be suspended or revoked if EPA determines that a significant deviation from the permit application, specifications, and supporting data furnished has been, or is to be, made.

J. ENFORCEABILITY OF PERMIT

On the effective date of this permit, the conditions herein become enforceable by EPA pursuant to any remedies it now has or may have in the future, under the Clean Air Act.

K. TREATMENT OF EMISSIONS

Emissions in excess of the limits specified in this permit shall constitute a violation.

III. SPECIAL PERMIT CONDITIONS

A. POINT SOURCE EMISSION LIMITS

At all times, including during startup, shutdown and malfunction, the Permittee shall not allow the discharge of GHG emissions from each unit into the atmosphere, in excess of the following:

Table 1: Emission Limits

Emission Point/Equipment	**Limitations**
581 Crude Heater – 233 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 133,266 ton CO_{2e} /yr • No fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
583 Vacuum Heater – 64.2 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 36,720 ton CO_{2e} /yr • No fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
#1 HDS Heater – 33.4 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 19,103 ton CO_{2e} /yr • No fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
Naphtha Splitter Heater– 46.3 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 26,482 ton CO_{2e} /yr • No fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
Hydrocracker H5 Heater– 44.9 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 25,681 ton CO_{2e} /yr • No fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
BSI Heater– 50.0 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 28,598 ton CO_{2e} /yr • No fuel oil combustion. Use of refinery fuel gas or purchased natural gas only.
Emergency Air Compressor	• 114.5 ton CO_{2e} /yr • Diesel fuel only • Limited to 500 hours of operation per 12 month rolling period.
Coker Unit Flare– 100.0 MMBtu/hr	• 58,161 ton CO_{2e} /yr • Minimization of flaring events through use of Flare Gas recovery System. • In event of unavoidable flaring event, maximum flare combustion efficiency will be utilized.
Fugitive Emissions and Drains	• Use of existing LDAR program • Addition of FGR as a source to be monitored under LDAR program

B. REQUIREMENTS FOR 581 CRUDE HEATER, 583 VACUUM HEATER, #1 HDS HEATER, NAPHTHA SPLITTER HEATER, HYDROCRACKER H5 HEATER, AND BSI HEATER

1. Compliance with lb CO_{2e}/MMBtu BACT Emission Limit

Each of the above listed emission units shall demonstrate compliance with the lb CO_{2e}/MMBtu BACT emission limit by the following equation:

Equation 1

$$W_{CO2e} \geq W_{CH4} + W_{N2O} + W_{CO2}$$

Where:

W_{CO2e} = 146 lb CO_{2e}/MMBtu

W_{CH4} = 0.14 lb CO_{2e}/MMBtu, assumed constant

W_{N2O} = 0.41 lb CO_{2e}/MMBtu, assumed constant

W_{CO2} = CO_2, lb CO_{2e}/MMBtu, as measured by Special Condition III.B.3.a.

2. Compliance with ton CO_{2e} /yr BACT Emission Limit

Each of the above listed emission units shall demonstrate compliance with the ton CO_{2e}/yr BACT emission limit by the following equation:

Equation 2

$$T_{CO2e} \geq \sum_{i=1}^{52} \frac{(W_{CH4} + W_{N2O} + W_{CO2})}{2000} \; x \; W_{GCV} \; x \; V_{Di}$$

Where:

T_{CO2e} = Individual unit tonnage/yr limit in Special Condition III.A, Table 1

W_{CH4} = 0.14 lb CO_{2e}/MMBtu

W_{N2O} = 0.41 lb CO_{2e}/MMBtu

W_{CO2} = CO_2 (as measured by Special Condition III.B.3.a expressed in lb CO_{2e}/MMBtu)

W_{GCV} = GCV (MMBtu/dscf)

V_{Di} = Seven day volumetric flow rate (dscf)

3. Work Practice and Operational Requirements

a. To demonstrate compliance with the lb CO_{2e}/MMBtu BACT emission limits, for each emission unit, the Permittee shall calculate the lbs/MMBtu of CO_2 emitted at least once every seven days.

The Permittee shall conduct gas chromatograph testing at least once every seven days to determine the lbs/MMBtu value. Gas chromatograph testing will quantify the speciation of the refinery fuel gas and include the following:

Hydrogen (H_2)
Nitrogen (N_2)
Oxygen (O_2)
Carbon Monoxide (CO)
Carbon Dioxide (CO_2)
Carbon compounds with one (1) carbon atom
Carbon compounds with two (2) carbon atoms
Carbon compounds with three (3) carbon atoms
Carbon compounds with four (4) carbon atoms
Carbon compounds with five (5) carbon atoms
Carbon compounds with six (6) or greater carbon atoms
Gross Caloric Heating Value (GCV) in MMBtu/dscf

b. If gas chromatograph testing in accordance with Special Condition III.B.3.a. is not available during any seven day period, the Permittee shall record the reason for unavailability during each seven day period of unavailability and shall conduct stack testing in accordance with Special Condition IV. to determine lb CO_2/MMBtu for each emission unit.

c. Compliance with the lb CO_{2e}/MMBtu BACT emission limit shall be determined at least once every seven days.

d. The Permittee shall compare the calculated CO_{2e} emissions from Special Condition III.B.1. to the allowable BACT CO_{2e} limit required in Special Condition III.A. for each emission unit. The calculated CO_{2e} emissions shall be less than the allowable BACT CO_{2e} limit. If the Permittee finds that the calculated CO_{2e} emissions rate is greater than the allowable BACT CO_{2e} limit, the Permittee shall review the operational performance of the emission units and monitoring instrumentation. From this review, any necessary corrective measures shall be identified and recorded by the Permittee, including the reason for the CO_2 emissions difference. The Permittee shall complete corrective measures within 48 hours of identification of a difference.

e. The Permittee shall demonstrate compliance for each emission unit with the ton CO_{2e} /yr BACT limit on a 52-week rolling average.

f. The Permittee shall install, maintain and operate a non-resettable elapsed flow meter, to measure the flow rate of the fuel combusted in each emission unit. Flow rate will be recorded at least once every seven days and recorded as dscf.

g. The Permittee shall maintain and operate each emission unit to ensure the GHG emissions are continuously at or below the emissions limits specified in this permit.

C. REQUIREMENTS FOR COKER UNIT FLARE

1. The Permittee shall install, maintain and operate, at all times, a flare gas recovery system to capture all waste gases used as refinery fuel gas that would normally be sent to the Coker Unit Flare.

2. The Permittee shall use engineering calculations, company records, or similar estimates of volumetric flare gas flow to the Coker Unit Flare.

3. Total CO_{2e} emissions from the Coker Unit Flare shall be calculated by using the equations stated in Special Conditions III.C.4. Annual total CO_{2e} emissions shall not exceed 58,161 ton CO_{2e} /yr and shall be calculated by Equation 3.

   Equation 3

$$T_{CO2e} = CO_2 + CH_4 + N_2O$$

   Where:

   TCO2e = total annual emissions of CO2e (ton/yr)
   CO2 = total annual emissions of CO2 (ton/yr) calculated from Equation 4a, 4b, 5, or 6, below.
   CH4 = total annual emissions of CO2 (ton/yr) calculated from Equation 7, below.
   N2O = total annual emissions of CO2 (ton/yr) calculated from Equation 8, below.

4. If the Permittee has a continuous higher heating value monitor or gas composition monitor on the flare or if the permitee monitors these parameters at least weekly, the Permittee must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare using the applicable methods in Special Conditions III.C.4.(A) or Special Conditions III.C.4.(B) of this permit.

(A) If the Permittee monitors gas composition, the Permittee shall calculate the CO_2 emissions from the flare using either Equation 4a or Equation 4b of this section. If daily or more frequent measurement data are available, the permitee must use daily values when using Equation 4a or Equation 4b of this section; otherwise, use weekly values.

Equation 4a

$$\mathrm{CO_2} = 0.98\,x\,0.001\,x\left(\sum_{p=0}^{n}\left[\frac{44}{12}\,x\,(\mathrm{Flare})_p\,x\,\frac{(\mathrm{MW})_p}{\mathrm{MVC}}\,x\,(\mathrm{CC})_p\right]\right)$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year)

0.98 = Assumed combustion efficiency of a flare

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg)

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year)

p = Measurement period index

44 = Molecular weight of CO_2 (kg/kg-mole)

12 = Atomic weight of C (kg/kg-mole)

$(\mathrm{Flare})_p$= Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(\mathrm{MW})_p/\mathrm{MVC}$" with "1"

$(\mathrm{MW})_p$= Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 pounds per square inch absolute (psia) or 836.6 scf/kg-mole at 60 °F and 14.7 psia)

$(\mathrm{CC})_p$= Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average

Equation 4b

$$CO_2 = \sum_{p=1}^{n} \left[(\text{Flare})_p \times \frac{44}{\text{MVC}} \times 0.001 \times \left(\frac{(\%CO_2)_p}{100\%} + \sum_{x=1}^{y} \left\{ 0.98 \times \frac{(\%Cx)_p}{100\%} \times \text{CMNx} \right\} \right) \right]$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year)

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year)

p = Measurement period index

$(\text{Flare})_p$ = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, the Permittee must determine the average molecular weight of the flare gas during the measurement period and convert the mass flow to a volumetric flow

44 = Molecular weight of CO_2 (kg/kg-mole)

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia)

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg)

$(\%CO_2)_p$ = Mole percent CO_2 concentration in the flare gas stream during the measurement period (mole percent = percent by volume)

y = Number of carbon-containing compounds other than CO_2 in the flare gas stream

x = Index for carbon-containing compounds other than CO_2

0.98 = Assumed combustion efficiency of a flare (mole CO_2 per mole carbon)

$(\%C_X)_p$ = Mole percent concentration of compound "x" in the flare gas stream during the measurement period (mole percent = percent by volume)

CMN_X = Carbon mole number of compound "x" in the flare gas stream (mole carbon atoms per mole compound). E.g., CMN for ethane (C_2H_6) is 2; CMN for propane (C_3H_8) is 3

(B) If the Permittee monitors heat content but does not monitor gas composition, the Permittee shall calculate the CO_2 emissions from the flare using Equation 5 of this section. If daily or more frequent measurement data are available, the Permittee must use daily values when using Equation 5 of this section; otherwise, use weekly values.

<u>Equation 5</u>

$$CO_2 = 0.98\ x\ 0.001\ x \sum_{p=1}^{n} [(Flare)_p\ x\ (HHV)_p\ x\ EmF]$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year)
0.98 = Assumed combustion efficiency of a flare
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg)
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year)
p = Measurement period index
$(Flare)_p$= Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, the Permittee must also measure molecular weight and convert the mass flow to a volumetric flow as follows: $Flare[MMscf] = 0.000001 \times Flare[kg] \times MVC/(MW)_p$, where MVC is the molar volume conversion factor [849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia depending on the standard conditions used when determining $(HHV)_p$] and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).
$(HHV)_p$= Higher heating value for the flare gas combusted during measurement period (British thermal units per scf, Btu/scf = MMBtu/MMscf). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
EmF = Default CO_2 emission factor of 60 kilograms CO_2/MMBtu (HHV basis)

(C) If the Permittee does not measure the higher heating value or carbon content of the flare gas at least weekly, the Permittee must determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs Special Condition III.C.4.(C)(i) through (C)(iii) of this section.

(**i**) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event exceeding 500,000 scf/day.

(**ii**) For periods of normal operation, use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculations.

(**iii**) Calculate the CO_2 emissions using Equation 6 of this section.

Equation 6

$$CO_2 = 0.98 \, x \, 0.001 \, x \left(Flare_{NORM} \, x \, HHV \, x \, EMF + \sum_{p=1}^{n} \left[\frac{44}{12} \, x \, (Flare_{SSM})_P \, x \, \frac{(MW)_P}{MVC} \, x \, (CC)_P \right] \right)$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year)

0.98 = Assumed combustion efficiency of a flare

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg)

$Flare_{Norm}$= Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year)

HHV = Higher heating value for fuel gas or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf)

EmF = Default CO_2 emission factor for flare gas of 60 kilograms CO_2/MMBtu (HHV basis)

n = Number of start-up, shutdown, and malfunction events during the reporting year exceeding 500,000 scf/day

p = Start-up, shutdown, and malfunction event index

44 = Molecular weight of CO_2 (kg/kg-mole)

12 = Atomic weight of C (kg/kg-mole)

$(Flare_{SSM})_p$ = Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, (scf/event)

$(MW)_p$ = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole)

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia)

$(CC)_p$ = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas)

(D) Calculate CH_4 using Equation 7 of this section.

Equation 7

$$CH_4 = \left(CO_2 x \frac{EmF_{CH4}}{EmF}\right) + CO_2 x \frac{0.02}{0.98} x \frac{16}{44} x f_{CH4}$$

Where:

CH_4 = Annual methane emissions from flared gas (metric tons CH_4/year)
CO_2 = Emission rate of CO_2 from flared gas calculated in Equation 4a, 4b, 5 or 6 of this section (metric tons/year)
EmF_{CH4}= Default CH_4 emission factor for "Petroleum Products" from Table C–2 of subpart C 40 CFR Part 98 (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu)
EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis).
0.02/0.98 = Correction factor for flare combustion efficiency
16/44 = Correction factor ratio of the molecular weight of $CH_4$to CO_2
f_{CH4}= Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4

(E) Calculate N_2O emissions using Equation 8 of this section.

Equation 8

$$N_2O = \left(CO_2 x \frac{EmF_{N2O}}{EmF}\right)$$

Where:

N_2O = Annual nitrous oxide emissions from flared gas (metric tons N_2O/year)

CO_2 = Emission rate of CO_2 from flared gas calculated in Equation 3 of this section (metric tons/year)

EmF_{N2O}= Default N_2O emission factor for "Petroleum Products" from Table C–2 of subpart C 40 CFR Part 98 (General Stationary Fuel Combustion Sources) (kg N_2O/MMBtu)

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

5. The Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the flare gas recovery system associated with the Coker Unit Flare, including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring, hours of operation; and all other information required by this permit recorded in a permanent form suitable for inspection. The Permittee must retain the file for not less than 5 years following the date of such measurements, maintenance, and/or reports.

D. REQUIREMENTS FOR NEW EMERGENCY AIR COMPRESSOR

1. The Permittee shall install, maintain and operate a non-resettable elapsed time meter for the New Emergency Air Compressor.

2. The Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the New Emergency Air Compressor, including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the New Emergency Air Compressor; for each diesel fuel oil delivery, documents from the fuel supplier, hours of operation; and all other information required by this permit recorded in a permanent form suitable for inspection. The Permittee must retain the file for not less than 5 years following the date of such measurements, maintenance, reports, and/or records.

E. FUGITIVE EMISSION SOURCES

1. Fugitive Emission Sources Work Practice and Operational Requirements

a. For CH_4 emissions from Fugitive Emission Sources, emissions shall be calculated by the Permittee annually (calendar year). Emissions shall be calculated based on the method listed below.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA–453/R–95–017, NTIS PB96–175401).

b. The flare gas recovery system required by Special Condition III. C. 1. shall be included and monitored as a fugitive emission source and the emissions from the flare gas recovery system shall be included in the annual totals calculated under Special Condition III. C. 3.

2. Fugitive Emission Sources Compliance Demonstration

The Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emissions source including, but not limited to, the following: all records or reports pertaining to maintenance performed, equipment replacement, and all records relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR Part 98.

IV. RECORDKEEPING REQUIREMENTS

A. Including any recordkeeping requirements specified elsewhere in this permit, the Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; all records relating to performance tests and monitoring of auxiliary combustion equipment; and other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than 5 years following the date of such measurements, maintenance, reports, and/or records.

B. The Permittee shall maintain the following records for at least 5 years, including:

1. the occurrence and duration of any startup, shutdown, malfunction;
2. duration of any initial shakedown period for the emission units and pollution control units;
3. performance testing of emission units for demonstrating compliance with this permit;
4. the time and duration of any periods that monitoring devices are not operating; and
5. any emission data required by this permit.

C. The Permittee shall maintain records of all GHG emission units and CO_2 emission CEMS certification tests and monitoring and compliance information required by this permit.

D. The Permittee shall maintain records of any exceedance of limitations in this permit and submit a written report of all exceedances to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the authorized representative of the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

1. time intervals, data and magnitude of the exceedance, the nature and cause (if known), corrective actions taken and preventative measures adopted;
2. applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
3. if no exceedances of a permit limit occurred during the reporting period or the monitoring equipment has not been inoperative, repaired or adjusted, a statement that no exceedance of that limit occurred, and/or that the monitoring equipment has not been inoperative, repaired or adjusted (as applicable), shall be submitted;
4. any failure to conduct any required source testing, monitoring, or other compliance activities; and
5. any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator.

E. Exceedance shall be defined as any period in which the facility emissions or other parameter of operation exceed a maximum limit set forth in this permit.

F. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

G. All records required by this PSD Permit shall be retained for not less than 5 years following the date of such measurements, maintenance, and reports.

V. SHAKEDOWN PERIODS

The shakedown period is defined as the period beginning with initial startup and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant.

VI. PERFORMANCE TESTING REQUIREMENTS

A. Any performance tests to establish the actual quantities of CO_{2e} being emitted into the atmosphere from any emission unit and to determine compliance with the annual CO_{2e} emission limits established in this permit shall be conducted in accordance with 40 CFR 60.8 and EPA Method 3a or 3b for the concentration of CO_2. A written report of the performance testing results shall be furnished by the Permittee to the EPA.

B. Each source tested by the Permittee shall be at or above 90.0% of maximum load operations. Tested source load shall be identified by the Permittee in the sampling report. The Permittee shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Condition III.A.

C. The Permittee shall conduct performance tests under conditions that are representative of normal operation of the affected facility. The Permittee shall make available to the EPA such records as may be necessary to determine the conditions of the performance tests.

D. The Permittee shall provide the EPA at least 30 days prior notice of any performance test, to afford the EPA the opportunity to have an observer present, if desired, and/or to attend a pre-test meeting. If there is a delay in the original test date, the Permittee must provide at least 7 days prior notice of the rescheduled date of the performance test.

E. The Permittee shall provide, or cause to be provided, performance testing facilities as follows:

1. sampling ports adequate for test methods applicable to this facility;
2. safe sampling platform(s);
3. safe access to sampling platform(s); and
4. utilities for sampling and testing equipment.

F. Unless otherwise specified, each performance test conducted by the Permittee shall consist of 3 separate runs using the applicable test method. Each run shall be conducted by the Permittee for the time, and under the conditions, specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the 3 runs shall apply.

VII. AGENCY NOTIFICATIONS

A. The Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Air Program (8P-AR)
US EPA Region 8
1595 Wynkoop St.
Denver, CO 80202

B. The Permittee shall submit a copy of all compliance and enforcement correspondence as required by this permit to:

Air Technical Enforcement Program (8ENF-AT)
US EPA Region 8
1595 Wynkoop St.
Denver, CO 80202

C. For any notifications required to be delivered to EPA within a certain time frame, fulfillment of the requirement can be accomplished by delivery of the required information to EPA in writing, postmarked by such date.

Authorized By: United States Environmental Protection Agency, Region 8

Howard M. Cantor, for
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Date: 8/30/12

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

August 30, 2012

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 the draft 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), that would apply if the permit is issued. 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 has prepared the following SOB and draft 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) and 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 will be published on September 1, 2012, in the Rawlins Daily Times. The public comment period will begin on September 1, 2012 and close on October 18, 2012 at 8:30 p.m. During the public comment period, the public will be 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 will be 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 will also be 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 will also be 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 will be 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 is to gather comments concerning the issuance of the EPA GHG PSD permit. The scope of the hearing will be 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 will be accepted at the time of the hearing, but for accuracy of the record, written statements are encouraged and will be accepted at the time of the hearing or prior thereto. Since the EPA is not the permitting authority for the remainder of the NSR pollutants there will be 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 must be submitted to the WDEQ, which is running a concurrent public comment period for this facility.

In accordance with 40 CFR 124.13, *Obligation to raise issues and provide information during the public comment period,* anyone, including the permit applicant, who believes any condition of the draft permit is inappropriate, or that EPA's tentative decision to prepare a draft permit for the project is inappropriate, must raise all reasonably ascertainable issues and submit all arguments supporting the commenter's decision, by the close of the public comment period.

Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material. An extension of the 45 day public comment period may be granted if the request for an extension adequately explains why more time is needed to prepare comments.

In accordance with 40 CFR 124.15, *Issuance and Effective Date o/Permit,* the permit shall become effective immediately upon issuance as a final permit, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective 30 days after issuance of a final permit decision, unless a later effective date is specified in the final permit decision or review of the permit is requested under 40 CFR 124.19. Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice ofthe final permit decision.

In accordance with 40 CFR 124.19, *Appeal of RCRA, VIC, 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 (C02), methane (CH4), nitrous oxide (N20), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). GHG emissions can be measured using a "C02-equivalent" (C02e), 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 (from 40 CFR 98, Table A-I) are 1.0 for CO2, 21 for CH4, 310 for N20, and 23,900 for SF6. No emissions of HFCs, SF6, 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 ofGHG 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 C02e basis. Sinclair has presented C02e potential emissions from modified and new emission sources of328,166 tpy C02e. The potential GHG emissions from these sources on a mass basis are 326,775 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)(l». 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 is proposing to issue the non-GHG portion of the PSD permit and EPA is proposing to 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.

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.

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[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.

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	28,477.9	1.4	0.3	28,597.9
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		28,592.0	3.3	0.3	28,753.2

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	132,706.9	6.7	1.3	133,266.0
583 Vacuum Unit	583 Vacuum Heater – 64.2 MMBtu/hr	36,565.6	1.9	0.4	36,719.6
Coker	Coker Unit Flare– 100.0 MMBtu/hr	57,921.1	2.9	0.6	58,161.1
781 Reformer	Naphtha Splitter Heater– 46.3 MMBtu/hr	26,370.5	1.3	0.3	26,481.6
Hydrocracker	Hydrocracker H5 Heater– 44.9 MMBtu/hr	25,573.1	1.3	0.3	25,680.9
#1 HDS	#1 HDS Heater - 33.4 MMBtu/hr	19,023.2	1.0	0.2	19,103.4
TOTALS		298,160.4	15.1	3.1	299,412.6

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	13,669.4	0.7	0.1	13,727.0
	#1 Reformer Heater – 44.6 MMBtu/hr	25,402.3	1.3	0.3	25,509.3
	#2 Reformer Heater – 74.8 MMBtu/hr	42,602.9	2.2	0.4	42,782.4
	#3 Reformer Heater – 11.1 MMBtu/hr	25,573.1	0.6	0.1	12,811.8
	Stabilizer Heater – 74.8 MMBtu/hr	6,322.1	0.3	<0.1	6,348.7
Hydrocracker	Heater H1/H2 – 38.0 MMBtu/hr	21,643.2	1.1	0.2	21,734.4
	Heater H3 – 56.0 MMBtu/hr	31,895.2	1.6	0.3	32,029.6
	Heater H4 – 57.0 MMBtu/hr	32,464.8	1.6	0.3	32,601.6
Coker	Coker Heater – 145.0 MMBtu/hr	82,585.9	4.2	0.8	82,933.8
	Coker (Material Handling)	N/A	N/A	N/A	N/A
780 FCCU	780 FCCU Heater B3 – 10 MMBtu/hr	5,695.6	0.3	<0.1	5,719.6
	780 FCCU Heater H2 – 19.4 MMBtu/hr	11,049.4	0.6	0.1	11,096.0
	780 FCCU Regenerator – N/A	235,738.0	25.3	3.7	237,411.5
#2 HDS	Charge Heater – 28.0 MMBtu/hr	15,947.6	0.8	0.2	16,014.8
#3 HDS	Charge Heater – 18.0 MMBtu/hr	10,252.0	0.5	0.1	10,295.2
#4 HDS	H2 Heater (25-HT-101) – 22.0 MMBtu/hr	12,530.3	0.6	0.2	12,583.1
	H2 Heater (25-HT-101) – 24.0 MMBtu/hr	13,669.4	0.7	0.2	13,727.0
#1 H2 Plant	#1 H2 Plant Heater – 288.0 MMBtu/hr	164,032.6	8.3	8.3	166,788.4
#2 H2 Plant	#2 H2 Plant Heater – 288.0 MMBtu/hr	164,032.6	8.3	1.7	164,723.6
#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	4,556.5	0.2	<0.1	4,575.7

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		924,667.9	61.4	17.3	931,334.8

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.

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.

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

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 3 (March 2011)). To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. 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 CO_2 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 these technologies 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.

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

Energy Efficient Design -Technically Feasible

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 this facility.

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 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 including the equipment needed for capture, compression, pipeline transportation, and injection/storage is approximately $54.1 million. These estimated costs for post-CCS would represent greater than 90% 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.

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.

Impacts of Both CCS Options

In addition to the adverse economic impacts that show CCS is not a viable option for this project, the use of both Post and Pre-Combustion 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.

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:

- 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 insitu or hand-held monitors.

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 5 – Process heaters and associated BACT limits

Equipment	Limitations
581 Crude Heater – 233 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 133,266 ton CO_{2e} /yr
583 Vacuum Heater – 64.2 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 36,720 ton CO_{2e} /yr
#1 HDS Heater – 33.4 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 19,103 ton CO_{2e} /yr
Naphtha Splitter Heater– 46.3 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 26,482 ton CO_{2e} /yr
Hydrocracker H5 Heater– 44.9 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 25,681 ton CO_{2e} /yr
BSI Heater– 50.0 MMBtu/hr	• 146 lb CO_{2e} /MMBtu • 28,598 ton CO_{2e} /yr

B. Process Heater CH_4 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.

Table 6 – Default CH_4 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 must have reached the licensing and commercial demonstration phase of its development. 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. 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 7 – Default N_2O Emission Factors by Fuel Type (extracted from 40 CFR part 98, Subpart C, Table C-2)

Fuel type	Default N_2O emission factor (kg N_2O/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_2O 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 must have reached the licensing and commercial demonstration phase of its development. 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).

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.

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 3 (March 2011)). To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. 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 3 (March 2011)). To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration.

All provided control technologies are feasible and have been chosen as BACT, therefore no further analysis is required.

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 present BACT.

F. Fugitive Emission Components CH_4 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,
- 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.

A CO_{2e} ton per year emission limit of 58,161 ton CO_{2e} /yr will be established for the Coker Unit Flare. This limit is based upon the firing rate of the Coker Unit Flare of 100.0 MMBtu/hr and an emission rate of 132.24 lb CO_2/MMBtu, 0.0066 lb CH_4/MMBtu, and 0.00132 lb N_2O/MMBtu.

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, if finalized, 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 Proposed 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 facility would employ BACT for GHG under the terms contained in the draft permit. Therefore, EPA is proposing to issue Sinclair, a PSD permit for GHG for the described project, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received (if any) during the public comment period.

Certified Mail
Return Receipt Requested

 # 7008 0500 0001 0314 2863

October 10, 2011

Mr. Christopher Razzazian
Air Program (8P-AR)
United States Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, CO 80202

Re: Sinclair Wyoming Refining Company (SWRC)
Crude Oil Optimization Project
Transmittal of Greenhouse Gas (GHG) Construction Permit Application

Dear Mr. Razzazian:

SWRC is planning to increase the crude oil refining capacity and implement other miscellaneous projects at its petroleum refinery located in Sinclair, Wyoming. Because EPA Region 8 currently has primacy over the processing of GHG permit applications for PSD sources in Wyoming, the GHG portion of the permit application is being submitted to your attention. The crude optimization project consists of:

- Removal of the 581 Crude Unit heater firing rate limit and replacement of the 581 Crude Unit atmospheric distillation tower;
- Modification of the 583 Vacuum tower to accommodate the resulting increase in reduced crude feedstock from the debottlenecked 581 Crude Unit; and
- 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, this application includes the following projects that are unrelated to the increase of crude oil refining capacity:

- Removal of the firing rate limits for the #1 HDS heater, Naphtha Splitter heater and Hydrocracker H5 heater so that these units will able to fire at their design maximum firing rates. This change will eliminate the requirement for fuel gas flow monitor testing to demonstrate that these heaters operate at the sub-design firing rates specified in the current permit. Note that this action is being requested solely to eliminate the need for annual fuel gas flow meter testing.

- Installation of a new Naphtha Splitter and Benzene Saturation/Isomerization (BSI) Unit to provide the capability to reduce the benzene content in the refinery's gasoline product to meet the specifications of the February 2007 Mobile Source Air Toxics II (MSAT II) rule. This potential project is totally unrelated to the Crude Oil Optimization Project. Depending on SWRC's success at meeting MSAT II requirements using the current refinery configuration, SWRC may elect to forego installing a new Naphtha Splitter and/or BSI unit.

- Upgrade of the refinery's sour water stripping system which will include increasing the capacity of the existing sour water stripping system and installation of an additional sour water stripper. Sour water is a byproduct of the refining process that refers to water containing hydrogen sulfide and ammonia. A sour water stripper removes the H_2S and Ammonia gases from sour water using steam heat. The gases then go to the refinery Sulfur Recovery Plants where 99+% of the sulfur is recovered as product sulfur. The stripped water is either used in other refining processes or goes to the refinery wastewater treatment plant for processing. The installation of the new sour water stripper will improve the refinery's ability for continuous sour water stripping and is included in the project description for completeness.

- Installation of a new emergency air compressor that will supply instrument air to the refinery in the event of a power failure.

SWRC has conservatively elected to treat all of the projects described above as a single project from a New Source Review (NSR) applicability perspective. As described in the application, this project will result in net emission increases of Carbon Dioxide (CO_2), Methane (CH_4), and Nitrous Oxide (N_2O). Because there will be a significant increase in GHGe emissions, Prevention of Significant Deterioration (PSD) permitting requirements are required for these GHG pollutants.

Please note that on June 30, 2008 SWRC entered into a Consent Decree (CD) with Wyoming and EPA (Civil Action No. 08CV 020-D). The application demonstrates that the proposed projects do not conflict with any CD provisions.

SWRC is planning to perform the activities included in this construction permit application in the 2012 timeframe. Because permit issuance is required prior to commencing actual construction, SWRC is available at any time to discuss this project and permit application with the Agency. Please contact Mr. John Pfeffer, Environmental Manager, at (307) 328-3548 with any questions or comments regarding this transmittal.

Based upon information and belief formed after reasonable inquiry, I certify that the information contained in this permit application is true, accurate, and complete.

Sincerely,

Ray FOR JPM

Jim Maguire
Refinery Manager

JM/sbg

attachment

cc:
M. Serres – Sinclair Wyoming Refining Company

cc: Electronic
Mike Owens – EPA Region 8
J. Pfeffer – Sinclair Wyoming Refining Company
S. Greene– Sinclair Wyoming Refining Company
J. Maffuccio– Sinclair Wyoming Refining Company

Sinclair Wyoming Refining Company

Crude Oil Optimization Project
Greenhouse Gas Permit Application

October 10, 2011

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SECTION 1
INTRODUCTION

Sinclair Wyoming Refining Company (SWRC) is proposing to increase the crude oil refining capacity at its petroleum refinery in Sinclair, Wyoming. In addition, this application includes miscellaneous projects that are unrelated to the increase of crude oil refining capacity. This construction permit application is intended to satisfy all construction permit requirements under the Greenhouse Gas (GHG) Tailoring Rule issued in May 2010, GHG emissions from the largest stationary sources will, for the first time, be covered by the Prevention of Significant Deterioration (PSD) beginning January 2, 2011.

Because EPA Region 8 currently has primacy over the processing of GHG permit applications for PSD sources in Wyoming, the GHG portion of the permit application is being submitted to EPA Region 8. The criteria pollutant portion of the permit application is being submitted to the Wyoming Department of Environmental Quality Air Quality Division (WDEQ/AQD) under separate cover.

The refinery has submitted a complete Title V operating permit renewal application and is currently operating under the operating permit shield provisions in the Wyoming Air Quality Standards and Regulations (WAQS&R). The refinery is also operating under the provisions of other various WAQS&R construction permits/waivers issued after submittal of the operating permit renewal application.

1.1 Actions to Optimize Crude Oil Throughput

The Crude Oil Optimization Project consists of:

- Removal of the 581 Crude Unit heater firing rate limit and replacement of the 581 Crude Unit atmospheric distillation tower;
- Modification of the 583 Vacuum tower to accommodate the resulting increase in reduced crude feedstock from the debottlenecked 581 Crude Unit; and,
- 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.

1.2 Elimination of Firing Rate Limits on Selected Heaters

In a project that is unrelated to the actions to expand crude processing capacity, SWRC is proposing to remove the firing rate limits on the #1 HDS heater, Naphtha Splitter Heater and Hydrocracker H5 heater so that these units will able to fire at their design maximum firing rates. This change will eliminate the requirement for fuel gas flow monitor testing to demonstrate that these heaters operate at the sub-design firing rates specified in the current permit. Note that this action is being requested solely to eliminate the need for annual fuel gas flow meter testing.

1.3 New Naphtha Splitter and/or Benzene Saturation/Isomerization Unit

SWRC is proposing to install a new Naphtha Splitter and Benzene Saturation/Isomerization (BSI) Unit to provide the capability to reduce the benzene content in the refinery's gasoline product to meet the specifications of the February 2007 Mobile Source Air Toxics II (MSAT II) rule. This potential project is totally unrelated to the actions to expand crude oil refining capacity. Depending on SWRC's success at meeting MSAT II requirements using the current refinery configuration, SWRC may elect to forego installing a new Naphtha Splitter and/or BSI unit.

1.4 Sour Water Stripper System Upgrade

Sour water is a byproduct of the refining process that refers to water containing hydrogen sulfide and ammonia. A sour water stripper removes the H_2S and Ammonia gases from sour water using steam heat. The gases then go to the refinery Sulfur Recovery Plants where 99+% of the sulfur is recovered as product sulfur. The stripped water is either used in other refining processes or goes to the refinery wastewater treatment plant for processing.

In order to upgrade of the refinery's sour water stripping system, SWRC is proposing to increase the capacity of the existing sour water stripping system and install a new sour water stripper. The new sour water stripper will provide the capability to treat sour water during periods of downtime for the current sour water stripper system. The sour water stripper system upgrade will improve the refinery's ability for continuous sour water stripping and is included in the project description for completeness.

1.5 New Emergency Air Compressor

A new emergency air compressor will be installed to supplement the existing emergency air supply system. The emergency air compressor system supplies instrument air to the refinery in the event of a power failure.

1.6 Consent Decree Implications

Please note that on June 30, 2008 SWRC entered into a Consent Decree (CD) with Wyoming and EPA (Civil Action No. 08CV 020-D). The application demonstrates that the proposed projects do not conflict with any CD provisions.

1.7 Area Map, Block Flow Diagram and Plot Plan

Figure 1-1 provides the location area map of the SWRC. Figure 1-2 is a simplified block flow diagram showing the overall process flow. In this figure, the new equipment is shown in red and the modified equipment is shown in yellow and green highlight. Figure 1-3 shows the plot plan of the refinery process areas, and the specific location of each process unit included in this application.

1.8 Correspondence with Applicant

Please direct all correspondence and telephone requests regarding review of the permit application to:

Mr. John Pfeffer, Environmental Manager
Sinclair Wyoming Refining Company
PO Box 277
Sinclair, WY 82334-0277
(307) 328-3548
Facsimile: (307) 328-3574
Email: jpfeffer@sinclairoil.com

1.9 Application Contents

The application contents are organized in the following Sections:

- Section 1 – Introduction;
- Section 2 – Federal GHG Permitting Applicability;
- Section 3 – Project Descriptions;
- Section 4 – GHG Emission Calculation Methodologies;
- Section 5 – GHG Netting Emission Calculations;
- Section 6 – GHG Best Available Control Technology Review;
- Appendix A CO2 Emission Calculations;
- Appendix B CH4 Emission Calculations;
- Appendix C N2O Emission Calculations;
- Appendix D Fugitive Emission Calculations;
- Appendix E CO2 Equivalent Emission Totals; and
- Appendix F GHG BACT Cost Analyses.

Figure 1-1 Area Map

Sinclair Wyoming Refining Company

Figure 1-2 Block Flow Diagram

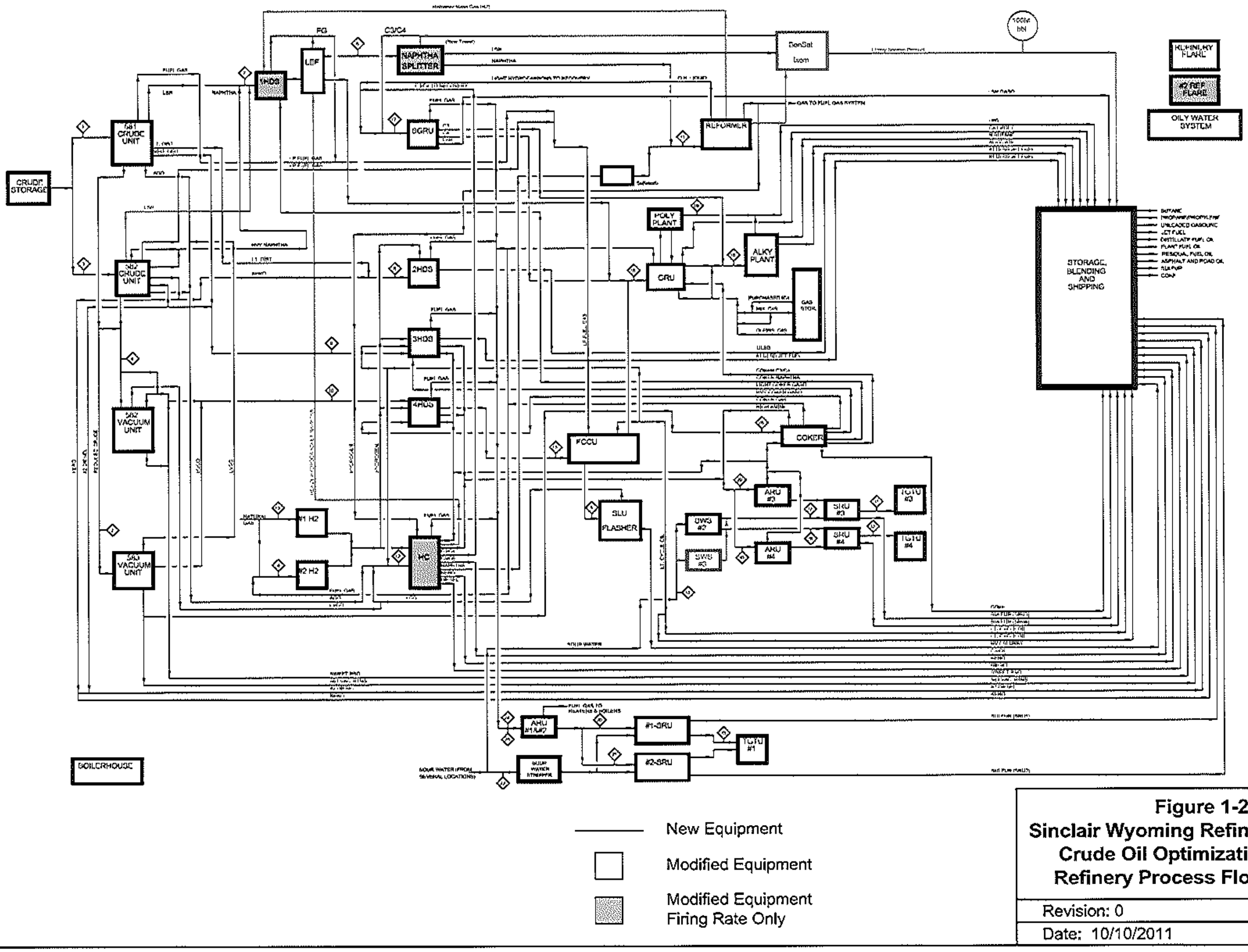

Figure 1-2
Sinclair Wyoming Refining Company
Crude Oil Optimization Project
Refinery Process Flow Diagram

Revision: 0

Date: 10/10/2011

Figure 1-3 Plot Plan

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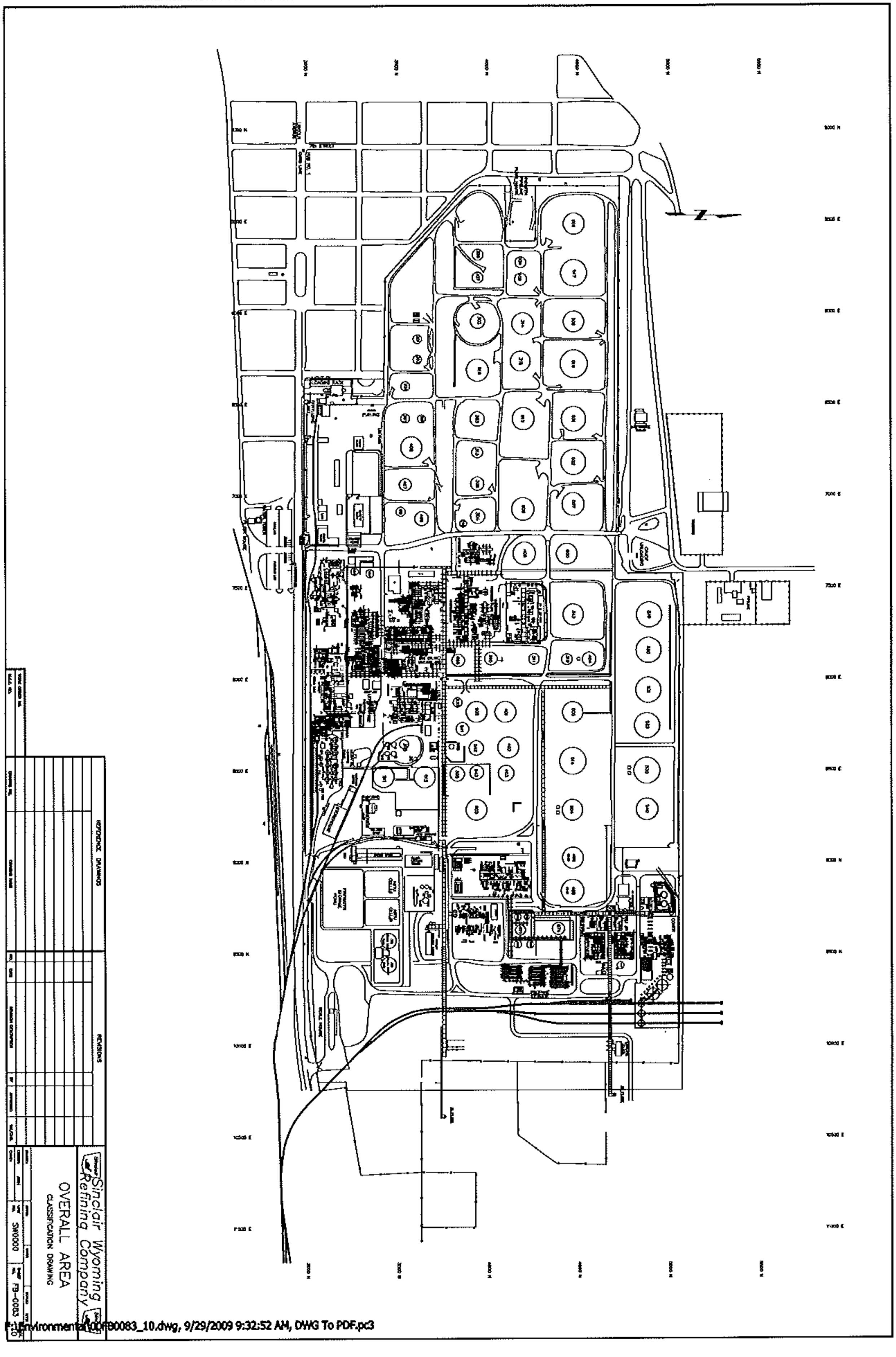

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SECTION 2
FEDERAL GHG PERMITTING APPLICABILITY

Under the Greenhouse Gas (GHG) Tailoring Rule issued in May 2010, GHG emissions from the largest stationary sources will, for the first time, be covered by the Prevention of Significant Deterioration (PSD) beginning January 2, 2011.

Specifically under Step 2 of this rule, PSD applies to the GHG emissions from a proposed modification to an existing source if any of the following is true:

- PSD for GHGs would be required under Tailoring Rule Step 1.

Or both:

- The existing source's PTE for GHGs is equal to or greater than 100,000 TPY on a CO_2 equivalent (CO_2e) basis and is equal to or greater than 100/250 TPY (depending on the source category) on a mass basis, and
- The emissions increase and the net emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis and greater than zero TPY on a mass basis.

GHG emissions from the proposed Crude Optimization Project including Carbon Dioxide (CO_2), Methane (CH_4), and Nitrous Oxide (N_2O) are provided in the following table and are also expressed as CO_2e. As shown, the increases are greater than PSD significance levels and the project triggers a PSD review for GHG emissions.

Table 2-1 Project GHG Emission Summary

POLLUTANT*	PROJECT GHG NET EMISSION INCREASES Ton/yr
CO_2	632,003.7
CH_4	37.3
N_2O	13.4
CO_2e	636,925.6

* Note: No other emissions of GHG regulated pollutants (hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) nor sulfur hexafluoride (SF6)) are emitted as part of the Crude Oil Optimization Project.

SECTION 3
PROJECT DESCRIPTION

This permit application is comprised of three projects as described below. The overall refinery process flow and major equipment orientation is provided in the process flow diagram (Figure 1-2). The plot plan (Figure 1-3) indicates the proposed area of installation of equipment for the new MSAT II Project.

A description of the new and modified units associated with this permit application is provided in the following sections. These process descriptions include general descriptions of process equipment with their upgrades (where applicable) and do not include all equipment that will be installed or modified. For example, there are heat exchangers, pumps, piping components, instruments, etc. that will be included in these projects but not explicitly listed in this permit application.

3.1 Increased Crude Oil Throughput

This project involves the following modifications:

- Removal of the firing rate limit at the 581 Crude Unit heater and replacement of the 581 Crude Unit atmospheric distillation tower. This heater was designed for a firing rate of 233 MM Btu/hr but limited by permit[1] to a firing rate of 133.2 MM Btu/hr. This project includes removal of the current firing rate limit to allow operation of this heater at its maximum capacity which will allow the 581 Crude Unit to operate at a higher crude oil throughput. In addition, the 581 Crude Unit atmospheric distillation tower will be replaced.

- Modification of the 583 Vacuum Unit. The vacuum tower system and vacuum heater will be modified to allow for an increase in charge rate.

- Allow the combustion of sweetened refinery fuel gas in the Coker Flare. SWRC has recently discussed with the EPA Region 8 (and WDEQ/AQD) its issues regarding fuel gas balance. While SWRC is striving to operate in fuel gas balance, SWRC has identified operational scenarios where it may need the capability to combust sweetened refinery fuel gas (i.e. meeting the NSPS Subpart Ja H2S standards) in its flare system. Given this need, this construction permit application includes provisions for routing excess sweetened refinery fuel gas to the Coker Unit Flare during periods of fuel gas imbalance.

---

[1] Permit MD-1351

3.2 Elimination of Firing Rate Limits on Select Heaters

This project is needed to eliminate the need for current refinery fuel gas flowmeter testing requirements at the #1 HDS heater, Naphtha Splitter heater and Hydrocracker H5 heater and includes removal of the firing rate limits at the #1 HDS heater, Naphtha Splitter heater and Hydrocracker H5 heater.

3.3 New Naphtha Splitter and/or Benzene Saturation / Isomerization Unit (MSAT II Project)

SWRC is currently assessing the refinery's capability to meet the MSAT II provisions with the current refinery configuration. If it is determined the current refinery configuration cannot meet these standards, SWRC may elect to install a new Naphtha Splitter and/or Benzene Saturation/Isomerization (BSI) unit. This project will provide SWRC options for complying with current motor gasoline benzene content standards of the MSAT II rule.

The project includes the installation of new refinery process equipment with pumps, valves, and other fugitive emissions sources, an associated gas-fired heater and a new 100,000 barrel floating-roof storage tank.

3.4 Sour Water Stripper System Upgrade

SWRC is planning to install a new sour water stripper (#3 SWS) to provide additional capability to treat sour water and provide redundancy during periods of downtime for the current sour water stripper system. SWRC is planning to increase the capacity of the existing sour water stripping system that includes #1 SWS and #2 SWS.

3.5 New Emergency Air Compressor

A new emergency air compressor will be installed to supplement the existing emergency air supply system. The emergency air compressor system supplies instrument air to the refinery in the event of a power failure.

3.6 Modified Equipment

The following existing units will be modified (either physically modified or modified by removal of a current permit limitation) in conjunction with the Crude Oil Optimization Project. A description of the modified units is provided in the following sections. These process descriptions include general descriptions of process equipment with their upgrades (where applicable) and do not include all equipment that will be installed or modified. For example, there may be heat exchangers, pumps, piping components, instruments, etc. that will be included in this project but not explicitly listed in this permit application.

3.6.1 581 Crude Unit

SWRC is planning to eliminate the current firing rate limit at the 581 Crude Unit heater. Removal of this limit will allow the 581 Crude Unit to operate at enhanced throughputs up to its inherent hydraulic capacity. Additionally, this project will also replace the 581 Crude Unit atmospheric distillation tower.

A summary of the current firing rate limit, design firing rates and actual firing rates (average of 2009 and 2010) is provided below for the 581 Crude Unit heater.

Heater	Current Firing Rate Limit (MM Btu/hr)	Design Firing Rate Capacity (MM Btu/hr)	Actual Firing Rate – Average 2009 and 2010 (MMBtu/hr)
581 Crude Unit Heater	133.2	233.0	102.5

3.6.2 583 Vacuum Unit

SWRC is planning to modify the 583 Vacuum Unit to allow the processing of additional reduced crude produced by the 581 Crude Unit modification. This unit will be physically modified as follows:

- Rework of the 583 heater heat exchange system. The existing heater has sufficient heat release capacity to process the additional reduced crude produced by the 581 Crude Unit.

- Installation of a larger vacuum producing system required to address higher cracked gas (non condensables) volumes associated with the 581 Crude Unit modification. The vacuum producing system uses eductors, with steam being the motive fluid, to produce vacuum. The increased steam needed for the eductors will be provided by waste heat recovery steam generation system on the 581 Crude Unit heater. In addition, the #1 H2 plant and #2 H2 plant both have waste heat recovery systems that will be used to meet steam requirements for this project. This project will result in a net steam increase from waste heat recovery systems and will not require any additional steam to be produced by refinery boilers. The following table provides the estimated steam demand for the refinery pre and post project.

Estimated* SWRC Steam Demand	Estimated Pre-Project Steam Demand from Boilers (total lbs/hr steam)	Estimated Post-Project Steam Demand from Boilers (total lbs/hr steam)
	262,704	254,078

*Note the estimated steam demand values are calculated assuming maximum production rates and do not necessarily reflect past actual refinery steam consumption.

3.6.3 Coker Unit Flare

SWRC is planning to modify the Coker Unit Flare to allow the routing of excess sweetened refinery fuel gas to the Coker Flare during periods of refinery fuel gas imbalance. This modification will include:

- Installation of piping and piping components from the refinery sweet fuel gas drum to the Coker Unit Flare.

The maximum capacity of the Coker Unit Flare will remain unchanged. No upstream units will be affected by modification of the Coker Unit Flare. #1 HDS Heater, Naphtha Splitter Heater and Hydrocracker H5 Heater

3.6.4 #1 HDS Heater, Naphtha Splitter Heater and Hydrocracker H5 Heater

These heaters were recently retrofitted with Ultra Low NOx Burners (ULNB) and had firing rate limits imposed by permit[2]. The firing rate limits were needed because the ULNB used in the retrofits had higher design firing rates than the burners they replaced. Because of these firing rate limits, SWRC is required to confirm the accuracy of the fuel gas flow meters with annual testing[3]. This project includes removal of the current firing rate limits to allow operation of these heaters at their design firing rates without the need for annual fuel gas flow meter testing.

A summary of the current firing rate limits, design firing rates and actual firing rates (average of 2009 and 2010) is provided below.

---

[2] Permit MD-1381A2, Condition 28 (1/29/08)

[3] Permit MD-1381A2, Condition 29 (1/29/08)

Heater	Current Firing Rate Limit (MM Btu/hr)	Design Firing Rate Capacity (MM Btu/hr)	Actual Firing Rate – Average 2009 and 2010 (MMBtu/hr)
#1 HDS heater	24.0	33.4	13.0
Naphtha Splitter heater	34.5	46.3	10.6
Hydrocracker H5 heater	35.7	44.9	21.9

It is important to note these heaters have historically operated well below their currently permitted firing rates and SWRC anticipates operating below these maximum firing rates limits with the increased crude throughput. SWRC's desire to remove the current firing rate limits is due solely to the elimination of the fuel gas flow meter annual testing requirements.

3.6.5 Naphtha Splitter (MSAT II)

As part of the MSAT II project, SWRC will require improved fractionation in the Naphtha Splitter Unit to obtain a more precise distillation cut of the intermediate stream sent to the BSI Unit. Please note that beyond the potential fugitive emission component increases previously identified, these updates to the Naphtha Splitter Unit will not impact the existing Naphtha Splitter emission source (i.e., fired heater) potential to emit. Although this heater is not being physically modified, it has been included in the emissions analysis as part of a modified unit. These updates to the #1 HDS will include:

- Replace the existing Naphtha Splitter tower with a larger tower with 60 trays;
- Modify the Reactor Section by improving the hydraulics (piping and pumps)

3.6.6 #1 Sour Water Stripper (#1SWS) and #2 Sour Water Stripper (#2SWS)

SWRC is planning to increase sour water charge rate capacity of the #1 SWS and #2 SWS with the installation of new sour water charge pumps.

3.7 New Equipment

3.7.1 Fugitive Emission Components (Increased Crude Oil Throughput)

There may be minor additions of new fugitive emission components associated with the modified equipment and a conservative estimate of these new components is included in this application.

3.7.2 MSAT II Project

The MSAT II Project includes the following construction plans for new sources:

- Construct a new process unit, the BSI Unit, to reduce the benzene content of gasoline while maintaining its octane rating. This process unit will include a new gas fired heater with a heat input capacity of 50 MM Btu/hr.
- Construct a new 100,000 barrel (bbl) floating roof tank for storage of gasoline and intermediate products.
- Construct the interconnecting process and utility piping to tie the BSI Unit into the existing refinery process and utility systems. Pumps, flanges, valves, drains, and other piping components will be installed which may emit fugitive VOCs.

The MSAT II project also results in modification of the existing Naphtha Splitter tower by replacing it with a larger tower. A new closed-loop glycol system will also be installed for the project, although this system will not emit any air pollutants.

3.7.2.1 BSI Unit (MSAT II)

The purpose of this process unit is to reduce the benzene concentration in gasoline while preserving the octane rating of the product.

Benfree™ is a process which reduces benzene in the feedstock through integrated reactive distillation. The process uses high-pressure pumps to withdraw benzene rich light fraction from the splitter where the benzene is converted to cyclohexane. Consequently, this conversion process affects the octane rating of the product. Note that the octane rating is distinct from the actual concentration of isomers of octane present in the product; octane rating is a measure of gasoline's tendency to pre-combust in an internal combustion engine.

In order to preserve the octane rating of the gasoline, SWRC will also utilize the Par-Isom™ process in conjunction with the Benfree™ process. The Par-

Isom™ process uses a catalytic reaction to isomerize the hydrocarbon molecules, creating a blend with the appropriate octane rating.

The combination of the Benfree™ Par-Isom™ process trains are designated BSI Unit by the SWRC refinery. A new 50 MM Btu/hr rated gas-fired heater will be installed as part of the BSI Unit.

3.7.2.2 BSI Product Tank (MSAT II)

SWRC will construct a new, external floating roof storage tank to support the new BSI Unit operation. This tank will have a nominal storage capacity of 100,000 bbl, and will primarily be used to store gasoline intermediate with a Reid Vapor Pressure (RVP) of approximately 4. However, under certain circumstances this tank may hold other materials, so emission calculations for the tank were developed assuming the contents is gasoline with a RVP of 6.

The tank will have the following design characteristics:

Type of Tank: External Floating Roof
Diameter: 120 feet
Throughput: 10,327 Barrels per day (Bpd) (typical value - for emissions estimation only)
Paint color: White
Roof Type: Pontoon Deck
Tank Construction: Welded
Primary Seal: Mechanical Shoe
Secondary Seal: Rim-Mounted
Fittings: Access Hatches, Roof Legs, Non-Slotted Guidepoles

3.7.2.3 Fugitive Emission Components (MSAT II)

The new BSI Unit, the updates to the #1 HDS unit, the new storage tank, and the modified Tank 401 will require the installation of piping components such as valves, pumps, flanges, and drains. The BSI Unit will also require the construction of interconnecting process and utility piping to tie the new unit into the refinery process and utility systems, which will require the installation of additional piping components. The new equipment in VOC service will result in potential fugitive emissions and are incorporated into the project emission calculations.

3.7.3 #3 Sour Water Stripper (3#SWS)

SWRC is planning to install a new sour water stripper (#3SWS) to provide the capability to treat sour water during periods of downtime for the current sour water stripper system.

3.7.4 New Emergency Air Compressor

SWRC operates an emergency air compressor system to provide instrument air to critical instruments in the event of a power failure. A new emergency air compressor will be installed to supplement the existing emergency air supply system. The new air compressor will be driven by a diesel engine meeting the provisions of 40 CFR Part 89.112 for Tier III engines. This engine will be limited to 500 hours of non emergency operation.

3.8 Non-Modified Equipment

The following units will not be physically modified or undergo a change in method of operation but may see an incremental increase in actual emissions from associated process unit emission sources as a result of the increase in crude oil throughput (section 3.1), elimination of the selected heater firing rates (section 3.2), operation of the MSAT II project (section 3.3), or operation of the upgraded sour water stripper system (section 3.4). The process units associated with the non-modified equipment have sufficient capacity to process the incremental increases in intermediate streams associated with the increased crude oil throughput. Emission sources associated with the non-modified equipment will have no increases in allowable emission rates with respect to previous permitting actions. Heater firing rates associated with the non-modified equipment will have no increases above the values used to calculate the allowable emission rates in previous permitting actions.

3.8.1 #1 and #2 Hydrogen Plants

Increased crude throughput will result in increased Hydrogen (H2) generation (needed for hydrotreating) at the refinery which will result in incremental increases in the firing rates of the heaters associated with these units. In addition, the new BSI Unit is expected to require a supply of up to 4 million standard cubic feet per day (MMscfd) of hydrogen beyond the amount of hydrogen needed for current refinery operations. This increased hydrogen may be produced by either the existing #1 or #2 Hydrogen plants and will require an incremental increase in the firing rate of the #1 and/or #2 Hydrogen plant Heaters.

During BSI Unit startup, a small incremental increase in steam production will be required. Startup will only occur for a two-day period approximately twice per year. This steam will be provided from the increased firing of the 581 Crude Unit heater, #1 H2 plant and #2 H2 plants which all have waste heat recovery systems used to produce steam.

3.8.2 #1 HDS

As identified previously, increased crude throughput will result in increased hydrotreating at the #1 HDS which will result in an incremental increase in the firing rate of the #1 HDS heater associated with this unit.

As part of the MSAT II project, SWRC will require #1 HDS to process the BSI Unit feedstock but will not result in any incremental increase in the firing rate of associated heaters. As a result of this project, light naphtha from the Hydrocracker and the 582 Crude Unit will now be fed to the #1 HDS. However, heavy naphtha from the Hydrocracker Unit, which is currently fed to the #1 HDS, will now be fed directly to the LEF Tower and Naphtha Splitter instead. The flow of heavy Hydrocracker naphtha exceeds the combined flow of the two light naphtha streams, therefore the #1 HDS will not receive an overall increase in feed rate as a result of the MSAT II project. Note that beyond the potential fugitive emission component increases previously identified as part of the MSAT II Project, these updates to the #1 HDS will not impact any existing #1 HDS emission source (i.e., fired heater).

3.8.3 Light Ends Fractionator (LEF)

Increased crude throughput will result in increased throughput at the LEF which will result in an incremental increase in the firing rates of the heater associated with this unit.

As part of the MSAT II project, SWRC will require LEF Unit to process the BSI Unit feedstock. Please note that beyond the potential fugitive emission component increases previously identified, these updates to the LEF Unit will not impact any existing LEF emission sources (i.e., fired heater) at the SWRC refinery nor increase the processing capacity of the unit. As a result of this project, heavy naphtha from the Hydrocracker Unit, which is currently fed to the #1 HDS Unit, will now be fed directly to the LEF Tower.

There will be incremental increases in throughputs to the Light Ends Fractionator Unit and Naphtha Splitter Unit as a result of the increased firing rate at the 581 Crude Unit which will result in small incremental increases in the firing rates of the two heaters associated with these units.

3.8.4 781 Reformer

Increased crude throughput will result in increased throughput at the 781 Reformer which will result in an incremental increase in the firing rates of the heaters associated with this unit (reformer heaters 1 through 3 and the stabilizer heater). Currently, heavy naphtha from the Hydrocracker Unit is fed to the #1 HDS Unit. After implementation of the MSAT II Project, this heavy naphtha will instead be fed to the LEF Tower and processed through the Naphtha Splitter that will also result in an incremental increase in reformer heater firing.

3.8.5 #2 HDS

Increased crude throughput will result in increased hydrotreating at the #2 HDS which will result in an incremental increase in the firing rates of the heater associated with this unit. Light cycle oil (a kerosene/diesel range intermediate) from the FCCU may be routed to the #2 HDS Unit for further processing. Its capacity is limited by the hydraulic capacity of its charge pumps.

3.8.6 #3 HDS

Increased crude throughput will result in increased hydrotreating at the #3 HDS which will result in an incremental increase in the firing rates of the heater associated with this unit. Light cycle oil (a kerosene/diesel range intermediate) from the FCCU may be routed to the #3 HDS Unit for further processing. Its capacity is limited by the hydraulic capacity of its charge pumps.

3.8.7 #4 HDS

Increased crude throughput will result in increased hydrotreating at the #4 HDS which will result in an incremental increase in the firing rates of the heaters associated with this unit. The #4 HDS Unit supplies hydrotreated gasoil feed to the FCCU. Its capacity is limited by the hydraulic capacity of its charge pumps.

3.8.8 Fluid Catalytic Cracking Unit (FCCU)

Increased crude throughput will result in increased throughput at the FCCU which will result in an incremental increase in emissions from this source. The FCCU receives hydrotreated gasoils from the #4 HDS. Its capacity is limited by the hydraulic capacity of its charge pumps and it air blowers.

3.8.9 Hydrocracker Unit (HCU)

Increased crude throughput will result in increased hydrotreating at the HCU which will result in an incremental increase in the firing rates of the heaters associated with this unit. Light cycle oil from the FCCU may be routed to the HCU for further processing. Coker gasoil from the Coker Unit may also be sent to the HCU for further processing. Its capacity is limited by the hydraulic capacity of its charge pumps.

3.8.10 Gas Recovery Unit (GRU)

Increased crude throughput will result in increased throughput at the GRU. Overhead gases generated by the FCCU are sent to the GRU for processing/separation prior to sending them to the Alky Unit, Poly Plant or to storage. Its capacity is limited by the hydraulic capacity of its charge pumps. There are no point sources of emissions associated with the GRU.

3.8.11 Saturate Gas Recovery Unit (SGRU)

Increased crude throughput will result in increased throughput at the SGRU. Overhead gases generated by the HCU, Naphtha Splitter and Reformer are sent to the SGRU for processing/separation prior to sending them to the Alky Unit, Poly Plant or to storage. Its capacity is limited by the hydraulic capacity of its charge pumps. There are no point sources of emissions associated with the SGRU.

3.8.12 Poly Plant

Increased crude throughput will result in increased throughput at the Poly Plant. The Poly Plant processes gases from the GRU and produces a gasoline blendstock that is sent to storage. Its capacity is limited by the hydraulic capacity of its charge pumps. There are no point sources of emissions associated with the Poly Plant.

3.8.13 Alky Unit

Increased crude throughput will result in increased throughput at the Alky Unit. The Alky Unit processes olefins generated by the FCCU and butane/butylenes from storage to produce alkylate, a gasoline blendstock. Its capacity is limited by the hydraulic capacity of its charge pumps. There are no point sources of emissions associated with the Alky Unit.

3.8.14 Coker Unit

Vacuum Tower bottoms and Slurry from the FCCU (both heavy hydrocarbon intermediates) may be routed to the Coker Unit for further processing. Increased crude throughput will result in increased throughput at the Coker Unit which will result in an incremental increase in the firing rates of the heater associated with this unit. Its capacity is limited by the hydraulic capacity of its charge pumps.

3.8.15 Sulfur Recovery Plants (SRPs)

Intermediate streams throughout the refinery are routed to the various hydrotreater units for sulfur removal. The resulting acid gas generated by the hydrotreating units is processed through the following SRP systems:

- #1 and #2 Sulfur Recovery Units (#1SRU, #2 SRU) and their associated Tail Gas Treatment Unit (#1TGTU)
- The SRP #3 Sulfur Recovery Unit (#3SRU) and its associated Tail Gas Treatment Unit (#3TGTU)
- #4 Sulfur Recovery Unit (#4SRU) and its associated Tail Gas Treatment Unit (#4TGTU)

In addition, sour water stripper overhead gases from #1SWS, #2SWS and #3SWS are routed to #2SRU, #3SRU and/or #4SRU for processing. Increased crude throughput will result in an incremental increase in throughput at all SRPs.

3.8.16 Light Oil Loading Rack (LOLR)

Increased crude throughput will result in increased throughput at the LOLR. The increase in finished products may be distributed to commerce via the LOLR System. Its capacity is limited by the hydraulic capacity of its loading pumps and market demand.

3.8.17 Storage Tanks

Increased crude throughput will result in increased working loss emissions from the majority of the crude, intermediate and product storage tanks at the refinery.

3.8.18 Pressure Vessels

Increased crude throughput will result in increased pressure vessel throughput. There are no routine emissions associated with the pressure vessels.

3.8.19 Asphalt Plant

The increase in the production of vacuum tower bottoms or FCCU slurry associated with this project may be directed to the Asphalt Plant for processing. Please note the #2 Asphalt heater has been idled and is in the process of being permanently removed from service.

3.9 Unaffected Units

This section describes process units at the refinery that will not be debottlenecked, physically modified or experience a change in the method of operation as a result of the Crude Oil Optimization Project. The capacities of these process units are limited by the equipment as is but are identified in the following for application completeness.

3.9.1 582 Crude Unit / 582 Vacuum Unit

Throughput to these units will be unaffected by the increase in crude rate to the 581 Crude Unit. The 582 Crude Unit and 582 Vacuum Unit capacity is limited by the hydraulic capacity of their charge pumps.

3.9.2 Boilerhouse

The Crude Oil Optimization project will require additional steam generation for use as stripping steam at the 581 Crude Unit and 583 Vacuum Unit Eductor system. Additionally, during normal operations, the new BSI Unit will not require any additional steam compared to current conditions, as the project involves gasoline-range intermediates, which do not require steam tracing. However, a small amount of steam will be required during startup of the BSI Unit. Startup of this unit is conservatively estimated to occur twice per year, and will take place over two days. During these startup periods, the refinery will be required to provide an incremental increase in steam that may be supplied by any of the steam generators at the refinery.

However, as identified previously in Section 3.4.2, this project will result in a net steam increase from waste heat recovery systems and will not require any additional steam to be produced by refinery boilers.

3.9.3 Flare Gas Recovery (FGR) System

SWRC is currently upgrading the FGR system to comply with the provisions of the Consent Decree[4]. These upgrades include several provisions to reduce the generation of refinery gas vented to the flare. After completion of these upgrades, SWRC believes the FGR system will be adequate to capture the routinely generated refinery fuel gases for treatment in the refinery's amine system for ultimate use as NSPS J and Ja compliance refinery fuel gas.

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[4] Civil Action No. 08CV 020-D

3.9.4 Oily Water Treatment System

The 581 crude unit and downstream units associated with the Crude Optimization Project will not see an increase in water throughput or wastewater generation associated with the Crude Optimization Project. The 581 desalter is designed to operate over a range of water/oil ratios, and running at the increased crude rate will result in operation at a lower water/oil ratio with the overall oily water generation remaining constant.

SWRC is currently in the process of upgrading its Oily Water treatment system in accordance with its settlement agreement with WDEQ/SHWD[5]. The operation of the upgraded Oily Water treatment system and enhanced controls will result in no additional emissions from waste water treatment.

3.9.5 Cooling Towers

Increased crude throughput may result in increased duty at the refineries cooling tower systems that include the following:

- 583 Cooling Tower
- Fluor Cooling Tower
- Marley Cooling Tower
- Coker Cooling Tower

These cooling towers operate at a constant water circulation rate that is independent of duty. Total dissolved solids (TDS) and Total suspended solids (TSS) content of the circulating water are controlled to prescribed levels currently in place at the refinery. Because there will be no change to the water circulation rate or TSS/TDS levels in the water, there will be no emission changes to these cooling towers associated with this project.

Additionally, there will be no change to the operation of the 582 Cooling Tower as a result of the project.

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[5] Settlement Agreement for Notice of Violation Docket # 4713-10

SECTION 4
EMISSION CALCULATION METHODOLOGY

4.1 Estimated Emissions

4.1.1 New Sources

The proposed PTE (or proposed allowable emissions) for the new sources associated with the Crude Oil Optimization Project are presented in Table 4.1. The following table includes proposed potential emissions for CO_2, CH_4, and N_2O which are also expressed as CO_2e.

Table 4-1 Potential to Emit – New Sources

Operating Unit	Emission Source	Firing Rate for Estimated Emissions (MMBtu/hr)	CH4 Emissions TPY	N2O Emissions TPY	CO2 Emissions TPY	CO2e Emissions TPY
BSI	BSI Heater	50.0	1.4	0.3	28,477.9	28,597.9
Tank Farm	100 M bbl tank	N/A	Insignificant	N/A	N/A	Insignificant
Boilerhouse	New Emergency Air Compressor	N/A	<0.1	<0.1	114.1	114.5
Equipment Leaks	Fugitive Emissions	N/A	1.9	N/A	N/A	40.8
Total New Sources:			**3.3**	**0.3**	**28,592.0**	**28,753.2**

4.1.2 Modified Sources

Table 4.2 presents the PTE from the modified sources associated with the project.

Table 4-2 Potential to Emit – Modified Sources

Operating Unit	Emission Source	Firing Rate for Estimated Emissions (MMBtu/hr)	CH4 Emissions TPY	N2O Emissions TPY	CO2 Emissions TPY	CO2e Emissions TPY
581 Crude Unit	581 Crude Heater	233.0	6.7	1.3	132,706.9	133,266.0
583 Vacuum Unit	583 Vacuum Heater	64.2	1.9	0.4	36,565.6	36,719.6
Coker	Coker Unit flare	100.0	2.9	0.6	57,921.1	58,161.1
781 Reformer	Naphtha Splitter Heater	46.3	1.3	0.3	26,370.5	26,481.6
Hydrocracker	Heater H5	44.9	1.3	0.3	25,573.1	25,680.9
#1 HDS	#1HDS Heater	33.4	1.0	0.2	19,023.2	19,103.4
Total Modified Sources:			**15.1**	**3.1**	**298,160.4**	**299,412.6**

4.1.3 Non-Modified Sources

The estimated incremental emissions from non-modified/ancillary sources are presented in Table 4.3. The emission rates shown are the emissions that will result from the incremental increases involving these sources.

Table 4-3 Potential to Emit – Non-Modified Sources

Operating Unit	Emission Source	Firing Rate for Estimated Emissions (MMBtu/hr)	CH4 Emissions TPY	N2O Emissions TPY	CO2 Emissions TPY	CO2e Emissions TPY
781 Reformer	LEF Heater	24.0	0.7	0.1	13,669.4	13,727.0
	#1 Reformer Heater	44.6	1.3	0.3	25,402.3	25,509.3
	#2 Reformer Heater	74.8	2.2	0.4	42,602.9	42,782.4
	#3 Reformer Heater	22.4	0.6	0.1	12,758.1	12,811.8
	Stabilizer Heater	11.1	0.3	<0.1	6,322.1	6,348.7
Hydrocracker	Heater H1/H2	38.0	1.1	0.2	21,643.2	21,734.4
	Heater H3	56.0	1.6	0.3	31,895.2	32,029.6
	Heater H4	57.0	1.6	0.3	32,464.8	32,601.6
Coker	Coker Heater	145.0	4.2	0.8	82,585.9	82,933.8
	Coker (Material Handling)	N/A	N/A	N/A	N/A	N/A
780 FCCU	780 FCC Heater B3	10.0	0.3	<0.1	5,695.6	5,719.6
	780 FCC Heater H2	19.4	0.6	0.1	11,049.4	11,096.0
	780 FCCU Regenerator	N/A	25.3	3.7	235,738.0	237,411.5
#2 HDS	Charge Heater	28.0	0.8	0.2	15,947.6	16,014.8
#3 HDS	Charge Heater	18.0	0.5	0.1	10,252.0	10,295.2
#4 HDS	H2 Heater (25-HT-101)	22.0	0.6	0.1	12,530.3	12,583.1
	H2 Heater (25-HT-102)	24.0	0.7	0.1	13,669.4	13,727.0
#1 H2 Plant	#1 H2 Plant Heater	288.0	8.3	8.3	164,032.6	166,788.4
#2 H2 Plant	#2 H2 Plant Heater	288.0	8.3	1.7	164,032.6	164,723.6
#1,#2,#3,#4 SRU	#1,#3,#4 TGTU	N/A	0.9	0.2	17,086.7	17,158.7
Asphalt Loading	Asphalt Heater #1	8.0	0.2	<0.1	4,556.5	4,575.7
Tank Farm	Working Losses - aggregate	N/A	Insignificant	N/A	N/A	Insignificant
Light Oil Loading	Loading Rack Flare	N/A	1.2	<0.1	733.4	762.9
Total Non-Modified Sources:			**61.4**	**17.3**	**924,667.9**	**931,334.8**

Emissions calculations supporting Tables 4.1 through 4.3 for the new, modified, non-modified, and decommissioned sources associated with this project are provided in the following Appendices:

Appendix A: CO_2 Emission Calculations
Appendix B: CH_4 Emission Calculations
Appendix C: N_2O Emission Calculations

Appendix D: Fugitive Emission Calculations
Appendix E: CO_2e Emission Totals
Appendix F: GHG BACT Cost Analyses

4.2 Emissions Calculation Basis

A discussion of the basis for the calculations provided in Appendices A through E is provided in the following. Note that only the sources that are new, modified or may see an incremental increase in ancillary emissions are listed. The emission calculation basis for all sources unaffected by the project is reflected in their corresponding construction permits and permit applications.

4.2.1 CO_2 Emissions

Heaters

These units will be fired with refinery fuel gas and/or purchased natural gas and PSA gas (in the case of the #1 and #2 Hydrogen Plant) and emissions are conservatively estimated by using emission factors taken from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, CO_2 emissions from refinery fuel gas combustion are calculated based on the emission factor of 59 kg-CO2 / MM Btu (40 CFR 98 Subpart C Table C-1).

Coker Unit Flare

The Coker Unit Flare is currently an NSPS J compliant flare. As part of this permitting action SWRC will require 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. Emissions of CO_2 are conservatively estimated by using emission factors taken from the Federal GHGMRR Rule 40 CFR 98 Subpart Y – Petroleum Refineries. Specifically, CO_2 emissions from flared gas are calculated based on the emission factor of 60 kg-CO2 / MM Btu (40 CFR 98 Subpart Y Equation Y-2).

SRPs

Sulfur Recovery Units will be fired with refinery fuel gas and/or purchased natural gas and emissions are conservatively estimated by using emission factors taken from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, CO_2 emissions from refinery fuel gas combustion are calculated based on the emission factor of 59 kg-CO2 / MM Btu (40 CFR 98 Subpart C Table C-1).

FCCU

Emissions of CO_2 are conservatively estimated by using emission the methodology identified in the Federal GHGMRR Rule 40 CFR 98 Subpart Y

– Petroleum Refineries. Specifically, CO_2 emissions from the FCCU are calculated based on 40 CFR 98 Subpart Y Equation Y-6 and converting from metric tons to U.S. tons.

LOLR

CO_2 emissions from the combustion of controlled vapors of gasoline and distillate at the LOLR is not explicitly required under the Federal GHGMRR Rule. However, SWRC has conservatively calculated the LOLR emissions of CO_2 from the combustion of controlled vapors based on the LOLR throughput, vendor emission factor, and a ratio of CO_2 emissions (40 CFR 98 Subpart C Table C-1) and CO emissions (AP-42) from combustion.

New Emergency Air Compressor

CO_2 emissions from the new emergency air compressor are conservatively estimated by using emission factors taken from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, CO_2 emissions from diesel combustion are calculated based on the emission factor of 73.96 kg-CO_2 / MM Btu (40 CFR 98 Subpart C Table C-1) at maximum design operation for 500 hrs/yr.

4.2.2 CH_4 Emissions

Heaters

These units will be fired with refinery fuel gas and/or purchased natural gas and PSA gas (in the case of the #1 and #2 Hydrogen Plant) and emissions are conservatively estimated by using emission factors taken from the Federal GHG MRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, CH_4 emissions from refinery fuel gas combustion are calculated based on the emission factor of 3×10^{-3} kg-CH_4 / MM Btu (40 CFR 98 Subpart C Table C-2).

Coker Unit Flare

The Coker Unit Flare is currently an NSPS J compliant flare. As part of this permitting action SWRC will require 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. Emissions of CH_4 are conservatively estimated by using emission factors taken from the Federal GHGMRR Rule 40 CFR 98 Subpart Y – Petroleum Refineries. Specifically, CH_4 emissions from glared gas are calculated based on the emission factor of 3×10^{-3} kg-CH_4 / MM Btu (40 CFR 98 Subpart Y Equation Y-4 that references Table C-2).

SRPs

Sulfur Recovery Units will be fired with refinery fuel gas and/or purchased natural gas and emissions are conservatively estimated by using emission factors taken from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, CH_4 emissions from refinery fuel gas combustion are calculated based on the emission factor of 3 x 10^{-3} kg-CH_4 / MM Btu (40 CFR 98 Subpart C Table C-2).

FCCU
Emissions of CH_4 are conservatively estimated by using emission the methodology identified in the Federal GHGMRR Rule 40 CFR 98 Subpart Y – Petroleum Refineries. Specifically, CH_4 emissions from the FCCU are calculated based on 40 CFR 98 Subpart Y Equation Y-9 and converting from metric tons to U.S. tons.

LOLR
CH_4 emissions from the combustion of controlled vapors of gasoline and distillate at the LOLR is not explicitly required under the Federal GHGMRR Rule. However, SWRC has conservatively calculated the LOLR emissions of CH_4 from the combustion of controlled vapors based on the LOLR throughput, AP-42 VOC emission factors (distillate loading), federal VOC emission limits (gasoline loading) and a conservative estimate of 55% methane (AP-42 Chapter 13.5 Table 13.5-2).

New Emergency Air Compressor
CH_4 emissions from the new emergency air compressor are conservatively estimated by using emission factors taken from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, CH_4 emissions from diesel combustion are calculated based on the emission factor of 3 x 10^{-3} kg-CH_4 / MM Btu (40 CFR 98 Subpart C Table C-2) at maximum design operation for 500 hrs/yr.

Fugitive Emissions
Fugitive emissions estimates are based on a conservative estimate of piping component to be added with this project and the Protocol for Equipment Leak Emission Estimates screening value correlations and AP-42[6] for VOC. Fugitive CH_4 emissions are then calculated conservatively assuming 25% CH_4.

4.2.3 N_2O Emissions

Heaters
These units will be fired with refinery fuel gas and/or purchased natural gas and PSA gas (in the case of the #1 and #2 Hydrogen Plants) and emissions are conservatively estimated by using emission factors taken from the Federal

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[6] Protocol for Equipment Leak Emission Estimates, (EPA-453/R-95-017, Table 2-10: Screening Value correlations, Table 2-2: Refinery Average Emission Factors) AP-42, 4 ed, (Fugitive Emission Factors, Table 9.1-2).

GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, N_2O emissions from refinery fuel gas combustion are calculated based on the emission factor of 6×10^{-4} kg- N_2O / MM Btu (40 CFR 98 Subpart C Table C-2).

Coker Unit Flare

The Coker Unit Flare is currently an NSPS J compliant flare. As part of this permitting action SWRC will require 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. Emissions of N_2O are conservatively estimated by using emission factors taken from the Federal GHGMRR Rule 40 CFR 98 Subpart Y – Petroleum Refineries. Specifically, N_2O emissions from flared gas are calculated based on the emission factor of 6×10^{-4} kg- N_2O / MM Btu (40 CFR 98 Subpart Y Equation Y-5 that references Table C-2).

SRPs

Sulfur Recovery Units will be fired with refinery fuel gas and/or purchased natural gas and emissions are conservatively estimated by using emission factors taken from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, N_2O emissions from refinery fuel gas combustion are calculated based on the emission factor of 6×10^{-4} kg- N_2O / MM Btu (40 CFR 98 Subpart C Table C-2).

FCCU

Emissions of N_2O are conservatively estimated by using emission the methodology identified in the Federal GHGMRR Rule 40 CFR 98 Subpart Y – Petroleum Refineries. Specifically, N_2O emissions from the FCCU are calculated based on 40 CFR 98 Subpart Y Equation Y-10 and converting from metric tons to U.S. tons.

LOLR

N_2O emissions from the combustion of controlled vapors of gasoline and distillate at the LOLR is not explicitly required under the Federal GHGMRR Rule. However, SWRC has conservatively calculated the LOLR emissions of N_2O from the combustion of controlled vapors based on the LOLR throughput, vendor emission factor, and a ratio of N_2O emissions (40 CFR 98 Subpart C Table C-2) and NOx emissions (AP-42) from combustion.

New Emergency Air Compressor

N_2O emissions from the new emergency air compressor are conservatively estimated by using emission factors taken from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources. Specifically, N_2O emissions from diesel combustion are calculated based on the emission factor of 6 x 10^{-4} kg-N_2O / MM Btu (40 CFR 98 Subpart C Table C-2) at maximum design operation for 500 hrs/yr.

4.2.4 CO_2e Emissions

CO2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). SWRC has used the GWP values in Table A-1 of the GHG MRR Rule (40 CFR Part 98, Subpart A, Table A-1) to calculate CO2e emissions from estimated emissions of CO_2, CH_4, and N_2O by multiplying the individual GHG pollutant rates by their applicable GWP provided below.

POLLUTANT	GWP
CO_2	1
CH_4	21
N_2O	310

SECTION 5
NETTING EMISSION CALCULATIONS

The sum of the GHG emission increases from new equipment and increased emissions from modified and non-modified equipment for the Crude Oil Optimization Project is above the PSD significance levels. Therefore, netting emission calculations for all increases and decreases in emissions of GHG in the contemporaneous period can be applied. However, for the purposes of this application, SWRC has elected not to perform netting emission calculations in order to "net out" of PSD permitting requirements. SWRC reserves the right to perform historical GHG netting calculations for future refinery projects but has not elected to do so for the purposes of the Crude Oil Optimization Project and thus a Best Available Control Technology Review (BACT) for GHG is included in the following section.

SECTION 6
GHG BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

As shown in the Sections 4.0 and 5.0, the increase in potential GHG emissions associated with this project are above the PSD threshold. Subsequently, any new or modified affected emissions unit where a net increase in CO_2, CH_4, and N_2O emissions has occurred is subject to the application of BACT.

6.1 Methodology

BACT is defined in 40 CFR 52.21(b)(12) of the PSD regulations as "..an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any…source…which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs". For the past fifteen years it has been EPA's policy to require a "top-down" BACT analysis as described in EPA's October, 1990, Draft New Source Review Workshop Manual. Two key elements of a top-down analysis are that the most stringent control technologies must be considered, and a decision to require a lesser degree of emissions reduction must be based on an objective analysis of energy, environmental and economic impacts.
The five basic steps of a top-down BACT analysis are listed below:

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

The first step is to identify potentially "available" control options for each emission unit triggering PSD, for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emission unit in question. The list should include lowest achievable emission rate (LAER) technologies, innovative technologies, and controls applied to similar source categories. For this analysis, the following sources were relied upon:

- EPA's New Source Review Website,
- U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database,
- Various state air quality regulations and websites,
- Recent EPA Consent decrees within the refining industry,

- Control Technology Vendors,
- Technical Books and Articles (as specified in the references to this document), and
- Guidance Documents.

After identifying potential technologies, the second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important, in this step, that the technical basis for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source-specific factors related to safe and successful use of the controls.

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation. Potential adverse impacts, however, must still be identified and evaluated.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. The economic or cost-effectiveness" analysis is conducted in a manner consistent with EPA's *OAQPS Control Cost Manual* Fifth Edition (EPA 1996) and subsequent revisions. An important aspect of the top-down BACT methodology is the establishment of baseline emission levels that are used in calculating the cost-effectiveness of alternative control options. EPA's Draft *New Source Review Workshop Manual* states that baseline emissions should be a realistic upper bound estimate of emissions taking into account physical or operational constraints and historical operating data.

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern.

6.2 Identify all control technologies

BACT considerations for CO_2, CH_4, and N_2O emissions from the proposed new and modified sources follow.

6.2.1 CO2 Control Technologies

6.2.1.1 CO2 Emissions from Coker Flare

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 (see Section 6.1) 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.

6.2.1.2 CO2 Emissions from New and Modified Process Heaters

CO_2 will be emitted from the new and modified 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 is a low carbon fuel. 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 CO has long been a regulated pollutant with established adverse health impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidized to CO_2 in the atmosphere. CO_2 emissions are generated and emitted from the new and modified heaters and exhausted to the atmosphere from multiple stacks located throughout the refinery.

The following technologies were identified as CO_2 control options for refinery process heaters based on available information and data sources (see Section 6.1).

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

6.2.1.2.1 Use of Low Carbon Fuels

The following table presents the amount of CO_2 formed when combusting fossil fuels[7], including some of the fuels that will be used by the new and modified heaters at SWRC.

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[7] 40 CFR 98 Subpart C Table C-1

Fuel type	**Default CO_2 emission factor**
Coal and coke	kg CO_2/mmBtu
Anthracite	103.54
Bituminous	93.40
Subbituminous	97.02
Lignite	96.36
Coke	102.04
Mixed (Commercial sector)	95.26
Mixed (Industrial coking)	93.65
Mixed (Industrial sector)	93.91
Mixed (Electric Power sector)	94.38
Natural gas	kg CO_2/mmBtu
(Weighted U.S. Average)	**53.02**
Petroleum products	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	73.25
Distillate Fuel Oil No. 2	73.96
Distillate Fuel Oil No. 4	75.04
Residual Fuel Oil No. 5	72.93
Residual Fuel Oil No. 6	75.10
Used Oil	74.00
Kerosene	75.20
Liquefied petroleum gases (LPG)	62.98
Propane	61.46
Propylene	65.95
Ethane	62.64
Ethanol	68.44
Ethylene	67.43
Isobutane	64.91
Isobutylene	67.74
Butane	65.15
Butylene	67.73

Fuel type	Default CO_2 emission factor
Naphtha (<401 deg F)	68.02
Natural Gasoline	66.83
Other Oil (>401 deg F)	76.22
Pentanes Plus	70.02
Petrochemical Feedstocks	70.97
Petroleum Coke	102.41
Special Naphtha	72.34
Unfinished Oils	74.49
Heavy Gas Oils	74.92
Lubricants	74.27
Motor Gasoline	70.22
Aviation Gasoline	69.25
Kerosene-Type Jet Fuel	72.22
Asphalt and Road Oil	75.36
Crude Oil	74.49
Other fuels-solid	kg CO_2/mmBtu
Municipal Solid Waste	90.7
Tires	85.97
Plastics	75.00
Petroleum Coke	102.41
Other fuels—gaseous	kg CO_2/mmBtu
Blast Furnace Gas	274.32
Coke Oven Gas	46.85
Propane Gas	61.46
Fuel Gas	**59.00**
Biomass fuels—solid	kg CO_2/mmBtu
Wood and Wood Residuals	93.80
Agricultural Byproducts	118.17
Peat	111.84
Solid Byproducts	105.51

Fuel type	Default CO_2 emission factor
Biomass fuels—gaseous	kg CO_2/mmBtu
Biogas (Captured methane)	52.07
Biomass Fuels—Liquid	kg CO_2/mmBtu
Ethanol	68.44
Biodiesel	73.84
Biodiesel (100%)	73.84
Rendered Animal Fat	71.06
Vegetable Oil	81.55

As shown in the table, the use of natural gas and refinery fuel gas reduces the production of CO_2 from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

6.2.1.2.2 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.

6.2.1.2.3 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,
- Excess Combustion Air Monitoring and Control, and
- Cogeneration as a CO_2 Reduction Technique.

6.2.1.2.4 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. 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.

There are several major unresolved issues with respect to CO_2 sequestration including the legal process for closing and remediating sequestration sites and liability for accidental releases from these sites. Until these legal and financial responsibility issues are defined and codified by the Federal government, companies and most likely states will not undertake commercial geologic CO_2 sequestration activities beyond those states that already have regulations for this.

6.2.1.2.5 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 percent nitrogen and because the refinery fuel gas is a low-carbon fuel, the CO_2 concentration in the exhaust gases is approximately 5 percent or less. 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.

There are several major unresolved issues with respect to CO_2 sequestration including the legal process for closing and remediating sequestration sites and liability for accidental releases from these sites. Until these legal and financial responsibility issues are defined and codified by the Federal government, companies and most likely states will not undertake commercial geologic CO_2 sequestration activities beyond those states that already have regulations for this.

6.2.1.3 CO2 Emissions from New Emergency Air Compressor

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 (see Section 6.1)

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

6.2.1.3.1 Use of Low Carbon Fuels

As previously shown in Section 6.2.1.2.1, 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).

6.2.1.3.2 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.

6.2.1.3.3 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, and
- Proper Combustion Air Monitoring and Control.

6.2.2 CH4 Control Technologies

6.2.2.1 CH4 Emissions from New Fugitive Emission Sources

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.

Based on available information and data sources (see Section 6.1) 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.

6.2.2.2 CH4 Emissions from Coker Flare

Operation of the Coker Flare results in CH_4 emissions from the combustion of gas supplied to the flare. Based on available information and data sources (see Section 6.1) there is no technology for CH_4 control options post combustion for refinery flares. Thus, the only potential BACT control for the flare is to minimize all potential flaring events.

6.2.2.3 CH4 Emissions from New and Modified Process Heaters

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 (see Section 6.1)

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

6.2.2.3.1 Use of Low Carbon Fuels

The following table presents the amount of CH_4 formed when combusting fossil fuels[8], including some of the fuels that will be used by the new and modified heaters at SWRC.

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.1×10^{-02}
Natural Gas	1.0×10^{-03}
Petroleum (All fuel types in Table C–1)	3.0×10^{-03}
Municipal Solid Waste	3.2×10^{-02}
Tires	3.2×10^{-02}
Blast Furnace Gas	2.2×10^{-05}
Coke Oven Gas	4.8×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	3.2×10^{-02}
Biogas	3.2×10^{-03}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-03}

As shown in the table, the use of natural gas and refinery fuel gas reduces the production of CH_4 from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

6.2.2.3.2 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,

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[8] 40 CFR 98 Subpart C Table C-2

- 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.

6.2.2.3.3 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.

6.2.2.3.4 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.

6.2.2.4 CH4 Emissions from New Emergency Air Compressor

As previously identified for new and modified process heaters, CH_4 will be emitted from the new emergency air compressor as a result of any incomplete combustion of fuel. The following technologies were identified as CH_4 control options for the new emergency air compressor based on available information and data sources (see Section 6.1).

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

6.2.2.4.1 Use of Low Carbon Fuels

As previously shown in Section 6.2.2.3.1, the use of diesel fuel reduces the production of CH_4 from combustion of fuel relative to burning solid fuels (e.g. coal or coke).

6.2.2.4.2 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.

6.2.2.4.3 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, and
- Proper Combustion Air Monitoring and Control.

6.2.3 N2O Control Technologies

6.2.3.1 N2O Emissions from Coker Flare

Operation of the Coker Flare results in N_2O emissions from the combustion of gas supplied to the flare. N_2O will be emitted from the Coker Flare in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process. Based on available information and data sources (see Section 6.1) there is no technology for N_2O control options post combustion for refinery flares. Thus, the only potential BACT control for the flare is to minimize all potential flaring events.

6.2.3.2 N2O Emissions from New and Modified Process Heaters

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 CH_4 control options for refinery process heaters based on available information and data sources (see Section 6.1).

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

6.2.3.2.1 Use of Low Carbon Fuels

The following table presents the amount of CH_4 formed when combusting fossil fuels[9], including some of the fuels that will be used by the new and modified heaters at SWRC.

Fuel type	Default N_2O emission factor (kg CH_4/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.6×10^{-03}
Natural Gas	1.0×10^{-04}
Petroleum (All fuel types in Table C–1)	6.0×10^{-04}
Municipal Solid Waste	4.2×10^{-03}
Tires	4.2×10^{-03}
Blast Furnace Gas	1.0×10^{-04}
Coke Oven Gas	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	4.2×10^{-03}
Biogas	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-04}

As shown in the table, the use of natural gas and refinery fuel gas reduces the production of N_2O from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

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[9] 40 CFR 98 Subpart C Table C-2

6.2.3.2.2 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.

6.2.3.2.3 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.

6.2.3.3 N2O Emissions from New Emergency Air Compressor

As previously identified for new and modified process heaters, N_2O will be emitted from the new emergency air compressor because in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process. The following technologies were identified as N_2O control options for the new emergency air compressor based on available information and data sources (see Section 6.1).

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

6.2.3.3.1 Use of Low Carbon Fuels

As previously shown in Section 6.2.3.2.1, the use of diesel fuel reduces the production of N_2O from combustion of fuel relative to burning solid fuels (e.g. coal or coke).

6.2.3.3.2 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.

6.2.3.3.3 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, and
- Proper Combustion Air Monitoring and Control.

6.3 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration technically infeasible options, a control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

A number of the process 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.

6.3.1 CO2 Control Technologies

6.3.1.1 Use of Lower Carbon Fuels for New and Modified Process Heaters

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 low-carbon fuels in process heaters that are technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas.

6.3.1.2 Pre-Combustion CO_2 Capture for New and Modified Process Heaters

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, for the purpose of this BACT analysis it is assumed that these technologies would be technically feasible.

6.3.1.3 Post-Combustion CO_2 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 in the following sections.

6.3.1.3.1 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 NO_X, and the energy requirements for solvent regeneration. To minimize the issue of reacting with SO_2 and NO_X, these impurities must be removed from the exhaust gas prior to separation.

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

6.3.1.3.2 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 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. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

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. 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.

6.3.1.3.3 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

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. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

6.3.1.3.4 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. Membrane technology is not fully developed for CO_2 concentration and gas flow such as the process heaters at a petroleum refinery. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

6.3.1.4 Carbon Transport and Storage

As discussed 6.2.1.3.4 and 6.2.1.3.5, 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 three sections.

6.3.1.5 Use of Lower Carbon Fuels for New Emergency Air Compressor

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 SWRC with the most reliable resource. The only identified fuels with lower CO_2 formation rates are syngas, pressure swing adsorption ("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.

6.3.2 CH4 Control Technologies

6.3.2.1 CH4 Emissions from New Fugitive Emission Sources

It is considered technically infeasible to propose a numeric CO_2e emission limit for fugitive emission sources due to the infrequent, unplanned, and undesired nature of these emissions. SWRC utilizes stringent NSPS and Consent Decree requirements to govern its LDAR program in an effort to minimize these emissions for both environmental and economic purposes. Moreover, it would be less effective to propose an allowable numeric limit for fugitive emission sources under which the refinery could operate than it is to follow the current LDAR program monitoring and repair requirements. Proposing a numeric CO_2e emission limit for fugitive emission sources would potentially allow for greater potential fugitive emissions based on only an emission factor estimate of future equipment leaks whereas the current LDAR program requirements require specific monitoring and repair action items to minimize fugitive emissions but cannot be used to set a future emission limit.

6.3.2.2 Use of Lower Carbon Fuels for New and Modified Process Heaters

The process heaters at the refinery combust refinery fuel gas which is a low-carbon fuel. The only identified fuels with lower CH_4 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 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 low-carbon fuels in process heaters that are technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas.

6.3.2.3 Oxidation Catalysts for New and Modified Process Heaters

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. Acceptable catalyst operating temperatures range from 400 to 1250 °F, with the optimal range being 850 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.

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. In addition, for heaters equipped with SCR for NO_x control, the presence of SO_3 in the exhaust gas will result in plugging or deactivation of the SCR catalyst. For these reasons, catalytic oxidation of CH_4 is not considered technically feasible for the refinery fuel gas fired process heaters.

6.3.2.4 Use of Lower Carbon Fuels for New Emergency Air Compressor

As previously identified, 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 SWRC with the most reliable resource. The only identified fuels with lower CO_2 formation rates are syngas, pressure swing adsorption ("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.

6.3.3 N2O Control Technologies

6.3.3.1 Use of Lower Carbon Fuels for New and Modified Process Heaters

The process heaters at the refinery combust refinery fuel gas which is a low-carbon fuel. The only identified fuels with lower N_2O 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 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 GHG emissions. Thus there are no control options involving the use of low-carbon fuels in process heaters that are technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas.

6.3.3.2 Use of Lower Carbon Fuels for New Emergency Air Compressor

As previously identified, 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 SWRC with the most reliable resource. The only identified fuels with lower CO_2 formation rates are syngas, pressure swing adsorption ("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.

6.4 Rank Remaining Control Technologies by Control Effectiveness

6.4.1 CO2 Control Technologies

The technologies that remain following completion of the technical feasibility analysis for CO_2 emissions are provided in the following sections.

6.4.1.1 CO2 Emissions from Coker Flare

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 (see Section 6.1) 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.

6.4.1.2 CO2 Emissions from New and Modified Process Heaters

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),
- Use of low carbon fuels (NA% control efficiency),
- Use of good combustion practices (NA% control efficiency), and
- Energy efficient design (NA% control efficiency).

6.4.1.3 CO2 Emissions from New Emergency Air Compressor

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.

- Use of low carbon fuels (NA% control efficiency),
- Use of good combustion practices (NA% control efficiency), and
- Energy efficient design (NA% control efficiency).

6.4.2 CH4 Control Technologies

The technologies that remain following completion of the technical feasibility analysis for CH_4 emissions are provided in the following sections.

6.4.2.1 CH4 Emissions from New Fugitive Emission Sources

Based on available information and data sources (see Section 6.1) 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.

6.4.2.2 CH4 Emissions from Coker Flare

Operation of the Coker Flare results in CH_4 emissions from the combustion of gas supplied to the flare. Based on available information and data sources (see Section 6.1) there is no technology for CH_4 control options post combustion for refinery flares. Thus, the only potential BACT control for the flare is to minimize all potential flaring events.

6.4.2.3 CH4 Emissions from New and Modified Process Heaters

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.

- Use of low carbon fuels (NA% control efficiency),
- Use of good combustion practices (NA% control efficiency), and
- Energy efficient design (NA% control efficiency).

6.4.2.4 CH4 Emissions from New Emergency Air Compressor

The following technologies and control efficiencies (where applicable) were identified as CH_4 control options for the new emergency air compressor based on available information and data sources.

- Use of low carbon fuels (NA% control efficiency),
- Use of good combustion practices (NA% control efficiency), and
- Energy efficient design (NA% control efficiency).

6.4.3 N2O Control Technologies

The technologies that remain following completion of the technical feasibility analysis for N_2O emissions are provided in the following sections.

6.4.3.1 N2O Emissions from Coker Flare

Operation of the Coker Flare results in N_2O emissions from the combustion of gas supplied to the flare. N_2O will be emitted from the Coker Flare in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process. Based on available information and data sources (see Section 6.1) there is no technology for N_2O control options post combustion for refinery flares. Thus, the only potential BACT control for the flare is to minimize all potential flaring events.

6.4.3.2 N2O Emissions from New and Modified Process Heaters

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.

- Use of low carbon fuels (NA% control efficiency),
- Use of good combustion practices (NA% control efficiency), and
- Energy efficient design (NA% control efficiency).

6.4.3.3 N2O Emissions from New Emergency Air Compressor

The following technologies and control efficiencies (where applicable) were identified as N_2O control options for the new emergency air compressor based on available information and data sources.

- Use of low carbon fuels (NA% control efficiency),
- Use of good combustion practices (NA% control efficiency), and
- Energy efficient design (NA% control efficiency).

6.5 Evaluate the Most Effective Controls and Document Results

6.5.1 CO2 Control Technologies

6.5.1.1 CO2 Emissions from Coker Flare

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 (see Section 6.1) 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.

6.5.1.2 *CO2 Emissions from New and Modified Process Heaters*

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

The use of low carbon fuels and good combustion practices are inherent in the operation of all process heaters at SWRC. These practices are of the utmost importance to SWRC 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 Combustion Air Preheat, Process Heat to Generate Steam, Process Integration and Heat Recovery, and Excess Combustion Air Monitoring and Control are utilized where possible but can be limited for heaters that do not have the physical area in the refinery to utilize these technologies. Additionally, SWRC currently does not have the regulatory authority to utilize Cogeneration as a CO_2 Reduction Technique for any of the new and modified process heaters.

6.5.1.2.2 Pre-Combustion Carbon Capture ("Oxyfuel")

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 costs for the CCS equipment needed for capture, compression, pipeline transportation, and injection/storage are approximately \$42.9 million. The levelized annual costs, including operating costs, are estimated to be approximately \$38.3 million per year. The resulting cost of CCS is approximately \$163 per ton of CO_2 sequestered (See Appendix F-1 for details regarding these cost analyses). This cost effectiveness assumes that the revenue from enhanced oil recovery (EOR) is equal to the long term cost of monitoring, operating, and maintaining the storage facility. These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, Pre-Combustion Carbon Capture and Storage does not represent BACT for the process heaters at SWRC.

6.5.1.2.3 Post-Combustion Carbon Capture

For the purposes of the following analysis of CCS, chemical absorption using MEA based solvents[10] is assumed to represent the best post-combustion CO_2 capture option, and the use of depleted oil and gas reservoirs with EOR potential are assumed to represent the best option for long-term storage. This control option is assumed to be 93 percent effective. The CO_2 emissions increases from the new a modified process heaters are 268,717.3 tons per year. These 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 (Section 6.3.1.3.1), as it would be more cost effective then 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

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[10] Available physical absorption processes include UOP's Selexol™ process and Lurgi's Rectisol™ process. These processes are commonly used for CO_2 rejection from natural gas and synthesis gases. Use of physical absorption for CO_2 capture from combustion exhaust gas would entail a significant amount of gas compression capacity resulting in high energy use. Although the use of a physical absorption process is technically feasible, these processes would have higher costs relative to using MEA or other amine based solvents.

dried, compressed from low pressure up to 2,000 psi and transported by pipeline to an appropriate storage site.

The estimated capital costs for the CCS equipment needed for capture, compression, pipeline transportation, and injection/storage are approximately $54.1 million. The levelized annual costs, including operating costs, are estimated to be approximately $21.3 million per year. The resulting cost of CCS is approximately $85 per ton of CO_2 sequestered (See Appendix F-2 for details regarding these cost analyses). This cost effectiveness assumes that the revenue from EOR is equal to the long term cost of monitoring, operating, and maintaining the storage facility.

These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, CCS does not represent BACT for the new and modified process heaters at SWRC.

6.5.1.2.4 Carbon Transport and Storage

In addition to the adverse economic impacts that show CCS is not a viable option for this project, the use of CCS for the process heaters at SWRC 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 result in GHG emissions, which would offset some of the net GHG reduction achieved by capturing and storing the CO_2 emitted by the process heaters. The current power authority that provides service to multiple entities in the region is capacity limited and simply cannot provide this additional required electricity demand. Additionally, SWRC does not have the land, infrastructure, authority, or ability to provide this additional energy demand by installing electricity generation units.

6.5.1.3 CO2 Emissions from New Emergency Air Compressor

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

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 SWRC 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, and Excess Combustion Air Monitoring and Control are utilized where possible but can be limited for smaller sources such as the emergency air compressor that does 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. Moreover, the use of these energy efficient technologies have not been demonstrated in practice for small emergency fired diesel engines.

6.5.2 CH4 Control Technologies

6.5.2.1 CH4 Emissions from New Fugitive Emission Sources

Based on available information and data sources (see Section 6.1) 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.

6.5.2.2 CH4 Emissions from Coker Flare

Based on available information and data sources (see Section 6.1) there is no technology for CH_4 control options post combustion for refinery flares. Thus, the only potential BACT control for the flare is to minimize all potential flaring events.

6.5.2.3 CH4 Emissions from New and Modified Process Heaters

The use of low carbon fuels and good combustion practices are inherent in the operation of all process heaters at SWRC. Energy efficient design can be incorporated as feasible depending on heater and refinery design. Specifically, the use of Combustion Air Preheat, Process Heat to Generate Steam, Process Integration and Heat Recovery, and Excess Combustion Air Monitoring and Control are utilized where possible but can be limited for heaters that do not have the physical area in the refinery to utilize these technologies. Additionally, SWRC currently does not have the land, infrastructure, authority, or ability to utilize Cogeneration as a CH_4 Reduction Technique for any of the new and modified process heaters.

6.5.2.4 CH4 Emissions from New Emergency Air Compressor

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 SWRC 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, and Excess Combustion Air Monitoring and Control are utilized where possible but can be limited for smaller sources such as the emergency air compressor that does 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. Moreover, the use of these energy efficient technologies have not been demonstrated in practice for small emergency fired diesel engines.

6.5.3 N2O Control Technologies

6.5.3.1 N2O Emissions from Coker Flare

Operation of the Coker Flare results in N_2O emissions from the combustion of gas supplied to the flare. N_2O will be emitted from the Coker Flare in trace quantities due to partial oxidation of nitrogen in the air used as the oxygen source for the combustion process. Based on available information and data sources (see Section 6.1) there is no technology for N_2O control options post combustion for refinery flares. Thus, the only potential BACT control for the flare is to minimize all potential flaring events.

6.5.3.2 N2O Emissions from New and Modified Process Heaters

The use of low carbon fuels and good combustion practices are inherent in the operation of all process heaters at SWRC. Energy efficient design can be incorporated as feasible depending on heater and refinery design. Specifically, the use of Combustion Air Preheat, Process Heat to Generate Steam, Process Integration and Heat Recovery, and Excess Combustion Air Monitoring and Control are utilized where possible but can be limited for heaters that do not have the physical area in the refinery to utilize these technologies. Additionally, SWRC currently does not have the land, infrastructure, authority, or ability to utilize Cogeneration as a N_2O Reduction Technique for any of the new and modified process heaters.

6.5.3.3 N2O Emissions from New Emergency Air Compressor

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 SWRC 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, and Excess Combustion Air Monitoring and Control are utilized where possible but can be limited for smaller sources such as the emergency air compressor that does 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. Moreover, the use of these energy efficient technologies have not been demonstrated in practice for small emergency fired diesel engines.

6.6 Selection of BACT

6.6.1 CO2 BACT

6.6.1.1 CO2 BACT for Coker Flare

Based on available information and data sources (see Section 6.1) 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.

SWRC is currently operating and upgrading the FGR system to comply with the provisions of the Consent Decree[11]. These upgrades include several provisions to reduce the generation of refinery gas vented to the flare system as well as the installation of a third FGR system compressor operating in parallel with the existing compressors. After completion of these upgrades, SWRC believes the FGR system will be adequate to capture the routinely generated refinery fuel gases for treatment in the refinery's amine system for ultimate use as NSPS J and Ja compliance refinery fuel gas.

SWRC proposes the use of its flare gas recovery system in order to minimize flaring as BACT.

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[11] Civil Action No. 08CV 020-D

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 present BACT.

As previously identified, SWRC will become subject to the provisions of NSPS Ja with this permitting action and will also meet the applicable flare gas monitoring provisions[12].

6.6.1.2 CO2 BACT for New and Modified Process Heaters

The use of CO_2 capture at SWRC 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 addition to the adverse impacts from steam and electricity generation that will be needed, the capital cost of the equipment to capture, dry, compress, and transport CO_2 make it economically infeasible. The adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CO_2 capture for this project and does not represent BACT for process heaters at SWRC.

SWRC 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. Specifically, proposed BACT for the new and modified heaters 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 gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CO_2 emissions per unit of energy generated via combustion;
- Use of process heat to generate steam to improve energy efficiency and reduce the quantity of fuel burned per unit of production in the largest 581 Crude Heater[13];
- Use of process heat integration between, and/or internal to, process units to improve energy efficiency and reduce the quantity of fuel burned per unit of production. This is accomplished by feed/effluent

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[12] Note certain provisions of NSPS Ja regarding flares are currently stayed by EPA pending final approval and promulgation.

[13] Note the 581 Crude Heater is the only new or modified heater that can physically be equipped with waste heat recovery steam generator. The 581 Crude Heater is also the largest of the new and modified heaters resulting in the greatest waste heat recovery for steam generation.

heat exchange systems on new process units and nearly every existing process unit at the refinery; and

- Use of periodic CO and/or O_2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Periodic monitoring will be conducted using existing CEMS where applicable or via portable monitor.

SWRC proposes that a single GHG emission limit be established for the new and modified process heaters listed below.

- 581 Crude Unit Heater
- 583 Vacuum Heater
- 781 Reformer Naphtha Splitter Heater
- Hydrocracker Heater H5
- #1HDS Heater
- New BSI Heater

The proposed emission limit for all of these identified heaters combined is 269,849.3 tons CO_2e per year.

6.6.1.2.1 CO2 BACT Monitoring for New and Modified Process Heaters

The use of periodic CO and/or O_2 monitoring will be utilized to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned in the new and modified process heaters. Periodic monitoring will be conducted using existing CEMS where applicable or via portable monitor. Additionally, the refinery fuel gas that is combusted in the heaters will be monitored for carbon content. This additional monitoring will serve to assure that the CO_2 emissions from the combustion of carbon compounds in refinery fuel gas are well known. Direct emissions of CO_2 from refinery fuel gas combustion in heaters represent greater than 99.5% of the total CO_2e emissions. The BACT emission limit proposed will be based on CO_2e emissions but will not require any direct monitoring of CH_4 or N_2O because the emissions of these GHGs are negligible in the determination of total CO_2e emissions.

6.6.1.3 CO2 BACT for New Emergency Air Compressor

SWRC 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; and

- 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.

Moreover, 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.

SWRC proposes that a single GHG emission limit be established for the new emergency generator. The proposed emission limit is 114.5 tons CO_2e per year.

6.6.1.3.1 CO2 BACT Monitoring for New Emergency Air Compressor

The operating hours of the new emergency generator will be monitored and limited to 500 hrs/yr.

6.6.2 CH4 BACT

6.6.2.1 CH4 BACT for New Fugitive Emission Sources

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, SWRC 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 SWRC conduct the following:

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

SWRC will continue to implement all of the requirements in NSPS GGG and the enhanced CD requirements for fugitive emissions. SWRC is proposing to meet BACT control for CH_4 fugitive emissions by conducting the following:

- Comply with the requirements of 40 C.F.R. Part 60, Subpart GGG and the Consent Decree for existing process units.
- Comply with the requirements of 40 C.F.R. Part 60, Subpart GGGa and the Consent Decree for new BSI unit.
- Comply with the requirements of 40 C.F.R. Part 60, Subpart GGGa and the Consent Decree if reconstruction or modification is triggered for any process unit.

SWRC 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.

6.6.2.2 CH4 BACT for Coker Flare

As previously discussed, SWRC proposes the use of its flare gas recovery system in order to minimize flaring as BACT.

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 present BACT.

As previously identified, SWRC will become subject to the provisions of NSPS Ja with this permitting action and will also meet the applicable flare gas monitoring provisions.

6.6.2.3 *CH4 BACT for New and Modified Process Heaters*

As previously identified, SWRC proposes to meet BACT for the new and modified heaters including:

- 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 gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CH_4 emissions per unit of energy generated via combustion;
- Use of process heat to generate steam to improve energy efficiency and reduce the quantity of fuel burned per unit of production in the largest 581 Crude Heater;
- Use of process heat integration between, and/or internal to, process units to improve energy efficiency and reduce the quantity of fuel burned per unit of production. This is accomplished by feed/effluent heat exchange systems on new process units and nearly every existing process unit at the refinery; and
- Use of periodic CO and/or O_2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Periodic monitoring will be conducted using existing CEMS where applicable or via portable monitor.

SWRC proposes that a single GHG emission limit be established for the new and modified process heaters associated with this project (see Section 6.6.1.2).

6.6.2.3.1 CH4 BACT Monitoring for New and Modified Process Heaters

The use of periodic CO and/or O_2 monitoring will be utilized to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned in the new and modified process heaters. Periodic monitoring will be conducted using existing CEMS where applicable or via portable monitor. Additionally, the refinery fuel gas that is combusted in the heaters will be monitored for carbon content. This additional monitoring will serve to assure that the CO_2 emissions from the combustion of carbon compounds in refinery fuel gas are well known. Direct emissions of CO_2 from refinery fuel gas combustion in heaters represent greater than 99.5% of the total CO_2e emissions. The BACT emission limit proposed will be based on CO_2e emissions but will not require any direct monitoring of CH_4 or N_2O because the emissions of these GHGs are negligible in the determination of total CO_2e emissions.

6.6.2.4 CH4 BACT for New Emergency Air Compressor

SWRC 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; and
- Use of lower-carbon content diesel fuel (diesel fuel rather than coal or coke) to reduce CH_4 emissions per unit of energy generated via combustion.

Moreover, 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.

SWRC proposes that a single GHG emission limit be established for the new emergency generator. The proposed emission limit is 114.5 tons CO_2e per year.

6.6.2.4.1 CH4 BACT Monitoring for New Emergency Air Compressor

The operating hours of the new emergency generator will be monitored and limited to 500 hrs/yr.

6.6.3 N2O BACT

6.6.3.1 N2O BACT for Coker Flare

As previously discussed, SWRC proposes the use of its flare gas recovery system in order to minimize flaring as BACT.

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 present BACT.

As previously identified, SWRC will become subject to the provisions of NSPS Ja with this permitting action and will also meet the applicable flare gas monitoring provisions.

6.6.3.2 N2O BACT for New and Modified Process Heaters

As previously identified, SWRC proposes to meet BACT for the new and modified heaters including:

- 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 gaseous fuel (refinery fuel gas rather than fuel oil) to reduce N_2O emissions per unit of energy generated via combustion;
- Use of process heat to generate steam to improve energy efficiency and reduce the quantity of fuel burned per unit of production in the largest 581 Crude Heater;
- Use of process heat integration between, and/or internal to, process units to improve energy efficiency and reduce the quantity of fuel burned per unit of production. This is accomplished by feed/effluent heat exchange systems on new process units and nearly every existing process unit at the refinery; and
- Use of periodic CO and/or O_2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Periodic monitoring will be conducted using existing CEMS where applicable or via portable monitor.

SWRC proposes that a single GHG emission limit be established for the new and modified process heaters associated with this project (see Section 6.6.1.2).

6.6.3.2.1 N2O BACT Monitoring for New and Modified Process Heaters

The use of periodic CO and/or O_2 monitoring will be utilized to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned in the new and modified process heaters. Periodic monitoring will be conducted using existing CEMS where applicable or via portable monitor. Additionally, the refinery fuel gas that is combusted in the heaters will be monitored for carbon content. This additional monitoring will serve to assure that the CO_2 emissions from the combustion of carbon compounds in refinery fuel gas are well known. Direct emissions of CO_2 from refinery fuel gas combustion in heaters represent greater than 99.5% of the total CO_2e emissions. The BACT emission limit proposed will be based on CO_2e emissions but will not require any direct monitoring of CH_4 or N_2O because the emissions of these GHGs are negligible in the determination of total CO_2e emissions.

6.6.3.3 N2O BACT for New Emergency Air Compressor

SWRC 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; and
- Use of lower-carbon content diesel fuel (diesel fuel rather than coal or coke) to reduce N_2O emissions per unit of energy generated via combustion.

Moreover, 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.

SWRC proposes that a single GHG emission limit be established for the new emergency generator. The proposed emission limit is 114.5 tons CO_2e per year.

6.6.3.3.1 N2O BACT Monitoring for New Emergency Air Compressor

The operating hours of the new emergency generator will be monitored and limited to 500 hrs/yr.

6.6.4 CO2, CH4, and N2O BACT Summary

The following table has been prepared to summarize the results of the 5 step top down BACT analysis as identified in the previous sections for the new and modified sources for GHG emissions of CH4, CO_2, and N_2O.

New/Modified Emission Source	Proposed GHG BACT
581 Crude Heater	Proposed BACT 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 gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CO_2 emissions per unit of energy generated via combustion; • Use of process heat to generate steam to improve energy efficiency and reduce the quantity of fuel burned per unit of production (Note the 581 Crude Heater is the largest heater at the refinery modified with this project and is the only heater that can physically be equipped with waste heat recovery steam generator.); • Use of process heat integration between and in process units to improve energy efficiency and reduce the quantity of fuel burned per unit of production; and • Use of periodic CO and/or O_2 monitoring on the 581 Crude Heater to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production . Periodic monitoring will be conducted using existing CEMS where applicable or via portable monitor.
New BSI Heater, #1 HDS Heater, Naphtha Splitter Heater, and Hydrocracker H5 Heater	Proposed BACT 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 gaseous fuel (refinery fuel gas rather than fuel oil) to reduce CO_2 emissions per unit of energy generated via combustion; • Use of process heat integration between and in process units to improve energy efficiency and reduce the quantity of fuel burned per unit of production; and • Use of periodic CO and/or O_2 monitoring to ensure complete combustion and minimize energy use and reduce the quantity of fuel burned per unit of production. Periodic monitoring will be conducted using existing CEMS where applicable or via portable monitor.

New/Modified Emission Source	**Proposed GHG BACT**
New Emergency Air Compressor	Proposed BACT 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 N_2O emissions per unit of energy generated via combustion; and • The new emergency air compressor will reduce the potential for excess GHG emissions from the entire refinery as a result of unplanned power failures.
Coker Unit Flare	Proposed BACT includes: • Use of the Flare Gas Recovery System to capture refinery fuel gases that would have been flared and use them for process unit heat input. This will optimize the overall refinery fuel gas balance and while minimizing refinery fuel gas heat release.
New Fugitive Emissions/Drains	Proposed BACT includes: • Comply with the requirements of 40 C.F.R. Part 60, Subpart GGG and Consent Decree for existing units; • Comply with the requirements of 40 C.F.R. Part 60, Subpart GGGa and Consent Decree for new BSI unit; and • Comply with the requirements of 40 C.F.R. Part 60, Subpart GGGa and Consent Decree if reconstruction is triggered for any unit.

SECTION 7
AIR QUALITY IMPACTS ASSESSMENT

Currently there are no National Ambient Air Quality Standards (NAAQS) for GHG pollutants. As such there are no ambient air quality impact regulations or requirements to conduct any air quality impact assessment for GHG pollutants as part of this application.

APPENDIX A
CO2 EMISSION CALCULATIONS

Appendix A
CO2 Emissions Calculations

Fuel Gas Fired Heaters:

Basis:
Heaters
130.036 lb-CO2 / MM Btu (40 CFR 98 Subpart C Table C-1 for Refinery Fuel Gas Combustion)

Flares
132.240 lb-CO2 / MM Btu (40 CFR 98 Subpart Y Equation Y-2)

Then: CO2 emissions = (___ MMBtu/hr) x (____ lb-CO2 / MM Btu)

Operating Unit	Emission Source	Firing Rate (MMBtu/hr)	Emission Factor lb CO2/MM Btu	CO2 (Estimated)	
				lb/hr	TPY
Coker	Coker Heater	145.0	130.036	18,855.2	82,585.9
BSI	BSI Heater	50.0	130.036	6,501.8	28,477.9
#2 H2 Plant	#2 H2 Plant Heater	288.0	130.036	37,450.4	164,032.6
581 Crude Unit	581 Crude Heater	233.0	130.036	30,298.4	132,706.9
583 Vacuum Unit	583 Vacuum Heater	64.2	130.036	8,348.3	36,565.6
Hydrocracker	Heater H1/H2	38.0	130.036	4,941.4	21,643.2
	Heater H3	56.0	130.036	7,282.0	31,895.2
	Heater H4	57.0	130.036	7,412.1	32,464.8
Hydrocracker	Heater H5	44.9	130.036	5,838.6	25,573.1
780 FCCU	780 FCC Heater B3	10.0	130.036	1,300.4	5,695.6
	780 FCC Heater H2	19.4	130.036	2,522.7	11,049.4
#1 HDS	#1HDS Heater	33.4	130.036	4,343.2	19,023.2
781 Reformer	Naphtha Splitter Heater	46.3	130.036	6,020.7	26,370.5
	LEF Heater	24.0	130.036	3,120.9	13,669.4
	#1 Reformer Heater	44.6	130.036	5,799.6	25,402.3
	#2 Reformer Heater	74.8	130.036	9,726.7	42,602.9
	#3 Reformer Heater	22.4	130.036	2,912.8	12,758.1
	Stabilizer Heater	11.1	130.036	1,443.4	6,322.1
#4 HDS	H2 Heater (25-HT-101)	22.0	130.036	2,860.8	12,530.3
	H2 Heater (25-HT-102)	24.0	130.036	3,120.9	13,669.4
Coker	Coker Unit flare	100.0	132.240	13,224.0	57,921.1
#1 H2 Plant	#1 H2 Plant Heater	288.0	130.036	37,450.4	164,032.6
Asphalt Loading	Asphalt Heater #1	8.0	130.036	1,040.3	4,556.5
#2 HDS	Charge Heater	28.0	130.036	3,641.0	15,947.6
#3 HDS	Charge Heater	18.0	130.036	2,340.6	10,252.0
Total				227,796.4	997,748.2

SRP

Combined Emissions from #1, #2 and #3 TGTU

30.0 MM Btu/hr

130.036 lb-CO2 / MM Btu (40 CFR 98 Subpart C Table C-1 for Refinery Fuel Gas Combustion)

Then: CO2 emissions = (___ MMBtu/hr) x (0.082 lb-CO2 / MM Btu)

Operating Unit	Emission Source	CO2 (Estimated)	
		lb/hr	TPY
#1,#2,#3,#4 SRU	#1,#3,#4 TGTU	3,901.1	17,086.7

FCCU

Basis:

3,142,249.6 dscfh stack flowrate

Then: CO2 emissions (metric tons/yr) = (___ dscfh) x (%CO2+%CO)/100 x 44/849.5 x 0.001

CO2 emissions (tons/yr) = metric tons/yr x 1.10

(40 CFR 98 Subpart Y Equation Y-6)

Operating Unit	Emission Source	CO2 (Estimated)	
		lb/hr	TPY
780 FCCU	780 FCCU Regenerator	53,821.5	235,738.0

LOLR

Contemporaneous CO2 increase from Light Oil Loading Rack / Flare

Basis:

Facility Throughput:	M gpy
Gasoline	50,000

Emission Factor	3515.4 mg CO2/l	Source: John Zink estimate and 40 CFR 98 Subpart C Table
Emission Factor	29.3 lb CO2/M gal	C-1 CO2 / AP-42 CO Factor Ratio

Assume: Heat release from the combustion of distillate fuel oil is deminimis

Calculation: CO2 Emissions = (___ M gal/hr)/(____ lb CO2/M gal)

Operating Unit	Emission Source	CO2	
		lb/hr	TPY
Light Oil Loading	Loading Rack Flare	167.4	733.35

New Emergency Air Compressor
Hours of operation: 500 hrs/year
20.8 days/year

Calculation: CO2 Emissions = (___ BHP)x(____ g/BHP)

Operating Unit	Emission Source	Engine Power (BHP)	Emission Factor (g/BHP-hr) (Note: 1)	CO2	
				lb/hr	TPY
Unit	Source	400	517.72	456.5	114.14

Note: 1 GHG Emission Factors
CO2 (40 CFR 98 Subpart C Table C-1 for Distillate Fule Oil No. 2)

SBG/sbg

APPENDIX B
CH4 EMISSION CALCULATIONS

Appendix B
CH4 Emissions Calculations

Fuel Gas Fired Heaters:

Basis:
Heaters:
0.0066 lb-CH4 / MM Btu (40 CFR 98 Subpart C Table C-2 for Refinery Fuel Gas Combustion)
Flares
0.0066 lb-CH4 / MM Btu (40 CFR 98 Subpart C Table C-2 for Refinery Fuel Gas Combustion)

Then: CH4 emissions = (___ MMBtu/hr) x (___ lb-CH4 / MM Btu)

Operating Unit	Emission Source	Firing Rate (MMBtu/hr)	Emission Factor lb CH4/MM Btu	CH4 (Estimated)	
				lb/hr	TPY
Coker	Coker Heater	145.0	0.0066	1.0	4.2
BSI	BSI Heater	50.0	0.0066	0.3	1.4
#2 H2 Plant	#2 H2 Plant Heater	288.0	0.0066	1.9	8.3
581 Crude Unit	581 Crude Heater	233	0.0066	1.5	6.7
583 Vacuum Unit	583 Vacuum Heater	64.2	0.0066	0.4	1.9
Hydrocracker	Heater H1/H2	38	0.0066	0.3	1.1
	Heater H3	56	0.0066	0.4	1.6
	Heater H4	57	0.0066	0.4	1.6
Hydrocracker	Heater H5	44.9	0.0066	0.3	1.3
780 FCCU	780 FCC Heater B3	10	0.0066	<0.1	0.3
	780 FCC Heater H2	19.4	0.0066	0.1	0.6
#1 HDS	#1HDS Heater	33.4	0.0066	0.2	1.0
781 Reformer	Naphtha Splitter Heater	46.3	0.0066	0.3	1.3
	LEF Heater	24.0	0.0066	0.2	0.7
	#1 Reformer Heater	44.6	0.0066	0.3	1.3
	#2 Reformer Heater	74.8	0.0066	0.5	2.2
	#3 Reformer Heater	22.4	0.0066	0.1	0.6
	Stabilizer Heater	11.1	0.0066	<0.1	0.3
#4 HDS	H2 Heater (25-HT-101)	22.0	0.0066	0.1	0.6
	H2 Heater (25-HT-102)	24.0	0.0066	0.2	0.7
Coker	Coker Unit flare	100.0	0.0066	0.7	2.9
#1 H2 Plant	#1 H2 Plant Heater	288.0	0.0066	1.9	8.3
Asphalt Loading	Asphalt Heater #1	8.0	0.0066	<0.1	0.2
#2 HDS	Charge Heater	28.0	0.0066	0.2	0.8
#3 HDS	Charge Heater	18.0	0.0066	0.1	0.5
Total				11.6	50.6

SRP
Combined Emissions from #1, #2 and #3 TGTU
30.0 MM Btu/hr
0.0066 lb-CH4 / MM Btu (40 CFR 98 Subpart C Table C-2 for Refinery Fuel Gas Combustion)

Then: CH4 emissions = (___ MMBtu/hr) x (0.0023 lb-CH4 / MM Btu)

Operating Unit	Emission Source	CH4 (Estimated)	
		lb/hr	TPY
#1,#2,#3,#4 SRU	#1,#3,#4 TGTU	0.2	0.9

FCCU

Basis: CH4 = CO2 * (EMF2 / EMF1) (40 CFR 98 Subpart Y Equation Y-9)

(40 CFR 98 Subpart Y Equation Y-9)

Operating Unit	Emission Source	CH4 (Estimated)	
		lb/hr	TPY
780 FCCU	780 FCCU Regenerator	5.8	25.3

LOLR

Contemporaneous CH4 increase from Light Oil Loading Rack / Flare

Basis:

Facility Throughput:	M gpy
Gasoline	50,000
Distillate Fuel Oil	250,000
Total	300,000

Assume:

Total Organic Compounds (TOC) = Methane (CH4)

Gasoline Loading (controlled)

Emission Factor 10.0 mg TOC/l Source: 40 CFR 63.422
Emission Factor 0.0834 lb TOC/M gal Source: 40 CFR 63.422
55% Methane Source: AP-42 Chapter 13.5 Table 13.5-2
Calculation: CH4 Emissions = (___ M gal gasoline /hr) / (____ lb TOC/M gal) * Methane % = 0.3 lb CH4/hr

Distillate Fuel Oil Loading (controlled)

Basis:

Loading Losses (lb/1000 gal) = (12.46)(S)(P)(M)/T) Source: AP-42, 5th ed., Section 5.2, equation 1

Where:
S = saturation factor 1
P = True Vapor Pressure 0.0042 psia
M = Molecular Weight of Vapor 130
T = Liquid Temperature 507.3 deg. R
E = Control Efficiency 98.0 %
55% Methane

Calculation: CH4 Emissions = E*(___ gal. distillate fuel oil / hr)(12.46)(S)(P)(M)/T) = 0.004 lb CH4/hr

Combined Emissions (Gasoline + Distillate Fuel Oil Loading) = 0.3 lb CH4 / hr

Operating Unit	Emission Source	CH4 (Estimated)	
		lb/hr	TPY
Light Oil Loading	Loading Rack Flare	0.3	1.2

Storage Tanks CH4 content of gasoline/intermiediate tank contents is insignificant
There are no unstabilized crude tanks at SWRC

New Emergency Air Compressor

Hours of operation: 500 hrs/year
20.8 days/year

Calculation: CH4 Emissions = (___ BHP)x(____ g/BHP)

Operating Unit	Emission Source	Engine Power (BHP)	Emission Factor (g/BHP-hr) (Note: 1)	CH4	
				lb/hr	TPY
Storage Tanks	gasoline/intermiediate tank contents is insignificant	400	0.021	<0.1	<0.1

Note: 1 GHG Emission Factors
CH4 (40 CFR 98 Subpart C Table C-2 for Petroleum (All fuel types in Table C-1))

SBG/sbg

APPENDIX C
N2O EMISSION CALCULATIONS

Appendix C
N2O Emissions Calculations

40 CFR 98 Subpart C Emission Factor for Refinery Fuel Gas Combustion (Table C-2)

Emission Factor	0.00132	lb N2O/MM Btu

40 CFR Part 98 Emission Factor for Flares (Table C-2)

Emission Factor	0.00132	lb N2O/MM Btu

Calculation: N2O Emissions = (___ MMBtu/hr)x(____ lb N2O/MMBtu)

Operating Unit	Emission Source	Firing Rate (MMBtu/hr)	Emission Factor lb N2O/MM Btu	N2O (Proposed) lb/hr	TPY
Coker	Coker Heater	145.0	0.00132	0.2	0.8
BSI	BSI Heater	50.0	0.00132	<0.1	0.3
#2 H2 Plant	#2 H2 Plant Heater	288.0	0.00132	0.4	1.7
581 Crude Unit	581 Crude Heater	233.0	0.00132	0.3	1.3
583 Vacuum Unit	583 Vacuum Heater	64.2	0.00132	<0.1	0.4
Hydrocracker	Heater H1/H2	38.0	0.00132	<0.1	0.2
	Heater H3	56.0	0.00132	<0.1	0.3
	Heater H4	57.0	0.00132	<0.1	0.3
Hydrocracker	Heater H5	44.9	0.00132	<0.1	0.3
780 FCCU	780 FCC Heater B3	10.0	0.00132	<0.1	<0.1
	780 FCC Heater H2	19.4	0.00132	<0.1	0.1
#1 HDS	#1HDS Heater	33.4	0.00132	<0.1	0.2
781 Reformer	Naphtha Splitter Heater	46.3	0.00132	<0.1	0.3
	LEF Heater	24.0	0.00132	<0.1	0.1
	#1 Reformer Heater	44.6	0.00132	<0.1	0.3
	#2 Reformer Heater	74.8	0.00132	<0.1	0.4
	#3 Reformer Heater	22.4	0.00132	<0.1	0.1
	Stabilizer Heater	11.1	0.00132	<0.1	<0.1
#4 HDS	H2 Heater (25-HT-101)	22.0	0.00132	<0.1	0.1
	H2 Heater (25-HT-102)	24.0	0.00132	<0.1	0.1
Coker	Coker Unit flare	100.0	0.00132	0.1	0.6
#1 H2 Plant	#1 H2 Plant Heater	288.0	0.00132	0.4	1.7
Asphalt Loading	Asphalt Heater #1	8.0	0.00132	<0.1	<0.1
#2 HDS	Charge Heater	28.0	0.00132	<0.1	0.2
#3 HDS	Charge Heater	18.0	0.00132	<0.1	0.1
Total				2.3	10.1

SRP
Combined Emissions from #1, #2 and #3 TGTU
Basis: 30.0 MM Btu/hr
0.00132 lb N2O / MM Btu (40 CFR 98 Subpart C Table C-2 for Refinery Fuel Gas Combustion)
Calculation: lb/hr N2O = (30.0 MM Btu/hr) x (0.00022 lb N2O/MM Btu)

Operating Unit	Emission Source	N2O (Proposed)	
		lb/hr	TPY
#1,#2,#3,#4 SRU	#1,#3,#4 TGTU	<0.1	0.2

FCCU

Basis: N2O = CO2 * (EMF3 / EMF1) (40 CFR 98 Subpart Y Equation Y-10)

(40 CFR 98 Subpart Y Equation Y-10)

Operating Unit	Emission Source	N2O (Proposed)	
		lb/hr	TPY
780 FCCU	780 FCCU Regenerator	0.8	3.7

LOLR
Contemporaneous N2O increase from Light Oil Loading Rack / Flare

Basis:

Facility Throughput:		M gpy
Gasoline		50,000

Emission Factor 0.078 mg N2O/l
Emission Factor 0.0006 lb N2O/M gal

Source: John Zink estimate and 40 CFR 98 Subpart C Table C-2 N2O / AP-42 NOx Factor Ratio

Assume: Heat release from the combustion of distillate fuel oil is deminimis

Calculation: N2O Emissions = (___ M gal/hr)/(____ lb N2O/M gal)

Operating Unit	Emission Source	N2O	
		lb/hr	TPY
Light Oil Loading	Loading Rack Flare	<0.1	<0.1

New Emergency Air Compressor
Hours of operation: 500 hrs/year
20.8 days/year

Calculation: N2O Emissions = (___ BHP)x(____ g/BHP)

Operating Unit	Emission Source	Engine Power (BHP)	Emission Factor (g/BHP-hr) (Note: 1)	N2O	
				lb/hr	TPY
Unit	Source	400	0.004	<0.1	<0.1

Note: 1 GHG Emission Factors
N2O (40 CFR 98 Subpart C Table C-2 for Petroleum (All fuel types in Table C--1))

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APPENDIX D
FUGITIVE EMISSION CALCULATIONS

Appendix D
Fugitive Emissions Calculations

Re: Protocol for Equipment Leak Emission Estimates
(EPA-453/R-95-017, Table 2-10: Screening Value Correlations)
Valves / others = 500 ppm, Pumps = 2000 ppm
(EPA-453/R-95-017, Table 2-2: Refinery Average Emission Factors) - Connectors
AP-42, 4 ed, (Fugitive Emission Factors, Table 9.1-2) - Drains

Fuel Gas Service (Note 1)	Pump Seals	Valves	Flanges / Connectors	Drains	Others	CH4 Emission Rate (TPY)
Quantity (Note 2)	6	525	1313	40	80	
Emissions Factor (lb/hr-source)	0.0114	0.00052	0.00055	0.0175	0.0001	
Assumed CH4 Content	25%	25%	25%	25%	25%	
Emissions (TPY)	<0.1	0.3	0.8	0.8	<0.1	1.9

Notes:
Fugitive emission component counts are estimated
Drains are assumed to be included in "Others" category

$CH4 = (0.4 \times N_{CD} + 0.2 \times NP_{U1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS})$ (40 CFR 98 Subpart Y Equation Y-21)

FUGITIVE CH4 EMISSIONS

Conservative assumption of 1 new distillation column and 1 new fuel gas system

N_{CD}	N_{PU1}	N_{PU2}	N_{H2}	N_{FGS}
0	1	0	0	1

FUGITIVE EMISSIONS						
	EQN.	**GHG**	**MASS**		**MASS**	
TOTAL	Y-21	CH_4	6.2	METRIC TONS	6.8	TPY

SBG/sbg

APPENDIX E
CO2 EQUIVALENT EMISSION TOTALS

Appendix E
CO2 Emissions Calculations

EMISSIONS INCREASES

Operating Unit	Emission Source	Current Firing Rate	Firing Rate for Estimated Emissions	CH4 Allowable Emissions	N2O Allowable Emissions	CO2 Estimated Emissions	CO2e Estimated Emissions
		(MMBtu/hr)	(MMBtu/hr)	TPY	TPY	TPY	TPY
Modified and New Sources:							
581 Crude Unit	581 Crude Heater	133.2	233.0	6.7	1.3	132,706.9	133,266.0
583 Vacuum Unit	583 Vacuum Heater	64.2	64.2	1.9	0.4	36,565.6	36,719.6
Coker	Coker Unit flare	N/A	100.0	2.9	0.6	57,921.1	58,161.1
781 Reformer	Naphtha Splitter Heater	34.5	46.3	1.3	0.3	26,370.5	26,481.6
Hydrocracker	Heater H5	35.7	44.9	1.3	0.3	25,573.1	25,680.9
#1 HDS	#1HDS Heater	24.0	33.4	1.0	0.2	19,023.2	19,103.4
BSI	BSI Heater	N/A	50.0	1.4	0.3	28,477.9	28,597.9
Boilerhouse	New Emergency Air Compressor	N/A	N/A	<0.1	<0.1	114.1	114.5
Tank Farm	100 M bbl tank	N/A	N/A	Insignificant	N/A	N/A	Insignificant
Equipment Leaks	Fugitive Emissions	N/A	N/A	1.9	N/A	N/A	40.8
Subtotal Modified and New Sources:				**18.5**	**3.3**	**326,752.6**	**328,165.7**

EMISSIONS INCREASES

Operating Unit	Emission Source	Current Firing Rate (MMBtu/hr)	Firing Rate for Estimated Emissions (MMBtu/hr)	CH4 Allowable Emissions TPY	N2O Allowable Emissions TPY	CO2 Estimated Emissions TPY	CO2e Estimated Emissions TPY
Non-Modified Sources:							
781 Reformer	LEF Heater	24.0	24.0	0.7	0.1	13,669.4	13,727.0
	#1 Reformer Heater	44.6	44.6	1.3	0.3	25,402.3	25,509.3
	#2 Reformer Heater	74.8	74.8	2.2	0.4	42,602.9	42,782.4
	#3 Reformer Heater	22.4	22.4	0.6	0.1	12,758.1	12,811.8
	Stabilizer Heater	11.1	11.1	0.3	<0.1	6,322.1	6,348.7
Hydrocracker	Heater H1/H2	38.0	38.0	1.1	0.2	21,643.2	21,734.4
	Heater H3	56.0	56.0	1.6	0.3	31,895.2	32,029.6
	Heater H4	57.0	57.0	1.6	0.3	32,464.8	32,601.6
Coker	Coker Heater	145.0	145.0	4.2	0.8	82,585.9	82,933.8
	Coker (Material Handling)	N/A	N/A	N/A	N/A	N/A	N/A
780 FCCU	780 FCC Heater B3	10.0	10.0	0.3	<0.1	5,695.6	5,719.6
	780 FCC Heater H2	19.4	19.4	0.6	0.1	11,049.4	11,096.0
	780 FCCU Regenerator	N/A	N/A	25.3	3.7	235,738.0	237,411.5
#2 HDS	Charge Heater	28.0	28.0	0.8	0.2	15,947.6	16,014.8
#3 HDS	Charge Heater	18.0	18.0	0.5	0.1	10,252.0	10,295.2
#4 HDS	H2 Heater (25-HT-101)	22.0	22.0	0.6	0.1	12,530.3	12,583.1
	H2 Heater (25-HT-102)	24.0	24.0	0.7	0.1	13,669.4	13,727.0
#1 H2 Plant	#1 H2 Plant Heater	288.0	288.0	8.3	8.3	164,032.6	166,788.4
#2 H2 Plant	#2 H2 Plant Heater	N/A	288.0	8.3	1.7	164,032.6	164,723.6
#1,#2,#3,#4 SRU	#1,#3,#4 TGTU	N/A	N/A	0.9	0.2	17,086.7	17,158.7
Asphalt Loading	Asphalt Heater #1	8.0	8.0	0.2	<0.1	4,556.5	4,575.7
Tank Farm	Working Losses - aggregate	N/A	N/A	Insignificant	N/A	N/A	Insignificant
Light Oil Loading	Loading Rack Flare	N/A	N/A	1.2	<0.1	733.4	762.9
Subtotal Non-Modified Sources:				**61.4**	**17.3**	**924,667.9**	**931,334.8**
TOTAL: MODIFIED + NEW + NON MODIFIED SOURCES				**79.9**	**20.7**	**1,251,420.5**	**1,259,500.5**

PAST ACTUAL EMISSIONS

Operating Unit	Emission Source	CH4 Actual Emissions	N2O Actual Emissions	CO2 Actual Emissions	CO2e Actual Emissions
		TPY	TPY	TPY	TPY
581 Crude Unit	581 Crude Heater	2.6	0.5	50,607.1	50,820.6
583 Vacuum Unit	583 Vacuum Heater	0.7	0.1	12,826.0	12,880.1
781 Reformer	Naphtha Splitter Heater	0.3	<0.1	4,971.0	4,991.9
	LEF Heater	0.4	<0.1	8,233.5	8,268.2
	#1 Reformer Heater	0.8	0.2	15,065.5	15,129.1
	#2 Reformer Heater	0.6	0.1	11,353.4	11,401.3
	#3 Reformer Heater	0.2	<0.1	4,547.9	4,567.1
	Stabilizer Heater	0.2	<0.1	4,741.8	4,761.8
Hydrocracker	Heater H1/H2	0.4	<0.1	8,115.9	8,150.2
	Heater H3	0.6	0.1	12,299.4	12,351.3
	Heater H4	1.1	0.2	21,527.9	21,618.8
	Heater H5	0.5	<0.1	9,058.0	9,096.3
Coker	Coker Heater	1.6	0.3	31,073.9	31,205.1
	Coker (Material Handling)	N/A	N/A	N/A	N/A
780 FCCU	780 FCC Heater B3	0.2	<0.1	6,925.7	6,938.3
	780 FCC Heater H2	0.3	<0.1	7,968.4	7,991.9
	780 FCCU Regenerator	21.0	3.1	195,245.0	196,631.0
#1 HDS	#1HDS Heater	0.3	<0.1	6,197.8	6,224.0
#2 HDS	Charge Heater	<0.1	<0.1	1,219.3	1,224.4
#3 HDS	Charge Heater	0.2	<0.1	4,726.3	4,746.2
#4 HDS	H2 Heater (25-HT-101)	0.1	<0.1	2,643.7	2,654.9
	H2 Heater (25-HT-102)	0.1	<0.1	2,669.0	2,680.2
#1 H2 Plant	#1 H2 Plant Heater	4.9	1.0	96,234.0	96,640.1
#2 H2 Plant	#2 H2 Plant Heater	4.5	0.9	87,829.8	88,200.5
#1,#2,#3,#4 SRU	#1,#3,#4 TGTU	0.7	0.1	12,992.9	13,047.7
Asphalt Loading	Asphalt Heater #1	<0.1	<0.1	95.1	95.5
Tank Farm	Working Losses - aggregate	Insignificant	N/A	N/A	Insignificant
Light Oil Loading	Loading Rack Flare	0.4	<0.1	248.6	258.5
TOTAL: PAST ACTUAL EMISSIONS		**42.6**	**7.3**	**619,416.8**	**622,574.9**

SUMMARY

Operating Unit	Emission Source	CH4 Emissions	N2O Emissions	CO2 Emissions	CO2e Emissions
		TPY	TPY	TPY	TPY
NET EMISSIONS INCREASE		**37.3**	**13.4**	**632,003.7**	**636,925.6**
PSD SIGNIFICANCE THRESHOLDS		**NA**	**NA**	**NA**	**75,000.0**

APPENDIX F
GHG BACT COST ANALYSES

Appendix F-1
BACT Cost Analysis for GHG

Carbon Capture and Sequestration - Ion Tnsport Mebrane (ITM) Oxyfuel
Reference Study for Cost Estimate - Refinery Heaters and Boilers

Parameters	Units	SWRC	Comments
CO2 Captured			
Project CO2 Emissions	Millions Tons/yr	0.27	SWRC Emissions - New and Modified Heaters
Percent Reduction	%	87%	Efficiency from reference
CO2 Captured	Millions Tons/yr	0.24	

Direct Capital Cost (DCC)			
Air Separation Units (ITM + auxiliary)	Millions US$	6.1	
O2 Distribution and CO2 Gathering	Millions US$	0.8	
CO2 Drying, Compression, Purification	Millions US$	8.7	
Cogeneration System	Millions US$	23.7	
Cooling Water System	Millions US$	2.2	
Furnace Modifications	Millions US$	1.5	Reference also included boilers, but N/A to SWRC
Direct Capital Cost	Millions US$	43.1	All costs ratio from reference project

Indirect Capital Costs (ICC)			
General Facilities	Millions US$	2.2	5% of DCC
Engineering and Home Office	Millions US$	4.3	10% of DCC
Process Contingency	Millions US$	2.2	5% of DCC
Indirect Capital Costs	Millions US$	8.6	

Project Contingency (PC)			
Project Contingency	Millions US$	7.8	15% of (DCC + ICC)

Total Capital Investment (TCI)			
Total Plant Cost (TPC)	Millions US$	59.5	DCC + ICC + PC
Allowances	Millions US$	0.0	Assume none
Total Capital Investment	Millions US$	59.5	TPC + Allowances

Annualized Capital Costs			
Period	Years	10	Assume 10 Year Project Life
Interest	Percent	10%	Annual Interest Rate
Capital Recovery Factor (CRF)	Fraction	0.163	Capital Recovery Factor
Indirect Annual Cost	Millions US$/Yr	9.7	TCI x CRF

Utility Requirements			
Fuel Required	MMBtu/Hr	780.6	2,028 MW in Reference
Export Power	MW	50.3	
Reduced Fuel to Furnaces	MMBtu/Hr	19.4	22.75 + 27.75 MW in Reference

Direct Annual Costs			
Maintenance	Millions US$ /yr	0.9	1.5% TCI
Operator Manpower	Millions US$ /yr	0.2	Ratio from reference
Consumables	Millions US$ /yr	0.1	Ratio from reference
Fuel Cost	Millions US$ /yr	41.0	$6/MMBtu
Export Power	Millions US$ /yr	-12.3	$28/MW-Hr
Reduced Fuel to Furnaces	Millions US$ /yr	-1.0	$6/MMBtu
Direct Annual Costs	Millions US$ /yr	28.8	

Total Annual Cost			
Total Annual Cost	Millions US$ /yr	38.5	Indirect Annual Cost + Direct Annual Cost

CO2 Avoided			
CO2 from Fuel Combustion	Millions Tons/yr	0.44	130 Lb/MMBtu from 40 CFR 98 Table C-1
CO2 from Reduced Fuel to Furnaces	Millions Tons/yr	-0.02	130 Lb/MMBtu from 40 CFR 98 Table C-1
CO2 Credit from Power Export	Millions Tons/yr	-0.46	2.1 Lb/kW-Hr (Reference 3)
Indirect CO2 Emissions	Millions Tons/yr	-0.04	
CO2 Avoided	Millions Tons/yr	0.28	CO2 captured less indirect emissions

Cost Effectivenes			
Cost Effectivenes - CO2 Captured	US$/Ton	163.6	
Cost Effectivenes - CO2 Avoided	US$/Ton	138.4	

References
1. "Best Available Control Technology Review for Greenhouse Gas Emissions," Hyperion Energy Center, October 2010
2. "Oxyfuel Conversion of Refinery Process Equipment Utilising Flue Gas Recycle for CO2 Capture" Alam, McDonald et. al.
3. "Carbon Dioxide Emissions from the Generation of Electric Power in the United States", US Department of Energy, July 2000

Appendix F-2
BACT Cost Analysis for GHG

Carbon Capture and Sequestration - MEA Absorption
Reference Study for Cost Estimate - U.K. Refinery Heaters and Boilers

Parameters	Units	SWRC	Comments
CO2 Reduction			
Project CO2 Emissions	Millions Tons/yr	0.27	SWRC Emissions - New and Modified Heaters
Percent Reduction	%	93%	Assumed (same as Hyperion Energy)
CO2 Captured	Millions Tons/yr	0.25	

Direct Capital Cost (DCC)			
Gas Gathering Systems	Millions US$	4.4	
NOx and SO2 Removal	Millions US$	8.4	
CO2 Removal Equipment	Millions US$	18.9	
CO2 Drying and Compression System	Millions US$	5.5	
Utility and Offsite Systems	Millions US$	17.0	
Direct Capital Cost	Millions US$	54.3	All costs ratio from Grangemouth project

Indirect Capital Costs (ICC)			
General Facilities	Millions US$	2.7	5% of DCC
Engineering and Home Office	Millions US$	5.4	10% of DCC
Process Contingency	Millions US$	2.7	5% of DCC
Indirect Capital Costs	Millions US$	10.9	

Project Contingency (PC)			
Project Contingency	Millions US$	9.8	15% of (DCC + ICC)

Total Capital Investment (TCI)			
Total Plant Cost (TPC)	Millions US$	74.9	DCC + ICC + PC
Allowances	Millions US$	0.0	Assume none
Total Capital Investment	Millions US$	74.9	TPC + Allowances

Annualized Capital Costs			
Period	Years	10	Assume 10 Year Project Life
Interest	Percent	10%	Annual Interest Rate
Capital Recovery Factor (CRF)	Fraction	0.163	Capital Recovery Factor
Indirect Annual Cost	Millions US$/Yr	12.2	TCI x CRF

Utility Requirements			
Fuel Required to Generate Capture Energy	MMBtu/Hr	154.1	Ratio from Grangemouth Project

Direct Annual Costs			
Maintenance	Millions US$ /yr	1.1	1.5% TCI
Fuel Required to Generate Capture Energy	Millions US$ /yr	8.1	$6/MMBtu
Direct Annual Costs	Millions US$ /yr	9.2	

Total Annual Cost			
Total Annual Cost	Millions US$ /yr	21.4	Indirect Annual Cost + Direct Annual Cost

CO2 Avoided			
CO2 from Fuel to Generate Capture Energy	Millions Tons/yr	0.09	130 Lb/MMBtu from 40 CFR 98 Table C-1
Indirect CO2 Emissions	Millions Tons/yr	0.09	
CO2 Avoided		0.16	CO2 captured less indirect emissions

Cost Effectivenes			
Cost Effectivenes - CO2 Captured	US$/Ton	85.3	
Cost Effectivenes - CO2 Avoided	US$/Ton	131.2	

References
1. "Best Available Control Technology Review for Greenhouse Gas Emissions," Hyperion Energy Center, October 2010
2. "A Study of Very Large Scale Post Combustion CO2 Capture At a Refining & Petrochemical Complex," Grangemouth, UK