



4525 Wasatch Blvd | Suite 200 | Salt Lake City, UT 84124 | P (801) 272-3000 | F (801) 272-3040

trinityconsultants.com



Document Date: 04/28/2017



DAQ-2017-005322

April 28, 2017

Mr. John Jenks
Environmental Engineer
Utah Division of Air Quality
195 North 1950 West
P. O. Box 144820
Salt Lake City, Utah 84114-4820

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

APR 28 2017

DIVISION OF AIR QUALITY

RE: *Best Available Control Measure Analyses for HollyFrontier's Woods Cross Refinery*

Dear Mr. Jenks:

Please find enclosed one copy of the report, Best Available Control Measure Analyses for HollyFrontier's Woods Cross Refinery.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call Regina Doyle at HollyFrontier at (801)397-7432 or me at (801) 272-3000 ext. 305.

Sincerely,

MSI TRINITY CONSULTANTS

Linda Conger
Managing Consultant

CL:\lec\\MSI_SERVER_2012\msi_server\CONFIDENTIAL PROJECTS\HollyFrontier\Woods Cross\174501.0025 17-25 Holly Refining BACM Analysis\04 Report\UDAQ cover letter.docx

HEADQUARTERS >

12770 Merit Drive | Suite 900 | Dallas, TX 75251 | P (972) 661-8100 | F (972) 385-9203

North America | Europe | Middle East | Asia

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

APR 28 2017

DIVISION OF AIR QUALITY

BEST AVAILABLE CONTROL MEASURE ANALYSES HOLLYFRONTIER'S WOODS CROSS REFINERY

Prepared for:

HollyFrontier Woods Cross Refining LLC
1070 West 500 South
West Bountiful, Utah 84087

By

Meteorological Solutions Inc. a Trinity Consultants Company
Project No. 04171725

April 2017



TABLE OF CONTENTS

1.0	INTRODUCTION	1-1
2.0	FACILITY OVERVIEW	2-1
3.0	BEST AVAILABLE CONTROL MEASURE SELECTION PROCESS	3-1
3.1	Step 1 – Identify All Existing and Potential Emission Control Technologies	3-1
3.2	Step 2 – Eliminate Technically Infeasible Options	3-1
3.3	Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	3-1
3.4	Step 4 - Evaluate Most Effective Controls and Document Results	3-2
3.4.1	Energy Impact	3-2
3.4.2	Environmental Impacts	3-2
3.4.3	Costs of Control	3-2
3.5	Step 5 - Selection of BACM	3-2
4.0	BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR NITROGEN OXIDES	4-3
4.1	Process Heaters and Boilers	4-3
4.1.1	Step 1 – Identify All Existing and Potential Emission Control Technologies	4-3
4.1.1.1	Low NO _x Burners	4-5
4.1.1.2	Ultra-Low NO _x Burners	4-5
4.1.1.3	External Flue Gas Recirculation	4-5
4.1.1.4	SCR	4-5
4.1.1.5	SNCR	4-6
4.1.1.6	NSCR	4-6
4.1.1.7	Water/Steam Injection	4-7
4.1.1.8	Low Excess Air	4-7
4.1.1.9	Overfire Air (Boilers only)	4-7
4.1.1.10	CETEX	4-7
4.1.2	Step 2 – Eliminate Technically Infeasible Options	4-7
4.1.3	Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	4-9
4.1.4	Step 4 – Evaluate Impacts and Document Results	4-13
4.1.4.1	Energy and Environmental Impacts	4-17
4.1.4.2	Economic Impact	4-17
4.1.5	Selection of BACM	4-18
4.2	Flares	4-18
4.2.1	Step 1 – Identify all Existing and Potential Emission Control Technologies	4-19
4.2.1.1	Proper Equipment Design and Work Practices	4-19

Table of Contents Continued

Section

4.2.1.2 Good Combustion Practices.....	4-20
4.2.1.3 Conversion from Air Assisted to Steam Assisted	4-20
4.2.1.4 Flare Gas Recovery Systems.....	4-20
4.2.2 Step 2 - Eliminate Technically Infeasible Options.....	4-20
4.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	4-20
4.2.4 Step 4 - Evaluate Impacts and Document Results.....	4-21
4.2.4.1 Energy, Environmental, and Economic Impacts.....	4-21
4.2.5 Step 5 – Select BACT	4-21
4.3 Sulfur Recovery Unit Tail Gas Incinerator	4-23
4.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	4-23
4.3.2 Step 2 - Eliminate Technically Infeasible Options.....	4-23
4.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	4-23
4.3.4 Step 4 – Evaluate Impacts and Document Results.....	4-23
4.3.4.1 Energy, Environmental and Economic Impacts.....	4-23
4.3.5 Step 5 – Select BACT	4-24
4.4 Fluidized Catalytic Cracking Unit (FCCU)	4-25
4.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	4-25
4.4.2 Step 2 – Eliminate Technically Infeasible Options.....	4-25
4.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	4-25
4.4.3.1 SNCR.....	4-25
4.4.3.2 SCR.....	4-26
4.4.3.3 LoTOx™.....	4-26
4.4.3.4 Catalyst Additive and Combustion Promoters	4-26
4.4.4 Step 4 – Evaluate Impacts and Document Results.....	4-27
4.4.4.1 Energy, Environmental, and Economic Impacts.....	4-29
4.4.5 Step 5 – Select BACT	4-29
4.5 Emergency Diesel Engines	4-30
4.5.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	4-30
4.5.1.1 Ignition Timing Retard	4-30
4.5.1.2 Air-to-Fuel Ratio.....	4-30
4.5.1.3 Derating.....	4-30
4.5.1.4 Selective Catalytic Reduction.....	4-31

Table of Contents Continued

Section

4.5.1.5 Non-Selective Catalytic Reduction.....	4-31
4.5.1.6 NO _x Absorption Systems (Lean NO _x Traps).....	4-31
4.5.2 Step 2 – Eliminate Technically Infeasible Options.....	4-31
4.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	4-32
4.5.4 Step 4 – Evaluate Impacts and Document Results.....	4-32
4.5.4.1 Energy, Environmental, and Economic Impacts.....	4-32
4.5.5 Step 5 - Select BACT	4-33
4.6 Emergency Natural Gas-Fired Engines	4-35
4.6.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	4-35
4.6.1.1 Selective Catalytic Reduction.....	4-35
4.6.1.2 Non-selective Catalytic Reduction.....	4-35
4.6.1.3 Lean Burn Technology	4-35
4.6.1.4 Good Combustion Practices.....	4-35
4.6.2 Step 2 - Eliminate Technically Infeasible Options.....	4-36
4.6.3 Step 3 - Rank Remaining Control Technologies by Effectiveness	4-36
4.6.4 Step 4 - Evaluate Most Effective Controls.....	4-36
4.6.4.1 Energy, Environmental, and Economic Impacts.....	4-37
4.6.5 Step 5 - Select BACT	4-37
5.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR SULFUR DIOXIDE	5-1
5.1 Process Heaters and Boilers.....	5-1
5.1.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	5-1
5.1.1.1 Fuel Specifications.....	5-1
5.1.1.2 Flue Gas Desulfurization	5-1
5.1.1.3 Emerachem (EMX).....	5-2
5.1.2 Step 2 – Eliminate Technically Infeasible Options.....	5-2
5.1.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	5-2
5.1.4 Step 4 – Evaluate Impacts and Document Results.....	5-3
5.1.4.1 Energy, Environmental, and Economic Impacts.....	5-3
5.1.5 Selection of BACM.....	5-3
5.2 Flares	5-5
5.2.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	5-5
5.2.1.1 Maintain Flare Gas Parameters.....	5-5

Table of Contents Continued

Section

5.2.1.2 Meet the Requirements of 40 CFR 60.18	5-5
5.2.1.3 Proper Design	5-5
5.2.1.4 Good Combustion, Operating, and Maintenance Practices	5-5
5.2.1.5 Limit Sulfur Content of Feedstock and Fuels	5-6
5.2.1.6 Root Cause Analysis	5-6
5.2.1.7 Flare Gas Recovery System	5-6
5.2.2 Step 2 – Eliminate Technically Infeasible Options.....	5-6
5.2.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	5-6
5.2.4 Step 4 – Evaluate Impacts and Document Results.....	5-6
5.2.4.1 Energy, Environmental, and Economic Impacts.....	5-7
5.2.5 Step 5 – Selection of BACM	5-7
5.3 Sulfur Recovery Plant.....	5-9
5.3.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	5-9
5.3.1.1 Superclaus Process.....	5-9
5.3.1.2 Euroclaus Process.....	5-10
5.3.1.3 Mobil Oil Direct Oxidation Process.....	5-10
5.3.1.4 COPE, OxyClaus, and SURE Processes	5-10
5.3.1.5 Selectox.....	5-10
5.3.1.6 Sulfreen	5-10
5.3.1.7 Maxisulf, CBA, Clinsulf, and MCRC Processes.....	5-10
5.3.1.8 Wellman-Lord, CANSOLV, and CLINTOX Processes.....	5-10
5.3.1.9 Stretford, Z-SORB, LO-CAT, and CrystaSulf Liquid-Phase Oxidation Reduction Technologies.....	5-11
5.3.1.10 Shell Claus Offgas Treating (SCOT) Process.....	5-11
5.3.2 Step 2 – Eliminate Technically Infeasible Options.....	5-11
5.3.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	5-11
5.3.4 Step 4 – Evaluate Impacts and Document Results.....	5-11
5.3.4.1 Energy, Environmental, and Economic Impact.....	5-12
5.3.5 Step 5 – Selection of BACM	5-13
5.4 FCCU.....	5-14
5.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	5-14
5.4.1.1 Control of Sulfur in FCCU Feed.....	5-14

Table of Contents Continued

Section

5.4.1.2 Feed Hydrotreatment.....	5-14
5.4.1.3 Wet Gas Scrubbers.....	5-14
5.4.1.4 Wellman-Lord Flue Gas Desulfurization Process.....	5-14
5.4.1.5 DeSO _x Additives	5-15
5.4.2 Step 2 – Eliminate Technically Infeasible Options.....	5-15
5.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	5-15
5.4.4 Step 4 - Evaluate Impacts and Document Results.....	5-15
5.4.4.1 Energy, Environmental, and Economic Impacts.....	5-16
5.4.5 Step 5 – Selection of BACM	5-16
5.5 Emergency Diesel Engines	5-17
5.5.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	5-17
5.5.2 Step 2 – Eliminate Technically Infeasible Options.....	5-17
5.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	5-17
5.5.4 Step 4 – Evaluate Impacts and Document Results	5-17
5.5.4.1 Energy, Environmental, or Economic Impacts	5-17
5.5.5 Step 5 – Select BACT	5-17
5.6 Emergency Natural Gas-Fired Generators.....	5-19
5.6.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	5-19
5.6.2 Step 2 – Eliminate Technically Infeasible Options.....	5-19
5.6.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	5-19
5.6.4 Step 4 – Evaluate Impacts and Document Results	5-19
5.6.4.1 Energy, Environmental, or Economic Impacts	5-19
5.6.5 Step 5- Select BACT	5-19
6.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR PM _{2.5}	6-1
6.1 Process Heaters and Boilers	6-1
6.1.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	6-1
6.1.1.1 Good Combustion Practices.....	6-1
6.1.1.2 Gaseous Fuel Specifications.....	6-1
6.1.1.3 Wet Gas Scrubber.....	6-2
6.1.1.4 Electrostatic Precipitator.....	6-2
6.1.1.5 Cyclone	6-2
6.1.1.6 Baghouse.....	6-2

Table of Contents Continued

Section

6.1.2 Step 2 – Eliminate Technically Infeasible Options.....	6-2
6.1.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	6-3
6.1.4 Step 4 – Evaluate Impacts and Document Results.....	6-4
6.1.4.1 Energy, Environmental, or Economic Impacts.....	6-5
6.1.5 Selection of BACM.....	6-5
6.2 Flares	6-6
6.2.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	6-6
6.2.2 Step 2 – Eliminate Technically Infeasible Options.....	6-6
6.2.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	6-6
6.2.4 Step 4 - Evaluate Impacts and Document Results.....	6-6
6.2.4.1 Energy, Environmental, or Economic Impacts.....	6-7
6.2.5 Step 5 – Select BACT	6-7
6.3 Cooling Towers.....	6-8
6.3.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	6-8
6.3.2 Step 2 – Eliminate Technically Infeasible Options.....	6-8
6.3.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	6-9
6.3.4 Step 4 – Evaluate Impacts and Document Results.....	6-9
6.3.4.1 Energy, Environmental, or Economic Impacts.....	6-9
6.3.5 Step 5 - Selection of BACM	6-9
6.4 Sulfur Recovery Unit Incinerator	6-11
6.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	6-11
6.4.2 Step 2 - Eliminate Technically Infeasible Options.....	6-11
6.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	6-11
6.4.4 Step 4 – Evaluate Impacts and Document Results.....	6-11
6.4.4.1 Energy, Environmental, or Economic Impacts.....	6-11
6.4.5 Step 5 – Select BACT	6-11
6.5 FCCU.....	6-13
6.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	6-13
6.5.2 Step 2 – Eliminate Technically Infeasible Options.....	6-13
6.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	6-13
6.5.4 Step 4 - Evaluate Impacts and Document Results.....	6-13
6.5.4.1 Energy, Environmental, or Economic Impacts.....	6-14

Table of Contents Continued

Section

6.5.5 Step 5 – Select BACT	6-14
6.6 Emergency Diesel Engines	6-15
6.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	6-15
6.6.1.1 Good Combustion Practices.....	6-15
6.6.1.2 Ultra-Low Sulfur Diesel	6-15
6.6.1.3 Diesel Particulate Filters.....	6-15
6.6.1.4 Diesel Oxidation Catalyst.....	6-16
6.6.2 Step 2 - Eliminate Technically Infeasible Options.....	6-16
6.6.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	6-16
6.6.4 Step 4 - Evaluate Impacts and Document Results.....	6-16
6.6.4.1 Energy, Environmental, or Economic Impacts	6-16
6.6.5 Step 5 – Select BACT	6-17
6.7 Emergency Natural Gas-Fired Generators.....	6-19
6.7.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	6-19
6.7.2 Step 2 - Eliminate Technically Infeasible Options.....	6-19
6.7.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	6-19
6.7.4 Step 4 - Evaluate Impacts and Document Results.....	6-19
6.7.4.1 Energy, Environmental, or Economic Impacts	6-19
6.7.5 Step 5 – Select BACT	6-19
7.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR VOLATILE ORGANIC COMPOUNDS.....	7-1
7.1 Process Heaters and Boilers.....	7-1
7.1.1 Step 1 – Identify all Existing and Potential Emission Control Technologies	7-1
7.1.1.1 Good Combustion Practice.....	7-1
7.1.1.2 Fuel Specifications.....	7-1
7.1.1.3 Ultra-Low NO _x Burners.....	7-2
7.1.1.4 Catalytic Oxidation	7-2
7.1.1.5 Thermal Oxidation.....	7-2
7.1.1.6 Emerachem (EMx).....	7-2
7.1.2 Step 2 – Eliminate Technically Infeasible Options.....	7-2
7.1.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	7-3
7.1.4 Step 4 – Evaluate Impacts and Document Results.....	7-3

Table of Contents Continued

Section

7.1.4.1 Energy, Environmental, or Economic Impact	7-4
7.1.5 Step 5 - Selection of BACM	7-5
7.2 Flares	7-6
7.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies	7-6
7.2.1.1 Proper Equipment Design and Work Practices	7-6
7.2.1.2 Good Combustion Practices	7-6
7.2.1.3 Conversion from Air Assisted to Steam Assisted	7-6
7.2.1.4 Flare Gas Recovery Systems	7-7
7.2.2 Step 2 - Eliminate Technically Infeasible Options	7-7
7.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	7-7
7.2.4 Step 4 - Evaluate Impacts and Document Results	7-7
7.2.4.1 Energy, Environmental, or Economic Impacts	7-8
7.2.5 Step 5 - Select BACT	7-8
7.3 Cooling Towers	7-9
7.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies	7-9
7.3.2 Step 2 - Eliminate Technically Infeasible Options	7-9
7.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	7-9
7.3.4 Step 4 - Evaluate Impacts and Document Results	7-9
7.3.4.1 Energy, Environmental, or Economic Costs	7-9
7.3.5 Step 5 - Select BACT	7-9
7.4 Sulfur Reduction Unit Incinerator	7-11
7.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies	7-11
7.4.2 Step 2 - Eliminate Technically Infeasible Options	7-11
7.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	7-11
7.4.4 Step 4 - Evaluate Impacts and Document Results	7-11
7.4.4.1 Energy, Environmental, or Economic Impacts	7-11
7.4.5 Step 5 - Select BACT	7-11
7.5 FCCU	7-13
7.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies	7-13
7.5.1.1 Good Combustion Practices	7-13
7.5.1.2 Combustion Promoters	7-13
7.5.1.3 Catalytic Oxidation	7-13

Table of Contents Continued

Section

7.5.2 Step 2 – Eliminate Technically Infeasible Options.....	7-14
7.5.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	7-14
7.5.4 Step 4 – Evaluate Impacts and Document Results.....	7-14
7.5.4.1 Energy, Environmental, and Economic Impacts.....	7-14
7.5.5 Step 5 – BACM	7-14
7.6 Storage Tanks	7-15
7.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	7-15
7.6.2 Step 2 – Eliminate Technically Infeasible Options.....	7-16
7.6.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	7-16
7.6.4 Step 4 – Evaluate Impacts and Document Results.....	7-17
7.6.4.1 Energy, Environmental, and Economic Impacts.....	7-18
7.6.5 Step 5 – Proposed BACM.....	7-20
7.7 Equipment Leaks.....	7-25
7.7.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	7-25
7.7.2 Step 2 – Eliminate Technically Infeasible Options.....	7-25
7.7.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	7-25
7.7.4 Step 4 – Evaluate Impacts and Document Results.....	7-26
7.7.4.1 Energy, Environmental, and Economic Impacts.....	7-27
7.7.5 Step 5 - Selection of BACM	7-27
7.8 Wastewater Treatment Plant.....	7-29
7.8.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	7-29
7.8.2 Step 2 - Eliminate Technically Infeasible Options.....	7-29
7.8.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies	7-29
7.8.4 Step 4 – Evaluate Impacts and Document Results.....	7-30
7.8.5 Step 5 – Select BACT	7-31
7.9 Product Loading.....	7-32
7.9.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	7-32
7.9.2 Step 2 - Eliminate Technically Infeasible Options.....	7-32
7.9.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	7-32
7.9.4 Step 4 – Evaluate Impacts and Document Results.....	7-33
7.9.4.1 Energy, Environmental, and Economic Costs	7-33
7.9.5 Step 5 – Proposed BACM.....	7-34

Table of Contents Continued

Section

7.10 Diesel Emergency Engines.....	7-35
7.10.1 Step 1 - Identify all Existing and Potential Emission Control Technologies	7-35
7.10.1.1 Good Combustion Practices	7-35
7.10.1.2 Diesel Oxidation Catalyst	7-35
7.10.2 Step 2 - Eliminate Technically Infeasible Options.....	7-35
7.10.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies.....	7-35
7.10.4 Step 4 - Evaluate Impacts and Document Results	7-36
7.10.4.1 Energy, Environmental, and Economic Impacts	7-36
7.10.5 Step 5 - Proposed BACM.....	7-36
7.11 Emergency Natural Gas-Fired Engines.....	7-38
7.11.1 Step 1- Identify all Control Technologies.....	7-38
7.11.1.1 Good Combustion Practices	7-38
7.11.1.2 Oxidation Catalysts.....	7-38
7.11.1.3 Non-Selective Catalytic Reduction.....	7-38
7.11.2 Step 2 - Eliminate Technically Infeasible Options.....	7-38
7.11.3 Step 3 - Rank Remaining Control Technologies by Effectiveness	7-38
7.11.4 Step 4 - Evaluate Most Effective Controls	7-39
7.11.4.1 Energy, Environmental, and Economic Costs.....	7-39
7.11.5 Step 5 - Select BACT	7-39
8.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR AMMONIA.....	8-1
8.1 Process Heaters and Boilers	8-1
8.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies	8-1
8.1.2 Step 2 - Eliminate Technically Infeasible Options.....	8-1
8.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	8-1
8.1.4 Step 4 - Evaluate Impacts and Document Results.....	8-2
8.1.4.1 Energy, Environmental, and Economic Impacts.....	8-3
8.1.5 Step 5 - Select BACT	8-3
8.2 Wastewater Treatment.....	8-4
8.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	8-4
8.2.2 Step 2 - Eliminate Technically Infeasible Options.....	8-5
8.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies	8-5
8.2.4 Step 4 - Evaluate Impacts and Document Results.....	8-5

Table of Contents Continued

Section

8.2.4.1 Energy, Environmental, and Economic Impacts.....	8-5
8.2.5 Step 5- Select BACT	8-6
8.3 FCCU.....	8-7
8.3.1 Steps 1 – 4	8-7
8.3.2 Step 5 – Select BACT	8-7
8.4 Sour Water Stripper and Ammonia Stripping Unit.....	8-8
8.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies.....	8-8
8.4.2 Step 2 - Eliminate Technically Infeasible Options.....	8-8
8.4.3 Steps 3 - Evaluate Control Effectiveness of Remaining Control Technologies	8-8
8.4.4 Step 4 - Evaluate Impacts and Document Results.....	8-8
8.4.4.1 Energy, Environmental, and Economic Impacts.....	8-8
8.4.5 Step 5 - Select BACT	8-8

Tables

4-1	Potential NO _x Control Technologies for Refinery Process Heaters and Boilers.....	4-4
4-2	NO _x Control Efficiencies.....	4-9
4-3	Typical Emission Levels based on Control Technologies.....	4-10
4-4	Process Heaters and Boilers at HollyFrontier's Woods Cross Refinery.....	4-11
4-5	Technically Feasible Control Options for NO _x for Process Heaters and Boilers.....	4-12
4-6	BACT Determinations for NO _x from Process Heaters and Boilers with Heat Capacities between 10 and <100 MMBtu/hr.....	4-14
4-7	BACT Determinations for NO _x from Process Heaters and Boilers with Heat Capacities ≥100 MMBtu/hr.....	4-14
4-8	Current Control Technologies on HollyFrontier Process Heaters and Boilers.....	4-16
4-9	Proposed BACM Controls and Compliance Monitoring Methods for Flares.....	4-22
4-10	Proposed BACM Controls and Monitoring Method for SRU Tail Gas Incinerator.....	4-24
4-11	LoTOx™ NO _x Reduction Technology Installations.....	4-28
4-12	BACT Determinations for NO _x for FCCU	4-28
4-13	Proposed BACM Controls, NO _x Emission Limits, and Monitoring Methods for FCCUs.....	4-29
4-14	Cost Effectiveness of Installing SCR on Emergency Diesel Engines for NO _x Control.....	4-33
4-15	Proposed BACM Controls, Emission Limitations, and Compliance Monitoring Method for Emergency Diesel Engines	4-34
4-16	Proposed BACM Controls, Emission Limitations, and Monitoring for Emergency Natural Gas Engines.....	4-37
5-1	BACT Determinations for SO ₂ for Process Heaters and Boilers	5-3
5-2	Proposed BACM Controls, SO ₂ Emission Limits, and Monitoring Methods for Process Heaters and Boilers	5-4
5-3	Proposed BACM Controls, SO ₂ Emission Limits, and Monitoring Methods for Flares.....	5-8

Table of Contents Continued

Tables

5-4	BACT Determinations for SO ₂ for Sulfur Recovery Units	5-12
5-5	Proposed BACM Controls, SO ₂ Emission Limits, and Monitoring Methods for SRU	5-13
5-6	BACT Determinations for SO ₂ for FCCU	5-16
5-7	Proposed BACM Controls, SO ₂ Emission Limits, and Monitoring Methods for FCCU	5-16
5-8	Proposed BACM Controls, Emission Limitation, and Monitoring Methods for SO ₂ for the Emergency Diesel Engines	5-18
5-9	Proposed BACM Controls, Emission Limitations, and Monitoring Methods for SO ₂ for Natural Gas-Fired Emergency Engines	5-19
6-1	BACT Determinations for PM _{2.5} for Process Heaters and Boilers	6-5
6-2	Proposed BACM Controls, PM _{2.5} Emission Limits, and Monitoring Methods for Flares	6-7
6-3	Proposed BACM Controls, PM _{2.5} Emission Limitations, and Monitoring Methods for Cooling Towers	6-10
6-4	Proposed BACM Controls and Monitoring Methods for PM _{2.5} from the SRU	6-12
6-5	BACT for PM _{2.5} for FCCU	6-14
6-6	Proposed BACM Controls, PM ₁₀ /PM _{2.5} Emission Limits, and Monitoring Methods for FCCU	6-14
6-7	PM _{2.5} Control Technology Effectiveness for Diesel Engines	6-16
6-8	Cost Effectiveness of Installing DPF on Emergency Diesel Engines for PM _{2.5} Control	6-17
6-9	Proposed BACM Controls, PM _{2.5} Emission Limitations, and Monitoring for Emergency Diesel Engines	6-18
6-10	Proposed BACM Controls, PM _{2.5} Emission Limitations, and Monitoring Methods for Natural Gas- Fired Emergency Engines	6-20
7-1	VOC Control Technologies by Control Effectiveness	7-3
7-2	Summary of BACM Determinations for VOC for Process Heaters and Boilers	7-4
7-3	Proposed BACM Controls, VOC Emission Limits, and Monitoring for Process Heaters and Boilers	7-5
7-4	Proposed BACM Controls and Monitoring Methods for Flares	7-8
7-5	Proposed BACM Controls, VOC Emission Limits, and Monitoring Methods for Cooling Towers	7-10
7-6	Proposed BACM Controls and Monitoring Methods for SRU	7-12
7-7	Proposed BACM Controls and Monitoring Methods for FCCU	7-14
7-8	Hierarchy of Tank Control Options	7-16
7-9	Proposed BACM for HollyFrontier Storage Tanks	7-21
7-10	Repair Actions for Leaking Valves and Pumps	7-26
7-11	LDAR Monitoring Frequencies	7-28
7-12	Proposed BACM Controls, VOC Emission Limits, and Monitoring Methods for Wastewater Treatment	7-31
7-13	Cost Effectiveness of Installing DOC on Emergency Diesel Engines for VOC Control	7-36
7-14	Proposed BACM Controls, VOC Emission Limitations, and Monitoring Methods for Emergency Diesel Engines	7-37
7-15	Proposed BACM Controls, Emission Limitation, and Monitoring for Emergency Natural Gas Engines	7-39
8-1	Summary of BACM Determinations for Ammonia for Process Heaters and Boilers	8-2

Table of Contents Continued

Appendices

- A List of Refinery Permitted Equipment
- B Cost Analyses and Vendor Quotes

1.0 INTRODUCTION

In 2006, the United States Environmental Protection Agency (EPA) strengthened the 24-hour PM_{2.5} standard from 65 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) to 35 $\mu\text{g}/\text{m}^3$. As such, all or portions of seven Utah counties failed to meet the new 24-hour PM_{2.5} standard. Ultimately, only three areas of the state (Salt Lake City including Davis County, Logan, and Provo) were designated as nonattainment for the 24-hour PM_{2.5} standard. Once an area is designated as nonattainment, the Clean Air Act requires that fine particle pollution be controlled by a state, a state implementation plan (SIP) detailing how and when the 24-hour PM_{2.5} standard would be met is required to be prepared and submitted to EPA for approval.

The moderate PM_{2.5} nonattainment areas were required to meet the new standard by 2014. However, as the SIP for Salt Lake City was nearing completion, the D.C. Circuit Court of Appeals found that EPA had incorrectly interpreted the Clean Air Act when determining how to implement the National Ambient Air Quality Standards (NAAQS) for PM_{2.5}. The January 4, 2013 court ruling held that the EPA should have implemented the PM_{2.5} NAAQS based on both Clean Air Act (CAA) Subpart 1 and Subpart 4 of Part D, title 1. Previously, EPA had (incorrectly) required states to develop their SIPs based on subpart 1 only. If a moderate PM_{2.5} nonattainment area is not able to attain the 24-hr PM_{2.5} standard by the December 31, 2015 attainment date, Subpart 4 allows EPA to re-classify that area as a serious PM_{2.5} nonattainment area.

As of the December 31, 2015 attainment date, all three of Utah's PM_{2.5} nonattainment areas were found to be exceeding the 24-hour PM_{2.5} standard, and as such, EPA reclassified each of the three areas to serious.

Once re-classified to serious, the attainment date for the area is December 14, 2019. A new serious area PM_{2.5} SIP is being prepared by the Utah Division of Air Quality (UDAQ) and the requirements of such are detailed in 40 Code of Federal Regulations (CFR) 51 Subpart Z. This rule requires the UDAQ to identify, adopt and implement Best Available Control Measures (BACM) on major sources of PM_{2.5} and PM_{2.5} precursors (sulfur dioxide, oxides of nitrogen, volatile organic compounds, and ammonia).

HollyFrontier's Woods Cross Refinery has potential to emit emissions of PM_{2.5} and/or PM_{2.5} precursors above the 70 tons or more per year and is thus classified as a major source which is subject to the implementation rule. As a major source subject to the rule, the UDAQ has requested assistance from HollyFrontier in determining acceptable pollution controls that meet BACM/Best Available Control Technology (BACT) controls.

This document provides a written evaluation of each available control strategy for HollyFrontier PM_{2.5} and precursor emission sources, taking into account technological, energy, environmental and economic feasibility, provides documentation to justify the elimination of any available control option, establishes BACM, and emission monitoring requirements for each emission unit.

2.0 FACILITY OVERVIEW

HollyFrontier Woods Cross Refining, LLC is located at 1070 West 500 South in Woods Cross, Utah. Its Universal Transverse Mercator (UTM) Coordinates for the facility, in NAD27, are 4526.227 kilometers North and 424.00 kilometers East in Zone 12 at an elevation of 4,260 feet above mean sea level. The refinery is located in Davis County which is non-attainment area for PM_{2.5}, maintenance for ozone (O₃) and particulate matter (PM₁₀), and attainment for sulfur dioxide (SO₂), nitrogen oxides (NO_x), volatile organic compounds (VOC), and carbon monoxide (CO). The refinery is located within four miles of Salt Lake County, which is in non-attainment for PM_{2.5}, PM₁₀, and SO₂, and a maintenance area for O₃. The facility is subject to emission limitations and emission caps as found in HollyFrontier approval order (AO) DAQE-AN101230041-13, PM₁₀ State Implementation Plan (SIP), and Consent Decree requirements.

The HollyFrontier Woods Cross Refinery is owned by HollyFrontier Woods Cross Refining, LLC. The Woods Cross Refinery is a 40,000 barrel per day (BPD) refinery permitted up to 60,000 BPD that produces a variety of products including gasoline, natural gas liquids (NGL), propane, butanes, jet fuels, fuel oils, and kerosene products.

The Standard Industrial Code (SIC) for the refinery is 2911 (Petroleum Refining). A list of the equipment permitted at the refinery is presented in Appendix A.

3.0 BEST AVAILABLE CONTROL MEASURE SELECTION PROCESS

According to 40 CFR Part 51, Subpart Z, BACM is “any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after the date of reclassification of a Moderate PM_{2.5} nonattainment area to Serious and that generally can achieve greater permanent and enforceable emissions reductions in direct PM_{2.5} emissions and/or emissions of PM_{2.5} plan precursors from sources in the area than can be achieved through the implementation of RACM on the same source(s). BACM includes BACT”. However, the UDAQ has indicated that for this analysis, that any technologically and economically feasible control measure has to be implemented by the end of 2018 to be considered BACT.

In the preparation of this BACM analyses, several sources of information were examined including EPA’s RBLC RACT/BACT/LAER Clearinghouse, state agency databases, vendor data, and published literature.

EPA’s established five-step procedure that starts with the most stringent emission limits and lists all control technologies was utilized for determining the appropriate BACM limit for NO_x, SO₂, PM_{2.5}, and VOC. This is referred to as “Top-Down” BACT and includes the following five steps as outlined in the Draft New Source Review Manual, dated 1990.

3.1 Step 1 - Identify All Existing and Potential Emission Control Technologies

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for each subject pollutant. Available control technologies are those with a practical potential for application to the emission unit. HollyFrontier is a petroleum refinery. In order to identify the appropriate control technologies, the following sources were referenced:

- > US EPA RACT/BACT/LAER Clearinghouse (RBLC)
- > US EPA Control Technology Center
- > Recent Permit Actions
- > Vendor Information

3.2 Step 2 - Eliminate Technically Infeasible Options

The second step in performing the top-down BACT analysis is to eliminate technically infeasible options. Technically infeasible is defined as a control option that, based on physical, chemical, and engineering principles, would preclude the successful use of said control option on the emissions unit under review due to technical difficulties. Two key concepts in determining whether an undemonstrated technology is feasible are availability and applicability. A Technology is considered available if it can be obtained through commercial channels. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration. Technically infeasible control options are then eliminated from further consideration.

3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The third step of the BACT analysis is to rank all the remaining control options not eliminated in Step 2, based on control effectiveness for the pollutant under review. The emission limit or removal efficiency used in the ranking process is the level the technology has demonstrated it can consistently achieve under reasonably foreseeable worst-case conditions with an adequate margin of safety.

3.4 Step 4 - Evaluate Most Effective Controls and Document Results

In this step, an analysis is performed on each remaining control technology in order to determine whether the energy, economic, or environmental impacts from a given technology outweigh their benefits. Information including control efficiency, anticipated emission rate, expected emissions reduction, and economic, environmental, and energy impacts are to be considered.

If the top-ranked technology is chosen and there are no significant or unusual environmental impacts associated with that technology that have the potential to affect its selection, the BACT analysis is complete and no further information regarding economic, environmental, and energy impacts is required. However, if the top-ranked option is not chosen, an assessment of economic, environmental, and energy impacts (taking into consideration source-specific circumstances that distinguish it from other sources where the technology is in use or has been required) is performed on the next most cost-effective technology until the technology under consideration is not eliminated.

3.4.1 Energy Impact

The energy impact of each evaluated control technology is the energy benefit or penalty resulting from the operation of the control technology at the source. The costs of the energy impacts either in additional fuel costs or the cost of lost power generation impacts the cost-effectiveness of the control technology.

3.4.2 Environmental Impacts

The second evaluation to be reviewed is the environmental evaluation. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology.

3.4.3 Costs of Control

This third evaluation addresses the economic impact of the control technologies. The cost to purchase and to operate the control technology is analyzed. The capital and annual operating costs are estimated based on established design parameters or documented assumptions in the absence of established designed parameters. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. It also compares the potential technologies on an economic basis. US EPA's Air Pollution Control Cost Manual was used as well as vendor estimates to determine control costs.

3.5 Step 5 - Selection of BACM

The fifth, and final step is selection of the BACT (BACM) emission limit corresponding to the most stringent and technically feasible technology that was not eliminated based upon adverse economic, environmental, and energy impacts. BACM is the technologically and economically feasible control option that can be implemented that achieves permanent and enforceable emissions reductions. It typically is the highest ranked control technology and must not be less stringent than any applicable federal New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), or state-specific standards.

4.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR NITROGEN OXIDES

BACMs were evaluated for oxides of nitrogen (NO_x) emissions from certain emission units in operation or proposed at the Woods Cross Refinery. These units include: process heaters, boilers, flares, sulfur reduction unit (SRU), fluidized catalytic cracking units (FCCU), and emergency diesel and natural gas-fired engines.

4.1 Process Heaters and Boilers

At the Woods Cross Refinery, there are 24 existing or proposed process heaters (4H1, 6H1, 6H2, 6H3, 7H1, 7H3, 8H2, 9H1, 9H2, 10H1, 10H2, 11H1, 12H1, 13H1, 19H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1) 10 asphalt tank in-line heaters (68H2-H7, 68H10-H13), and 6 boilers (Boiler #4, #5, #8, #9, #10, and #11). The list of the ratings for this equipment is presented in Appendix A.

4.1.1 Step 1 - Identify All Existing and Potential Emission Control Technologies

Nitrogen oxides (NO_x) are formed during the combustion of fuels by oxidation of chemically-bound nitrogen in the fuel and by thermal fixation of nitrogen in the combustion air. There are three different formation mechanisms: thermal, fuel, and prompt NO_x . Thermal NO_x is primarily temperature dependent (above 2000°F); fuel NO_x is primarily dependent on the presence of fuel-bound nitrogen and the local oxygen concentration. Prompt NO_x is formed in relatively small amounts from the reaction of molecular nitrogen in the combustion air with hydrocarbon radicals in the flame front.

There are a variety of options available for control of NO_x emissions from combustion sources. These include equipment or modifications to equipment that reduce NO_x formation, add-on control devices, or combinations of both. Table 4-1 lists potential NO_x control technologies for refinery heaters and boilers. Abbreviated descriptions of each control technology are provided in Table 4-1.

Table 4-1 Potential NO_x Control Technologies for Refinery Process Heaters and Boilers

Control Technology	Description
Low NO _x Burners (LNB)	Reducing NO _x emissions through burner design.
Next generation and ultra-low NO _x burners (ULNB)	Reducing NO _x emissions through burner design.
External flue gas recirculation (FGR)	Flue gas is recirculated by a fan and external ducting and is mixed with combustion air
Selective catalytic reduction (SCR)	Post combustion control. Injection of ammonia into a catalyst bed within the flue gas path.
Selective non-catalytic reduction (SNCR)	Post combustion control. Injection of ammonia directly into the flue gas at a specific temperature.
Non-selective catalytic reduction (NSCR)	Post combustion control. Precious metal catalysts promote reactions that reduce most NO _x in exhaust streams with low oxygen content.
LNB + FGR	Combination of low NO _x burners and flue gas recirculation.
ULNB + FGR	Combination of ultra-low NO _x burners and flue gas recirculation.
LNB + SNCR	Combination of low NO _x burners and post-combustion add-on SNCR.
ULNB + SNCR	Combination of ultra-low NO _x burners and post-combustion add-on SNCR.
LNB + SCR	Combination of low NO _x burners and post-combustion add-on SCR.
ULNB + SCR	Combination of ultra-low NO _x burners and post-combustion add-on SCR
EM _x [™]	Post-combustion control. The EM _x [™] system uses a coated oxidation catalyst in the flue gas to remove both NO _x and other pollutants with a reagent such as ammonia.
LNB + EM _x [™]	Combination of low-NO _x burners and post-combustion add-on EM _x [™] .
ULNB + EM _x [™]	Combination of ultra-low NO _x burners and post-combustion add-on EM _x [™] .
Water/Steam injection	Decreases NO _x formation by injecting steam with the combustion air or fuel to reduce flame temperature.
Low excess air	Reduce excess air level by maintaining CO at minimum threshold using in-situ CO analyzer in the flow gas stream.
Staged Air/Fuel Combustion or Overfire Air Injection (OFA)	A controlled portion of the total combustion-air flow, typically 10-20%, is directed through over-fire ports located above the highest elevation of burners in the furnace.
CETEX	CETEX descales and coats tubes which reduces fire box temperature by improving heat transfer in applications where the tubes are externally scaled.

4.1.1.1 Low NO_x Burners

Low-NO_x burner (LNB) technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air burners. In a staged fuel LNB, the combustion zone is separated into two regions. The first region is a lean combustion region where a fraction of the fuel is supplied with the total quantity of combustion air. Combustion in this zone takes place at substantially lower temperatures than a standard burner. In the second combustion region, the remaining fuel is injected and combusted with left over oxygen from the first region. This technique reduces the formation of thermal NO_x.

4.1.1.2 Ultra-Low NO_x Burners

Ultra-low NO_x burners (ULNB) recirculate hot, oxygen-depleted flue gas from the flame or firebox back into the combustion zone. This reduces the average O₂ concentration within the flame without reducing the flame temperature below the temperatures that are necessary for optimal combustion efficiency. Reduced O₂ concentrations in the flame have a strong impact on fuel NO_x which makes these burners effective for controlling NO_x.

There are several types of ULNB currently available. These burners combine two NO_x reduction steps into one burner, typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment. In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel rich zone. High pressure atomization of the fuel creates recirculation. Secondary air is routed into the burner block to optimize flame and complete combustion. This type of design is usually used with liquid fuels.

In staged fuel burners with IFGR, fuel pressure induces IFGR which creates a fuel lean zone and a reduction in oxygen partial pressure. This design is predominantly used for gas fuel operations.

4.1.1.3 External Flue Gas Recirculation

In external flue gas recirculation (FGR), flue gas is recirculated using a fan and external ducting and is mixed with the combustion air stream thereby reducing the flame temperature and decreasing NO_x formation. External flue gas recirculation only works with mechanical draft heaters with burners that can accommodate increased gas flows. Achievable emission reductions are a function of the amount of flue gas recirculated and is limited by efficiency losses and flame instability at higher recirculation rates. Flue gas recirculation has not been demonstrated to function efficiently on process heaters that are subject to highly variable loads and that burn fuels with variable heat value.

4.1.1.4 SCR

SCR is a process that involves the post combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of the catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, and the ammonia slip emissions.

The applicability of SCR is limited to heaters that have both a flue gas temperature appropriate for the catalytic reaction and space for a catalyst bed large enough to provide sufficient residence time for the reaction to occur. Optimum NO_x reduction occurs at catalyst bed temperatures of 600°F to 750°F for vanadium or titanium based catalysts and 470°F to 510°F for platinum catalysts¹.

Sulfur content of the fuel can be of concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide to sulfur trioxide which combined with water to form sulfuric acid. Sulfur trioxide and sulfuric acid react with excess ammonia to form ammonia salts. These salts may condense as the flue gas is cooled leading to increased particulate emissions.

The SCR process also causes the catalyst to deactivate over time. Catalyst deactivation occurs through physical deactivation and chemical poisoning. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required which results in ammonia slip. This slip leads to emissions trade-off between NO_x and ammonia.

4.1.1.5 SNCR

Selective non-catalytic reduction (SNCR) is a post-combustion NO_x control technology based on the reactions of ammonia and NO_x. SNCR involves injecting urea/ammonia into the combustion gas to reduce the NO_x to nitrogen and water. The optimum exhaust gas temperature range for implementation of SNCR is 1,600 to 1,750°F for ammonia and from 1,000 to 1,900°F for urea-based reagents. Operating temperatures below this range results in ammonia slip which form additional NO_x. In addition, the ammonia/urea must have sufficient residence time, approximately 3 to 5 seconds, at the optimum operating temperatures for efficient NO_x reduction. At optimum temperatures, NO_x destruction efficiencies range from 30 to 50%².

SNCR reduces both thermal and fuel-derived NO_x. The SNCR systems require rapid chemical diffusion in the fuel gas. The injection point must be selected to ensure adequate flue gas residence time.

Unreacted ammonia in the emissions is known as slip and is potentially higher in SNCR systems than in SCR systems due to higher reactant injection rates.

4.1.1.6 NSCR

Non-selective catalytic reduction (NSCR) is a flue gas treatment add-on NO_x control technology for exhaust streams with low oxygen (O₂) content. Precious metal catalysts are used to promote reactions that reduce NO_x, CO, and hydrocarbons (HC) to water, carbon dioxide, and nitrogen. One type of NSCR system injects a reducing agent into the exhaust gas stream prior to the catalyst reactor to reduce the NO_x. A second type of NSCR system has an afterburner and two catalytic reactors (one reduction catalyst and one oxidation catalyst). In this system, natural gas is injected into the afterburner to combust unburned HC (at a minimum temperature of 1700°F). The gas stream is cooled prior to entering the first catalytic reactor where CO and NO_x are reduced. A second heat exchanger cools the gas stream (to reduce any NO_x reformation) before the second catalytic reactor where remaining CO is converted to CO₂.

¹ Midwest Regional Planning Organization, Petroleum Refinery Best Available Retrofit Technology (BART) Engineering Analysis, March 30, 2005.

² EPA, 2003.

The control efficiency achieved for NO_x from NSCR ranges from 80 to 90 percent. The NO_x reduction efficiency is controlled by similar factors as for SCR, including the catalyst material and condition, the space velocity, and the catalyst bed operating temperature. Other factors include the air-to-fuel (A/F) ratio, the exhaust gas temperature, and the presence of masking or poisoning agents. The operating temperatures for NSCR system range from approximately 700° to 1500°F, depending on the catalyst. For NO_x reductions of 90 percent, the temperature must be between 800° to 1200°F. One source indicates that the O₂ concentration for NSCR must be less than 4 percent; a second source indicates that the O₂ concentration must be at or below approximately 0.5 percent.

4.1.1.7 Water/Steam Injection

The injection of water or steam decreases NO_x formation by reducing the flame temperature. Water or steam is delivered either by injecting it directly into the root of the flame or by feeding it with the gaseous fuel. Water or steam injection can impact combustion unit operation by worsening flame pattern, reducing unit efficiency, and affecting unit stability.

4.1.1.8 Low Excess Air

Minimizing the amount of excess air (i.e., oxygen) during the initial stages of combustion decreases the amount of NO_x formed. However, reducing the amount of oxygen can cause incomplete combustion, which increases carbon monoxide (CO) emissions. The combustion unit can be operated based on the CO concentration moderating the excess air and therefore, controlling the amount of NO_x generated. This CO level would be monitored by an in-situ CO analyzer in the flue gas stream. This technique requires a high level of instrumentation and automation required for burner control (e.g., actuators for draft & air control).

4.1.1.9 Overfire Air (Boilers only)

In this technique, which is only applicable to boilers, a controlled portion (typically 10-20%) of the total combustion-air flow is directed through over-fire ports located above the highest elevation of burners in the furnace. The removal of the air flow from the burners results in a fuel rich primary combustion zone to limit the NO_x formation. The combustion of the CO produced in the primary combustion zone is completed using the air supplied by the over-fire air ports.

4.1.1.10 CETEX

Removing the scale and applying a coating to the heat transfer surfaces can reduce the firebox temperature and decrease NO_x formation by improving heat transfer. This technique applies in units where the heat transfer tubes are externally scaled. Conversely, the layer of scaling acts as insulation protecting the tubes from damage. Removing the scale to reduce emissions will also reduce firing rate.

4.1.2 Step 2 - Eliminate Technically Infeasible Options

SNCR has been commercially installed throughout the world. Installations include coal-fueled heating plant boilers, electric utility boilers, municipal waste incinerators, cement kilns and many package boilers. The NO_x reduction efficiency of SNCR processes depends on many factors including:

- > Flue gas temperature in reaction zone
- > Uniformity of flue gas temperature in the reaction zone
- > Normal flue gas temperature variation with load
- > Residence time

- > Distribution and mixing of ammonia/urea into the flue gases
- > Initial NO_x concentration
- > Ammonia/urea injection rate
- > Heater configuration, which affects location and design of injection nozzles.

The problem with the use of SNCR is that as the load changes, the optimum injection temperature window moves. In petroleum refineries, the loads vary considerably depending, for example, upon product needs or feedstock run. If ammonia is injected at just the right temperature, then NO_x can be reduced by approximately 60%. If ammonia is injected too hot, then more NO_x is produced. If ammonia is injected too cold, then ammonia does not react resulting in ammonia being emitted to the atmosphere. The exhaust temperatures of the process heaters and boilers range from approximately 430°F to 1000°F. Thus, no process control method has been developed that can match the temperature and rate of ammonia injection with flue gas rate, temperature, and other variables to ensure optimum emission control. Thus, SNCR was eliminated as not technically feasible for use as a post-combustion control for NO_x emissions from the process heaters and boilers.

NSCR is a flue gas treatment add-on NO_x control technology for exhaust streams with low O₂ content. Efficient operation of the catalyst typically requires the exhaust gases contain no more than 0.5% oxygen³. A second source⁴ indicates that the NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. Thus, NSCR was eliminated based on not having lean burn furnaces.

The EM_x[™] catalyst is the latest generation of SCONO_x[™] technology. EM_x[™] is a multi-pollutant catalyst that does not require ammonia. The emissions of NO_x are oxidized to NO₂ and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to regenerate the catalyst. This gas absorbs the NO₂ from the catalyst and reduces it to N₂ before it exits the stack.

EM_x[™] operates in a temperature range between 300°F to 700°F. The potassium carbonate coating reacts with NO₂ to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. When all the potassium carbonate coating on the surface of the catalyst has reacted to form nitrogen compounds, NO_x can no longer be absorbed and the catalyst must be regenerated.

The EM_x[™] system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. The EM_x[™] system is typically used to control emissions from natural gas-fired combustion turbines, reciprocating engines, and industrial boilers in which the sulfur concentration in the exhaust stream is low. The higher concentration of sulfur in the refinery gas will poison the EM_x[™] catalyst.

EM_x[™] has not been demonstrated on refinery fuel gas-fired process heaters or boilers since the SCONO_x[™] catalyst is sensitive to contamination by sulfur in the combustion fuel. This technology has been demonstrated to function efficiently on combustion sources burning fuels like natural gas. SCONO_x[™] systems have been installed at combined-cycle and co-generation turbine plants with capacities ranging from 5.2 to 32MW. Thus, since EM_x[™] was not identified or has been demonstrated for use on refinery process heaters or boilers, EM_x[™] was determined to be technically infeasible and was eliminated for further consideration.

3 http://www.meca.org/resources/MECA_stationary_IC_engine_report_0515_final.pdf Accessed 2/16/2017.

4 <https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf>. Accessed 2/16/2017

External flue gas recirculation (FGR) only works with mechanical draft heaters with burners that can accommodate increased gas flows. All but one heater at the refinery is naturally drafted. Also, heaters with burners closer than three feet cannot physical install FGR and associated piping. There is a safety risk associated with FGR at the process heaters due to the potential for formation of explosive gas mixtures if a heater tube should fail. Few applications have been made to refinery process heaters due to this risk. Thus, external flue gas recirculation is not technically feasible for the process heaters and boilers at the Woods Cross Refinery.

Water/steam injection can impact combustion unit operation by worsening flame pattern, reducing unit efficiency, and affecting unit stability. The modest NO_x reductions at the heater may be offset by NO_x emissions resulting from steam generation elsewhere. Also, minimal NO_x reductions will be gained in units already fitted with low NO_x burners. Water/steam injection is predominantly used on gas turbines.

No data could be found on the effectiveness of water/steam injection on process heaters and limited data was found for use on boilers. Thus, steam injection was determined to be not technically feasible for the process heaters or boilers at the Woods Cross Refinery.

Low access air was also considered technically infeasible for use on refinery heaters and boilers since low oxygen operation results in longer flames that could cause flame impingement. Also, it is difficult to maintain safe operating conditions at low oxygen levels.

4.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Table 4-2 presents a summary of the control efficiencies for the remaining NO_x control technologies that can be applied to process heaters and boilers.

Table 4-2 NO_x Control Efficiencies

Technology	Range of Control (%)
ULNB + SCR	85-99
LNB + SCR	80-99
ULNB + SNCR	75-95
SCR	80-90
ULNB (including FGR)	66-76
LNB + SNCR	50-89
LNB+FGR	45-60
SNCR	30-50
LNB	50-60
FGR	50-60
Overfire Air (Boilers only)	30-50
CETEX (Process heaters only)	NA

According to data found in EPA's Petroleum Tier 2 BACT Analysis Report, Final Report (2001), Table 4-3 presents NO_x control technologies with typical emission limits ranked from most efficient to least efficient.

Table 4-3 Typical Emission Levels based on Control Technologies

Technology	Typical Emission Level	
	ppmv	lb/MMBtu
SCR + GCP	7	0.0085
SCR	18	0.022
GCP	29	0.035
No controls	89	0.11

GCP = Good Combustion Practices

Table 4-4 presents a summary of the permitted process heaters and boilers at the HollyFrontier's Woods Cross Refinery. Table 4-5 presents a summary of the potential technically feasible options for reducing NO_x for each process heater and boiler at the Refinery.

Table 4-4 Process Heaters and Boilers at HollyFrontier's Woods Cross Refinery

A.O. ID	Holly Source ID	Source Description	Status	Rating (MMBtu/hr)
II.A.3	4H1	FCC Feed Heater	In Service	68.4/39.9 (restricted to)
II.A.10	6H1	Reformer Reheat Furnace	In Service	54.7
II.A.11	6H2	Prefractionator Reboiler Heater	In Service	12.0
II.A.12	6H3	Reformer Reheat Furnace	In Service	37.7
II.A.16	7H1	HF Alkylation Regeneration Furnace	In Service	4.4
II.A.17	7H3	HF Alkylation Depropanizer Reboiler	In Service	33.3
II.A.19	8H2	Crude Furnace # 1	In Service	99.0
II.A.21	9H1	DHDS Reactor Charge Heater	In Service	8.1
II.A.22	9H2	DHDS Stripper Reboiler	In Service	4.1
II.A.24	10H1	Asphalt Mix Heater	In Service	13.2
II.A.25	10H2	Hot Oil Furnace	In Service	99.0
II.A.27	11H1	SRGP Depentanizer Reboiler	In Service	24.2
II.A.30	12H1	NHDS Reactor Charge Furnace	In Service	50.2
II.A.32	13H1	Isomerization Reactor Feed Furnace	In Service	6.5
II.A.38	19H1	DHT Reactor Charge Heater	In Service	18.1
II.A.41	20H2	Fractionator Charge Heater	In Service	47.0
II.A.42	20H3	Fractionator Charge Heater	In Service	42.1
II.A.46	23H1	Reformate Splitter Reboiler Heater	In Service	21.0
II.A.48	24H1	Crude Unit Furnace	In Service	60.0
II.A.50	25H1	FCC Feed Heater	In Service	45.0
II.A.54	27H1	Reactor Charge Heater	Not Built	99.0
II.A.57	30H1	Hydrogen Reformer Feed Furnace	Not Built	123.1
II.A.58	30H2	Hydrogen Reformer Feed Furnace	Not Built	123.1
II.A.60	33H1	Vacuum Furnace Heater	Not Built	130.0
II.A.81	68H2	North In-tank Asphalt Heater	In Service	0.8
II.A.82	68H3	South In-tank Asphalt Heater	In Service	0.8
II.A.83	68H4	Northwest In-tank Asphalt heater	In Service	0.8
II.A.84	68H5	Northeast In-tank Asphalt Heater	In Service	0.8
II.A.85	68H6	Southeast In-tank Asphalt Heater	Not Built	0.8
II.A.86	68H7	Southwest In-tank Asphalt Heater	Not Built	0.8
II.A.87	68H10	North In-tank Asphalt Heater	Not Built	0.8
II.A.88	68H11	South In-tank Asphalt Heater	Not Built	0.8
II.A.89	68H12	North In-tank Asphalt Heater	Not Built	0.8
II.A.90	68H13	South In-tank Asphalt Heater	Not Built	0.8
II.A.63	Boil. #4	Boiler #4	In Service	35.6
II.A.64	Boil. #5	Boiler #5	In Service	70.0
II.A.65	Boil. #8	Boiler #8	In Service	92.7
II.A.66	Boil. #9	Boiler #9	In Service	89.3
II.A.67	Boil.#10	Boiler #10	In Service	89.3
II.A.68	Boil.#11	Boiler #11	Not Built	89.3

Table 4-5 Technically Feasible Control Options for NO_x for Process Heaters and Boilers

Source ID	NO _x Reduction Technology								
	LNB	ULNB	FGR	SCR	SNCR	NSCR	Steam Injection	Low Access Air	CETEX
4H1	Equipped	--	No	No ³	No	No	No	No	No
6H1	Yes ¹	Yes ¹	Yes	Yes	No	No	No	No	No
6H2	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
6H3	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
7H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
7H3	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
8H2	--	Equipped	No	No ³	No	No	No	No	No
9H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
9H2	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
10H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
10H2	Proposed	--	No	Proposed	No	No	No	No	No
11H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
12H1	Yes	Equipped	No	No ³	No	No	No	No	No
13H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
19H1	Equipped	--	No	No ³	No	No	No	No	No
20H2	--	Equipped	No	No ³	No	No	No	No	No
20H3	--	Equipped	No	No ³	No	No	No	No	No
23H1	--	Equipped	No	No ³	No	No	No	No	No
24H1	--	Equipped	No	No ³	No	No	No	No	No
25H1	--	Equipped	No	No ³	No	No	No	No	No
27H1	Proposed	--	No	Proposed	No	No	No	No	No
30H1	Proposed	--	No	Proposed	No	No	No	No	No
30H2	Proposed	--	No	Proposed	No	No	No	No	No
33H1	Proposed	--	No	Proposed	No	No	No	No	No
68H2	No ²	No ²	No	No	No	No	No	No	No
68H3	No ²	No ²	No	No	No	No	No	No	No
68H4	No ²	No ²	No	No	No	No	No	No	No
68H5	No ²	No ²	No	No	No	No	No	No	No
68H6	No ²	No ²	No	No	No	No	No	No	No
68H7	No ²	No ²	No	No	No	No	No	No	No
68H10	No ²	No ²	No	No	No	No	No	No	No
68H11	No ²	No ²	No	No	No	No	No	No	No
68H12	No ²	No ²	No	No	No	No	No	No	No
68H13	No ²	No ²	No	No	No	No	No	No	No

Note: Proposed means unit will be equipped with these controls when constructed.

¹ This option is only feasible if there is space in the firebox for larger burners.

² LNB and ULNB are not available on such small (<1 mmBtu/hr) heaters.

³ Existing process heaters are naturally drafted.

Table 4-5 (Continued) Technically Feasible Control Options for NO_x for Process Heaters and Boilers

Source ID	NO _x Reduction Technology								
	LNB	ULNB	FGR	SCR	SNCR	NSCR	Steam Injection	Low Access Air	CETEX
Boiler 4	Yes	--	No	Yes	No	No	No	No	Yes
Boiler 5	Yes	Yes	No	Equipped	No	No	No	No	Yes
Boiler 8	Equipped	Yes	No	Equipped	No	No	No	No	Yes
Boiler 9	Yes	Yes	No	Equipped	No	No	No	No	Yes
Boiler 10	Yes	Yes	No	Equipped	No	No	No	No	Yes
Boiler 11	Proposed	Yes	No	Proposed	No	No	No	No	Yes

4.1.4 Step 4 - Evaluate Impacts and Document Results

As stated previously, several sources of information were examined including EPA's RBLC RACT/BACT/LAER Clearinghouse, state agency databases, vendor data, and published literature to identify the most effective NO_x control technologies, most stringent emissions limitations to compare against current NO_x controls that have been or proposed to be implemented at the Woods Cross Refinery.

Table 4-6 presents a summary of BACT determinations for NO_x for process heaters with heat capacities between 10 and 100 MMBtu/hr. All units listed in Table 4-6 are fired on refinery gas. Table 4-7 presents a summary of BACT determination for NO_x for process heaters with heat capacities equal to or greater than 100 MMBtu/hr. These tables list the lowest emission rates identified in the past several years from select plants.

Table 4-6 BACT Determinations for NO_x from Process Heaters and Boilers with Heat Capacities between 10 and <100 MMBtu/hr

Facility	Permit Date	Size (MMBtu/hr)	Limit (lb/MMBtu)	Control
Sinclair Wyoming Refining Company	10/15/2012	50	0.025 (3-hr. avg.)	ULNB
Sinclair Wyoming Refining Company	10/15/2012	64.2	0.030	ULNB
Sinclair Wyoming Refining Company	10/15/2012	44.9, 33.4, 46.3	0.035 (30-day rolling avg)	ULNB
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	24, 32.4, 52, 86	0.04 (3 hr avg)	ULNB
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	68, 90	0.05 (3 hr avg.)	LNB
Tuscaloosa, Alabama	09/28/2009	57, 49, 34.7, 98.3, 69.3, 78.2, 60.9	0.025	NGULNB
Chevron Products Company, Pascagoula Refinery	04/14/2009	73.25, 73.95, 54.53	0.03 (30-day rolling avg.)	ULNB
Conoco Phillips Company, Ponca City Refinery	02/09/2009	45.0, 98	0.03 (annual average)	ULNB
Sunoco Inc., Tulsa Refinery	05/27/2008	44, 57.3	0.03 (3 hr avg.)	ULNB
Navajo Refining Company, Artesia Refinery	12/14/2007	9.6, 35	0.03 (3-hr roll. avg.)	ULNB
Arizona Clean Fuels Yuma LLC	04/14/2005	25, 23.2, 99.5	0.04 (3-hr avg.)	LNB

Table 4-7 BACT Determinations for NO_x from Process Heaters and Boilers with Heat Capacities ≥100 MMBtu/hr

Facility	Permit Date	Size (MMBtu/hr)	Limit (lb/MMBtu)	Control
Sinclair Wyoming Refining Company	10/15/2012	233	0.03 (3 hr avg.)	ULNB
Diamond Shamrock, Texas	12/30/2010	355.6	0.010/0.015 (annual/hourly)	SCR+LNB
Valero Delaware City Refinery	02/26/2010	240, 456	0.04	SCR+LNB
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	100, 135, 336	0.04 (3-hr avg.)	ULNB
Tuscaloosa, Alabama	09/28/2009	198, 254	0.025 (3-hr avg.)	NGULNB
ConocoPhillips, Ponca City Refinery	02/09/2009	125, 131.3	0.03 (annual avg.)	ULNB
Navajo Refining Company, Arteris Refinery	12/14/2007	120	0.035 (3-hr rolling avg)	ULNB
BP Products North America Inc., Whiting Indiana	10/2007	355, 331	0.04	ULNB
BP Products North America Inc., Whiting Indiana	10/2007	208	0.02	SCR+LNB

The top-ranked control option involves the use of LNB with SCR as the post-combustion control device for process heaters and boilers. This option is typically applied to process heaters and boilers approximately 100 MMBtu/hr or greater in rating. The NO_x emission level achievable with this control option is 0.0085 lb/MMBtu based on a three-hour average although emission levels reported in RBLC range from 0.01 to 0.04 lb/MMBtu.

The second ranked option is the use of ULNB; the third highest ranking option is the use of LNB.

Several sources of data indicate that ULNBs are capable of achieving lower NO_x emission levels than LNBs. Emission levels for NO_x reported by one refinery using ULNBs range from 0.050 to 0.031 lb/MMBtu. Controlled NO_x emissions of 0.025 lb/MMBtu have been reported for the Selas ULNx® burner. This emission level is reported for natural gas firing and a firebox temperature of 1250°C (2280°F). A John Zink burner for natural draft heaters was designed to meet 0.03 lb/MMBtu or 25 to 28 ppmv depending on fuel composition.

No additional controls were identified for small heaters such as the stab-in tank heaters which are rated at 0.8 MMBtu/hr.

The boilers at Hollyfrontier Woods Cross Refinery are chemically treated to remove scale on the boiler heat tubes which improves boiler efficiency and reduces NO_x emissions.

Table 4-8 presents a list of HollyFrontier's process heaters and boilers and the control technology being currently utilized.

Table 4-8 Current Control Technologies on HollyFrontier Process Heaters and Boilers

A.O. ID	Holly Source ID	Source Description	Control Technology
II.A.3	4H1	FCC Feed Heater	LNB
II.A.10	6H1	Reformer Reheat Furnace	GCP
II.A.11	6H2	Prefractionator Reboiler Heater	GCP
II.A.12	6H3	Reformer Reheat Furnace	GCP
II.A.16	7H1	HF Alkylation Regeneration Furnace	GCP
II.A.17	7H3	HF Alkylation Depropanizer Reboiler	GCP
II.A.19	8H2	Crude Furnace # 1	NGULNB
II.A.21	9H1	DHDS Reactor Charge Heater	GCP
II.A.22	9H2	DHDS Stripper Reboiler	GCP
II.A.24	10H1	Asphalt Mix Heater	GCP
II.A.25	10H2	Hot Oil Furnace	LNB + SCR
II.A.27	11H1	SRGP Depentanizer Reboiler	GCP
II.A.30	12H1	NHDS Reactor Charge Furnace	NGULNB
II.A.32	13H1	Isomerization Reactor Feed Furnace	GCP
II.A.38	19H1	DHT Reactor Charge Heater	LNB
II.A.41	20H2	Fractionator Charge Heater	ULNB
II.A.42	20H3	Fractionator Charge Heater	ULNB
II.A.46	23H1	Reformate Splitter Reboiler Heater	ULNB
II.A.48	24H1	Crude Unit Furnace	ULNB
II.A.50	25H1	FCC Feed Heater	ULNB
II.A.54	27H1	Reactor Charge Heater	LNB+SCR
II.A.57	30H1	Hydrogen Reformer Feed Furnace	LNB+SCR
II.A.58	30H2	Hydrogen Reformer Feed Furnace	LNB+SCR
II.A.60	33H1	Vacuum Furnace Heater	LNB+SCR, air preheat
II.A.81	68H2	North In-tank Asphalt Heater	GCP
II.A.82	68H3	South In-tank Asphalt Heater	GCP
II.A.83	68H4	Northwest In-tank Asphalt Heater	GCP
II.A.84	68H5	Northeast In-tank Asphalt Heater	GCP
II.A.85	68H6	Southeast In-tank Asphalt Heater	GCP
II.A.86	68H7	Southwest In-tank Asphalt Heater	GCP
II.A.87	68H10	North In-tank Asphalt Heater	GCP
II.A.88	68H11	South In-tank Asphalt Heater	GCP
II.A.89	68H12	North In-tank Asphalt Heater	GCP
II.A.90	68H13	South In-tank Asphalt Heater	GCP
II.A.63	Boil. #4	Boiler #4	
II.A.64	Boil. #5	Boiler #5	SCR
II.A.65	Boil. #8	Boiler #8	LNB+SCR
II.A.66	Boil. #9	Boiler #9	SCR
II.A.67	Boil.#10	Boiler #10	SCR
II.A.68	Boil.#11	Boiler #11	LNB+SCR

¹ lb/MMscf

4.1.4.1 Energy and Environmental Impacts

With the application of a SCR, additional adverse impacts are anticipated which include ammonia emissions and the handling and disposal of a spent catalysts as a solid waste stream. Ammonia that is injected in the SCR system and exits the unit without participating in the chemical reduction of NO_x emissions leads directly to emissions of ammonia and can lead indirectly to the formation of secondary particulate matter. These problems are less severe when the SCR catalyst is new and activity is greatest because the ammonia rate can be set near-stoichiometric levels. As the catalyst ages, the activity decreases requiring a higher ammonia injection rate to maintain the rate of NO_x reduction required for continuous compliance with NO_x emission levels.

Besides an environmental and air quality impact, an adverse energy impact is expected due to the electrical requirements of the SCR system operation and to the reduction in energy efficiency attributable to the power drop across the SCR catalysts grid.

4.1.4.2 Economic Impact

According to EPA, SCR reduces NO_x by 90 percent or greater in an uncontrolled mechanical draft process heater. SCR systems require mechanical draft operation due to the pressure drop across the catalyst. The only heater at HollyFrontier that is mechanically drafted is 6H1. All other heaters are naturally drafted.

In order to use an SCR system or systems on the process heaters at Holly Frontier, the refinery would need to replace all naturally draft heater with mechanical draft heaters which would not be economically feasible as well as limit refinery operations for a lengthy period of time. Thus, SCR is eliminated as technically infeasible for use on the naturally drafted heaters at HollyFrontier.

An analysis was performed to evaluate the technical feasibility and cost effectiveness of upgrading existing process heaters with LNB or ULNB. In conversations with representatives from John Zink, when upgrading the existing units to LNB or ULNB, the floor of each heater box would have to be reconstructed to insert the LNB or ULNB which are typically longer and wider than the existing burners. Also, LNB and ULNB have a lower heating duty per burner than traditional burners; therefore, in some cases, will result in a need for additional burners to achieve the firing rate needed for the process application. Most heaters at HollyFrontier are not designed to accommodate additional burners and would need to be reconstructed all together. If additional burners cannot be added and the heater is not reconstructed, then a process rate decrease would need to take place.

An additional consideration with retrofitting existing heaters to LNB or ULNB is the flame pattern. LNB and ULNB generally produce a longer flame in the fire box which can extend to contact process piping or the convection section of the heater. Contact with process piping can result in coking of the inside of the process pipes which results in a loss of heat transfer and eventual plugging. Flame extension into the convection section can result in heat transfer not consistent with engineered design resulting in process coking, inadequate heat transfer, heater box temperature, and loss of process control.

Thus, the application of LNB or ULNB on existing units (6H1, 6H2, 6H3, 7H1, 7H2, 7H3, 9H1, 9H2, 10H1, 11H1, and 13H1) is not technically possible due to space limitations in the firebox, lower heat duty, and a longer flame. It is not economically feasible to reconstruct all existing process heaters. Thus, for these reasons, retrofit of existing process heaters with LNB or ULNB has been determined to be technically and economically infeasible.

4.1.5 Selection of BACM

According to EPA, 7 ppmv of NO_x should generally be considered as LAER or the most stringent control measure for NO_x emissions from **new** refinery process heaters. Refiners can achieve this level of control through a combination of combustion controls (LNB with internal flue gas recirculation) and SCR. For boilers 100 MMBtu/hr or greater, the most stringent control is a NO_x limit of 5 ppm @ 3% O₂ using SCR. For boilers < 20 MMBtu/hr, the most stringent control is a NO_x limit of 9 ppm using LNB.

The Bay Area Air Quality Management District (BAAQMD), South Coast Air Quality Management District (SCAQMD), California Air Resources Board (CARB) BACT guidelines were reviewed for determining BACT emission rates for the refinery heaters with a firing rate greater than 50 MMBtu/hr. NO_x limits range from 5 ppmv (the most stringent identified by SCAQMD) to 10 ppmv, all corrected to 3% O₂. A 5 ppmv emission rate at 3% O₂ equates to approximately 0.006 lb/MMBtu; a 10 ppmv emission rate at 3% O₂ equates to approximately 0.012 lb/MMBtu. These limits were accomplished through the use of SCR and LNB. These controls are not practical for HollyFrontier for the reasons presented above (i.e. SCR requires mechanical draft) for the process heaters. Further, if SCR were practical, ammonia is a PM_{2.5} precursor which leads to higher PM_{2.5} emissions. Thus, these more stringent emission limits for the process heaters at HollyFrontier are not considered BACM.

The process heaters at HollyFrontier equipped with ULNB (20H2, 20H3, 23H1, 24H1, 25H1) have an emission limit of 0.04 lb/MMBtu which equates to approximately 30 ppbvd at 3% O₂; 10H2, and future heaters 27H1, 30H1, 30H2, 33H1 which are or will be equipped with LNB and SCR have an emission limit of 0.02 lb/MMBtu which equates to approximately 15 ppmv at 3% O₂. Compliance with these limits is/will be verified every three years through stack testing. This represents BACM for these heaters.

For the stab-in heaters, only good combustion practices (GCP) were identified to control NO_x emissions from these small heaters which is considered BACM. Compliance for 68H6, 68H7, 68H10, 68H12, and 68H13 is verified every three years through stack testing.

The highest-ranking option, LNB and SCR, is used on Boilers #8 and #11. Boilers #5, #9, and #10 are equipped with SCR. The NO_x emission limit is 0.02 lb/MMBTU for Boilers #8-#11 and represents BACM. Boiler #5, equipped with SCR, has a NO_x emission limit of 0.03 lb/MMBtu which also represents BACM. Stack test are performed every three years to verify that these units are in compliance with the permissible limits. Boiler #4 is a limited use boiler and it was not technically or economically feasible to install a SCR on this unit.

The cost of installing and operating CEMS on each heater and boiler was examined. The estimated equipment cost including a shelter and a NO₂ CEMS with affiliated equipment plus installation is over \$201,600 per system. Total annual operating costs were estimated to be approximately \$72,820. See Appendix B for a detailed cost analysis. Based on potential to emit (PTE) emissions for process heaters, the average cost-per-ton to monitor for NO_x with a CEMS is \$17,255.

4.2 Flares

Flares are used at petroleum refineries to destroy organic compounds in excess refinery fuel gas, purged products, or waste gases released during startups, shutdowns, and malfunctions. Most flares have a natural gas pilot flame and use the fuel value of the gas routed to the flare to sustain combustion.

There are two flare stacks located at the Northwest corner of the refinery. During refinery upsets, process equipment may experience over-pressures which are relieved through a spring-loaded pressure safety valve ("PSV"). Piping headers connect these devices to the flare stack, which is used to safely burn the released hydrocarbons. A small, continuous flame of purchased natural gas acts as a pilot light to ignite the process vapors as they enter the flare tip for final destruction.

The South Flare (66-2) handles relief gases from the Crude #2 Unit (Unit 24), FCC #2 Unit (Unit 25), Poly Unit (Unit 26), Hydrocracker/Hydroisom Unit (Unit 27), SWS #2 Unit (Unit 28), Hydrogen Plant (Unit 30), Tank Farm (Unit 68), Crude Unloading (Unit 86), and Rail Unloading (Unit 87).

The North Flare (66-1) handles relief gases from the FCC Unit (Unit 4), Reformer Unit (Unit 6), Alkylation Unit (Unit 7), Crude Unit (Unit 8), DHDS Unit (Unit 9), SDA Unit (Unit 10), SRGP Unit (Unit 11), NHDS Unit (Unit 12), Isomerization Unit (Unit 13), Amine Treatment Unit (Unit 16), SRU (Unit 17), SWS Unit (Unit 18), DHT Unit (Unit 19), GHC Unit (Unit 20), NaHS Sour Gas Treatment Unit (Unit 21), Sour water stripper/ASU (Unit 22), BenZap Unit (Unit 23), Vacuum Unit (Unit 33), Tank Farm (Unit 68), and Loading/Unloading (Unit 87).

4.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

For safe flare operation, the design of the flares requires the use of a pilot light. The combustion of the natural gas to fuel the pilot light and the combustion of refinery gases produces NO_x.

A search of the RBLC, state databases, and emission control literature was conducted to find available control technologies to control flare emissions. Flares operate primarily as air pollution control devices. The only technically feasible control options for emissions of all pollutants from flares are:

- proper equipment design and work practices;
- good combustion practices;
- conversion from air assisted to steam assisted, and
- flare gas recovery systems.

No add-on controls for NO_x emissions from flares were identified.

4.2.1.1 Proper Equipment Design and Work Practices

Proper equipment design and work practices include minimizing the quantity of gases combusted, minimizing exit velocity, ensuring adequate heat value of combusted gases, and installing an automatic pilot reignition. The flares at the Woods Cross Refinery are designed and operated in accordance with 40 CFR 60.18, general control device requirements which include a flame present at all times, no visible emissions, and heat content and maximum tip velocity specifications that meet the requirements of the rule. The use of pipeline-quality natural gas to fuel the pilot lights will reduce NO_x emissions.

4.2.1.2 Good Combustion Practices

A certain level of flame temperature control can be exercised for a flare by implementing fuel to air ratio control. Generation of NO_x is dependent on temperature. As the temperature rises, the generation rate of NO_x rises. Good combustion practices can be used to minimize emissions of NO_x .

4.2.1.3 Conversion from Air Assisted to Steam Assisted

Flares produce lower flame temperatures when operating with low heating value gases at low combustion efficiencies than when operating with high heating value gases at high combustion efficiencies. This leads to reduced formation of NO_x in the flame. In general, emissions were lower in steam assisted flare tests than in air assisted flare tests conducted under similar conditions.

4.2.1.4 Flare Gas Recovery Systems

Flaring can be reduced by installation of a flare gas recovery system. A flare gas recovery system includes a seal system to allow for recovery of process gases vented to the flare. Compressors recover the vapors and route them to the fuel gas treatment system for H_2S removal. After conditioning of the recovered vapors, the gases are combined with other plant fuel gas sources and combusted in heaters, boilers, and other devices that operate using fuel gas.

If the pressure in the flare gas headers exceeds the seal system settings, excess flare gases are allowed to flow to the flare for combustion. The pressure in the flare gas system increases due to additional process gas flow that cannot be recovered by the flare gas compressors. Once the pressure drops and the excess gases are combusted, the seal system re-establishes itself for continuous recovery of vapors.

The flare gas recovery system will not be sufficient to prevent flaring from process unit startup and shutdown events where large volumes of process gases will be sent to the flare. Also, during process upsets or malfunctions, the flare gases may not be entirely recovered due to the constraints of the flare gas recovery system. The flare gas recovery system will be sized for normal operating conditions.

4.2.2 Step 2 - Eliminate Technically Infeasible Options

None of the identified control options is considered technically infeasible for the flares at the Woods Cross Refinery.

4.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top-ranking control option is the installation of a flare gas recovery system. Flare gas recovery systems are achieved in practice. The second highest ranking control option includes proper equipment design and work practices which includes good combustion practices. The destruction efficiency of a properly operated flare is 98%. The flares at the Woods Cross refinery are steam assisted.

4.2.4 Step 4 - Evaluate Impacts and Document Results

HollyFrontier will install a flare gas recovery system to recover vent gas which is the highest ranked control option.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flares are located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18.

Emissions from the HollyFrontier Woods Cross Refinery flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases.

Flare management plans have been developed for both the north and south flares. These plans contain procedures to minimize or eliminate discharges to the flare during startups and shutdowns. To verify that the procedures are followed, records are maintained.

The flares at the refinery are steam-assisted which leads to lower NO_x formation in the flare flame.

4.2.4.1 Energy, Environmental, and Economic Impacts

Since HollyFrontier has chosen the highest ranked control option, flare gas recovery, energy, environmental and costs analyses are not required.

4.2.5 Step 5 - Select BACT

Holly is utilizing the following design elements and work practices as BACM for the flares:

- Use of low sulfur fuel such as natural gas as fuel for pilot flame;
- Maintaining an acceptable net heating value and exit velocity of flared gases under all flow conditions in accordance with manufacturer specifications;
- Use of a thermocouple to monitor presence of the pilot flame;
- Implementation of good combustion, operating, and maintenance practices;
- Implementation of Flare Management Plans;
- Flare operation in accordance to 40 CFR Part 60, Ja and design and work practice standards as codified in 40 CFR Part 60.18; and,
- Installation of flare gas recovery system.

No more stringent measures were identified for the flares at the Woods Cross Refinery. The flare design includes steam assisted combustion. The flares will be equipped with a flare gas recovery system for non-emergency releases, and a continuous pilot light. Pilot and sweep fuel will be natural gas or treated refinery gas. The north and south flares are equipped with flow meters and gas combustion monitors.

The proposed BACM controls and compliance monitoring method conducted for HollyFrontier flares are summarized in Table 4-9.

Table 4-9 Proposed BACM Controls and Compliance Monitoring Methods for Flares

Pollutant	Unit	Control Technology	Monitoring Methods
NO _x	66	Flare gas recovery system	Flow meters, Btu monitor

4.3 Sulfur Recovery Unit Tail Gas Incinerator

The SRU off gas is routed to the tail gas incinerator followed by a wet scrubber (4V82 or 25 FCCU scrubber). The SRU does not operate if the scrubbers are not in operation. Oxides of nitrogen are formed during the combustion of natural gas in the incinerator by oxidation of chemically-bound nitrogen in the fuel and by thermal fixation of nitrogen in the combustion air.

4.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The available control technologies for NO_x control from the tail gas incinerator are the same technologies listed in Table 4-2 above as well as the application of LoTOx™ which is a low temperature oxidation process which utilizes ozone to oxidize insoluble NO and NO₂ to N₂O (a highly soluble species of NO_x) which can be effectively removed by a variety of air pollution control equipment including wet scrubbers.

4.3.2 Step 2 - Eliminate Technically Infeasible Options

The only options that are technically feasible for an SRU tail gas incinerator is combustion control utilizing LNB or ULNB and utilization of a LoTOx™ system. The other technologies are either based on lowering flame temperature, which is not compatible with the primary function of an incinerator, or add-on controls that have not been demonstrated as technically feasible for a thermal oxidizer. There are significant technical differences between thermal oxidizers and the combustion sources for which these technologies have been demonstrated in practice.

4.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Technically feasible NO_x control technologies are combustion control utilizing LNB or ULNB fired on natural gas and/or the application of a LoTOx™ system.

4.3.4 Step 4 - Evaluate Impacts and Document Results

The tailgas incinerator is a thermal incinerator that is used to facilitate the oxidation of the common reduced sulfur compounds to SO₂ prior to release to the atmosphere. The incinerator combusts natural or refinery gas which creates the NO_x emissions. The tailgas incinerator is equipped with low NO_x burners to reduce NO_x emissions that may form during the combustion of gaseous fuels.

During normal operation, the gases from the SRU tailgas incinerator which is equipped with LNBs are routed to either Unit 4 or Unit 25 wet gas scrubbers. These wet gas scrubbers are configured to include the LoTOx™ process which provides greater than 95% NO_x reduction.

A review of the RBLC Clearinghouse identified two refineries, Sunoco Tulsa Refinery and Valero's St. Charles Refinery, with NO_x limits on the tail gas treatment units. These limits ranged from 0.14 lb/MMBtu or 1 lb/hr and 9.4 lb/hr and were met utilizing good combustion practices and proper equipment design. No indication of burner type was presented for these tail gas treatment units.

4.3.4.1 Energy, Environmental and Economic Impacts

As mentioned above, the tailgas incinerator is a thermal incinerator that is used to facilitate the oxidation of the common reduced sulfur compounds to SO₂ prior to release to the atmosphere. The incinerator combusts natural or refinery gas which creates the NO_x emissions.

The tailgas incinerator on the SRU at HollyFrontier is equipped with LNBs which reduce NO_x emissions that may form during the combustion of gaseous fuels. There are energy and environmental impacts associated with the use of the tailgas incinerator and pipeline natural gas. Additional energy and fuel are both required leading to increased NO_x emissions. However, emissions from the tailgas incinerator are controlled through one of the FCCU wet scrubbers which utilizes LoTOx™ to further reduce NO_x emissions.

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. There are no other anticipated energy, environmental, or environmental impacts associated with the use of the wet gas scrubbers during normal SRU operation.

4.3.5 Step 5 - Select BACT

During normal operations, emissions from the three-stage Claus SRU followed by a tailgas incinerator are sent to one of the wet gas scrubbers. Thus, NO_x BACM for the three-stage Claus SRU is the use of good combustion practices, pipeline quality natural gas in tail-gas incinerator with proper equipment design, wet scrubbing, and LoTOx™. No other measures were identified as more stringent to control NO_x emissions. HollyFrontier is meeting the NO_x emission rates of 40 ppm NO_x per 365-day rolling average and 80 ppm NO_x per 7-day rolling average from the wet scrubbers.

The proposed BACM controls and compliance monitoring method conducted for HollyFrontier's SRU tailgas incinerator are summarized in Table 4-10.

Table 4-10 Proposed BACM Controls and Monitoring Method for SRU Tail Gas Incinerator

Pollutant	Unit	Control Technology	Monitoring
NO _x	17	Tailgas incinerator followed by wet scrubbing, good combustion practices, pipeline quality fuel, LoTOx	O ₂ CEMS

4.4 Fluidized Catalytic Cracking Unit (FCCU)

This BACM review was based on data summarized by EPA in the RBLC RACT/BACT/LAER Clearinghouse, review of state databases and review of recent consent decrees. While the emission limits imposed by consent decrees do not necessarily represent BACT or LAER, they do represent the most stringent emissions limitations placed upon FCCUs.

The two FCCU regenerators at HollyFrontier are full-burn units which is recognized by EPA as an inherently low NO_x design. The predominant NO_x species inside an FCCU regenerator is NO that is further oxidized to NO₂ upon release to the atmosphere. NO_x in the regenerator can be formed by two mechanisms, thermal NO_x produced from the reaction of molecular nitrogen with oxygen and fuel NO_x which is produced from the oxidation of nitrogen-containing coke specie deposited on the catalyst inside the reactor.

4.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following is a list of control technologies which were identified for controlling NO_x emissions from the FCCUs:

- > SNCR,
- > SCR,
- > LoTOx, and
- > Catalyst additives and low NO_x combustion promoters.

4.4.2 Step 2 - Eliminate Technically Infeasible Options

All the options are technically feasible.

4.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options were ranked in order of reduction:

- > LoTox – 80 to 95% reduction with SCR
- > SCR – 80 to 90% reduction
- > SNCR – 60 to 80% reduction
- > Catalyst additives and low NO_x combustion promoters – 40 to 75% reduction.

4.4.3.1 SNCR

The SNCR system is a post-combustion control technology that reacts with urea or ammonia with flue gas without the presence of a catalyst to produce N₂ and H₂O. The typical operating temperature range for an SNCR is 1,600°F to 2,000°F. The SNCR temperature range is sensitive as the reagents can produce additional NO_x if the temperature is too high or removes too little NO_x if the reaction proceeds slowly if the temperature is too low. The NH₃ slip in SNCR applications can range from 10 to 100 ppmv. SNCR has been used successfully with CO boilers but are typically not used with full burn units due to low NO_x removal at temperatures below 1,400°F. In full burn units, such is utilized by HollyFrontier, the flue gas must be heated to 1,600 to 1,800°F to achieve NO_x removal rates of 50% and greater.

4.4.3.2 SCR

Selective catalytic reduction is a post combustion control technology that injects ammonia in flue gas in the presence of a catalyst (typically vanadium or tungsten oxides) to produce N_2 and H_2O . An SCR is similar to SNCR with the exception that a catalyst is used to accelerate the reactions at lower temperatures. The ideal temperature range for an SCR is 600°F to 750°F with guaranteed NO_x removal rates of 90+%. Design considerations include targeted NO_x removal level, service life, pressure drop limitation, ammonia slip, space limitation, flue gas temperature, composition and SO_2 oxidation limit. SCR suppliers typically guarantee the performance of the unit for NO_x removal, service life, pressure drop, ammonia slip and SO_2 oxidation. Ammonia slip, referring to the amount of ammonia which passes through the process unreacted, is typically guaranteed to 10 ppmv.

4.4.3.3 LoTOx™

The Belco LoTOx™ technology is a selective, low temperature technology that uses ozone to oxidize NO_x to water soluble nitric pentoxide (N_2O_5). These higher oxides of nitrogen are highly soluble. Inside a wet gas scrubber, the N_2O_5 forms nitric acid that is subsequently scrubbed by the scrubber nozzles and neutralized by the scrubber's alkali reagent. Since the process is applied at a controlled temperature zone in the wet gas scrubber, it can be used at any flue gas temperature. The controlled temperature zone in the wet gas scrubber is below 300°F. Since the LoTOx™ technology does not use a fixed catalyst bed, it can handle unit upsets without impacting overall reliability and mechanical availability.

The LoTOx™ technology generates ozone on demand based on the amount of NO_x in the flue gas. There is no storage of ozone required. Emission reductions using this process have been estimated to range from 80 to 95%.

4.4.3.4 Catalyst Additive and Combustion Promoters

Several vendors offer NO_x reducing catalyst additives and combustion promoters. Current NO_x additives affect the availability of nitrogen species to be oxidized and reduced and the performance of the additives is dependent on the application. Grace Davison's XNOx is a combustion promoter additive that can reduce NO_x emission from 50-75% in the regenerator. Grace Davison's DENOX promoter can reduce NO_x emissions up to 60%. Engelhardt's CLEANNOx and OxyClean reduce NO_x emissions by 45%. INTERCAT's COP-NP can reduce emissions from approximately 40-65%. The NO_x combustion promoters (catalysts and additives) are added directly into the FCCU reactor and regenerator. These additives can withstand the harsh environment of the regenerator but do not have the same life as catalyst.

A benefit associated with the use of additives is flexibility. Additives can be added and removed from the operation depending on the refiner's needs but are more expensive than FCC catalysts with an average cost approaching \$20 per pound. The additional cost associated with the recommended usage rate of these additives may triple the current catalyst cost resulting in negative process unit economics. Higher removal rates may require more additive and that can impact yields, product quality and unit throughput.

4.4.4 Step 4 - Evaluate Impacts and Document Results

SNCR is not feasible in this application because of the need to heat the flue gas to reach the optimum operating levels of the SNCR. The amount of NO_x reduction is also lower. Most EPA consent decree applications have achieved a 5 to 30% reduction with others in the industry achieving up to 70% depending on process conditions⁵. A drawback of using SNCR technology is the potential formation of ammonium sulfate salts and resultant fouling. These salts will exist as small particulates.

A SCR system can achieve between 80-90% reductions on uncontrolled NO_x emissions. SCRs operate in the temperature range of FCC regenerator flue gas. This control technology has a high NO_x reduction rate when compared to other NO_x control technologies. Although SCR offers high NO_x reduction rates, catalyst deactivation can occur from salt formation on the catalyst surface, cracks of the catalyst from the substrate material can occur from thermal stresses, and thermal degradation of the catalyst can occur at temperatures greater than 800°F. Other items that can lead to catalyst deactivation include erosion of the catalyst due to excessive catalyst fines loading and plugging of the catalyst system due to catalyst fines.

At the plants where SCR's have been installed, the majority of them have third stage separators or ESP's located before the SCR catalyst bed to protect against upsets in the FCC regenerator.

LoTOx™ in conjunction with wet scrubbing systems has been demonstrated to effectively reduce high levels of NO_x from a FCCU. The efficiency obtained from the combination of LoTOx™ and wet gas scrubbing systems is comparable to an SCR.

To apply SCR to the output of a wet gas scrubber with a LoTOx™ system is technically infeasible. The low temperature of the exhaust stream combined with the concentration of NO_x make further application of an add-on control like SCR impractical.

Combustion promoters will not reduce the NO_x emissions alone to meet NO_x BACT levels.

A review of the literature and the EPA's RBLC indicate that SCRs or LoTOx™ in conjunction with wet scrubbing systems are used for the reduction of NO_x in a number of FCCUs. BELCO, a subsidiary of DuPont, provided a list of locations where the LoTOx™ technology has been installed in FCCU regenerator applications. Table 4-11 presents a list of a few of these facilities. Table 4-12 presents the results of a search of the RBLC clearinghouse and a list of select refineries and the NO_x control technologies being utilized at these refineries.

⁵ Advances in Fluid Catalytic Cracking, Chapter 17, FCC NO_x Emissions and Controls, Jeffrey A. Sexton, 2010.

Table 4-11 LoTOx™ NO_x Reduction Technology Installations

Application	Location	Capacity	Start-up
Refinery FCCU (New EDV Scrubber with LoTOx technology)	HollyFrontier Woods Cross, UT	Confidential	2012, 2016
Refinery FCCU (New EDV Scrubber with LoTOx technology)	Petrochina, Sichuan	Confidential	2010
Refinery FCCU (New EDV Scrubber with LoTOx technology)	West Pacific, Dalian	Confidential	2010
Refinery FCCU (Retrofitted LoTOx Technology to existing EDV scrubber)	Valero, St. Charles, LA	100,000 bpsd	2010
Refinery FCCU (Retrofitted LoTOx addition to existing CANSOLV unit)	Valero, Delaware City, DE	75,000 bpsd	2010
Refinery FCCU (Retrofitted LoTOx addition to existing EXXON scrubber)	Flint Hills, Corpus Christi, TX	45,000 bpsd	2009
Refinery FCCU (New EDV Scrubber with LoTOx technology)	Petrobras, REFAP Brazil	7,000 m ³ /day	2009
Refinery FCCU (New EDV scrubber with LoTOx technology)	Valero, Houston, Texas	58,000 bpsd	April 2007
Refinery FCCU (Retrofitted LoTOx Technology to existing EDV® wet scrubber)	Marathon, Texas City, Texas	72,000 bpsd	February 2007
Refinery FCCU (New EDV scrubber with LoTOx technology)	BP, Texas City, Texas	130,000 bpsd	June 2007

Table 4-12 BACT Determinations for NO_x for FCCU

Facility	Permit ID/ Permit Date	NO _x Concentration Limit	Control
Alon Refining Krotz Springs Inc. Krotz Springs Refinery	LA-0261 04/26/2012	73.0 ppmvd @ 0% O ₂ 365-day rolling average 146.0 ppmvd @ 0% O ₂ 7-day rolling average	Consent Decree - LoTOx
Valero Energy Corp. Valero Delaware City Refinery	DE-0020 02/26/2010	20.0 ppmvd @ 0% O ₂ 365-day rolling average 40.0 ppmvd @ 0% O ₂ 7-day rolling average	LoTOx
Sunoco, Inc. Sun Company Inc. Toledo Refinery	OH-0308 02/23/2009	20.0 ppmvd @ 0% O ₂ 365-day rolling average 40.0 ppmvd @ 0% O ₂ 7-day rolling average	SCR
Shell Oil Company Deer Park Refinery Limited Partnership	TX-0290 09/27/2007	20.0 ppmvd @ 0% O ₂ 365-day rolling average 40.0 ppmvd @ 0% O ₂ 3-hour average	SCR
ExxonMobil Oil Corp. ExxonMobil Torrance Refinery	CA-1138 03/23/2007	20.0 ppmvd @ 0% O ₂ 365-day rolling average 40.0 ppmvd @ 0% O ₂ 7-day rolling average	SCR

4.4.4.1 Energy, Environmental, and Economic Impacts

There are environmental and economic impacts associated with a wet gas scrubber. Wet scrubbers will generate water vapor plumes, which during the winter months may reduce visibility. In addition, wet gas scrubbers generate wastewater, which must be managed and disposed of at the refinery. Lastly, wet gas scrubbers produce a significant amount of solid waste. Although wet gas scrubbers can be costly to install and annual operating costs can be comparatively high, wet gas scrubbers will be utilized to reduce NO_x emissions from the HollyFrontier FCCUs.

HollyFrontier is not proposing a SCR due to not being economically feasible because a third stage separator or ESP would have to be installed as part of the crude processing operations.

4.4.5 Step 5 - Select BACT

Thus, LoTOx™ systems in conjunction with wet gas scrubbers are utilized by HollyFrontier to reduce NO_x emissions in the regenerator flue gas from Units 4 and 25. The use of LoTOx™ in conjunction with wet gas scrubbers has a comparable removal efficiency as a SCR for NO_x.

The most stringent control identified as LAER in the RBLC database was SCR that is being utilized at the Deer Park Refinery with emission limits of 20 ppmvd @ 0% O₂ based on a 365-day rolling average and 40-ppmvd @0% O₂ based on a 3-hour average. According to HollyFrontier's Consent Decree, HollyFrontier designed the NO_x Control system to achieve a NO_x concentration of 20 ppmvd or lower on a three-hundred sixty five (365) day rolling average basis and 40 ppmvd on a seven (7) day rolling average basis, each corrected to 0% O₂. These levels are consistent with RBLC findings presented for several refineries as listed in Table 4-12.

After the 15-month demonstration period, the NO_x emission rates at HollyFrontier are slightly higher than the design and are 40 ppm NO_x per 365-day rolling average and 80 ppm NO_x per 7-day rolling average. Although these limits are slightly higher than the most stringent controlled facility, the use of LoTOx™ and wet gas scrubber achieves a NO_x control efficiency that is comparable to a SCR and is a top ranking control technology. Thus, the use of LoTOx™ and a wet gas scrubber to achieve the above listed emission rates has been determined to be BACM for the FCCUs operated by HollyFrontier.

The proposed BACM controls, NO_x emission limits, and compliance monitoring methods conducted for HollyFrontier's FCCUs are summarized in Table 4-13.

Table 4-13 Proposed BACM Controls, NO_x Emission Limits, and Monitoring Methods for FCCUs

Pollutant	Unit	Control Technology	NO _x Emission Limit	Monitoring Method
NO _x	4, 25	Wet Gas Scrubbers	40 ppm per 365-day rolling average 80 ppm per 7-day rolling average	CEMS, Annual Rata

4.5 Emergency Diesel Engines

Diesel emergency equipment at the Woods Cross refinery consists of a 135 kW portable diesel generator at the East Tank Farm, 224 HP diesel powered water well No. 3, 393 HP fire pump No. 1, 393 HP fire pump No. 2, 180 HP diesel fire pump, three 220 HP diesel-powered plant air backup compressors, 470 HP diesel standby generator at the Boiler House, 380 HP diesel standby generator at the Central Control Room, and a 540 HP diesel standby generator.

Diesel engines are classified as compression ignition (CI) internal combustion engines. In diesel engines, air is drawn into a cylinder as the piston creates space for it by moving away from the intake valve. The piston's subsequent upward swing then compresses the air, heating it at the same time. Next, fuel is injected under high pressure as the piston approaches the top of its compression stroke, igniting spontaneously as it contacts the heated air. The hot combustion gases expand, driving the piston downward. During its return swing, the piston pushes spent gases from the cylinder, and the cycle begins again with an intake of fresh air.

The predominant mechanism for NO_x formation from internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air.

4.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following technologies were evaluated for controlling NO_x emissions from the CI combustion engines. They are categorized as combustion modifications and post-combustion controls. Combustion modifications include: ignition timing retard, air-to-fuel ratio, and derating. Post combustion controls include SCR, NSCR catalyst, and NO_x absorption systems.

4.5.1.1 Ignition Timing Retard

As described above, the injection of diesel fuel into the cylinder of a CI engine initiates the combustion process. With ignition timing retard, this combustion modification lowers NO_x emissions by moving the ignition event to later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. Because the combustion chamber volume is not at its minimum, the peak flame temperature is reduced which reduces the formation of thermal NO_x.

4.5.1.2 Air-to-Fuel Ratio

Diesel engines are inherently lean-burn engines. The air-to-fuel ration can be adjusted by controlling the amount of fuel that enters each cylinder. By reducing the air-to-fuel ratio to near stoichiometric, combustion will occur under conditions of less excess oxygen and reduced combustion temperatures. Lower oxygen levels and combustion temperature reduce NO_x formation.

4.5.1.3 Derating

Derating involves restricting engine operation to lower than normal levels of power production. Derating reduces cylinder pressure and temperatures which reduces NO_x formation.

4.5.1.4 Selective Catalytic Reduction

Selective catalytic reduction systems introduce a liquid reducing agent such as ammonia or urea into the flue gas stream before the catalyst. The catalyst reduces the temperature needed to initiate the reaction between the reducing agent and NO_x to form nitrogen and water.

For SCR systems to function effectively, exhaust temperatures must be high enough (200°C to 500°C) to enable catalyst activation. For this reason, SCR control efficiencies are expected to be relatively low during the first 20 to 30 minutes after engine start up, especially during maintenance and testing. There are also complications controlling the excess ammonia (ammonia slip) from SCR use.

4.5.1.5 Non-Selective Catalytic Reduction

Non-selective catalytic reduction systems are used to reduce emission from rich-burn engines that are operated stoichiometrically or fuel-rich stoichiometric. In the engine exhaust, NSCR catalysts convert NO_x to nitrogen and oxygen. NSCR catalytic reactions require that O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel-ratios. Lean-burn engines are characterized by an oxygen-rich exhaust which minimizes the potential for NO_x reduction.

4.5.1.6 NO_x Absorption Systems (Lean NO_x Traps)

NO_x absorber development is a new catalyst advance for removing NO_x in a lean (i.e., oxygen rich) exhaust environment for both diesel and gasoline lean-burn direct-injection engines.

With this developing technology, NO is catalytically oxidized to NO_2 and stored in an adjacent chemical trapping site as a nitrate. The stored NO_x is removed in a two-step reduction step by temporarily inducing a rich exhaust condition. NO_x adsorbers (sometimes referred to as lean NO_x traps) employ precious metal catalyst sites to carry out the first NO to NO_2 conversion step. The NO_2 then is adsorbed by an adjacent alkaline earth oxide site where it chemically reacts and is stored as a nitrate. When this storage media nears capacity it must be regenerated. This is accomplished in by creating a rich atmosphere with injection of a small amount of diesel fuel. The released NO_x is quickly reduced to N_2 by reaction with CO on a rhodium catalyst site or another precious metal that is also incorporated into this unique single catalyst layer.

4.5.2 Step 2 - Eliminate Technically Infeasible Options

NSCR catalysts are effective to reduce NO_x emission when applied to rich-burn engines fired on natural gas, propane or gasoline. The proposed diesel engines are inherently lean-burn engines; thus, NSCR is eliminated from further consideration.

In addition, NO_x absorbers were eliminated from further consideration since NO_x adsorbers are experimental technology and no commercial applications of NO_x absorbers were identified in state or EPA's RBL/C RACT/BACT/LAER Clearinghouse databases as being employed on stationary emergency generators or fire pumps. Also, the literature indicates that testing of these NO_x absorbers has raised issues about sustained performance of the catalyst. Current lean NO_x catalysts are prone to poisoning by both lube oil and fuel sulfur.

4.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options, combustion modifications and the post-combustion control, SCR will be examined further. Combustion controls have been demonstrated to reduce NO_x emissions from CI engines by approximately 50%; the use of a SCR can reduce emissions in the range from 70 to 90%.

4.5.4 Step 4 - Evaluate Impacts and Document Results

The top control option, SCR, uses a reducing-agent like ammonia or urea (which is usually preferred) with a special catalyst to reduce NO_x in diesel exhaust to N₂. The SCR catalyst sits in the exhaust stream and the reducing agent is injected into the exhaust ahead of the catalyst. Once injected the urea becomes ammonia and the chemical reduction reaction between the ammonia and NO takes place across the SCR catalyst. With the use of an SCR, there is the potential for some ammonia to "slip" through the catalyst.

SCR systems have two key operating variables that work together to achieve NO_x reductions. These are the exhaust temperature and the injection of urea or ammonia. The exhaust temperature must be between 260°C and 540°C for the catalyst to operate properly. SCR systems will not begin injection of ammonia in the form of urea until the catalyst has reached the minimum operating temperature. Urea is a critical component in determining the control efficiency of the SCR. It must be injected in the exhaust stream upstream of the SCR system. In the catalyst, it reacts to reduce NO_x to form N₂ and H₂O. The reaction takes place because the catalyst lowers the reaction temperature necessary for NO_x.

Since SCR systems require an operating temperature between 260°C and 540°C, reaching these temperatures may be difficult in routine maintenance and testing operations where the engine is typically operated at low load for a short period of time. If the critical temperatures are not met while the engine is running, there will be no NO_x reduction benefit. To have NO_x reduction benefit, the engine would need to be operated with higher loads and for a longer period of time. This would be a challenge for HollyFrontier since each engine, with the exception of the generator at the East Tank Farm, is limited to 50 operating hours per year.

Urea handling and maintenance must also be considered. Urea crystallization in the lines can damage the SCR system and the engine itself. Crystallization in the lines is more likely in emergency standby engines due to their periodic and low hours of usage.

4.5.4.1 Energy, Environmental, and Economic Impacts

There are several downsides with using an SCR. First, an improperly functioning SCR system can create excess ammonia emissions. SCR systems also add significant equipment to the engine system which increases the possibility of failures and increasing on-going maintenance costs.

Cost evaluations were prepared to determine the cost of control per ton of NO_x removed from an SCR for the emergency generators and fire water pump. SCR retrofit information was obtained from Wheeler Machinery in Salt Lake City. Based on the cost information provided by Wheeler, the calculated costs per ton of NO_x removed are presented in Table 4-14 and in Appendix B.

Table 4-14 Cost Effectiveness of Installing SCR on Emergency Diesel Engines for NO_x Control

Equipment	Cost Effectiveness (\$/Ton)
135 kW generator (east tank farm)	\$ 16,201
224 HP (water well #3)	\$ 353,677
393 HP Fire Pump #1	\$ 353,998
393 HP Fire Pump #2	\$ 353,998
220 HP plant air backup compressor #1	\$ 353,456
220 HP plant air backup compressor #2	\$ 353,456
220 HP plant air backup compressor #3	\$ 353,456
470 HP diesel generator (boiler house)	\$ 354,736
380 HP diesel generator (central control room)	\$ 355,095
540 HP standby generator	\$ 723,683

In addition to the costs presented in Table 4-15, the cost of urea is \$1 per KW and its shelf life is approximately two years. This would increase the cost of operation a SCR for emergency standby engines since the low number of annual hours of operation could lead to the expiration of the urea. The urea would have to be drained and replaced, creating an extra maintenance step and an increased cost to HollyFrontier.

4.5.5 Step 5 - Select BACT

According to HollyFrontier's approval order, the 135 kW generator at the tank farm is limited to 1,100 operating hours per year. However, since its commission date of 11/15/2010, this generator has run only 89.9 hours (as of 3/9/2017). Based on the economic costs to install a SCR system, the likelihood that the engine would not be at proper operating temperature for the SCR to be effective due to limited operating hours, and the extra maintenance and disposal costs if urea were used, SCR has been eliminated from further consideration.

Currently, California has the most aggressive emission reduction standards for diesel engines. The MSM identified includes the use of SCR systems to reduce NO_x on diesel engines 1000 HP or greater. SCR systems have not seen wide application on emergency standby engines less than 1000 HP. Maine Department of Environmental Protection requires **non**-emergency engines to install SCR technology for NO_x control if their potential annual NO_x emissions exceed 20 tons as best available control technology.

Periodic maintenance is performed on the engines in accordance with manufacturer specifications. For those engines subject to Subpart ZZZZ, oil is changed and hoses/belts inspected every 500 hours or annually.

Thus, the only control technologies for the diesel emergency generators and fire pumps (except the 135 kW generator at the East Tank Farm) are the work practice requirements to adhere to GCP and NO_x Tier standard for each engine and the best practice of performing periodic maintenance. These requirements have been determined to be BACM. These control strategies are technically feasible and will not cause any adverse energy, environmental, or economic impacts.

The proposed BACM controls, emission limitations, and compliance monitoring methods for HollyFrontier emergency diesel engines are summarized in Table 4-15.

**Table 4-15 Proposed BACM Controls, Emission Limitations, and Compliance Monitoring
Method for Emergency Diesel Engines**

Pollutant	Units	Control Technology	Emission Limitations	Monitoring Method
NO _x	All emer. Engines except ETF gen.	Work Practice Requirements, Good Combustion Practice	600 hours total rolling 12-month period	Non-resettable hour meter
	ETF portable generator		1100 hours per rolling 12-month period	

4.6 Emergency Natural Gas-Fired Engines

HollyFrontier operates two natural gas-fired spark ignition emergency standby generators, each at 142 kW, at the Administration building. During combustion, the formation of NO_x is a result of thermal or fuel-bound reactions. The thermal formation of NO_x occurs when nitrogen and oxygen reacts at high temperatures. NO_x is also generated from the oxidation of nitrogen contained in the fuel. Since natural gas contains low concentrations of nitrogen, emissions of NO_x are primarily due to the thermal formation of NO_x in the combustion chamber.

4.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Four (4) control technologies were identified to reduce NO_x emissions from spark ignition engines which include:

- > SCR,
- > NSCR,
- > lean burn technology, and
- > good combustion practices.

4.6.1.1 Selective Catalytic Reduction

Selective catalytic reduction is a post-combustion NO_x control technology in which an aqueous urea solution is injected in the exhaust air stream which evaporates into ammonia. The ammonia and NO_x react on the surface of the catalyst forming water and nitrogen. SCR reactions occur in the temperature range of 650°F to 750°F. Precious metal catalysts are used to reduce NO_x .

4.6.1.2 Non-selective Catalytic Reduction

Non-selective catalytic reduction is a catalytic reactor that simultaneously reduces CO, NO_x , and HC emissions. The catalytic reactor is placed in the exhaust stream of the engine and requires fuel-rich air-to-fuel ratios and low oxygen levels.

4.6.1.3 Lean Burn Technology

Combustion is considered "lean" when excess air is introduced into the engine along with the fuel. The excess air reduces the temperature of the combustion process which reduces the amount of NO_x produced. In addition, since there is excess oxygen available, the combustion process is more efficient and more power is produced from the same amount of fuel.

4.6.1.4 Good Combustion Practices

Control of combustion temperature is the principal focus of combustion process control in natural gas-fired engines. There are combustion control tradeoffs, however. Higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons and CO but result in increased NO_x formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and therefore reduces NO_x formation. This allows a higher compression ratio or peak firing pressures resulting in higher efficiency. However, if the mixture is too lean, misfiring and incomplete combustion may occur.

Because the NO_x produced is primarily thermal NO_x, reducing the combustion temperature will result in less NO_x production. Thus, the main strategy for combustion control is to control the combustion temperature. This is most easily done by adding more air than what is required for complete combustion of the fuel. This raises the heat capacity of the gases in the cylinder so that for a given amount of energy released in the combustion reaction, the maximum temperature will be reduced.

4.6.2 Step 2 - Eliminate Technically Infeasible Options

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich burn turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NO_x reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures. Thus, the add-on combustion control of NSCR is deemed technically infeasible. In addition, the operation of each generators is limited to 50 hours for testing (non-emergency) purposes. Since it is unlikely that these units will achieve normal operating temperature for any period of time, the add-on control using SCR, which requires a consistent operating temperature to be effective, is also technically infeasible.

4.6.3 Step 3 - Rank Remaining Control Technologies by Effectiveness

The remaining control technologies, lean burn technology and good combustion practices are both effective in reducing NO_x emissions.

4.6.4 Step 4 - Evaluate Most Effective Controls

In lean burn engines, the combustion process is enhanced by pre-mixing the air and fuel upstream of the turbocharger before introduction into the cylinder. This creates a more homogeneous mixture in the combustion chamber. The microprocessor-based engine will regulate the fuel flow and air/gas mixture and ignition timing to achieve efficient combustion.

Combustion controls are integral in the combustion process as they are designed to achieve an optimum balance between thermal efficiency-related emissions (CO and VOC) and temperature related emissions (NO_x). Combustion controls will not create any energy impacts or significant environmental impacts. There are no economic impacts from combustion controls because they are part of the design for modern engines.

EPA describes natural gas generators as Stationary Spark Ignition Internal Combustion Engines (SI ICE). Depending on the year of manufacturer, natural gas generators are regulated by 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. Here, the EPA provides emissions standards that manufacturers must meet, emissions standards owners/operators must meet, EPA certification requirements, testing requirements, and compliance requirements.

According to Subpart JJJJ, the NO_x Emission Standards for stationary emergency engines >25 HP is 2.0 g/HP-hr or 1 ppmvd @ 15% O₂. The HollyFrontier natural-gas fired emergency generators were manufactured in 2012 and as such, meet the Subpart JJJJ NO_x emission standards.

4.6.4.1 Energy, Environmental, and Economic Impacts

There are no energy, environmental or economic impacts associated with the use of lean burn technology and good combustion practices.

4.6.5 Step 5 - Select BACT

The most stringent controls identified is the use of natural gas, good combustion practices and maintenance in accordance with manufacturer recommendations with an emission rate of 1 ppmvd @ 15% O₂ or 2.0 g/HP-hr. BACT for NO_x emissions from 2012 model year SI ICE generators at HollyFrontier is the application of a lean burn engine fired on natural gas, good combustion practices, limited operating hours, and operation in accordance to manufacturer's recommendations. The generators are EPA certified and the manufacturer lists a NO_x emission rate of 2.0 g/HP-hr or 1 ppmvd @ 15% O₂. The engines are in compliance with the applicable emission limits of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ. Maintenance on the engines will be performed in accordance with manufacturer specifications which includes inspection of the air cleaner. The proposed controls and maintenance satisfy BACM.

The proposed BACM controls, emission limitations, and compliance monitoring methods for HollyFrontier the emergency natural gas-fired engines are summarized in Table 4-16.

Table 4-16 Proposed BACM Controls, Emission Limitations, and Monitoring for Emergency Natural Gas Engines

Pollutant	Units	Control Technology	Emission Limitation	Monitoring Method
NO _x	Nat. gas fired emergency engines	Work Practice Requirements, Good Combustion Practice	600 hours total rolling 12-month period for all emergency engines	Non-resettable hour meter

5.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR SULFUR DIOXIDE

BACM's were evaluated for oxides of sulfur dioxide (SO₂) emissions from certain process units in operation or proposed at the Woods Cross Refinery. These include: process heaters, boilers, flares, SRU, FCCUs, and emergency diesel and natural gas-fired engines.

5.1 Process Heaters and Boilers

Sulfur dioxide (SO₂) emissions from process heaters and boilers are a direct function of the sulfur content of the fuel that is burned. Reduced sulfur compounds in the fuel are readily oxidized to SO₂ and to a small extent SO₃. Both refinery gas and natural gas contain sulfur, mostly in the form of hydrogen sulfide (H₂S). In general, refinery fuel has higher sulfur content than pipeline quality natural gas.

5.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following is a list of control technologies which were identified for controlling SO₂ emissions:

- fuel specification - low sulfur fuels;
- wet flue gas desulfurization (wet FGD);
- advanced flue gas desulfurization (AFGD);
- dry absorption (dry FGD); and,
- Emerachem EMX.

5.1.1.1 Fuel Specifications

In general, sulfur combusted in the fuel will be converted to SO₂. By limiting the sulfur content of the fuel, emissions of SO₂ will be reduced. Emissions of SO₂ from process heaters and boilers can be controlled by fuel specifications or by using post-combustion controls.

Pipeline quality natural gas has very low sulfur content (approximately 4 ppmv) generally in the form of mercaptans used for odorization. The gas may also contain trace quantities of reduced sulfur compounds (a few grains/100 scf). SO₂ emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Refinery fuel gas has a higher sulfur content than the natural gas purchased from a pipeline. The refinery gas sulfur content is dependent on the removal efficiency of the fuel gas amine scrubbing units in a refinery. HollyFrontier operates an amine scrubbing system to produce refinery gas with less than 60 ppmv H₂S, on an annual average basis (40 CFR 60, Subpart Ja). On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (e.g., as much as 162 ppmv sulfur on a 3-hour average basis). Based on natural gas usage, SO₂ emissions are determined based on 0.60 lb SO₂/MMscf.

5.1.1.2 Flue Gas Desulfurization

Flue gas desulfurization (FGD) is commonly used for control of SO₂ from solid fuel-combustion, such as coal. FGD technology can be achieved through a variety of wet or dry scrubbing processes. Generally speaking, it has control efficiencies of up to 95 percent on coal-fired combustion systems.

The simplest method for flue gas desulfurization is with the use of a wet scrubber. In a wet caustic scrubbing system, the flue gas and a caustic solution flow counter-current to each other. The sulfur reacts with the caustic solution and is stripped out of the flue gas.

The advanced FGD process accomplishes SO₂ removal by utilizing a single absorber which performs three functions which are prequenching the flue gas, adsorption of SO₂, and oxidation of the resulting calcium sulfite to wallboard-grade gypsum. Incoming flue gas is cooled and humidified with process water sprays before passing to the absorber.

In the absorber, two tiers of fountain-like sprays distribute reagent slurry over polymer grid packing that provides a large surface area for gas/liquid contact. The gas then enters a large gas/liquid disengagement zone above the slurry reservoir in the bottom of the absorber and exits through a horizontal mist eliminator. As the flue gas contacts the slurry, the SO₂ is absorbed, neutralized, and partially oxidized to form calcium sulfite and calcium sulfate.

Dry FGD systems spray lime slurry into an absorption tower where the SO₂ is absorbed by the slurry forming calcium sulfite and calcium sulfate. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or an electrostatic precipitator (ESP).

5.1.1.3 Emerachem (EMx™)

Emerachem EMx™ is an add-on technology that utilizes a catalyst to absorb the SO₂ in the flue gas. The catalyst is periodically regenerated using hydrogen. The regenerated stream is treated in a sulfur recovery unit or adsorbed on carbon.

5.1.2 Step 2 - Eliminate Technically Infeasible Options

FGD is commonly used for control of SO₂ from solid fuel-combustion, such as coal. A review of the recent literature, recent permits, and the RBLC database did not result in AFGD and wet FGD or dry FGD as BACT. Limestone slurry scrubbing systems are usually applied to power plants for flue gas desulfurization. With wet caustic scrubbing, water contamination issues arise with the disposal of large volumes of sodium sulfite and sodium sulfate solution. In addition, based on available literature, FGD technology is not commercially demonstrated on refinery process heaters because it is cost-prohibitive compared to the cost of desulfurizing the fuel gas (in this case, via the use of an amine scrubbing system).

As mentioned above, Emerachem EMx™ is an add-on technology that utilizes a catalyst to absorb the SO₂ in the flue gas. This technology has not been proven to run longer than one year without a turnaround. HollyFrontier requires the refinery heaters to be able to operate at least three years between turnarounds. Thus, Emerachem EMx™ was not considered to be technically feasible on the refinery heaters at the refinery.

5.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top-performing feasible SO₂ control technology is the firing of 100% purchased natural gas in the heater, because of the very low sulfur content of natural gas. The next most effective control technology is the use of refinery fuel gas treated to sulfur levels that meet the requirements of 40 CFR 60, Subpart Ja.

5.1.4 Step 4 - Evaluate Impacts and Document Results

Several sources of information were examined including EPA's RBLC RACT/BACT/LAER Clearinghouse, state agency databases, vendor data, and published literature to identify the most effective SO₂ control technologies, most stringent emissions limitations to compare against current SO₂ controls that have been or proposed to be implemented at the Woods Cross Refinery. Table 5-1 presents a summary of select BACT determinations for SO₂ for process heaters and boilers. All units listed in Table 5-1 are fired on refinery gas.

Table 5-1 BACT Determinations for SO₂ for Process Heaters and Boilers

Facility	Permit Date	Size (MMBtu/hr)	H ₂ S Limit (lb/MMBtu)	Control
Lima Refining Company	12/23/2013	Crude distillation unit II	60 ppmv (365-day rolling average)	Refinery fuel gas sulfur removal
Sinclair Wyoming Refining Company	10/15/2012	50, 233	--	Follow Ja Fuel Gas H ₂ S limits (162 ppm in RFG, 3-hour basis and 60 ppm in RFG, 365-day rolling average)
ConocoPhillips Company Billings Refinery, Montana	11/19/2008	Crude heater, No1 & No 2 H ₂ Heater	34 ppmv H ₂ S (rolling 365-day average) 162 ppmv H ₂ S 3-hour rolling avg. during startup/shutdown	Fuel gas cleanup-chemical absorption/amine system
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	24, 52, 83, 86, 100, 135, 336	--	Use of pipeline quality natural gas or refinery fuel gases with an H ₂ S concentration less than 100 ppmv (annual average)

As seen from Table 5-1, the only method indicated to control SO₂ emissions in process heaters and boilers is to limit the sulfur content in the gaseous fuel. HollyFrontier employs an amine treatment unit which uses methyl diethanolamine (MDEA) to remove H₂S out of plant fuel gas to a level of 60 ppm or less on an annual basis.

5.1.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated energy or environmental impacts associated with top control option which is the treatment of the refinery fuel gas to limit the sulfur content of the fuel.

5.1.5 Selection of BACM

BACT for SO₂ is a refinery-wide permit limit on the sulfur content on the refinery gas system, including both short-term and long-term H₂S limits and the use of pipeline quality natural gas to supplement the refinery gas when needed.

The most stringent emission limit identified is at the Hyperion Energy Center which has a maximum refinery gas sulfur level of 35 ppmv, based on an hourly rolling 24-hour average, excluding periods of startup, shutdown, and malfunction. The Hyperion Energy Center is comprised of an Integrated Gasification Combined Cycle (IGCC) Power Plant with a petroleum refinery. A second facility, the Billings Refinery in Montana lists a H₂S limit of 34 ppmv based on a rolling 365-day average using a chemical absorption/amine system. Although this limit is more stringent than HollyFrontier's 60 ppmv limit based on a 365-day average, HollyFrontier utilizes an amine treatment system to limit sulfur content.

Thus, BACT has been determined to limit the sulfur content on the refinery gas to meet the limit of 60 ppmv on a 365 day basis and 162 ppmv based on a three-hour rolling average. The H₂S fuel content of the refinery gas is verified through a continuous emission monitor. These limits meet the applicable NSPS Subpart Ja and AO requirements.

The cost of installing and operating CEMS on each heater and boiler was examined. The estimated equipment cost including a shelter and a SO₂ CEMS with affiliated equipment plus installation is over \$201,600 per system. Total annual operating costs were estimated to be approximately \$72,820. See Appendix B for a detailed cost analysis. Based on PTE emissions from the process heaters, the average cost-per-ton to monitor for SO₂ with a CEMS is over \$1.6 million dollars.

The proposed BACM controls, SO₂ emission limits, and compliance monitoring methods conducted for HollyFrontier the process heaters and boilers are summarized in Table 5-2.

Table 5-2 Proposed BACM Controls, SO₂ Emission Limits, and Monitoring Methods for Process Heaters and Boilers

Pollutant	Units	Control Technology	Emission Limit	Monitoring
SO ₂	4H1, 6H1, 6H2, 6H3, 7H1, 7H3, 8H2, 9H1, 9H2, 10H1, 10H2, 11H1, 12H1, 13H1, 19H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1, 68H2, 68H3, 68H4, 68H5, 68H6, 68H7, 68H10, 68H11, 68H12, 68H13, Boilers #4, #5, #8, #9, #10, #11	Sulfur content on the refinery gas Pipeline quality natural gas (supplemental) as needed	H ₂ S content of 60 ppmv on a 365 consecutive operating day average. H ₂ S content to 162 ppmv on a 3-hour rolling average basis.	CEMS located at plant fuel gas mix drum/header

5.2 Flares

SO₂ emissions from flares result primarily from the combustion of sulfur-containing gases vented from the refinery processes. A minor contributor to SO₂ emissions from the flares is the natural gas combustion of the pilot flame.

5.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following control technologies were identified to control SO₂ emissions from flares:

- Maintain flared gas parameters (e.g. heat content, composition, velocity) to allow for good combustion,
- Meet the requirements of 40 CFR 60.18 and 40 CFR Part 60 Subpart Ja,
- Proper design including know-out pot and seal drum and monitor for continuous presence of flame,
- Good combustion, operating, and maintenance practices,
- Limit sulfur content of feedstock and fuels,
- Root cause analysis, and
- Flare gas recovery.

5.2.1.1 Maintain Flare Gas Parameters

The key parameters to be maintained to assure proper gas flow through the system and appropriate conditions for thermal destruction of combustible pollutants include flame presence, exit gas velocity, temperatures at flare inlet and outlet and combustion zone, pressure and pressure differentials of system components, and liquid levels in water seals and knockout drum.

5.2.1.2 Meet the Requirements of 40 CFR 60.18

If a flare is used as the control device, it has to meet the specifications described in the general control device requirements (Sec. 60.18). This includes that flares be designed and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, that a flame is present at all times, that either the heat content specifications and the maximum tip velocity specifications are met, to name a few of the requirements.

5.2.1.3 Proper Design

Flare design depends on the sources of the gas being vented into the flare heater and such gas characteristics as flowrate, composition, and temperature, the available gas pressure and utility costs. Safety, regulatory, and environmental requirements are considered as well.

5.2.1.4 Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for improving combustion efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare per manufacturer's specifications.

5.2.1.5 Limit Sulfur Content of Feedstock and Fuels

HollyFrontier processes sweeter crudes, those lower in sulfur content, than sour crudes which are pumped from wells in Mexico and Saudi Arabia, for example. Crudes, such as black and yellow wax crudes, are inherently low in sulfur, around 900 ppm. Western Canadian Select which is also processed by HollyFrontier has a sulfur content of 34,000 ppm.

Pipeline quality natural gas has very low sulfur content (approximately 4 ppmv) generally in the form of mercaptans used for odorization. The gas may also contain trace quantities of reduced sulfur compounds (a few grains/100 scf). SO₂ emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Refinery fuel gas has a higher sulfur content than the natural gas purchased from a pipeline. HollyFrontier operates an amine scrubbing system to produce refinery gas with less than 60 ppmv H₂S on an annual average basis (40 CFR 60, Subpart Ja). On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (e.g., as much as 162 ppmv sulfur on a 3-hour average basis).

5.2.1.6 Root Cause Analysis

Developing and implementing procedures for conducting a root cause analyses (RCA) following process upsets and malfunctions that produce flare gas in excess of a designated volumetric flow rate threshold is an effective option for minimizing flaring during these events. Performing a RCA involves a specific evaluation of each flaring incident caused by process upset or malfunction, including the identification of the causes of flaring, assessment of measures to eliminate or reduce future flaring from the same cause, and implementation of any feasible measures identified.

5.2.1.7 Flare Gas Recovery System

Flaring can be reduced by installation of commercially available recovery systems. A flare gas recovery system is a system comprised of compressors, pumps, heat exchangers, knock-out pots and water seals, installed to prevent or minimize the combustion of vent gas in a flare.

5.2.2 Step 2 - Eliminate Technically Infeasible Options

The control technologies identified above have been determined to be technically feasible.

5.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top ranking control option is the installation of a flare gas recovery system. Flare gas recovery systems are achieved in practice. The second highest ranking control option includes proper equipment design and work practices, good combustion practices, and limiting of sulfur content of feedstock and fuels.

5.2.4 Step 4 - Evaluate Impacts and Document Results

HollyFrontier will install a flare gas recovery system to recover vent gas which is the highest ranked control option. Since this is the highest ranked control option, energy, environmental and costs analyses are not required.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flares are located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18.

Flare management plans have been developed for both the north and south flare. These plans contain procedures to minimize or eliminate discharges to the flare during startups and shutdowns. To verify that the procedures are followed, records are maintained. A RCA is initiated for each event resulting in emissions of SO₂ greater than 500 pounds in any 24-hour period or a discharge to the flare in excess of 500,000 standard cubic feet above the baseline in any 24-hour period and corrective action is implemented for reportable flaring incidents.

The amount of H₂S is limited in the refinery fuel gas to 162 ppm for continuous, intermittent, routinely-generated refinery fuel gases and this limit is continuously monitored or intermittently monitored under an EPA approved alternative monitoring system.

Emissions from the HollyFrontier Woods Cross Refinery flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

5.2.4.1 Energy, Environmental, and Economic Impacts

Since HollyFrontier has chosen the highest ranked control option, flare gas recovery, energy, environmental and costs analyses are not required.

5.2.5 Step 5 - Selection of BACM

Holly is proposing the following design elements and work practices as BACM for the flares:

- Use of low sulfur fuel such as natural gas as fuel for pilot flame;
- Maintaining an acceptable net heating value and exit velocity of flared gases under all flow conditions in accordance with manufacturer specifications;
- Use of a thermocouple to monitor presence of the pilot flame;
- Implementation of good combustion, operating, and maintenance practices;
- Implementation of flare management plan;
- Conduct of Root Cause Analyses;
- Flare operation in accordance to 40 CFR Part 60, Ja and design and work practice standards as codified in 40 CFR Part 60.18; and,
- Installation of flare gas recovery system.

No other measures were identified as more stringent measures for the flares at the Woods Cross Refinery. The flare design includes steam assisted combustion. The flares will be equipped with a flare gas recovery system for non-emergency releases, and a continuous pilot light. Pilot and sweep fuel will be natural gas or treated refinery gas.

The north and south flares are equipped with flow meters and gas combustion monitors. H₂S and SO₂ CEMS are also installed on each flare. Records of discharges greater than 500 lb SO₂ in 24-hour period and in excess of 500,000 scf above baseline in 24-hour period would cause a root cause analysis to be prepared and corrective action taken.

The proposed BACM controls, SO₂ emission limits, and monitoring methods conducted for HollyFrontier the flares are summarized in Table 5-3.

Table 5-3 Proposed BACM Controls, SO₂ Emission Limits, and Monitoring Methods for Flares

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Methods
SO ₂	66	Flare gas recovery system Low sulfur fuel, GCP Flare management plan	500 lb SO ₂ in 24-hour period 500,000 scf above baseline in 24-hr period	Flow meters, gas combustion monitors, and H ₂ S and SO ₂ CEMS

5.3 Sulfur Recovery Plant

Hydrogen sulfide that has been removed in the Amine Treatment Unit (Unit 16) is processed in a Claus SRU to convert the H_2S to elemental sulfur which is sold commercially. H_2S rich gases from the Sour Water Stripping Unit (SWS) (Unit 18) go to Unit 22, the ammonia stripper. Unit 22 removes ammonia and results in a feed to the SRU that produces higher recovery than would occur if the ammonia were left in the gas. The SO_2 and remaining H_2S are sent to catalytic reactors where additional sulfur is recovered. Any unconverted H_2S and SO_2 are sent to the SRU Tailgas Incinerator (17-1) where purchased natural gas is used to burn any remaining H_2S . It should be noted, however, that in October 2016, the effluent from the SRU Tailgas Incinerator is redirected to a Belco wet gas scrubber (Unit 4 or Unit 25). The SRU does not operate if the wet gas scrubber is not operational. The recovered elemental sulfur is stored in a sulfur pit as a liquid until sold. Liquid sulfur is pumped from the pit and loaded into trucks for shipment off-site.

5.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Control options for SO_2 emissions include equipment configuration as well as proprietary adaptations of the Claus SRU technology.

Equipment configurations are control options. Equipment configurations include:

- > Claus SRU without tail gas treatment unit (TGTU),
- > Claus SRU without incinerator,
- > Claus SRU with TGTU but without incinerator,
- > Claus SRU with TGTU and with incinerator, and
- > Claus SRU with TGTU and wet scrubbing.

In any of the configurations above (i.e. Claus SRU without TGTU), a Claus unit can be replaced with a different number of Claus units. For example, a three-stage Claus unit can be replaced with two-stage Claus unit. Also, the TGTU could be replaced with multiple TGTUs.

Other alternatives, which include a number of proprietary adaptations of the Claus SRU technology, were identified. These adaptations generally operate by extending the Claus reaction to improve the thermodynamically achievable sulfur conversion efficiency. The proprietary adaptations identified include:

- > the Superclaus process,
- > the Euroclaus process,
- > the Mobil Oil Direct Oxidation process,
- > the COPE, Oxyclaus, and SURE processes,
- > the Selectox process,
- > the Sulfreen process,
- > the Maxisulf, CBA, Clinsulf, and MCRC processes,
- > the Wellman-Lord, CANSOLV, and CLINTOX processes,
- > the Stretford, Z-SORB, LO-CAT, and CrystaSulf liquid-phase oxidation reduction technologies, and,
- > the Shell Claus Offgas Treating (SCOT) process.

5.3.1.1 Superclaus Process

The Superclaus process is a conventional Claus process with a proprietary catalyst replacing the conventional, activated alumina Claus catalyst in the final catalytic reactor stage. The proprietary catalyst in the Superclaus process oxidizes H_2S to form elemental sulfur and water.

5.3.1.2 Euroclaus Process

The Euroclaus process is an enhancement of the Superclaus process with a hydrogenation reactor inserted upstream of the final catalytic reactor stage. This hydrogenation reactor reduces SO_2 concentration in the final reactor stage.

5.3.1.3 Mobil Oil Direct Oxidation Process

The Mobil Oil Direct Oxidation Process also involves a hydrogenation reactor and a catalytic direct oxidation reactor added to the back end of a Claus SRU.

5.3.1.4 COPE, OxyClaus, and SURE Processes

Oxygen enrichment is used in order to improve temperature control in the first-stage thermal reactor in several proprietary adaptations of the Claus process. These include the COPE, OxyClaus, and SURE processes. The typical SRU reaches its ultimate capacity when maximum allowable front-end pressure prevents further increase in feed rate. The front-end pressure of an SRU is usually limited by either process seal leg depth, combustion air blower discharge pressure or the operating pressure of an upstream amine unit regenerator. Oxygen enrichment reduces process flow rate by reducing the quantity of nitrogen that enters with the combustion air. This reduction in process flow rate allows a corresponding increase in SRU feed rate.

5.3.1.5 Selectox

The Selectox process is similar to the conventional Claus process but has a catalytic oxidizer in place of the first-stage thermal reactor.

5.3.1.6 Sulfreen

The Sulfreen process utilizes a conventional Claus process with an additional Claus-type reactor after the final sulfur condenser. This additional reactor operates at a temperature below the sulfur dew point and adsorbs the sulfur on the Claus catalyst. Each of the two beds in the additional reactor is cycled between adsorption and regeneration. During the regeneration cycle, the hot gases are produced in an integral heater and, after desorbing the sulfur from the catalyst, are passed through an integral condenser.

5.3.1.7 Maxisulf, CBA, Clinsulf, and MCRC Processes

The Maxisulf, CBA, Clinsulf, and MCRC processes are similar to the Sulfreen process but without the integral heater and the recycle function in the sub-dew point part of the process.

5.3.1.8 Wellman-Lord, CANSOLV, and CLINTOX Processes

The Wellman-Lord, CANSOLV, and CLINTOX process are essentially wet scrubbers in which proprietary solvents are used for SO_2 removal. All of these technologies require an upstream combustion device in order to convert reduced sulfur compounds to SO_2 . Also, any of these technologies can be used with or without SRU's upstream of the combustion device. When used in conjunction with an upstream Claus SRU, these technologies allow the SO_2 to be stripped from the solvent and returned to the front end of the SRU.

5.3.1.9 Stretford, Z-SORB, LO-CAT, and CrystaSulf Liquid-Phase Oxidation Reduction Technologies

Stretford, Z-SORB, LO-CAT, and CrystaSulf are proprietary liquid-phase oxidation-reduction technologies providing indirect oxidation of H₂S to form elemental sulfur and water. The Stretford process uses a vanadium-based chelating agent, the Z-SORB process uses a zinc-based chelating agent, and the LO-CAT and CrystaSulf technologies use proprietary, iron-based chelating agents.

5.3.1.10 Shell Claus Offgas Treating (SCOT) Process

The SCOT process removes sulfur from Claus SRU vent streams and is the basis for the TGTU.

5.3.2 Step 2 - Eliminate Technically Infeasible Options

Several of the identified proprietary technologies, Wellman-Lord CANSOLV, CLINTOX, LO-CAT, and CrystaSulf control strategies are considered technology infeasible because, based on available literature, they have not been demonstrated to function efficiently in removing sulfur from acid gas streams from refinery sour water strippers and amine regeneration units.

Any control strategy involving a combustion device to burn the acid gases to control SO₂ emissions is a technically infeasible control option because it would not meet the NSPS requirements set forth in 40 CFR 60, Subpart Ja.

Using a conventional Claus SRU without a TGTU, either with or without an incinerator, also is technically infeasible as a control option because it would not meet the NSPS requirements set forth in 40 CFR 60, Subpart Ja. The same applies to a Claus SRU that is replaced with any of the Claus adaptations that use oxygen enrichment (COPE, OxyClaus, and SURE) or the Superclaus, Euroclaus, Mobil Oil Direct Oxidation, Selectox, Sulfreen, Maxisulf, CAB, Clinsulf or MCRC processes.

5.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The SRU at the Woods Cross Refinery is comprised of a three-stage Claus SRU followed by tailgas incinerator and a wet scrubber. This control option will achieve an overall sulfur recovery efficiency of 99.8 percent.

Several other alternative control strategies similar to the one utilized by HollyFrontier were identified that would achieve similar control efficiencies. These include:

- > any number of SRU's in parallel, followed by any number of TGTU's in parallel,
- > one three-stage Claus SRU followed by any number of parallel TGTU's and a downstream incinerator,
- > three, three-stage Claus SRU's followed by any number of parallel TGTU's and a downstream incinerator.

5.3.4 Step 4 - Evaluate Impacts and Document Results

Each of the control options would allow sulfur to be emitted to the atmosphere at a rate that is the same as the control option proposed by HollyFrontier. The Claus SRU employs a three-stage reactor train to convert feed sulfur, in the form of H₂S, into elemental sulfur. The system is operated sub-stoichiometrically with air such that only one third of the H₂S is oxidized to SO₂. This oxidation reaction occurs primarily in the first reactor.

The second reaction begins in the first reactor and continues in the two catalytic reactors. Each of the three reactor states is followed by a condenser that cools, condenses, and removes the elemental sulfur.

In addition to the two primary chemical reactions described above, secondary reactions also occur due to impurities in the system. Hydrocarbons in the acid gas streams entering the thermal reactor are partially oxidized to form carbon dioxide and water. Carbon dioxide and unreacted hydrocarbons react with sulfur to form carbonyl sulfide (COS) and carbon disulfide (CS₂). These carbon-sulfur compounds may be partially hydrolyzed in the first catalytic reactor to form H₂S but mainly flow unreacted through the SRU.

Because the Claus process, from the third condenser of the Woods Cross Claus SRU, the resulting SRU off gas is routed to a tail gas incinerator and then to one of the wet gas scrubbers (4V82 FCC or 25 FCC Scrubber).

The EPA's RBLC database was reviewed to determine SO₂ control methods for SRU's. The results of this search are presented in Table 5-4.

Table 5-4 BACT Determinations for SO₂ for Sulfur Recovery Units

Facility	Permit Date	SO ₂ Concentration Limit	Control
Lima Refining Company	12/23/2013	19.18 lb/hr (12-hour average) 250 ppmv dry basis 0% excess air	Tail gas treatment unit and tail gas incinerator
Diamond Shamrock Refining Company Valero McKee Refinery	12/20/2013	No limits listed	SCOT technology and tail gas incinerators to achieve 99.8% sulfur recovery
BP Products, North America Inc.	09/20/2013	250 ppmv dry basis 0% excess air, 12-hour average	SRU followed by tail gas incinerator. Meets subpart J requirements
Valero Refining, Texas LP, Corpus Christi East Texas Refinery	08/19/2010	267.0 lb/hr	Minimize TGCU down time and operating rate
Valero Refining, Texas LP, Corpus Christi West Texas Refinery	03/29/2010	761.0 lb/hr	Minimize TGCU down time and operating rate
Valero Refining - New Orleans LLC St. Charles Refinery	11/17/2009	250 ppmvd 12-hour rolling average	Thermal oxidizers - comply with Subpart J requirements
Sunoco Company Inc. Toledo Refinery	01/29/2008	9.88 lb/hr 250 ppmv dry basis 0% excess air rolling 12-hour average	Tail gas treatment units and SRU Incinerator for H ₂ S
Navajo Refining Company, LLC Arteria Refinery	12/14/2007	192.0 ppmvd 12-hour rolling average @ 0% O ₂	Tail gas incinerator

5.3.4.1 Energy, Environmental, and Economic Impact

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. During normal operation, the use of a three-stage Claus SRU followed by the tailgas incinerator and a wet scrubber is a top ranked technology and besides waste generation, no adverse energy or economic impacts are anticipated.

5.3.5 Step 5 - Selection of BACM

The existing equipment and control options chosen by HollyFrontier are widely used and have demonstrated 99.8% sulfur recovery efficiency or better in the petroleum industry. The SO₂ BACM emission limit is based on the use of a three-stage Claus SRU followed by tail gas incinerator and a wet scrubber during normal operations. Amine scrubbing is used to reduce H₂S emissions in the fuel gas at HollyFrontier. The FCCU wet scrubbers (4V82 FCC Scrubber and 25FCC Scrubber) are equipped with CEMS to measure SO₂ emissions. The SRU is not operated if the wet scrubbers are not operational.

The most stringent controls identified for a SRU > 10 LTPD is a three-stage Claus, amine-based tail gas treating units with an expected control efficiency of 99.9% (10 ppmvd).

The proposed BACM controls, SO₂ emission limits, and monitoring methods conducted by HollyFrontier for the SRU are summarized in Table 5-5.

Table 5-5 Proposed BACM Controls, SO₂ Emission Limits, and Monitoring Methods for SRU

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Methods
SO ₂	17	Three-stage Claus followed by tail gas incinerator and a wet scrubber	95% sulfur recovery based on 30-day average except during startup, shutdown, malfunction	Flow rate and H ₂ S concentration in the feed
			0.05 tons per day (wet scrubbers) 17.7 tons per year (wet scrubbers)	SO ₂ CEMS

5.4 FCCU

Depending on the feed sulfur content and FCCU design, sulfur emissions in the form of SO₂ and SO₃ from the regenerator can vary significantly. In the FCCU reactor, 70 to 95 percent of the incoming feed sulfur is transferred to the acid gas and product side in the form of H₂S. The remaining of the incoming feed sulfur is attached to the coke where it is oxidized into sulfur oxides and emitted in the FCCU regenerator flue gas.

5.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following is a list of control technologies which were identified for controlling SO₂ emissions from the FCCUs:

- > Control of sulfur in the FCCU feed
- > Feed hydrotreatment
- > Wet Gas Scrubbers
- > Wellman-Lord Flue Gas Desulfurization Process
- > DeSO_x Additives

5.4.1.1 Control of Sulfur in FCCU Feed

HollyFrontier processes sweeter crudes, those lower in sulfur content, than sour crudes which are pumped from wells in Mexico and Saudi Arabia, for example. Crudes, such as black and yellow wax crudes, are inherently low in sulfur, around 900 ppm. Western Canadian Select which is also processed by HollyFrontier has a sulfur content of 34,000 ppm.

5.4.1.2 Feed Hydrotreatment

At HollyFrontier, the Unit 4 feedstock is hydrotreated in Unit 20, the gas oil hydrocracker (GHC). The GHC unit desulfurizes gas oil to the FCCU which reduces sulfur in the unit products. In the feedstock hydrotreatment process, the FCCU feedstock is treated over a metal catalyst in a hydrogen environment before the cracking process. Depending on initial sulfur levels, flue gas emissions of SO₂ can be reduced by up to 90 percent with the additional benefit of reductions in nitrogen compound and trace metal emissions. The feed to Unit 25 is not hydrotreated but lower sulfur feed is used by this unit.

5.4.1.3 Wet Gas Scrubbers

Wet gas scrubbers are principally defined in Section 6.1.1.3. The water used in a wet gas scrubber is mixed with an alkaline reagent to react with the SO₂ to form sulfate and sulfite salts. These compounds are captured as a wet solid in the filtering section of the wet gas scrubber. The SO₂ removal efficiencies typically range from 95 to 99.9%.

5.4.1.4 Wellman-Lord Flue Gas Desulfurization Process

In the Wellmann-Lord flue gas desulfurization process, flue gas enters the absorber and gas is scrubber using an aqueous sodium sulfate solution. The scrubbed flue gas exits the absorber, passes through a set of demisters and is discharged to the atmosphere. The SO₂ removal efficiency using this process is between 85 to 98%.

5.4.1.5 DeSO_x Additives

DeSO_x additives are typically metal oxide catalysts that are added to the regenerator to convert SO₂ to SO₃. The metal oxide catalyst is introduced to the feed in the riser with the regenerated catalyst. The SO₃ is adsorbed to a sulfate and then recycled back to the reactor with the FCCU catalyst where it is reduced in the riser/reactor to H₂S which is controlled by a refinery's sulfur plant.

5.4.2 Step 2 - Eliminate Technically Infeasible Options

All options are technically feasible.

5.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The following lists the ranking of the remaining control options:

- > Wet Gas Scrubbers - 95-99.9%
- > Wellman-Lord Flue Gas Desulfurization Process - 85-98%
- > Feed hydrotreatment - ≤90%
- > DeSO_x additives - 30%
- > Control of sulfur in the FCCU feed - Baseline

5.4.4 Step 4 - Evaluate Impacts and Document Results

According to EPA's RBL, wet scrubbers have been successfully applied to several refinery FCCUs to control emissions of SO₂. Recent consent decrees will require several refineries to install wet gas scrubbers to reduce SO₂ emissions. Several designs of wet scrubbers are available (plate or tray towers, spray chambers, and venturi) and emission control levels for SO₂ between 95-99.9% have been achieved.

The Wellman-Lord Flue Gas Desulfurization process has been used successfully in Japan, Germany, and the United States but no new units were identified that have been built in recent years.

DeSO_x additives are added to a regenerator to reduce the SO_x from the flue gas of the regenerator. This catalyst converts SO₂ in the regenerator to SO₃ and stabilizes it as a metal sulfate. This metal sulfate is then introduced to the feed in the riser with the regenerated catalyst. The riser has a reducing atmosphere as opposed to the oxidizing atmosphere in the regenerator. The metal sulfate is converted to H₂S in the riser/reactor and released with the products to the fractionator.

Although more than 70 refiners have successfully used DeSO_x additives worldwide, there are a number of operating variables that have been identified as having significant effects on the performance of SO_x reduction additives. Some of these include the presence of combustion promoters, the ratio of catalyst circulation rate to unit catalyst inventory, temperature, availability of oxygen in the regenerator, feed sulfur content, and SO_x concentration. Various scientific studies have shown that the fraction of sulfur in the feed has a direct impact on the coke sulfur content deposited on spent catalyst and, thus, on SO_x emissions. Since the sulfur content of the proposed feed is low and the amount of SO₂ control that can be achieved by using DeSO_x additives is significantly less than the top ranking option, DeSO_x additives are eliminated from further consideration.

Table 5-6 presents a summary of BACT determinations for SO₂ from FCCU units.

Table 5-6 BACT Determinations for SO₂ for FCCU

Facility	Permit Date	Emission Limit	Control
Krotz Springs Refinery	04/26/2012	25 ppmvd@0% O ₂ 365-day rolling average	None listed
Valero Delaware City Refinery	02/26/2010	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
Valero Three Rivers Refinery	04/05/2007	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
Valero Texas City Refinery	04/03/2007	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
Map Texas City Plant	03/28/2007	20 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
ExxonMobil Torrance Refinery	03/23/2007	25 ppmvd@0% O ₂ 365-day rolling average	Low sulfur feed
Chevron El Segundo Refinery	03/30/2007	25 ppmvd@0% O ₂ 365-day rolling average	Low sulfur feed
ConocoPhillips Ponca City Refinery	02/09/2007	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
Valero St. Charles Refinery	02/08/2007	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber

5.4.4.1 Energy, Environmental, and Economic Impacts

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. There are no other anticipated environmental, energy, or economic impacts associated with the use of the highest ranking control technology.

5.4.5 Step 5 - Selection of BACM

The top control option, wet gas scrubbers with a control efficiencies of up to 99% is utilized by HollyFrontier to reduce SO₂ emissions from the FCCU's (Unit 4 and 25) and is considered BACM.

No more stringent control technologies were identified to reduce SO₂ emissions from an FCCU. Marathon Ashland Petroleum Texas City list a 20 ppmvd @ 0% O₂ based on 365-day rolling average and a 7-day average of 50 ppmvd @0% O₂ emission rates based on control by a wet gas scrubber.

The proposed BACM controls, SO₂ emission limits, and monitoring methods conducted for the FCCU's at HollyFrontier are summarized in Table 5-7.

Table 5-7 Proposed BACM Controls, SO₂ Emission Limits, and Monitoring Methods for FCCU

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Method
SO ₂	4, 25	Wet Scrubbers	≤25 ppmvd at 0% O ₂ based on a 365-day rolling average ≤50 ppmvd at 0% O ₂ based on a 7-day rolling average	SO ₂ CEMS

5.5 Emergency Diesel Engines

As presented above, diesel emergency equipment at the Woods Cross refinery consists of a 135 kW portable diesel generator at the East Tank Farm, 224 HP diesel powered water well No. 3, 393 HP fire pump No. 1, 393 HP fire pump No. 2, 180 HP diesel fire pump, three 220 HP diesel-powered plant air backup compressors, 470 HP diesel standby generator at the Boiler House, 380 HP diesel standby generator at the Central Control Room, and a 540 HP diesel standby generator.

Sulfur dioxide emissions occur from the reaction of various elements in the diesel fuel. Sulfur in diesel fuel oxidizes during combustion to SO_2 and sulfur trioxide (SO_3). In the presence of water vapor, these hydrolyze to H_2SO_4 .

5.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Only one control option was found to reduce SO_2 emissions from the proposed CI combustion engines which is the use of low-sulfur diesel fuel.

5.5.2 Step 2 - Eliminate Technically Infeasible Options

The control option identified in Step 1 is technically feasible.

5.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of ultra-low sulfur diesel fuel containing no more than 15 parts per million by weight of sulfur is the only feasible SO_2 control technology for the emergency diesel combustion engines.

5.5.4 Step 4 - Evaluate Impacts and Document Results

Based on the emission standards of 40 CFR Part 60, Subpart IIII, the minimum standards that would meet BACT requirements for SO_2 emissions from IC engines at the Woods Cross Refinery include a maximum sulfur content of 15 ppmw or 0.0015 percent by weight.

5.5.4.1 Energy, Environmental, or Economic Impacts

There are no anticipated energy, environmental or economic impacts associated with the use of ultra-low sulfur diesel fuel.

5.5.5 Step 5 - Select BACT

The emergency generators at the Woods Cross Refinery will burn only ultra-low-sulfur diesel fuel with a maximum sulfur content of 15 ppmw and limited hours of operation. No more stringent control technologies were identified for control of SO_2 from emergency diesel generators.

BACM for SO_2 emissions from the emergency diesel generators and fire pumps is the use of ultra-low-sulfur diesel fuel, limited operating hours, the work practice requirements to adhere to GCP, and the best practice of performing periodic maintenance. These control strategies are technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Maintenance is performed on the engines in accordance with manufacturer specifications. For those engines subject to Subpart ZZZZ, oil is changed and hoses/belts inspected every 500 hours or annually.

The proposed BACM, emission limitations, and monitoring methods for SO₂ for the emergency diesel engines are presented in Table 5-8.

Table 5-8 Proposed BACM Controls, Emission Limitation, and Monitoring Methods for SO₂ for the Emergency Diesel Engines

Pollutant	Units	Control Technology	Emission Limit	Monitoring Methods
SO ₂	All emer. Engines except ETF gen.	Ultra-low-sulfur diesel fuel	600 hours total rolling 12-month period	Non-resettable hour meter Sulfur content ≤0.0015% by weight
	ETF portable generator		1100 hours per rolling 12-month period	

5.6 Emergency Natural Gas-Fired Generators

SO₂ is generated during the combustion process from the thermal oxidation of the sulfur contained in the fuel.

5.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Only one control technology was identified to reduce SO₂ emissions and this is through the use of low sulfur fuels.

5.6.2 Step 2 - Eliminate Technically Infeasible Options

The above listed control technology is technically feasible.

5.6.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of low sulfur fuels is the highest ranking control technology for SI IC engines.

5.6.4 Step 4 - Evaluate Impacts and Document Results

The amount of sulfur in natural gas is regulated per 40 CFR 72.2. Pipeline-quality natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Thus, natural gas is a low sulfur content fuel.

5.6.4.1 Energy, Environmental, or Economic Impacts

There are no environmental, energy or economic impacts that would preclude the use of natural gas in these engines.

5.6.5 Step 5- Select BACT

BACT for SO₂ emissions for the SI IC engines at HollyFrontier is the use of natural gas and limiting hours of operation. No more stringent control technologies to reduce SO₂ emissions from natural-gas fired lean burn engines was identified. Maintenance is performed on the engines in accordance with manufacturer specifications.

The proposed BACM, emission limitations, and monitoring methods for SO₂ from the emergency natural gas-fired engines are presented in Table 5-9.

Table 5-9 Proposed BACM Controls, Emission Limitations, and Monitoring Methods for SO₂ for Natural Gas-Fired Emergency Engines

Pollutant	Units	Control Technology	Emission Limitations	Monitoring
SO ₂	Nat. gas fired emergency engines	Low sulfur fuels such as natural gas	600 hours total rolling 12-month period for all emergency engines	Non-resettable hour meter

6.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR PM_{2.5}

BACM's were evaluated for PM_{2.5} emissions for certain emission units in operation or proposed at the Woods Cross Refinery. These emission units include: process heaters, boilers, flares, cooling towers, SRU, FCCU, and emergency diesel and natural-gas fired engines.

6.1 Process Heaters and Boilers

PM_{2.5} is particulate matter 2.5 microns or smaller. Particulate matter emissions from process heaters and boilers with properly designed and tuned burners are inherently low when gaseous fuels are used. Filterable particulate matter in gas-fired sources that are properly tuned originates from the dust in the inlet air and metal erosion within the sources (e.g., tubes, combustion surfaces, etc.). Sources that are not properly tuned may also produce filterable particulate matter as a result of incomplete combustion of fuel hydrocarbons that agglomerate to form soot particles. These particles pass through the firebox and are emitted in the exhaust gas. Condensable particulate matter can also result from oxidation of fuel sulfur (to sulfur trioxide) and from incomplete combustion of hydrocarbons in the fuel.

6.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following is a list of control technologies identified for controlling PM_{2.5} emissions:

- good combustion practice;
- use of low sulfur gaseous fuels;
- proper design and operation;
- wet gas scrubber;
- electrostatic precipitator (ESP);
- cyclone; and
- baghouse/fabric filters.

6.1.1.1 Good Combustion Practices

By maintaining the heaters in good working order per manufacturer specifications with low sulfur gaseous fuels, emissions of PM_{2.5} are reduced. Proper combustor design and operation to achieve good combustion efficiency in heaters and boilers will minimize the generation of filterable particulate matter, CO and VOC's. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature, and combustion zone turbulence in combination with proper control of the air-to-fuel ratio, are essential elements of good combustion control.

6.1.1.2 Gaseous Fuel Specifications

A form of particulate matter control from combustion sources is the use of a specified gaseous fuel (e.g., natural gas). Whereas solid fuel (e.g., coal) produces a larger amount of particulate matter, gaseous fuels are considered "clean" with respect to generation of particulate matter emissions. Natural gas is processed to meet certain specifications such that the key combustion parameters (i.e., heating value, sulfur content, percent methane) are relatively consistent throughout the country.

Refinery fuel gas is a byproduct of refining operations that is processed and utilized on-site. As a result, refinery fuel does not meet pipeline natural gas composition specifications. With proper burner design and operation, refinery fuel gas-fired sources can achieve PM_{2.5} emission levels that approach those of natural gas.

6.1.1.3 Wet Gas Scrubber

A wet gas scrubber is an air pollution control device that removes PM_{2.5} and acid gases from waste streams from stationary point sources. PM_{2.5} and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers are particularly useful in removing PM_{2.5} with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM_{2.5} in the presence of soluble gases; and
- PM_{2.5} in gas stream with high moisture content.

6.1.1.4 Electrostatic Precipitator

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. Some precipitators remove the particles by washing with water. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

6.1.1.5 Cyclone

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier material hits the outside wall and drops to the bottom where it is collected. The cleaned gas escapes through an inner tube.

6.1.1.6 Baghouse

A baghouse removes particulate from an exhaust stream by passing the gas through a fabric filter bags that are periodically cleaned using any of a number of techniques such as high-pressure reverse flow air pulses, high intensity sonic horns and shaking. A baghouse is generally capable of achieving the lowest particulate emission rates of any type of add-on particulate control device.

6.1.2 Step 2 - Eliminate Technically Infeasible Options

In a wet scrubber, the flue gas is introduced into a chamber filled with packing material that provides a large surface area for liquid-particle contact. Scrubbing liquid is evenly introduced above the packing and flows down through the bed. The liquid coats the packing and establishes a thin film. The particulate in the flue gas is extracted when it impacts the thin film of the scrubbing liquid. The spent scrubbing liquid must be treated and disposed of.

The flue gas follows a path around the packing material and the inertia of the entrained particulate causes the particles to fall out of the gas flow and impact the thin film of scrubbing liquid. The fine particulate generated from gaseous fuel combustion has little inertia so that the particles follow the gas stream through the packing without impacting the scrubbing liquid and being collected. Therefore, wet scrubbers are not a suitable control technology for application to gas fired refinery heaters and is eliminated based on technical infeasibility.

ESPs rely on the ability of a particle to acquire an electrical charge. Once charged, the particles migrate from the flue gas to oppositely charged plates where they deposit. The deposits are removed by "rapping" the plates and they settle by gravity to collection hoppers. The organic nature of the ultra-fine particulates generated by gaseous fuel combustion is such that acquiring the necessary electrical charge is difficult. ESPs also rely on gravity settling of the collected particulates. The fine particles produced in gas-fired heaters are such that gravity settling is unlikely to occur and any particles collected on the plates would likely be re-entrained in the flue gas as the plates are rapped. As such, ESPs are not used for particulate control for combustion devices burning natural/refinery gas and are eliminated based on technical infeasibility.

Cyclones use inertia to remove particles from the gas stream. The cyclone imparts centrifugal force on the gas stream, usually within a conical shaped chamber. Particles in the gas stream are forced toward the cyclone walls by the centrifugal force of the spinning gas. The collected particulate must be treated and disposed of as appropriate. The centrifugal force on the small particles resulting from gaseous fuel combustion is insufficient to separate them from the gas stream; the particulate follows the gas stream through the cyclone. Therefore, cyclones are not a suitable control technology for application to refinery heaters and were eliminated based on technical infeasibility.

The use of baghouses for post-combustion controls is common on residual oil and coal-fired combustion units that require significant particulate matter reduction, and which typically have much higher particulate loading, solid particle sulfur content, and larger sized particles. Baghouses have not been used for particulate control for combustion devices burning gaseous fuels such as natural gas or refinery fuel gas.

Particulate matter emissions are made up of two fractions: filterable and condensable. Due to the relatively high proportion of condensable particulate matter emissions (approximately 72% condensable according to AP-42), the majority of combustion particulate matter will not be collected by a fabric filter treating the flue gas. Also, due to the low particulate concentration, a cake will be slow to form resulting in poor collection efficiency.

Fabric filters rely on the build-up of a filter cake to act as a filtering medium for collection of particulate matter. Periodically, this filter cake is removed, and filtration efficiency declines until a filtering cake can be re-established. The ultra-fine size of particulate emissions from firing of gaseous fuels is such that no cake could be established in a fabric filter. Instead, the very fine particles would be expected to either pass through the bags uncontrolled, or they would "blind" filter bags fairly quickly, resulting in unacceptable pressure drops and requiring frequent bag replacement. Thus, baghouses are not technically feasible for control of PM_{2.5} from refinery-gas fired process heaters.

6.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

PM_{2.5} emissions from properly designed and controlled natural gas-fired equipment are generally considered the lowest achievable.

Combustion of refinery fuel gas will result in slightly higher PM_{2.5} emissions than combustion with pipeline-quality natural gas because of the higher molecular weight hydrocarbons (propane and butane) and the presence of sulfur compounds. The presence of higher molecular weight hydrocarbons in refinery fuel gas makes it more difficult to properly tune the burner to minimize the formation of particulates. The higher level of sulfur compounds in refinery fuel gas results in production of more SO₃, a compound that contributes to condensable particulate matter emissions.

The next most effective technically feasible PM control option is the use of good combustion practices in combination with use of low sulfur gaseous fuel.

6.1.4 Step 4 - Evaluate Impacts and Document Results

The concept of applying combustion controls and appropriate furnace design or “proper combustion” to minimize PM_{2.5} emissions include adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. Optimization of these factors for PM_{2.5} control can result in an increase in the NO_x emissions. Heater and boiler designers strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants. Thus, the only control technology identified in the RBLC database for the refinery fuel or natural gas-fired process heaters and boilers is a work practice requirement to adhere to good combustion practices and use of low sulfur gaseous fuel.

Table 6-1 presents a summary of BACT determinations for PM_{2.5} for process heaters and boilers. All units listed in Table 6-1 are fired on refinery gas.

Table 6-1 BACT Determinations for PM_{2.5} for Process Heaters and Boilers

Facility	Permit Date	Size (MMBtu/hr)	PM_{2.5} Limit (lb/MMBtu)	Control
Holly Refining & Marketing, Tulsa Refinery	04/20/2015	76, 127	0.0075 (three-hour average)	Use of gaseous fuel
Sasol Chemicals (USA) LLC, Lake Charles Chemical Complex GTL Unit	05/23/2014	13.4, 18, 31, 40, 56.8, 71.2, 73.8, 78	0.0075 (three-hour average)	Use of gaseous fuels and good combustion practices
BP Products North America Inc. BP-Husky Refining LLC	09/20/2013	225, 150	0.0075	None listed.
St. Charles Refinery Valero Refining	11/17/2009	15-95	0.0074 (Annual avg.)	Proper equipment design and operation, good combustion practices, gaseous fuels
Hunt Refinery Co.	09/28/2009	34.7-254	0.0075	None listed.
Marathon Petroleum CO LLC Garyville Refinery	12/27/2006	63.7-183.3	0.0075 (3-hr avg.)	Proper design, operations and good engineering practices
Arizona Clean Fuels Yuma LLC	04/14/2005	23.2 - 346	0.0075	None listed.
ExxonMobil Refining & Supply Baton Rouge Refinery	02/18/2004	22-82	0.0080	Good engineering design and proper combustion practices

6.1.4.1 Energy, Environmental, or Economic Impacts

For the process heaters and boilers, HollyFrontier calculated the cost of firing purchased pipeline-quality natural gas in place of RFG to be greater than \$2.2 million/ton PM_{2.5} reduced, based on a natural gas price of approximately \$0.22 Mscf. The cost to switch to pipeline-quality natural gas is not economically feasible. There are no additional environmental or energy impacts associated with firing the process heaters or boilers on pipeline-quality natural gas.

6.1.5 Selection of BACM

Consistent with all PM_{2.5} BACT determinations for RFG-fired sources found in the RBLC, HollyFrontier will utilize proper design, good combustion techniques, minimizing ammonia slip for heaters and boilers equipped with SCR for control of NO_x emissions, along with use of treated refinery gas or natural gas is considered BACM. The most stringent emission rate found was 0.0075 lb/MMBtu based on a 3-hour average utilizing proper equipment design, good combustion practices, and fuel specification.

6.2 Flares

Due to the combustion of natural gas in the pilot light and the combustion of refinery vent gases, flares emit small quantities of PM_{2.5}.

6.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Available technologies to control PM_{2.5} from flare emissions include:

- Air or steam assisted smokeless flare technology,
- Compliance with applicable federal NSPS (40 CFR 60.18) and NESHAP requirements (40 CFR 63.11),
- Good combustion practices,
- Opacity limits,
- Proper operation and maintenance,
- Use of natural gas or LPG as pilot fuel, a continuous pilot and a method for detection,
- Development of a flare management plan,
- Flares to be operated during period of emergency upsets or breakdowns, and
- Flare gas recovery system for non-emergency releases.

No add-on control technologies for flares were found or known to be in commercial use.

6.2.2 Step 2 - Eliminate Technically Infeasible Options

The control technologies listed above are technically feasible.

6.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top ranking control option is the installation of a flare gas recovery system. Flare gas recovery systems are achieved in practice. The second highest ranking control option includes proper equipment design and work practices which includes good combustion practices and use of clean gaseous fuels such as natural gas for pilot light fuel. The combustion efficiency of a properly operated flare is 98%.

6.2.4 Step 4 - Evaluate Impacts and Document Results

The flares at HollyFrontier incorporate steam-assisted smokeless flare design and are operated in accordance with good combustion practices to minimize PM_{2.5} emissions. The flares have been designed for and are operated without visible emissions. Each flare is equipped with an opacity monitor. Pilot fuel is pipeline quality natural gas; sweep gas is either pipeline quality-natural gas or refinery fuel gas.

HollyFrontier will install a flare gas recovery system to recover vent gas which is the highest ranked control option.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. The flares at the refinery are subject to the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18 and 40 CFR 63.11.

Flare management plans have been prepared for both the north and south flares. Procedures have been developed to minimize or eliminate discharges to the flare during planned startups and shutdowns.

Emissions from the HollyFrontier Woods Cross Refinery flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

6.2.4.1 Energy, Environmental, or Economic Impacts

Since HollyFrontier has chosen the highest ranked control option, flare gas recovery, energy, environmental and costs analyses are not required.

6.2.5 Step 5 - Select BACT

Holly is proposing the following design elements and work practices as BACM for the flares:

- Use of low sulfur fuel such as natural gas as fuel for pilot flame;
- Maintaining an acceptable net heating value and exit velocity of flared gases under all flow conditions in accordance with manufacturer specifications;
- Use of a thermocouple to monitor presence of the pilot flame;
- Implementation of good combustion, operating, and maintenance practices;
- Development of Flare Management Plan;
- Conduct of Root Cause Analyses;
- Flare operation in accordance to 40 CFR Part 60, Ja and design and work practice standards as codified in 40 CFR Part 60.18 and 40 CFR Part 63.11; and,
- Installation of flare gas recovery system.

No more stringent measures were identified for the flares at the Woods Cross Refinery. The flare design includes steam assisted combustion. The flares will be equipped with a flare gas recovery system for non-emergency releases, and a continuous pilot light. Pilot and sweep fuel will be natural gas or treated refinery gas. The north and south flares are equipped with flow meters and gas combustion monitors.

The proposed BACM controls, PM_{2.5} emission limits, and monitoring methods for the flares at HollyFrontier are summarized in Table 6-2.

Table 6-2 Proposed BACM Controls, PM_{2.5} Emission Limits, and Monitoring Methods for Flares

Pollutant	Unit	Control Technology	Emission Limit	Monitoring
PM _{2.5}	66	Flare gas recovery system Use of low sulfur fuel GCP Flare management plan	20% opacity	Flow meters, gas combustion monitors

6.3 Cooling Towers

The Woods Cross refinery has six (6) cooling water towers (Unit 54), labeled 4, 6, 7, 8, 10 and 11. These towers have a designed maximum circulation rate of 6,000 gallons per minute (gpm), 4,400 gpm, 3,000 gpm, 10,000 gpm, 8,500 gpm and 8,500 gpm, respectively. Cooling towers 10 and 11 are equipped with high efficiency drift eliminators that control drift to 0.0005% of circulating water.

Warm water is pumped into the top of the tower which cools as it falls downward and mixes with the rising air. The inside of the tower is filled with wooden or plastic grids so the falling water splashes and mixes with air. The water falls down into a concrete basin beneath the tower. Pumps then circulate the cool water to the units where it is used to cool hydrocarbons. Heat exchangers are used so the water does not become contaminated with the hydrocarbons. Warm water from the outlet of heat exchangers is piped back to the cooling tower, where it is cooled again.

Chemicals (no chromium based chemicals are used as per corporate policy) are added to the circulating water and react with water hardness to keep deposits from accumulating on the inside piping and exchangers. These chemicals also prevent algae and bacteria growth from forming inside pipes and exchangers.

6.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Particulate matter is emitted from wet cooling towers due to the presence of dissolved or suspended solids in water droplets from cooling tower drift. As the drifted droplet evaporates, the dissolved solids present in the droplet collected into a single particle. The size of the resulting particle depends on the size of the droplet, the mass of the dissolved solids present, and the density of the resultant particle.

Four control technologies were identified to limit $PM_{2.5}$ drift from cooling towers. These include:

- Use of dry cooling heat exchanger units;
- High-efficiency drift eliminators;
- Limitation on total dissolved solid (TDS) concentrations in the circulating water; and
- Combination of drift eliminator efficiency rating and TDS limit.

6.3.2 Step 2 - Eliminate Technically Infeasible Options

Dry cooling or non-evaporative cooling towers have been adopted for heat rejection at combined-cycle power plants in arid or low precipitation climates. This type of cooling tower circulates the process water through a large bank of radiator coils. These coils are cooled by forced flow of ambient air on the outer finned surfaces of the radiator. Ambient airflow is driven by very large axial propeller fans, typically located below the radiator bank, so that the air is blown upward through the radiator and the warmer air exits the top of the tower. Because there is no contact between the water and the ambient air, and thus no opportunity for drift, a dry cooling tower would not be a source of particulate matter emissions.

Dry cooling has been employed at primary combined-cycle power plants as a means to reduce water consumption rather than as BACT for reducing PM_{10} emissions. There is a very substantial capital cost penalty as well as significant process changes that would be required in utilizing this control technology. Because of the high capital cost and process design changes involved in using dry cooling, and that dry cooling has not been identified as being utilized at a refinery, this option was determined to be technically infeasible and was eliminated from further consideration.

6.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options were ranked in order from most to less stringent:

1. Combinations of high-efficiency drift eliminators and TDS limit;
2. High-efficiency drift eliminators to control drift as low as 0.0005% of circulating water;
3. Limitation of TDS concentrations in the circulating water.

6.3.4 Step 4 - Evaluate Impacts and Document Results

All modern cooling towers are equipped with drift eliminators. The drift eliminator forces the exhaust air to make sharp turns before exiting. The momentum of entrained droplets carries the droplets to the drift eliminators surfaces where they coalesce and drip back into the tower. Typically, for cross-flow designs the drift rate will be less than 0.005% because of the use of higher efficiency eliminators; counterflow and forced-draft counterflow designs routinely achieve 0.001%.

Incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media needs to be reduced. This is necessary to use drift eliminator media with small passages without encountering a high pressure drop. Since reducing the air velocity reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the size of the media will be needed. These changes may also result in an energy penalty in the form of larger and higher powered fans to accommodate higher drift eliminator efficiency for the same heat injection duty.

6.3.4.1 Energy, Environmental, or Economic Impacts

In using drift eliminators, no significant energy or environmental impacts are expected.

The drift eliminators on cooling towers 4,6,7,8 have an effectiveness of 0.002%. To upgrade with more efficient drift eliminators, vendor costs estimates were obtained and are presented in Appendix B. To upgrade from 0.002% to 0.0005%, total PM_{2.5} emission reduction equated to 3.2 lbs at a capital cost of approximately \$419,000 for the four towers. The cost effective per ton of PM_{2.5} is, on average, over 95 million dollars per tower. Thus, it is not economically feasible to upgrade the existing cooling towers with high efficiency drift eliminator with a drift rate of 0.0005%.

6.3.5 Step 5 - Selection of BACM

HollyFrontier's cooling towers 10 and 11 have been upgraded with high-efficiency drift eliminators with a drift rate of 0.0005 percent. Cooling towers 4,6,7,8 are equipped with drift eliminators with a drift rate of 0.002 percent. Retrofit of these cooling towers with high-efficiency drift eliminators with a drift rate of 0.0005 percent has been determined to be economically infeasible. The TDS of the makeup water is monitored weekly which aids in the control of PM_{2.5} emissions.

For newly constructed cooling towers, BACT for PM_{2.5} was determined to be utilization of high-efficiency drift eliminators with a drift rate of 0.0005 percent. A drift rate of 0.0005 is the most effective drift eliminator commercially available although the cooling tower vendor indicated that 0.0006% will be coming out in the future. No more stringent measures were identified to control PM_{2.5} emissions from cooling towers.

The proposed BACM controls, PM_{2.5} emission limitations, and monitoring methods for the cooling towers at HollyFrontier are summarized in Table 6-3.

Table 6-3 Proposed BACM Controls, PM_{2.5} Emission Limitations, and Monitoring Methods for Cooling Towers

Pollutant	Unit	Control Technology	Emission Limitations	Monitoring
PM _{2.5}	54	High efficiency drift eliminators	0.0005 drift rate (CT 10&11) 0.002 drift rate (CT 4,6,7,8)	TDS monitored weekly

6.4 Sulfur Recovery Unit Incinerator

Particulate matter from refinery gas or natural gas combustion is usually composed of larger molecular weight hydrocarbons that have not been fully combusted.

6.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The available technologies available for control of PM_{2.5} emissions include:

- > proper equipment design,
- > good combustion practices,
- > clean gaseous fuels,
- > electrostatic precipitators,
- > fabric filters (baghouse), and
- > wet scrubbing.

6.4.2 Step 2 - Eliminate Technically Infeasible Options

Electric static precipitators and fabric filters are not technically feasible due to the temperature of exhaust gas that would go to these control devices. Significant negative impacts occur to fabric filters when temperature are greater than 400°F and to electrostatic precipitators when temperatures are greater than 350°F. The temperature of the exhaust gases from the SRU incinerator will be approximately 550°F. Thus, these two options are eliminated from further consideration and were considered to be not technically feasible.

6.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of proper equipment design, good combustion practices, use of clean gaseous fuels and the post-combustion control of wet scrubbing are technically feasible. Wet gas scrubbers have the potential to remove in excess of 95% of particulate emissions.

6.4.4 Step 4 - Evaluate Impacts and Document Results

As mentioned above, emissions from the SRU are sent to the tail gas incinerator and then to the wet scrubber. The use of a wet scrubber is highly efficient in removing PM_{2.5} from the effluent stream. The SRU does not operate when the wet gas scrubbers are not operational.

6.4.4.1 Energy, Environmental, or Economic Impacts

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. There are no other energy, environmental, or economic impacts anticipated with the use of a wet scrubber to remove PM_{2.5} from the effluent stream from the SRU during normal operations.

6.4.5 Step 5 - Select BACT

PM_{2.5} emissions from the SRU are controlled through the use of a tailgas incinerator followed by a wet gas scrubbers. The wet gas scrubber is estimated to have a high PM_{2.5} removal efficiency (>85%). Thus BACM for control of PM_{2.5} emissions from the SRU is proper equipment design, good combustion practice, use of clean gaseous fuels followed by the post-control technology of wet scrubbing.

No more stringent measures were identified to reduce PM_{2.5} emissions from a SRU.

The proposed BACM control technologies and monitoring methods for the SRU at the Woods Cross Refinery are summarized in Table 6-4.

Table 6-4 Proposed BACM Controls and Monitoring Methods for PM_{2.5} from the SRU

Pollutant	Unit	Control Technology	Monitoring Methods
PM _{2.5}	17	Wet scrubbers (normal operation) Proper equipment design, good combustion practices, use of clean gaseous fuels (emergency operation)	Differential pressures across the filter modules and the discharge pressure from the liquid circulation pump to ensure adequate scrubbing. These parameters are set in a performance test

6.5 FCCU

The main source of PM_{2.5} from a FCCU is catalyst fines and products of incomplete combustion that are released in the regenerator exhaust stack.

6.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Available control technologies to control PM_{2.5} emissions from the FCCU regenerator stacks include:

- > Wet Gas Scrubber;
- > Electrostatic Precipitator (ESP); and
- > Third Stage Separator (TSS)/Cyclone.

Descriptions of the ESP and the wet gas scrubber are presented in Sections 6.1.1.3 and 6.1.1.4. A third stage separator (TSS) is a specially designed cyclone or set of cyclones, for the flue gas from an FCCU regenerator. The TSS is in a separate vessel, outside the regenerator, that houses a number of small diameters, high efficiency cyclones arranged in parallel in the vessel. There is a flow distributor at the inlet to evenly distribute the regenerator flue gas to each small cyclone to create better efficiencies in particulate removal. The TSS is able to remove a significant amount of particulate that would normally go out the regenerator stack.

6.5.2 Step 2 - Eliminate Technically Infeasible Options

All of the control technologies are technically feasible.

6.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The following lists the ranking of the remaining control options:

- > Electrostatic Precipitators – Up to 95% reduction
- > Wet Gas Scrubber – 85 to 95 % reduction
- > Third Stage Separator – No efficiency percentages were found but the literature suggests that the TSS is able to reduce the amount of particulate to approximately 0.6 lbs per 1000 lbs of coke burned.

6.5.4 Step 4 - Evaluate Impacts and Document Results

ESP is a proven technology. The collected particulate is disposed of as a dry solid. The discharge doesn't have a vapor plume. There is a small pressure drop across the ESP. The particle collection process begins when the particle absorbs a charge sufficient amount to be attracted to the collection plates. However, the particle charging and collection process can be affected by several factors including particle size, particle resistivity, electric field and the temperature and composition of the flue gas stream.

There are reliability issues with electrostatic precipitators, so in many cases, multiple units are installed for redundancy which adds cost. Temperature and humidity affect the resistivity of PM. An ESP has a limited ability to handle high temperature excursions or FCCU upsets. In addition, any VOCs that might be in the stream because of an upset are dangerous to the unit. ESPs are also susceptible to changes in catalysts. Although ESP's are a viable option, HollyFrontier utilizes wet scrubbers which are more efficient in reducing PM_{2.5} from the FCCUs than are ESPs.

Wet gas scrubbers are also a proven technology. They have been demonstrated on a long-term basis to remove particles to very low levels. They have an excellent reliability so there is no need for multiple units. Wet scrubbers have a much broader operating range and are more able to handle upsets from the FCCU. A wet gas scrubber also has a lower operating temperature than an ESP which provides for improved removal of condensable PM. The waste from a wet gas scrubber can be disposed of as a wet solid.

The TSS removes a significant amount of catalyst fines from the flue gas stream. However, a TSS by itself will not reduce particulate to meet the NSPS standard of 0.5 lb/1000 lb coke burned. Thus, a TSS has been eliminated from further consideration as it does not meet the required NSPS standard.

A review of the RBLC database was performed and Table 6-5 presents a summary of BACT determinations for PM_{2.5} for FCCUs.

Table 6-5 BACT for PM_{2.5} for FCCU

Facility	Permit Date	PM _{2.5} Emission Limit	Control Method
Lion Oil Company	09/09/2011	1.0 lb/1000lb coke	Wet Gas Scrubber
ConocoPhillips Company Sweeny Refinery	12/29/2011	1.334 lb/ton of coke burn	Regenerator cyclones and Electrostatic Precipitator
Sunoco Company Inc. Toledo Refinery	01/29/2008	0.9 lb/1000 lb coke pound per 1000 lb of coke burnoff	Wet Gas Scrubber
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	2.0 lb/ton of coke	Wet Gas Scrubber

6.5.4.1 Energy, Environmental, or Economic Impacts

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. Because HollyFrontier has chosen the remaining highest ranking control option, the use of a wet gas scrubber, energy, environmental and costs analyses are not required.

6.5.5 Step 5 - Select BACT

According to the RBLC, wet scrubbers are used extensively as one method to reduce particulate from FCCUs and wet gas scrubbers are utilized by Holly to reduce PM emissions from the FCCU's. Thus, a wet gas scrubber is considered BACM for reduction of particulate from the FCCU regenerator stack. No more stringent measures were identified to control PM_{2.5} emissions from FCCU regenerator vents.

The proposed BACM controls, PM₁₀/PM_{2.5} emission limits, and monitoring methods for the FCCU at the Woods Cross Refinery are summarized in Table 6-6.

Table 6-6 Proposed BACM Controls, PM₁₀/PM_{2.5} Emission Limits, and Monitoring Methods for FCCU

Pollutant	Unit	Control Technology	PM ₁₀ Emission Limit	Monitoring Method
PM _{2.5}	4	Wet scrubber 4V82	0.5 lbs/1000 lbs coke burn-off	Annual stack test
	25	Wet Scrubber 25FCC	0.3 lbs/1000 lbs coke burn-off	Annual stack test

6.6 Emergency Diesel Engines

As presented above, diesel emergency equipment at the Woods Cross refinery consists of a 135 kW portable diesel generator at the East Tank Farm, 224 HP diesel powered water well No. 3, 393 HP fire pump No. 1, 393 HP fire pump No. 2, 180 HP diesel fire pump, three 220 HP diesel-powered plant air backup compressors, 470 HP diesel standby generator at the Boiler House, 380 HP diesel standby generator at the Central Control Room, and a 540 HP diesel standby generator.

Diesel particulate emissions are composed of a variety of liquid phase hydrocarbons and solid phase soot (carbon). The literature suggests that the majority of particulate emissions from diesel combustion are in the PM_{2.5} size or smaller range.

6.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following control options were evaluated for controlling PM_{2.5} emissions from the CI combustion engines. They include:

- > GCP,
- > use of low sulfur fuels,
- > diesel particulate filters, and
- > diesel oxidation catalysts.

6.6.1.1 Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The emergency generators and fire water pump engines are designed to achieve maximum combustion efficiency. The manufacturers provide operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

6.6.1.2 Ultra-Low Sulfur Diesel

Limiting the sulfur content of diesel fuel is a pollution prevention method to reduce the sulfate fraction (25-25%) of diesel particulate matter.

6.6.1.3 Diesel Particulate Filters

Diesel particulate filters (DPFs) are add-on devices that filter out particulate matter. In general, A DPF consists of a porous substrate that permits gases in the engine exhaust to pass through but collects or traps the diesel PM. This is typically referred to as regenerating the DPF. During regeneration, the collected PM, which is mostly carbon, is burned off.

Particulate filters can employ either an active or passive system, depending on the method used to clean the filters. Active DPFs use a source of energy beyond the heat in the exhaust stream itself to help regeneration. Active DPFs can be regenerated electrically, with fuel burners or microwaves, or by additional fuel injection to increase exhaust temperature. Active DPFs have a broader range of application and a much lower probability of getting plugged than passive DPFs.

A passive DPF is one in which a catalytic material, typically a platinum group metal, is applied to the substrate. The catalyst lowers the temperature at which trapped PM will oxidize to temperatures periodically reached in diesel exhaust. No additional energy is needed for regeneration.

6.6.1.4 Diesel Oxidation Catalyst

A diesel oxidation catalyst utilizes metal catalysts to oxidize particulate matter in the diesel exhaust. Diesel oxidation catalysts are commercially available and are reliable for reducing particulate matter emissions.

6.6.2 Step 2 - Eliminate Technically Infeasible Options

All options identified in Step 1 are technically feasible.

6.6.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Table 6-7 presents in descending order the control effectiveness of the identified control technologies.

Table 6-7 PM_{2.5} Control Technology Effectiveness for Diesel Engines

Control Technology	Control Effectiveness
DPF	≤85%
Oxidation Catalyst	30%
Ultra-low sulfur diesel	10-20%
GCP	Baseline

6.6.4 Step 4 - Evaluate Impacts and Document Results

The top ranked control option, diesel particulate filters can significantly reduce PM_{2.5} emissions. Typical operation of the emergency generators at the Woods Cross Refinery include weekly 15 minute testing and maintenance operations with low or no load to ensure that the engine is operating properly. The number of times that an engine can operate for maintenance and testing before regenerations is typically between 10 and 30 cold starts with 30 minute run times. For regeneration to occur on passive systems, the exhaust temperature needs to be between 300°C to 465°C. To reach this temperature and for a regeneration cycle to be completed, the engine should operate for about 30 minutes at a 30 percent load.

Active DPFs are independent of temperature and will work on emergency standby engines without the same regeneration concerns presented above. The active DPF uses an electrical current or fuel combustion to remove or burn off the collected PM.

6.6.4.1 Energy, Environmental, or Economic Impacts

A cost effectiveness evaluation for the top ranking option, in costs per ton of PM_{2.5} removed, is presented in Table 6-8 and in Appendix B.

The installation of a DPF causes engine efficiency to decrease with increasing backpressure due to thermodynamic reasons. The pressure drop of the DPF increases as it captures particulate matter from the engine. A rule of thumb is that the engine power will decrease by 1% for every 3-4 kPa increase in engine backpressure.

The DPF must be regenerated, continuously or intermittently which consumes energy. DPF regeneration, either active or passive, intermittent or continuous, comes with a fuel penalty.

Table 6-8 Cost Effectiveness of Installing DPF on Emergency Diesel Engines for PM_{2.5} Control

Equipment	Cost Effectiveness (\$/Ton)
135 kW generator (east tank farm)	\$ 33,930
224 HP (water well #3)	\$ 750,907
393 HP Fire Pump #1	\$ 736,568
393 HP Fire Pump #2	\$ 736,568
220 HP plant air backup compressor #1	\$ 755,935
220 HP plant air backup compressor #2	\$ 755,935
220 HP plant air backup compressor #3	\$ 755,935
470 HP diesel generator (boiler house)	\$ 745,363
380 HP diesel generator (central control room)	\$ 746,118
540 HP standby generator	\$ 22,265,725

Based on the economic impact presented in Table 6-8, DPF's are not cost effective for the emergency generators or the fire water pumps at the Woods Cross Refinery and have been eliminated from further consideration.

6.6.5 Step 5 - Select BACT

As mentioned above, California has the most aggressive emission reduction standards for diesel engines. The most stringent control includes the use of DPF's to reduce PM_{2.5} emissions. Several emergency standby engines were identified operating in California that had DPF's installed on them. In most cases, however, DPFs were installed to meet permit requirements or to address odor issues. Operational considerations using active DPF's are minimal and can be accommodated by normal maintenance and testing procedures.

As seen from Table 6-8, the installation of DPFs on the emergency diesel engines at HollyFrontier's Woods Cross Refinery is cost prohibitive. The use of ultra-low sulfur diesel, which will reduce PM_{2.5} emissions up to 20%, limited operating hours (50 hours per each unit except the generator at the East Tank Farm), the use of GCP and EPA Tier standards, and best practice of periodic maintenance is considered BACM for the diesel engines at HollyFrontier.

40 CFR 60, Subpart IIII applies to engines which commenced construction after 7/11/2005 and are manufactured after 4/1/2006 (for non-fire-pump engines), or an engine modified or reconstructed after 7/11/2005. Subpart IIII applies to the emergency diesel equipment at the refinery. Records of maintenance and hours of operation are kept. A non-resettable totalizer is installed on each emergency diesel engine. Maintenance is performed on the engines in accordance with manufacturer specifications. The oil/filter as well as the hoses/belts are inspected every 500 hours or annually.

The proposed BACM, emission limitations, and monitoring methods for the emergency diesel engines are presented in Table 6-9.

**Table 6-9 Proposed BACM Controls, PM_{2.5} Emission Limitations, and Monitoring for
Emergency Diesel Engines**

Pollutant	Units	Control Technology	Emission Limitations	Monitoring Method
PM _{2.5}	All emer. Engines except ETF gen.	GCP, ultra-low sulfur fuel	600 hours total rolling 12-month period	Non-resettable hour meter
	ETF portable generator		1100 hours per rolling 12-month period	

6.7 Emergency Natural Gas-Fired Generators

Particulate matter (PM) is a mixture of solid particles and liquid droplets; PM_{2.5} emissions are particles less than 2.5 microns in diameter. PM_{2.5} emissions from natural gas combustion in the generator will be low. PM_{2.5} emissions result from carryover of noncombustible trace elements present in the natural gas and solids or dust in the ambient air used for combustion.

6.7.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Only one method for PM_{2.5} emission control from natural-gas fired engines was identified which was good combustion practices using natural gas since there is little ash in natural gas that would contribute to the formation of PM_{2.5}.

6.7.2 Step 2 - Eliminate Technically Infeasible Options

The option identified in Step 1 are technically feasible.

6.7.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of good combustion practices and natural gas is the only feasible PM_{2.5} control technology for the emergency SI IC combustion engines at HollyFrontier.

6.7.4 Step 4 - Evaluate Impacts and Document Results

Natural gas generators are regulated by 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. Here, the EPA provides emissions standards manufacturers must meet, emissions standards owners/operators must meet, EPA certification requirements, testing requirements, and compliance requirements.

The natural-gas fired engines used at the administration building are limited to 50 hours per year for testing and maintenance. Manufacturer recommendations are followed in the operation and maintenance of these engines and records are kept. Each engine is equipped with a non-resettable hour meter. The operating standards for these engines are work practice standards which include annual oil changes and spark plug and hose inspection.

6.7.4.1 Energy, Environmental, or Economic Impacts

There are no environmental, energy or economic impacts that would preclude the use of natural gas.

6.7.5 Step 5 - Select BACT

BACT for PM_{2.5} emissions is the use of natural gas and good combustion practices. No more stringent control technologies were identified for use on lean-burn natural gas-fired engines. These engines meet the requirements as set forth in 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. Maintenance is performed on the engines in accordance with manufacturer specifications.

The proposed BACM, PM_{2.5} emission limits, and monitoring methods for the emergency natural gas-fired engines are presented in Table 6-10.

**Table 6-10 Proposed BACM Controls, PM_{2.5} Emission Limitations, and Monitoring Methods
for Natural Gas-Fired Emergency Engines**

Pollutant	Units	Control Technology	Emission Limitations	Monitoring
PM _{2.5}	Nat. gas fired emergency engines	Low sulfur fuels and good combustion practices	600 hours total rolling 12-month period for all emergency engines	Non-resettable hour meter

7.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR VOLATILE ORGANIC COMPOUNDS

BACM's were evaluated for VOC emissions for certain emission units in operation or proposed at the Woods Cross Refinery. These emission units include: process heaters, boilers, flares, cooling towers, SRU incinerator, FCCU, tanks, leaking components, waste water treatment, product loading/unloading, and emergency diesel and natural gas-fired engines.

7.1 Process Heaters and Boilers

Emissions of VOC's from process heaters and boilers result from incomplete combustion of the heavier molecular weight components of the refinery gas fuel. Operating conditions such as low temperatures, insufficient residence time, low oxygen levels due to inadequate mixing, and/or a low air-to-fuel ratio in the combustion zone also result in VOC formation. In addition, VOC emissions are produced to some degree by the reforming of hydrocarbon molecules in the combustion zone.

7.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Control options for VOC generally consist of fuel specifications, combustion modification measures, or post-combustion controls. Six control technologies were identified for controlling VOC emissions. These control technologies are:

- Good Combustion Practice
- Fuel Specifications (use of natural gas or refinery gas)
- ULNB
- Catalytic Oxidation
- Thermal Oxidation
- EMx (formerly SCONO_x)

7.1.1.1 Good Combustion Practice

Combustion controls (proper design and operation) are the most typical means of controlling VOC emissions. Implementation of proper burner design to achieve good combustion efficiency in heaters and boilers will also minimize the generation of VOC.

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature and combustion zone turbulence, in combination with proper control of air-to-fuel ratio, is essential for a low VOC emissions.

7.1.1.2 Fuel Specifications

Pipeline natural gas is a fuel predominantly comprised of methane. An odorant is added to allow easy leak detection of the otherwise odorless gas. It is processed to meet certain specifications such that key combustion parameters are relatively consistent throughout the United States. These parameters include percent methane, heating value, and sulfur content.

Refinery fuel gas is a byproduct of the refining operations and is consumed on-site. It may contain significant proportions of fuel components other than methane, such as hydrogen, ethane, propane, and butanes. Because it is a byproduct of various refinery processes with varying compositions between streams, expected VOC emissions for process heaters and boilers firing refinery gas may not be as low as expected for process heaters and boilers firing natural gas.

7.1.1.3 Ultra-Low NO_x Burners

ULNB technology has developed to provide increasing lower levels of NO_x emissions. However, when operated using good combustion practices, ULNB can also provide significant reductions in VOC emissions.

7.1.1.4 Catalytic Oxidation

The formation of VOC in combustion units depends on the efficiency of combustion. Catalytic oxidation decreases VOC emissions by allowing the complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second. The optimal range for oxidation catalysts is approximately 850 to 1,100 °F.

7.1.1.5 Thermal Oxidation

Thermal oxidizers combine temperature, time, and turbulence to achieve complete combustion. Thermal oxidizers are equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO and VOC. The waste gas is passed through burners, where the gas is heated above its ignition temperature. Thermal oxidation requires raising the flue gas temperature to 1,300 to 2,000°F in order to complete the CO and VOC oxidation.

7.1.1.6 Emerachem (EM_x™)

EM_x™ is the second generation of SCONO_x NO_x absorber technology. EM_x™ is a catalyst-based post-combustion control, which simultaneously oxidizes CO to CO₂, VOC to CO₂ and water, and NO to NO₂, subsequently adsorbing the NO₂ onto the surface of a catalyst where a chemical reaction removes it from the exhaust stream.

7.1.2 Step 2 - Eliminate Technically Infeasible Options

Oxidation catalysts have traditionally been applied to the control of CO and to a lesser extent, VOC emissions from natural gas fired combustion turbines. Refinery fuel gas contains sulfur as H₂S, which when burned oxidizes to SO₂. Oxidation catalyst is not applied to sources where fuels containing sulfur are fired because much of the SO₂ formed by the combustion process is further oxidized to SO₃ which readily becomes sulfuric acid mist in the atmosphere. In addition, the precious metals which are the active components in oxidation catalyst are subject to irreversible poisoning when exposed to sulfur compounds.

The only application of oxidation catalyst used by a refinery gas fired combustion device was identified as a combustion turbine in Southern California which fired a mix of refinery gas and natural gas. No other applications of oxidation catalyst applied to refinery process heaters was found. Thus, based on the issues presented above with the use of a oxidation catalysts with sulfur bearing fuels, this control option is not considered technically feasible.

EMx™ has only been demonstrated on natural-gas fired combustion turbines and this technology has not been demonstrated on units that fire refinery fuel gas. As such, EMx™ is not considered to be demonstrated in practice for refinery fuel gas fired process heaters and is considered technically infeasible.

7.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Presented in Table 7-1 are the remaining control options ranked based on effectiveness.

Table 7-1 VOC Control Technologies by Control Effectiveness

Control Technology	Control Effectiveness
Thermal Oxidation	75-95%
ULNB	25-75%
GCP	baseline

7.1.4 Step 4 - Evaluate Impacts and Document Results

The top control strategy identified is the use of thermal oxidation which has a VOC control effectiveness ranging between 75 to 95%.

The second ranking control strategy identified for the refinery fuel gas-fired process heaters and boilers is the use of ultra-low NO_x burners with a control adherence to good combustion practices.

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, VOC emissions are minimized.

Good combustion practice and proper equipment design is the industry standard for control of VOC emissions from refinery process heaters. VOC emissions are controlled by maintaining various operational combustion parameters.

Table 7-2 presents a summary of previous BACT determinations for VOC for process heaters and boilers. This table is not exhaustive, rather lists the lowest emission rates identified in the past several years from select plants. The top ranking option, thermal oxidation was not identified in RBLC as BACT for control of VOC emissions from process heaters and boilers.

Table 7-2 Summary of BACM Determinations for VOC for Process Heaters and Boilers

Facility	Permit Date	Size (MMBtu/hr)	Limit (lb/MMBtu)	Control Technology
Sasol Chemicals (USA) LLC, Lake Charles Chemical Complex GTL Unit	05/23/2014	13.4, 18, 31, 40, 56.8, 71.2, 73.8, 78	0.0054 (annual average)	Use of gaseous practices and tune ups
IPL Eagle Valley Generating Station, Indiana	10/11/2013	79.3	0.0053 (three-hour average)	Advanced ultra-low NO _x burner
BP Products North America Inc. BP-Husky Refining LLC	09/20/2013	225, 150	0.0054	None listed
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	Heaters/reboilers	0.0054 (annual average)	Proper design operation, and good engineering practices and use of gaseous fuels
Navajo Refining Company, Artesia Refinery	12/14/2007	9.6, 35	0.0050 (1-hour avg.)	Gaseous fuels
Marathon Petroleum CO LLC. Garyville Refinery	12/27/2006	Sources: 5-08, 9-08, 11-08 & 12-08, 1-08 & 2-08, 15-08	0.015 (3-hr average)	Proper design operation, and good engineering practices

7.1.4.1 Energy, Environmental, or Economic Impact

Depending on specific furnace and thermal oxidizer operational parameters (fuel gas heating value, excess oxygen in the flue gas, flue gas temperature, and oxidizer temperature) raising the flue gas temperature can require an additional heat input of 10 to 25% above the process heater heat input. In addition, depending on the design of the thermal oxidizer, emissions of NO_x, SO₂ and PM_{2.5} can be 10 to 25% higher than emissions without a thermal oxidizer. Installation costs and operating costs for a thermal oxidizer (mostly from the 10 to 25% increase in fuel consumption) can be significant. Thus, since this technology was not determined to meet BACT and causes adverse environmental impacts, the use of this technology has been determined to be technically infeasible for VOC control on process heaters and has been eliminated from further consideration.

The cost to fire all process heaters on a natural gas is \$1.2 million which is cost prohibitive.

As discussed in Section 4.1.4.2, the application of LNB or ULNB on existing units (6H1, 6H2, 6H3, 7H1, 7H2, 7H3, 9H1, 9H2, 10H1, 11H1, and 13H1 is not technically possible due to space limitations in the firebox, lower heat duty, and a longer flame. It is not economically feasible to reconstruct all existing process heaters. Thus, for these reasons, retrofit of existing process heaters with LNB or ULNB has been determined to be technically and economically infeasible.

The use of good combustion practices will not cause adverse energy, environmental, or economic impacts.

7.1.5 Step 5 - Selection of BACM

HollyFrontier will follow good combustion practices which has been selected as BACT for control of VOC emissions from the process heaters and boilers. Boiler #11 has an emission limit of 0.004 lb/MMBtu; no other units have VOC emission limits. No more stringent measures were identified to control VOC emissions from process heaters and boilers other than the use of good combustion practices.

The cost of installing and operating CEMS on each heater and boiler was examined. The estimated equipment cost including a shelter and a VOC CEMS with affiliated equipment plus installation is over \$201,600 per system. Total annual operating costs were estimated to be approximately \$72,820. See Appendix B for a detailed cost analysis. Based on PTE emissions from the process heaters, the average cost-per-ton to monitor for VOCs with a CEMS is over \$1.0 million dollars.

The proposed BACM, VOC emission limit, and monitoring methods for the process heaters and boilers are presented in Table 7-3.

Table 7-3 Proposed BACM Controls, VOC Emission Limits, and Monitoring for Process Heaters and Boilers

Pollutant	Units	Control Technology	Emission Limit (lb/MMBtu)	Monitoring
VOC	4H1, 6H1, 6H2, 6H3, 7H1, 7H3, 8H2, 9H1, 9H2, 10H1, 10H2, 11H1, 12H1, 13H1, 19H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1, 68H2, 68H3, 68H4, 68H5, 68H6, 68H7, 68H19, 68H11, 68H12, 68H13, Boilers #4, #5, #8, #9, #10	GCP	None	None
	Boiler #11	GCP	0.004	Stack test performed every 3 years

7.2 Flares

As mentioned previously, there are two flare stacks located at the Northwest corner of the refinery. During refinery operating upsets, process equipment may experience over-pressures which are relieved through a spring-loaded pressure safety valve ("PSV"). Piping headers connect these devices to the flare stack, which is used to safely burn the released hydrocarbons. A small, continuous flame of pipeline-quality natural gas purchased from Questar acts as a pilot light to ignite the process vapors as they enter the flare tip for final destruction. Emissions from flaring may include unburned VOC's and partially burned and altered hydrocarbons.

7.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

For safe flare operation, the design of the flares requires the use of a pilot light. The combustion of the natural gas to fuel the pilot light and the combustion of refinery gases produce VOC.

A search of the RBLC, state databases, and emission control literature was conducted to find available control technologies to control flare emissions. Flares operate primarily as air pollution control devices. The only technically feasible control options for emissions of all pollutants from flares are:

- proper equipment design and work practices;
- good combustion practices;
- conversion from air assisted to steam assisted, and
- flare gas recovery systems.

No add-on controls for VOC emissions from flares were identified.

7.2.1.1 Proper Equipment Design and Work Practices

Proper equipment design and work practices include minimizing the quantity of gases combusted, minimizing exit velocity, ensuring adequate heat value of combusted gases, and installing an automatic pilot reignition. The flares at the Woods Cross Refinery are designed and operated in accordance with 40 CFR 60.18, general control device requirements which include a flame present at all times, no visible emissions, and heat content and maximum tip velocity specifications that meet the requirements of the rule. The use of pipeline-quality natural gas to fuel the pilot lights will reduce VOC emissions.

7.2.1.2 Good Combustion Practices

A certain level of flame temperature control can be exercised for a flare by utilizing steam which improves mixing. Good combustion practices can be used to minimize emissions of VOC.

7.2.1.3 Conversion from Air Assisted to Steam Assisted

Flares produce lower flame temperatures when operating with low heating value gases at low combustion efficiencies than when operating with high heating value gases at high combustion efficiencies. This leads to reduced formation of VOC in the flame. In general, emissions are lower in steam assisted flare tests than in air assisted flare tests conducted under similar conditions.

7.2.1.4 Flare Gas Recovery Systems

Flaring can be reduced by installation of a flare gas recovery system. A flare gas recovery system include a seal system to allow for recovery of process gases vented to the flare. Compressors recover the vapors and vapors are sent to the fuel gas treatment system for H₂S removal. After conditioning of the recovered vapors, the gases are combined with other plant fuel gas sources and combusted in heaters, boilers, and other devices that operate using fuel gas.

If the pressure in the flare gas headers exceeds the seal system settings, excess flare gases are allowed to flow to the flare for combustion. The pressure in the flare gas system increases due to additional process gas flow that cannot be recovered by the flare gas compressors. Once the pressure drops and the excess gases are combusted, the seal system re-establishes itself for continuous recovery of vapors.

The flare gas recovery system will not be sufficient to prevent flaring from process unit startup and shutdown events where large volumes of process gases will be sent to the flare. Also, during process upsets or malfunctions, the flare gases may not be entirely recovered due to the constraints of the flare gas recovery system. The flare gas recovery system will be sized for normal operating conditions.

7.2.2 Step 2 - Eliminate Technically Infeasible Options

None of the identified control options is considered technically infeasible for the flares at the Woods Cross Refinery.

7.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top ranking control option is the installation of a flare gas recovery system. Flare gas recovery systems are achieved in practice. The second highest ranking control option includes proper equipment design and work practices which includes good combustion practices. The combustion efficiency is the percentage of hydrocarbon in the flare vent gas that is completely converted to CO₂ and water vapor. Destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound. The destruction efficiency of a properly operated flare is 98%.

7.2.4 Step 4 - Evaluate Impacts and Document Results

HollyFrontier will install a flare gas recovery system to recover vent gas which is the highest ranked control option.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flares are located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18.

Emissions from the HollyFrontier Woods Cross Refinery flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flares are located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18.

Flare management plans have been developed for both the north and south flare. These plans contain procedures to minimize or eliminate discharges to the flare during startups and shutdowns. To verify that the procedures are followed, records are maintained.

The flares at the refinery are steam-assisted and have a destruction efficiency of 98% or greater.

7.2.4.1 Energy, Environmental, or Economic Impacts

Since HollyFrontier has chosen the highest ranked control option, flare gas recovery, energy, environmental and costs analyses are not required to be addressed.

7.2.5 Step 5 - Select BACT

HollyFrontier is proposing the following design elements and work practices as BACM for the flares:

- Use of low sulfur fuel such as natural gas as fuel for pilot flame;
- Maintaining an acceptable net heating value and exit velocity of flared gases under all flow conditions in accordance with manufacturer specifications;
- Use of a thermocouple to monitor presence of the pilot flame;
- Implementation of good combustion, operating, and maintenance practices;
- Implementation of Flare Management Plans;
- Flare operation in accordance to 40 CFR Part 60, Ja and design and work practice standards as codified in 40 CFR Part 60.18; and,
- Installation of flare gas recovery system.

No other measures were identified as more stringent to control VOC emission from the flares at the Woods Cross Refinery. The flare design includes steam-assisted combustion. The flares will be equipped with a flare gas recovery system for non-emergency releases, and a continuous pilot light. Pilot and sweep fuel will be natural gas or treated refinery gas.

The proposed BACM controls and monitoring methods conducted for the flares at HollyFrontier are summarized in Table 7-4.

Table 7-4 Proposed BACM Controls and Monitoring Methods for Flares

Pollutant	Unit	Control Technology	Monitoring
VOC	66	Flare gas recovery system	Flow meters and gas combustion monitors on gas line

7.3 Cooling Towers

VOC emissions are due to the evaporation of VOC's that may be present in the cooling water due to equipment or heat exchanger leaks. Small amounts of hydrocarbons may be present in the cooling water.

7.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Only one control technology was identified for controlling VOC emissions from cooling towers which is the implementation of a heat exchanger leak detection and repair (LDAR) program.

7.3.2 Step 2 - Eliminate Technically Infeasible Options

The implementation of a heat exchanger leak detection and repair program was determined to be technically feasible.

7.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The only identified, technically feasible control option is to implement a heat exchanger leak detection and repair program for the cooling towers. In using this option, no significant energy, environmental, or economic impacts are expected. This program involves monitoring cooling water for the presence of hydrocarbons, and finding and repairing leaks when hydrocarbons are found.

7.3.4 Step 4 - Evaluate Impacts and Document Results

Therefore, to satisfy BACT, HollyFrontier conducts monthly monitoring to identify leaks of strippable VOC from heat exchange systems. A leak is a total strippable VOC concentration in the stripping gas of 6.2 ppmv or greater. Monthly water samples are collected and analyzed from each cooling tower return line to determine the total strippable VOC concentration using the Texas El Paso method as required by 40 CFR Subpart CC. Monthly records kept including date of inspection, cooling tower/heat exchanger inspected, total strippable VOC concentration, repairs, and follow up testing.

7.3.4.1 Energy, Environmental, or Economic Costs

Since HollyFrontier has chosen the highest ranked control option, LDAR; energy, environmental and costs analyses are not required.

7.3.5 Step 5 - Select BACT

No more stringent measures than LDAR were determined to control VOC emissions from the cooling towers. BACM is based on the implementation of a heat exchanger LDAR program and compliance with 40 CFR Part 63, Subpart UUU. Monthly testing is conducted to determine total strippable VOC concentrations.

The proposed BACM controls, VOC emission limits, and monitoring methods conducted for the cooling towers at HollyFrontier are summarized in Table 7-5.

Table 7-5 Proposed BACM Controls, VOC Emission Limits, and Monitoring Methods for Cooling Towers

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Methods
VOC	54	LDAR	Leaks of strippable VOC <6.2 ppmv (CT's 4,6,7,8)	Modified El Paso Method, Monthly testing Repair identified leak within 15 days
		LDAR	Leaks of strippable VOC < 3.1 ppmv (CT 10, 11)	

7.4 Sulfur Reduction Unit Incinerator

VOC's from the SRU incinerator result from incomplete fuel combustion of carbon and organic compounds in the fuel gas.

7.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Since the tail gas incinerator is a combustion device, the only VOC emission control techniques identified were good combustion practices, engineering design, and use of clean burning fuels.

7.4.2 Step 2 - Eliminate Technically Infeasible Options

Good combustion practices, engineering design, and the use of clean burning fuels are all technically feasible.

7.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The only technically feasible control options for VOC from the SRU tail gas incinerator are good combustion practices and engineering design, and the use of clean-burning fuel.

7.4.4 Step 4 - Evaluate Impacts and Document Results

As mentioned above, emissions from the SRU are sent to the tail gas incinerator followed by a wet gas scrubber.

7.4.4.1 Energy, Environmental, or Economic Impacts

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. There are no other anticipated energy, environmental, or economic impacts associated with the use of a wet scrubber to remove VOC from the effluent stream from the SRU during normal operations.

Although natural gas is considered a clean fuel, natural gas combustion in the tail gas incinerator will result in increased VOC combustion emissions. Economic impacts occur due to the cost to use natural gas to fire the tail gas incinerator. There are no other anticipated impacts associated with the use of the tailgas incinerator.

7.4.5 Step 5 - Select BACT

Emissions from the SRU tail gas incinerator are sent to one of the wet gas scrubbers. VOC BACM for the SRU tail gas incinerator and wet gas scrubber is good combustion practices, engineering design, and use of clean burning fuels utilizing natural gas. No other measures were identified as more stringent to control VOC emissions from SRU tailgas incinerators. Combustion is monitored through the use of an O₂ CEMS.

The proposed BACM controls and monitoring methods conducted for the SRU tailgas incinerator at the Woods Cross Refinery are summarized in Table 7-6.

**Table 7-6 Proposed BACM Controls and Monitoring Methods for SRU
Tail Gas Incinerator**

Pollutant	Unit	Control Technology	Monitoring
VOC	17	Good combustion practices, engineering design and use of clean burning fuels	O ₂ CEMS

7.5 FCCU

Fluidized catalytic cracking units are complex processing units at refineries that convert heavy components of crude oil into light, high-octane products that are required in the production of gasoline.

The FCCU consists of two vessels. In the reactor vessel, the conversion reaction occurs in the presence of a fine, powdered catalyst and steam, during which the catalyst becomes coated with petroleum coke. In the regenerator vessel, this coke is removed from the surface of the spent catalyst by burning it off in the presence of air so that the catalyst can be reused. The cracked products from the reactor vessel are separated in a fractionator column into intermediate streams for further processing. The catalyst regenerator exhaust contains VOCs.

7.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Three available control technologies to control VOC emissions from a full burn FCCU regenerator include:

- > Good combustion practices,
- > Combustion promoters, and
- > Catalytic reduction.

7.5.1.1 Good Combustion Practices

Full burn regenerators operate with excess oxygen in the flue gas. The minimum excess oxygen required to promote VOC oxidation is a function of bed temperature, gas residence time in the bed, and how efficiently the regenerator design utilizes the available oxygen. Assuming that the full burn unit is properly designed and as long as sufficient oxygen is present, the oxidation of CO to CO₂ should be complete, resulting in both reduced CO and VOC concentrations. Thus, good combustion design and operation will effectively control VOC emissions present in the FCCU regenerator exhaust gas.

7.5.1.2 Combustion Promoters

CO combustion promoters are an additive to the coke combustion process in the regenerator that hampers the formation of NO_x while enhancing the combustion of coke on the catalyst. The CO combustion promoters are readily fluidized, mixing with the catalyst. They are added to the circulating fluid bed (CFB) regenerator unit to improve the efficiency of VOC burning, reduce emissions of VOC and improve the efficiency of the unit. The CO combustion promoter accumulates in, or just above, in the fast fluidized bed combustion zone of the regenerator. There are several CO promoters that are available for use including Engelhard Corporation's OxyClean™, Intercat, and Grace Davison's XNO_x all of which are effective in reducing VOC emissions while controlling NO_x emissions.

7.5.1.3 Catalytic Oxidation

Catalytic oxidation decreases VOC emissions by allowing the complete oxidation to take place at a faster rate and a lower temperature. The oxidation reaction typically requires a temperature of 650 to 1000°F to achieve optimal oxidation efficiencies. Catalytic oxidation cannot be used in waste streams with large amounts of particulate matter since the particulate deposits foul the catalyst and inhibit the control efficiency.

7.5.2 Step 2 - Eliminate Technically Infeasible Options

A review of the RBLC, state data bases, and air permits did not identify the use of catalytic oxidizers to control VOC emissions from an FCCU regenerator. The use of a catalytic oxidation system is not technically feasible due to the relatively low temperatures of the FCCU exhaust stream. The process of reheating the flue gas would result in the formation of additional combustion products including VOC. Thus, the use of this technology to control VOC emissions from FCCU exhaust gas has been determined to be technically infeasible.

7.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining technologies include the use of good combustion practices and combustion promoters.

7.5.4 Step 4 - Evaluate Impacts and Document Results

The FCCU regenerators at HollyFrontier utilize full burn combustion technology which minimizes VOC emissions to the fullest extent possible. The regenerative vent is continuously monitored through use of a CEMS to ensure the CO (hence VOC) emissions are controlled to the maximum extent possible. The use of good combustion practices to reduce VOC emissions from FCCU's has been achieved in practice and is used throughout the industry. In addition, HollyFrontier utilizes a combustion promotor, LoTOx to reduce NO_x emissions.

7.5.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated environmental, energy, or economic impacts associated with use of good combustion practices and a combustion promoter.

7.5.5 Step 5 - BACT

The use of full burn technology for the FCCU regenerator, good combustion practices, and a combustion promoter are used by HollyFrontier to minimize VOC emissions from the FCCUs. Thus, the use of these technologies is considered BACT for VOC. No more stringent measures were identified to reduce VOC emissions from an FCCU.

The proposed BACM controls and monitoring methods conducted for the FCCU at the Woods Cross Refinery are summarized in Table 7-7.

Table 7-7 Proposed BACM Controls and Monitoring Methods for FCCU

Pollutant	Unit	Control Technology	Monitoring
VOC	4, 25	Good combustion practices, combustion promoter	O ₂ CEMS

CO emissions are continuously monitored and are limited to ≤500 ppmv based on a one-hour average at 0% O₂. By insuring CO emissions are within these limits, VOC emissions will also be controlled.

7.6 Storage Tanks

Storage tanks are used at the HollyFrontier Woods Cross Refinery to store raw materials, intermediates, blend stocks, and finished products. Emissions from storage tanks generally depend on several factors; tank size (capacity), dimensions (diameter and height), type (fixed roof, internal floating roof, external floating roof), vapor pressure of substance stored, and tank turnovers. Storage tanks that store chemicals that are not hydrocarbon based are assumed to have no emissions. The emissions from storage tanks include VOCs. There are 102 above-ground storage tanks for volatile organic compounds, 12 above ground-cylindrical storage tanks for water, and 25 pressurized storage vessels at the Woods Cross Refinery.

There are three types of storage vessels: fixed roof tanks, external floating roof tanks, and internal floating roof tanks. A typical fixed roof tank consists of a cylindrical shell with a cone- or dome-shaped roof that is permanently affixed to the tank shell. An external floating roof tank consists of a cylindrical shell equipped with a deck or roof that floats on the surface of the stored liquid, rising and falling with the liquid level. An internal floating roof tank has both a permanently affixed roof and a roof that floats inside the tank on the liquid surface or is supported on pontoons several inches above the liquid surface. The internal roof rises and falls with the liquid level.

For fixed roof or internal floating roof tanks, emissions occur as a result of the displacement of headspace vapor during filling operations or from tank rim seals in the case of external floating roof tanks (working losses). To a lesser degree, diurnal temperature variations and solar heating result in emission from storage tanks (breathing losses).

The nominal requirements to control VOC emissions are provided in the petroleum refinery NESHAP regulation, 40 CFR 63 Subpart CC, the Hazardous Organic NESHAP, 40 CFR Part 63 Subpart G, or in 40 CFR Part 60 Subpart Kb. Because high vapor pressure volatile organic liquids must be stored in "controlled tanks", the regulations define how these tanks are constructed and monitored. Tanks constructed after July 23, 1984 are required to operate in accordance with 40 CFR Part 60 Subpart Kb and are exempt from refinery MACT requirements (63.640(n)). Tanks constructed before that date and storing volatile organic liquids containing HAPS are required to meet the applicable Refinery MACT requirements of NESHAP 40 CFR 63 Subpart CC which refers to the control standards of 40 CFR Part 63 Subpart G.

7.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The available control technologies for tanks storing organic liquids include control equipment designed to minimize leakage from tanks, air pollution control equipment, and combinations of each. The control options that were identified include:

- Fixed roof tank (baseline),
- External floating roof, vapor-mounted primary and secondary seals,
- External floating roof, dome, vapor recovery $\geq 98\%$ efficiency for products ≥ 3 psia except for crude oil
- Internal floating roof, bolted construction, vapor-mounted primary seal with uncontrolled deck fittings,
- Internal floating roof, bolted construction, liquid-mounted primary seal with uncontrolled deck fittings,
- Internal floating roof, bolted construction, liquid-mounted primary seal with controlled deck fittings,
- Internal floating roof, bolted construction, liquid-mounted primary and secondary seals with controlled deck fittings,

- Internal floating roof, welded construction, liquid-mounted primary and secondary seals with controlled deck fittings,
- Fixed roof with add-on vapor recovery equipment, and
- External floating roof, welded deck type, liquid mounted primary and secondary seals,
- Operating the vessel under pressure such that it operates with no emissions, and
- Routing vapors to a process or a fuel gas system via hard piping, such that the vessel operates with no emissions.

7.6.2 Step 2 - Eliminate Technically Infeasible Options

The control options involving internal floating and external floating roof tank designs are not technically feasible for the asphalt tank due to the nature of the material being stored and due to the storage temperature of the material.

7.6.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The control options for the storage tanks are listed in ascending order of control effectiveness. As mentioned above, there are three major types of vessels used to store liquids. In addition, optional equipment designs exist within each major tank type (e.g. seal design, roof fabrication, fittings closure). Table 7-8 presents a hierarchy of tank control options.

Table 7-8 Hierarchy of Tank Control Options

Control Option	Equipment Description
1	Fixed roof tank (baseline)
2	External floating roof, vapor-mounted primary and secondary seals
3	Internal floating roof, bolted construction, vapor-mounted primary seal with uncontrolled deck fittings
4	Internal floating roof, bolted construction, liquid-mounted primary seal with uncontrolled deck fittings
5	Internal floating roof, bolted construction, liquid-mounted primary seal with controlled deck fittings
6	Internal floating roof, bolted construction, liquid-mounted primary and secondary seals with controlled deck fittings
7	Internal floating roof, welded construction, liquid-mounted primary and secondary seals with controlled deck fittings
8	Fixed roof with add-on vapor recovery equipment
9	External floating roof, welded deck type, liquid mounted primary and secondary seals
10	Operating the vessel under pressure
11	Routing vapors to a process or a fuel gas system via hard piping

Routing vapors to a process or a fuel gas system via hard piping, such that the vessel operates with no emissions, where technically feasible, is the highest ranking control which is nearly 100 percent effective in reducing emissions from storage tanks.

The second highest ranking control option is operating a vessel under pressure. This type of tank is only applicable to pressurized tanks, i.e. as bullets or spheres, storing certain products such as propane, butane, NGL liquids, etc.

The third highest ranking control option for reducing emissions from storage tanks is a fixed roof in combination with an internal floating roof with a vapor collection in a closed vent system routed to a control device. This design incorporates a roof structure that floats on the surface of the stored liquid with dual flexible seals along the edge of the roof. This design effectively eliminates working losses. As additional control, the headspace between the floating roof and the top of the tank is filled with sweep gas that is vented under a slight vacuum. The breathing losses that escape through the seals are carried with the sweep gas to an add-on control device such as a thermal oxidizer.

The fourth effective option includes an internal floating roof and dual rim seals. This option does not include sweep gas routed to a control device.

The fifth effective option used to control VOC emissions from storage tanks includes the use of an external floating roof with dual rim seals. This control option has overall effectiveness equivalent to a tank which is equipped with an internal floating roof and dual rim seals. This design is similar to the internal floating roof configuration discussed above but without the enclosed headspace. The floating roof and seals reduce volatilization losses.

The Mid-Atlantic Regional Air Management Association (MARAMA) report, *The Assessment of Control Technology Options for Petroleum Refineries in the Mid-Atlantic Region Final Report* January, 2007 summarizes tank control technologies for reducing VOC emissions as follows:

Technology	Percent Reduction
Install internal floating roof in fixed roof tank	60-99
Install domed fixed roof on an external floating roof	96
Replace a vapor-mounted primary seal with a liquid-mounted primary seal	30-70 EFR 43-45 IFR
Install secondary seals on floating roof tanks	75-95%
Vapor balancing	80%
Incineration	95-99%
Apply tank standards to tanks storing organic liquids with vapor pressure 0.1-0.5 psia	Varies

7.6.4 Step 4 - Evaluate Impacts and Document Results

Under NSPS regulations, control equipment is required when storing volatile organic liquids with maximum vapor pressure of 0.75 psia. Otherwise, control requirements generally are triggered at 1.5 psia. Tanks storing volatile organic liquids below the vapor pressure threshold are required to keep records of types of products stored and their vapor pressures, periods of storage and tank design specifications.

Because high vapor pressure volatile organic liquids must be stored in "controlled tanks", the regulations define how these tanks are constructed and monitored. Tanks over 40,000 gallons and built, modified, or reconstructed between June 11, 1973 and May 19, 1978 are required to operate in accordance with 40 CFR Part 60 Subpart K. Subpart K is only applicable to Tanks 145 and 146 at the refinery.

Tanks over 40,000 gallons and built, modified, or reconstructed between May 18, 1978 and July 23, 1984 are required to operate in accordance with 40 CFR Part 60 Subpart Ka. Tanks constructed after July 23, 1984 are required to operate in accordance with 40 CFR Part 60 Subpart Kb and are exempt from refinery MACT requirements (63.640(n)). This rule applies to Tanks 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 98, 99, 159, and 323 at the facility. Tanks 85-97, and 99 are subject to Kb by size of tank and date of construction only and have no applicable requirements.

Tanks constructed before August 18, 1994 and storing volatile organic liquids containing HAPS are required to meet the applicable Refinery MACT requirements of NESHAP 40 CFR 63 Subpart CC which refers to the control standards of 40 CFR Part 63 Subpart G. For Group 1 storage vessels storing liquids for which the maximum true vapor pressure of the total organic hazardous air pollutants in the liquid is less than 76.6 kilopascals, the use of fixed roof and internal floating roof, an external floating roof, an external floating roof converted to an internal floating roof, a closed vent system and control device, routing the emissions to a process or a fuel gas system, or vapor balancing is required. Group1 tanks at the Woods Cross refinery include 72, 100, 101, 103-108, 121, 126, 132, 145, and 146.

Compliance options for VOC emission controls on tanks includes using a fixed roof with an internal floating roof, an external floating roof meeting certain design specifications, and using a closed-vent system and control device that meet the requirements of 40 CFR Part 60 Subpart Kb. For tanks 85, 87-97, 99, 170, and 175-187, the applicable NSPS and/or NESHAP rules do not require any control of VOC emissions due to the low vapor pressure (<0.5 psia) of these tank contents. Thus, fixed roof tanks are appropriate for storage of these low vapor pressure products.

In addition, Utah Administrative Code R307-327 presents the requirements of petroleum liquid storage in ozone nonattainment and maintenance areas. R307-327-4 states (1) Any existing stationary storage tank, with a capacity greater than 40,000 gallons (150,000 liters) that is used to store volatile petroleum liquids with a true vapor pressure greater than 10.5 kilo pascals (kPa) (1.52 psia) at storage temperature shall be fitted with control equipment that will minimize vapor loss to the atmosphere. Storage tanks, except for tanks erected before January 1, 1979, which are equipped with external floating roofs, shall be fitted with an internal floating roof that shall rest on the surface of the liquid contents and shall be equipped with a closure seal or seals to close the space between the roof edge and the tank wall, or alternative equivalent controls. The owner/ operator shall maintain a record of the type and maximum true vapor pressure of stored liquid. (2) The owner/operator of a petroleum liquid storage tank not subject to (1) above, but containing a petroleum liquid with a true vapor pressure greater than 7.0 kPa (1.0 psia), shall maintain records of the average monthly storage temperature, the type of liquid, throughput quantities, and the maximum true vapor pressure.

The facility has several tanks that comply with this rule. Tanks equipped with internal floating roofs with secondary seals which have (or will be when constructed) include Tanks 12, 71, 72, 85, 98, 131, 138, and 323. Floating roof tanks erected prior to January 1, 1979 include Tanks 100-102, 104-109, 121, 126, 128, 129, 132, 135, 145, and 146.

7.6.4.1 Energy, Environmental, and Economic Impacts

The most effective control option of recovering vapors and routing them to a process or a fuel gas system via hard piping such that the tank operated with no emissions would result in adverse energy and environmental impacts due to the significant electrical power demand of the required compression system.

An economic analysis was performed for gathering vapors discharged from cone-roof tanks and processing these vapors for the recovery of condensable hydrocarbons by means of absorption which is the top ranking control over condensation, mechanical refrigeration, and adsorption using carbon beds for recovery of hydrocarbon vapors from storage tanks. This requires extensive processing equipment, the most common method involving compression, cooling, absorption, heating, stripping, and final condensation by cooling. This equipment must be designed to operate under conditions of varying compositions of the vapors and fluctuating vapor flow rates from the tanks. The recovered liquid can be used as feed stock for further processing or stored in tanks.

For the vapor recovery process, vapors from each tank are gathered, pass through a pressure-control valve into the main gathering header and are drawn into the suction of a compressor. After compression, the vapors are discharged into the absorption chamber where they are absorbed in circulating lean oil. The lean oil, enriched with these vapors pass from the bottom of the absorber and the recovered hydrocarbons from the top of the stripper are cooled and condensed.

The \$/ton of VOC reduced from the addition of an absorption system was estimated to be approximately \$280,000 (see Appendix B). This estimate does not include for vapor balancing between tanks. With the use of this option, additional steam, electricity, and cooling water as utilities are needed as well as extra labor costs to operate the system.

Although this option is theoretically possible, HollyFrontier is not aware of any petroleum refinery operating with this equipment on any cylindrical storage tanks. In addition, to the best of HollyFrontier's knowledge, EPA has never identified this as a control option for consideration in establishing MACT for storage tanks at refineries.

The second highest control option, use of a closed vent system routed to a thermal oxidizer or carbon absorber, for tanks storing relatively volatile materials, an internal floating roof is considered inherent to the process for product loss minimization. For tanks storing less volatile materials, an uncontrolled fixed roof is considered the baseline control.

The installation of a thermal oxidizer or carbon absorber would result in adverse energy and environmental impacts due to the auxiliary fuels needs for the required thermal oxidizer and the additional combustion emissions (NO_2 , SO_2 , $\text{PM}_{2.5}$, VOC) that result from a thermal oxidizer. If activated carbon were used, a solid waste could also be generated.

The cost of a vapor control system is a function of the vapor flow rate to the system. The flow rate is controlled by the rate at which liquids are pumped into the tank. Due to time constraints, detailed engineering and site-specific costs could not be obtained for the installation of a vapor control system. According to EPA estimates adjusted to 2011 dollars, the total annualized costs of installing a vapor control system by incineration is approximately \$425,000. If carbon adsorption were used for vapor control, the projected annualized costs would be approximately \$595,000. Like above, although this option is theoretically possible, HollyFrontier is not aware of any petroleum refinery operating with this equipment on any cylindrical storage tanks. In addition, to the best of Holly's knowledge, EPA has never identified this as a control option for consideration in establishing MACT for storage tanks at refineries.

The use of internal floating roof and dual rim seals does not result in any adverse energy or environmental impacts. Because of the low volatility off the products being stored in fixed roof tanks, the installation of internal floating roofs and seals or an external floating roof is not warranted. The capital cost to install internal floating roof to a fixed roof tank ranges from \$240,000 to \$480,900 per tank (MARAMA). For an external floating roof, the estimated capital cost would be over \$210,000. This control option has overall effectiveness equivalent to a tank which is equipped with an internal floating roof and dual rim seals.

A closed vent system and a control device have been eliminated from further consideration. In addition, since the emissions from the proposed fixed roof tanks are not significant, i.e., less than one ton per year, a floating roof is not proposed for the lower vapor pressure product tanks. The MARAMA report estimated to apply tank standards to tanks storing organic liquids with vapor pressures between 0.1 to 0.5 psia, the cost effectiveness ranges from \$20,500 to \$34,000 per ton VOC reduced.

Vapor balancing can be accomplished through a network of vapor lines interconnecting the vapor spaces of all tanks. Under the most favorable conditions of perfectly balanced pumping, where the input rate and the output rate were equal, it is not possible to eliminate all filling losses. However, control of losses caused by unbalanced pumping and breathing requires variable-space vapor storage with a capacity equal to the volume of the maximum breathing plus unbalanced pumping. The primary operating consideration is the potentially adverse effect of the interchange of vapors between tanks storing different products.

In the case where the pump-out rate is equal to the input rate, a simple interconnection pipe system would only recover the filling losses estimates to be approximately 30% of the total loss. The addition of a vapor tank prevent all vapor losses but adds an additional cost to the system. Other items to consider include the size of the vapor recovery tank and if there is adequate space for the installation of this tank.

The estimated capital costs to install a vapor-balancing system with a network of interconnecting vapor lines and a vapor tank are estimate to be close to \$150,000⁶. Annual operating costs are estimated to be approximately \$38,000. The installation of a vapor balancing system to control less than a ton of VOC emissions from the fixed roof tanks is not economically feasible.

7.6.5 Step 5 - Proposed BACM

Based on the analyses presented above, the top options, vapor recovery from fixed roof tanks, installation of a thermal oxidizer or utilization of carbon adsorption, vapor control systems for higher VOC product tanks, closed vent system and control device for fixed roof tanks, and vapor balancing has been determined to be not economically feasible.

The proposed BACM for refinery tanks is compliance with the equipment design and work practices requirements as set forth in 40 CFR 63, Subpart G and 40 CFR 60, Subpart Kb. The floating roof tanks consist of a shell and a roof that floats on the hydrocarbon liquid. The quantity of loss for floating roof depends on the rim seal design and emission control on the roof fittings. Thus, for 12, 71, 72, 85, 98, 131, 138 and 323, HollyFrontier is utilizing Control Option 7 (above) for reducing VOC emissions from these tanks. This includes the use of internal floating roofs, welded construction, liquid-mounted primary and secondary seals with controlled deck fittings, and vapor-mounted wiper seals.

Floating roof tanks are used to store hydrocarbons having a greater tendency of vapor generation on exposure to high temperature, i.e. higher vapor pressure. The floating roof helps in vapor suppression. As seen from Table 7-9, Control Option 9, external floating roof, welded deck type, liquid mounted primary and secondary seals is the most effective control option. This option will be utilized for storage tanks 100-102, 104-109, 121, 126, 128, 132, 135, 145 and 146. This type of tank roof minimizes the vapor space between it and the liquid surface. Since there is no large vapor space for the liquid to evaporate into, vapor losses are also minimized.

During tank degassing operations, which occurs infrequently at the refinery, VOC vapors are routed to a portable (mobile) thermal oxidizer which is at least 98% efficient. Control is maintained until the VOC concentration is less than 10,000 ppmv VOC or 10% of the lowest explosive level (lel) which meets R307 requirements.

Table 7-9 presents a list of the current and proposed tanks, tank type, the vapor pressure of the material stored, and the control method. The 25 pressurized storage tanks (i.e. bullets or spheres) are not sources of emissions at the Woods Cross Refinery. The monitoring conducted on the tanks must comply with LDAR requirements.

⁶ C.A Day, Economics of Vapor Recovery from Storage Tanks, Journal of Air Pollution Control, 5:1 17-63.

Table 7-9 Proposed BACM for HollyFrontier Storage Tanks

Tank ID	Product Stored	Vapor Pressure of Stored Material (psia)	Control Method
Tank 11	Empty-Out of Service	--	--
Tank 12	Reformer Charge	2.5	IFR
Tank 14	Kerosene	0.02	Fixed Roof
Tank 15	Fuel Oil	0.02	Fixed Roof
Tank 19	Stove Oil (Ultra Low Sulfur)	0.02	Fixed Roof
Tank 20	Stove Oil (Ultra Low Sulfur)	0.02	Fixed Roof
Tank 21	Out of service	--	Hor. Elliptical
Tank 23	Diesel ULSD	0.02	Fixed Roof
Tank 24	Diesel ULSD	0.02	Fixed Roof
Tank 28	Diesel ULSD	0.02	Fixed Roof
Tank 29	Caustic	0.00	Fixed Roof
Tank 31	Residual oil no. 6	0.02	Fixed Roof
Tank 35	Gas Oil	0.02	Fixed Roof
Tank 37	Fuel Oil	0.02	Fixed Roof
Tank 42A	Jet Fuel Additive	0.02	Fixed Roof
Tank 47	Diesel ULSD	0.02	Fixed Roof
Tank 48	Light Cycle Oil	0.02	Fixed Roof
Tank 50	Empty-Out of Service	--	Hor. Dish
Tank 51	Empty-Out of Service	--	Hor. Flat
Tank 52	Fuel Oil	0.02	Fixed Roof
Tank 53	Fuel Oil	0.02	Fixed Roof
Tank 54	Fuel Oil	0.02	Fixed Roof
Tank 55	Fuel Oil	0.02	Fixed Roof
Tank 56	Fuel Oil	0.02	Fixed Roof
Tank 57	Fuel Oil	0.02	Fixed Roof
Tank 58	Fuel Oil	0.02	Fixed Roof
Tank 59	Empty-Out of Service	0.00	Fixed Roof
Tank 60	Caustic	0.00	Fixed Roof
Tank 61	out of service	0.00	Fixed Roof
Tank 63	Stove Oil (Ultra Low Sulfur)	0.02	Fixed Roof
Tank 64	out of service	0.00	Fixed Roof
Tank 65	out of service	0.00	Fixed Roof
Tank 70	Gas Oil	0.02	Fixed Roof
Tank 71	Black Wax	1.9	IFR, 40 CFR 63, Sub. CC
Tank 72	Gasoline (RVP 8 WX)	5	IFR, 40 CFR 63, Sub. CC
Tank 73	out of service	0.00	Fixed Roof
Tank 74	out of service	0.00	Fixed Roof
Tank 75	out of service	0.00	Fixed Roof
Tank 76	out of service	0.00	Fixed Roof
Tank 77	Biodiesel	<0.5	Fixed Roof
Tank 78	Biodiesel	<0.5	Fixed Roof
Tank 79	Asphalt	<0.5	Fixed Roof
Tank 81	NaHS	0.33	Umbrella
Tank 82	NaHS	0.33	Umbrella

IFR = Internal floating roof

EFR – External floating roof

Table 7-9 (Continued) Proposed BACM for HollyFrontier Storage Tanks

Tank ID	Source Description	Vapor Pressure of material Stored (psia)	Applicability
Tank 83	Caustic	0.00	Umbrella
Tank 85	Poly Gasoline	2.1	IFR, 40 CFR 60, Sub. Kb
Tank 86	Gas Oil	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 87	Gas Oil	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 88	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 89	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 90	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 91	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 92	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 93	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 94	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 95	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 96	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 97	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 98	Gasoline Blendstock	2.1	IFR, 40 CFR 60, Sub. Kb
Tank 99	Distillate fuel oil no. 2	0.02	Fixed Roof, 40 CFR 60, Sub. Kb
Tank 100	Reformate	2.1	EFR
Tank 101	Gasoline (RVP 7 WX)	2.1	EFR
Tank 102	Gas Oil	0.02	EFR
Tank 103	Crude Oil (heavy)	1.9	Fixed Roof
Tank 104	Isomerate	2.6	EFR, 40 CFR 63, Sub. CC
Tank 105	Isomerate	2.6	EFR, 40 CFR 63, Sub. CC
Tank 106	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 63, Sub. CC
Tank 107	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 63, Sub. CC
Tank 108	Gasoline (RVP 11 WX)	5	EFR, 40 CFR 63, Sub. CC
Tank 109	Alkylate	2.1	EFR, 40 CFR 63, Sub. CC
Tank 113	Caustic	0.00	Flat
Tank 114	Caustic	0.00	Flat
Tank 116	Caustic	0.00	Flat
Tank 117	API Trap Sludge	0.00	Open
Tank 118	Recovered Slop	5	Flat
Tank 121	Crude Oil (RVP 8 WX)	4.9	EFR, 40 CFR 63, Sub. CC
Tank 122	Propane	190	Hor. Ell.
Tank 123	Propane	190	Hor. Ell.
Tank 124	Ammonia	124.6	Hor. Ell.
Tank 125	Ammonia	124.6	Hor. Ell.
Tank 126	Crude Oil (RVP 4 WX)	1.9	EFR, 40 CFR 63, Sub. CC
Tank 127	Diesel ULSD	0.02	Fixed Roof
Tank 128	Jet Fuel	0.02	EFR
Tank 129	Out of service	--	EFR
Tank 130	NHDS Charge	0.33	Hor. Ell.
Tank 131	Stove Oil WX Input	0.02	IFR
Tank 132	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 63, Sub. CC
Tank 133	Isobutane	72.2	Hor. Sphere

IFR = Internal floating roof

EFR – External floating roof

Table 7-9 (Continued) Proposed BACM for HollyFrontier Storage Tanks

Tank ID	Source Description	Vapor Pressure of material Stored (psia)	Applicability
Tank 134	Isobutane	72.2	Hor. Sphere
Tank 135	Naptha WX Input	11.1	EFR
Tank 136	Propane	190	Hor. Ell
Tank 138	Stove Oil WX Input	0.02	IFR
Tank 139	SDA Charge	0.02	Fixed Roof
Tank 140	SDA Charge	0.02	Fixed Roof
Tank 141	Solvent	142	Hor. Sphere
Tank 145	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 60, Sub. K
Tank 146	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 60, Sub. K
Tank 147	Propane	190	Hor. Ell
Tank 148	Propane	190	Hor. Ell
Tank 149	Butane	51.6	Hor. Ell
Tank 150	Butane	51.6	Hor. Ell
Tank 151	Butane	51.6	Hor. Ell
Tank 152	Olefin	110	Hor. Ell
Tank 153	Olefin	110	Hor. Ell
Tank 159	NGL	200	Sphere, 40 CFR 60, Sub. Kb
Tank 170	Finished Diesel	<0.5	Fixed Roof
Tank 171	Propane	190	Hor. Ell
Tank 172	Propane	190	Hor. Ell
Tank 173	Propane	190	Hor. Ell
Tank 174	Propane	190	Hor. Ell
Tank 300	Chemical	0.1	Fixed Roof
Tank 301	Chemical	0.1	Fixed Roof
Tank 302	Chemical	0.02	Fixed Roof
Tank 303	Chemical	0.02	Fixed Roof
Tank 304	Out of service	--	Fixed Roof
Tank 305	Out of service	--	Fixed Roof
Tank 306	Out of service	--	Fixed Roof
Tank 307	Out of service	--	Fixed Roof
Tank 308	Out of service	--	Fixed Roof
Tank 310	Out of service	--	Fixed Roof
Tank 312	Out of service	--	Fixed Roof
Tank 313	Out of service	--	Fixed Roof
Tank 323	Ethanol	4.5	IFR, 40 CFR 60, Sub. Kb
Tank 324	Olefin	110	Hor. Ell.
Tank 54-V4	Sulfuric Acid	0.00	Hor. Ell.
Tank 54-V5	Sulfuric Acid	0.00	Hor. Ell.
Tank 54-V7	Phosphate	0.00	Dome

IFR = Internal floating roof

EFR – External floating roof

Monitoring conducted on the tanks include annual seal gas inspections which are typically conducted in March and annual visual inspections conducted in September. Once every 5 years the primary seals are inspected. The tank valves are included in the LDAR program.

HollyFrontier will install leg covers on tank legs (that are set at high legs). Guidepole covers have been installed on certain tanks per the Consent Decree.

The most stringent controls identified is the installation of an internal or floating roof or approved emission control systems on tanks with products with vapor pressures ≤ 1.5 psia. The external floating roofs must be equipped with a primary and secondary seal and must rest on the surface of the liquid tank contents. For internal floating roof tanks, depending on the date of installation, the tank must be equipped with either a liquid mounted primary seal, mounted in full contact with the liquid in the annular space between the tank shell and floating roof, a metallic shoe primary seal, or a vapor mounted primary and a secondary seal. The SCAQMD requires domed roofs be installed on all external floating roof tanks that contain organic liquids having true vapor pressure ≥ 3 psia.

According to European Commission, Integrated Pollution Prevention & Control (ECIPPC) report, Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries, 2003, the costs to install IFR on tanks storing products with a vapor pressure ≤ 1.5 psia ranges from \$240,000 to \$480,900 per tank (in 2003 dollars). Tanks storing low vapor pressure liquids inevitably generate fewer VOC emissions than tanks storing high vapor pressure liquids. For this reason, to implement control devices on storage tanks containing low vapor pressure emissions would not be cost effective. See Appendix B.

To install a domed fixed roof on an external floating roof tank, the average cost was estimated by ECIPPC to range from \$21,640 to \$240,500 (in 2003 dollars). To place domes over external floating roofs is not economical. Although the \$/ton VOC removed for Tank 135 is less than \$10,000 (see Appendix B), this cost does not include any engineering fees and the likelihood that the existing tank and roof could not support a dome. According to the ECIPPC report, the costs to install and operate a vapor recovery system or to incinerate is more costly than the installation of domes, so these options have been determined to not be cost-effective.

7.7 Equipment Leaks

The Wood Cross Refinery is required to monitor equipment in hydrocarbon service that is greater than 10% VOC. Equipment that is monitored includes pumps, valves, compressors, flanges, and pressure relief devices. Numbered tags are used to identify equipment included in the Leak Detection and Repair (LDAR) Program. These components are sources of VOC emissions due to leakage.

The facility's leak detection and repair program is regulated under the Utah Administrative Code (R307-326-9 Leaks from Petroleum Refinery Equipment), 40 CFR Part 60 Subparts GGG and GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries), 40 CFR Part 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries), and the July 2, 2008 Consent Decree.

7.7.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Potential enhancements to a LDAR program work practice requirements include the following:

- > Lowering the definition of a "leaking" component threshold concentration as measured at the leak interface. This has the potential of broadening the repair obligations for leaking components to include components that would not normally require repair under NSPS or NESHAP rules.
- > Increase leak monitoring frequencies which could accelerate the identification and repair of leaking components.

In addition, equipment specifications and maintenance practices are designed and implemented to reduce leaks. For certain applications, components with inherently leakless features are available. These components reduce VOC emissions. Some leakless designs include the following:

- > Magnetic drive or diaphragm pumps without external seals
- > Pumps with double mechanical seals
- > Magnetic-drive centrifugal pumps
- > Diaphragm valves
- > Connectors welded around the entire circumference such that the joint cannot be disassembled by unscrewing or unbolting the components

Another control option would be to take an enforceable limit on the number of leaking components.

7.7.2 Step 2 - Eliminate Technically Infeasible Options

Each control option that was identified in Step 1 is technically feasible.

7.7.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The most effective of the identified control options is a combination of each option. This includes an LDAR program with enhanced work practices relative to the NSPS or NESHAP plus enforceable limits on leaking components.

7.7.4 Step 4 - Evaluate Impacts and Document Results

The most effective control strategy listed above has been implemented by HollyFrontier at the Woods Cross Refinery. The LDAR program at the refinery meets the requirements of NSPS, NESHAP, and consent decree requirements.

The following leak rate goals have been set to be achieved through the LDAR program at the Woods Cross Refinery: (1) A facility wide component leak rate goal has been set at less than or equal to 2.0% of total components; and, (2) Each process unit leak rate goal is less than or equal to 2.0% of total components.

The following leak definitions are utilized at the refinery:

1. All units have a leak definition for recordkeeping, reporting, and repair of 2,000 ppm for pumps and compressors and 500 ppm for valves.
2. Internal leak definitions for first attempt at repair is 200 ppm will be utilized for all valve components subject to NSPS and NESHAP regulations.

EPA Method 21 is used to determine the presence of leaking sources. Monitoring and leak rate calculations are divided into groups. Most of these groups are based on units, fluid types, and regulatory requirements. Each month, the LDAR technicians complete the scheduled monitoring and results of monitoring are entered into the LDAR database at the end of each shift. Work Requests for identified leaks that were not repaired by the LDAR technician are initiated by the end of the monitoring shift. Operations personnel perform a visual inspection of pumps subject to MACT and NSPS regulations each week. Any observed leaks are reported to the facility LDAR Coordinator within 24 hours. Olfactory, visual and auditory leak checks are performed daily and repairs are reported and fixed within 24 hours.

Leaks are defined by the various regulatory requirements. The LDAR Technician will make an initial attempt to repair on leaking components and leaking components are tagged. The VOC reading for each leaking component is recorded on the tag by the technician. Table 7-10 defines actions for various leak rates.

Table 7-10 Repair Actions for Leaking Valves and Pumps

Component	Requirement	Leak Rate (ppm)	First Attempt	Final Repair	Report as Leak
Valves	Consent Decree	200-499	5 days	-	No
		500-9,999	5 days	30 days	No
		>9,999	5 days	15 days	Yes
	40 CFR GGGa	>499	5 days	15 days	Yes
	R307-326-9	>9,999	5 days	15 days	Yes
Pumps	Consent Decree	2,000-9,999	5 days	30 days	No
		>9,999	5 days	30 days	Yes
	40 CFR GGGa	>1,999	5 days	15 days	Yes
	R307-326-9	>9,999	5 days	15 days	Yes

Components are re-monitored within 5 days after a repair attempt. After the first attempt, valves with leaks less than 500 ppm require no further action. For valves found to be leaking greater than 10,000 ppm that cannot be repaired, a drill and tap repair or similarly effective repair method will be performed, unless it can be documented that there is a safety, mechanical, or major environmental concern with repairing the leak with such a method. The initial repair attempt will be made within 15 days and a second, if necessary, within 30 days of identification of the leak, as stated in paragraph 132 (b) of the Consent Decree.

Gas/vapor and light liquid valves that leak, and are repaired, will be monitored for two consecutive months before going back to quarterly monitoring. A chronic leaker is a valve that has leaked greater than 10,000 ppm at least twice in any 4 consecutive quarters. Chronic leaking, non-control valves, are replaced, repacked, or similarly repaired at the next process unit turnaround.

All process units are subject to the R307-326-9, Leaks from Petroleum Refinery Equipment and 40 CFR Part 60 Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries). Those that contain HAP are subject to 40 CFR Part 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries).

Leakless designs, including pumps with double mechanical seals have been installed on Units 4, 8, 24, 25, 26, and 28.

7.7.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated energy, environmental and economic impacts associated with the top ranking control of operation of a LDAR program.

7.7.5 Step 5 - Selection of BACM

The LDAR program in operation at the Woods Cross Refinery incorporates the effective control technologies listed above and is considered the BACM. The LDAR program at the refinery meets the requirements of NSPS, NESHAP, and consent decree requirements. A LDAR program is the most stringent control measure identified at refineries for controlling VOC emissions from equipment leaks. Monitoring is performed on components based on the requirements presented in Table 7-11. No more stringent controls were identified other than the implementation of an effective LDAR program.

Table 7-11 LDAR Monitoring Frequencies

Equipment	Type	Requirements		Comments
		State and Federal*	Consent Decree (7/2/08)	
Leak Detection Monitoring				
Valves	Light Liquid	Monthly	Quarterly	
	Heavy Liquid	As noticed	Exempt	<10% VOC
	Gas	Monthly	Quarterly	
	Plant Gas	Monthly	Quarterly	>10% VOC
	Natural Gas	Exempt	Exempt	<10% VOC
Pumps	Light Liquid	Monthly	Monthly	
	Heavy Liquid	As noticed	Exempt	<10% VOC
Compressor	Seals	Auto-sensors	Quarterly	
Drains	Process	None	NA	
All	Unsafe to Monitor	When possible	When possible	
All	Difficult to Monitor	Annual	Annual	
Visual Monitoring				
Pumps	Light Liquid	Weekly	NA	
	Heavy Liquid	None	NA	<10% VOC
Drains	Process	Monthly	NA	NSPS Subpart QQQ

7.8 Wastewater Treatment Plant

The Waste Water Treatment Plant (WWTP) (Unit 56) treats plant wastewater and storm water runoff from process areas. Wastewater is collected and routed through a grit collector then to a main process lift station. The main process lift station supplies process waste water to two American Petroleum Institute (API) separators. Oil is skimmed off the separators and gravity fed to an API oil collection drum then to Tank 118. The sludge from the API separators is collected and dewatered in a sludge thickening vessel and later sent for disposal.

The effluent water from the API separators is pumped to two equalization tanks (Tanks 155 and 158). From the equalization tanks, waste water is pumped into two dissolved gas floatation units (DGF). The DGFs work to remove emulsified oil from the waste water by adding a polymer and inducing small N₂ bubbles into the water to bring oil to the surface. This skimmed oil, or float, is gravity fed to a storage tank before being pumped to the sludge thickening vessel.

Finally the waste water is sent to a series of moving bed bio-film reactors (MBBR) for biological polishing before being discharged to the South Davis County Public Owned Treatment Works (POTW). All process tanks and equipment at the WWTP are covered to control fugitive emissions.

7.8.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Emission control technologies for control of VOC emissions from the wastewater treatment plant include equipment design and work practice requirements that are set forth in the following regulations:

- 40 CFR Part 60, Subpart QQQ requires water seal controls or more effective controls for the wastewater system drains and sumps and a floating roof or a closed-vent system and a control device, such as a catalytic oxidizer for the API separators.
- 40 CFR Part 61, Subpart FF generally requires the same controls for the wastewater collection system drains and sumps as Subpart QQQ.
- 40 CFR Part 63, Subpart CC requires compliance with the requirements of 40 CFR Part 61, Subpart FF.

Per the above regulations, identified controls include water seal controls on drains, wastewater stripping, floating roofs for treatment vessels, and carbon absorption and incineration for removal of VOC from vent streams. Inspection and maintenance programs as well as performance-based work standards are also control strategies that can be implemented to reduce VOC emissions.

7.8.2 Step 2 - Eliminate Technically Infeasible Options

Water stripping, floating roofs, and incineration are technically infeasible for application to wastewater drains. The requirements of Subpart QQQ and Subpart FF are technically feasible.

7.8.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Equipment control strategies can require the installation of new equipment or devices, or can include physical changes to the wastewater system. Potential control strategies include:

- > Collecting and venting the emissions to a control device can achieve a control efficiency of greater than 95 percent. Potential emission control devices for wastewater collection systems (predominately junction box vents) include: carbon absorption, thermal oxidation, catalytic oxidation, and condensation.

- > Installing water seals on process drains and vents open to the atmosphere would help prevent emissions from the downstream sewer lines from escaping back out of the drain or vent opening. The overall control efficiency of this method is estimated at an average of 65%, and varies depending on the proper maintenance of the water seal.
- > Some control measures, such as water seals, can require an extensive inspection and maintenance (I&M) program in order to be effective. An effective I&M program is designed to inspect (on a regular basis), maintain and repair (as necessary) the pertinent components of a pollution control system for proper operation.
- > By establishing performance-based standards, such as setting an emission limit of 500 ppm VOC from a drain or vent, equivalent emission reduction can be achieved without specifying a particular control technology.

For wastewater treatment plant vessels, the most effective control strategy includes wastewater stripping to reduce VOC concentrations in wastewater entering the API separators, floating roofs for the equalizations tanks, and closed vent systems and oxidation of the VOC-containing vent streams from the API separators and dissolved gas floatation (DGF) units. Hard piping from the process units to the wastewater separator, from process units to a drain box enclosure, from those process units identified as the largest contributors to process drain emissions, or from junction boxes that are completely covered and sealed with no openings are also most effective in reducing VOC emissions.

Less effective control options would omit the use of a wastewater stripper or use floating roofs rather than closed vent systems and oxidation systems for the API separators and DGF units.

7.8.4 Step 4 - Evaluate Impacts and Document Results

During wastewater treatment, volatilization/stripping, sorption, and biodegradation primarily determine the fate of VOCs. Of these, volatilization and stripping result in air emissions. Biodegradation and sorption onto sludge serve to suppress air emissions. Stripping is the pollutant loss from the wastewater due to water movement caused by mechanical agitation, head loss, or air bubbles, while volatilization may be defined as quiescent or wind-driven loss. The magnitude of emissions from volatilization/stripping depends on factors such as the physical properties of the pollutants (vapor pressure, Henry's Law constants, solubility in water, etc.), the temperature of the wastewater, and the design of the individual collection and treatment units (including wastewater surface area and depth of the wastewater in the system). Wastewater unit design is important in determining the surface area of the air-water interface and the degree of mixing occurring in the wastewater (CARB, 2003).

In 2015, HollyFrontier upgraded their wastewater treatment system to include covered oil-water separators with fixed roofs and venting VOC vapors that accumulate under the headspace of the fixed roofs through a closed system to carbon absorption units, equipping new drains with a water seals, and covering new junction boxes. Monthly visual inspections are performed on the individual drain systems and semi-annual inspections are performed on the closed vent system and sealed junction boxes and oil/water separators. Carbon adsorber monitoring is performed at intervals no greater than 20 percent of the design carbon replacement intervals. The piping used for the new sewer lines associated with the upgrade are compliant with Subpart QQQ.

Performance based standards exist at the refinery with emission limits of 500 ppm above background for the carbon adsorber and closed vent system. The closed vent systems are designed and operated with no detectable emissions which are verified semi-annually. Sealed junction boxes are also used and inspected semi-annually.

7.8.4.1 Energy, Environmental, and Economic Impacts

There are no energy, environmental, and economic impacts anticipated with the top ranking control options that have been utilized on the wastewater treatment plant.

7.8.5 Step 5 - Select BACT

VOC emissions from the wastewater treatment system meet the requirements of Subpart QQQ and Subpart FF. Emissions from the wastewater system control device comply with 40 CFR 60 Subpart QQQ and are monitored in accordance with 40 CFR 60.695. 40 CFR Part 61, Subpart FF requires that the oil water separators be equipped with a fixed roof and vapors directed to a control device which HollyFrontier has installed. No more stringent requirement were found than compliance with 40 CFR 60 Part QQQ and 40 CFR Part 61, Subpart FF.

The proposed BACM controls, VOC emission limits, and monitoring methods conducted for the wastewater treatment at the Woods Cross Refinery are summarized in Table 7-12. The most stringent measures identified for control of VOC emission from wastewater treatment include installing covers and seals on the collection components to reduce fugitive VOC emissions, and maintaining or installing a control device such as carbon canisters to destroy VOCs released during treatment. HollyFrontier has included the most stringent measures for the design of their wastewater treatment unit.

Table 7-12 Proposed BACM Controls, VOC Emission Limits, and Monitoring Methods for Wastewater Treatment

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Methods
VOC	56	Carbon adsorber	500 ppm (above background)	Monitored at intervals $\leq 20\%$ of design carbon replacement interval
		Closed vent system	500 ppm (above background)	Method 21, semi-annual inspections
		Individual drain system water seal	None	Monthly visual inspections
		Sealed junction boxes and oil-water separators	None	Semiannual visual inspections

7.9 Product Loading

Unit 87 consists of truck and rail loading/unloading operations. Truck loading and unloading operations consist of sixteen crude/gas/oil/NGL truck unloading bays, one NaSH truck loading spot, three caustic truck unloading spots, two sulfur truck loading arms, one fuel oil truck loading spot, one fuel oil truck unloading spot, one asphalt truck loading spot, one diesel truck unloading spot, one light cycle oil truck unloading spot, two propane truck loading spots, one kerosene truck loading spot, one gasoline truck unloading spot, fourteen fuel oil or asphalt loading spots, twenty-four lube oil loading spots, and, two dedicated ethanol unloading areas.

The rail operations consist of two NaSH/caustic rail car loading/unloading spots, four fuel oil/asphalt rail car loading/unloading spots, four oil/diesel/caustic rail car loading/unloading spots and ethanol rail car unloading spots, four NGL rail car loading/unloading spots, five NGL/olefin rail car loading/unloading spots, and, two biodiesel rail car unloading spots.

7.9.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Several control technologies were identified to reduce product loading emissions. They include use of submerged or bottom loading, installation of a vapor balance system and vapor recovery or destruction technologies which include carbon adsorption, condensation, and incineration.

7.9.2 Step 2 - Eliminate Technically Infeasible Options

All control technologies identified in Step 1 are technically feasible.

7.9.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Vapor recovery through carbon adsorption or condensation provides the most effective control of emissions by collecting the vented material for recycle or reuse. Vapor destruction through incineration provides control of emissions by combustion of the hydrocarbon to form CO₂ and H₂O vapor. Individually, each identified control technology has approximately the same control effectiveness. Each technology, when applied to the exhaust stream from a loading rack will reduce VOC emissions in excess 98%.

The use of submerged or bottom loading as a means of control offers the low cost way to control loading emissions. A significant reduction in vapor generation is possible by decreasing the turbulence created when liquid is introduced into a compartment. This can be done through the use of bottom or submerged loading rather than splash loading.

In vapor balancing, hydrocarbon vapors are collected from the compartment where the liquid is being loaded and returned to the tank from which the liquid is being sent. This balancing works since the volume of displaced vapors is almost identical to the volume of liquid removed from the tank. This technique is most effective when loading tank trucks from fixed roof tanks. Vapor balancing cannot be applied when loading from floating roof tanks since there is no closed vapor space in the tank to which vapors can be returned.

7.9.4 Step 4 - Evaluate Impacts and Document Results

VOC emissions from loading/unloading are a function of the vapor pressure of the liquid and the design of the equipment. Liquids with very low vapor pressure, diesel, kerosene, caustic, NaSH, asphalt will have limited VOC emissions.

At the refinery, HollyFrontier only load/unloads fuels such as oil, gas oil, asphalt, NaSH, kerosene, diesel, and ethanol, all of which have low volatility. The majority of the crude and refined products are brought in and shipped out via pipeline which is a closed system. For products with low vapor pressures that are loaded at the rail and truck spots, the reduction of VOC emissions from excess vapors is accomplished through the use of submerged or bottom loading as well as vapor balancing. For truck loading, control of VOC emissions is through vapor balancing. For VOC emissions from LPG railcar unloading, a vapor recovery system consisting of recovery of LPG emissions by pumping back into the tank.

Gasoline, diesel, and jet fuel from the HollyFrontier Woods Cross Refinery are sent to the Holly Energy Partners Terminal via pipeline. A loading rack is utilized to load these products into tanker trucks. The Terminal has four loading bays for local sales of diesel, jet fuel, and gasolines. A limit of 4.5 million barrels per year of fuels dispensed is specified in the DAQE-AN0101230023B-07 for the Terminal. The Terminal is equipped with a John Zink Model JZ1017886 VRU that captures and recovers hydrocarbon vapors that are displaced during bulk loading operations at the Woods Cross Terminal. The VRU consists of two carbon collection beds operated and regenerated alternately. The two beds vent to the atmosphere through a common stack. John Zink has provided a guarantee to limit hydrocarbon emissions from exceeding 10 milligrams per liter of product loaded for any consecutive six-hour period during normal operation.

In the event the VRU is not operational, a natural-gas fired John Zink VCU is also available as a backup to control emissions of volatile hydrocarbons. Hydrocarbon vapors from gasoline truck loading flow to a condensate collection tank. This tank is important to the operation of the VCU. It allows any condensed liquid and overfill of the transport vehicles to be removed prior to the combustion step. The design basis for the VCU is based on a maximum truck loading rate of 4,500 gallons per minute (gpm), a maximum vapor flow to the combustor of 601 standard cubic feet per minute (SCFM), ambient temperatures ranging from 20 to 100°F, and a maximum hydrocarbon concentration of 60 volume percent. Available pressure at inlet of vapor combustion is 12" W.C. The VCU operation is limited to 1,056 hours per year.

7.9.4.1 Energy, Environmental, and Economic Costs

Routing the emissions from low VOC products that are loaded or unloaded from trucks and railcars at the refinery to a regenerative thermal oxidizer (RTO) was examined. Based on HollyFrontier's 2015 annual emission inventory, VOC emissions from loading/unloading sulfur, asphalt, kerosene, stove oil, fuel oil, ethanol, crude, and gas oil were approximately 3.5 tons per year. The cost effectiveness for installation of a regenerative thermal oxidizer is approximately \$175,000 per year including the increase in VOC emissions from combustion. In addition, additional energy in the form of natural gas will be needed to fuel the RTO leading to increased VOC emissions. Thus, it was determined that use of a RTO was not cost, energy, or environmentally effective and was not considered BACT for this analysis.

7.9.5 Step 5 - Proposed BACM

BACM for HollyFrontier is the delivery of crude and high VOC products through pipeline and the use of a VRU and VCU at the terminal loadout. BACM for the tanker and railcar loading and unloading at the Woods Cross Refinery is the use of submerged or bottom loading as well as vapor balancing.

The most stringent measures identified for product loading for tank truck and rail car loading includes a submerged pipe fill and vapor collection system vented to a thermal incinerator with a destruction efficiency >98.5%. As mentioned above, the installation of a thermal incinerator would increase VOC emissions and is not cost effective. Thus, the installation of a thermal incinerator does not represent BACT for emissions of VOC from railcar and tanker truck loading/unloading at the Woods Cross Refinery.

7.10 Diesel Emergency Engines

Diesel emergency equipment at the Woods Cross refinery consists of a 135 kW portable diesel generator at the East Tank Farm, 224 HP diesel powered water well No. 3, 393 HP fire pump No. 1, 393 HP fire pump No. 2, 180 HP diesel fire pump, three 220 HP diesel-powered plant air backup compressors, 470 HP diesel standby generator at the Boiler House, 380 HP diesel standby generator at the Central Control Room, and a 540 HP diesel standby generator.

VOC emissions are primarily the result of incomplete combustion of the diesel fuel. These emissions occur when there is a lack of available oxygen, the combustion temperature is too low, or if the residence time in the cylinder is too short.

7.10.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following control options were evaluated for controlling VOC emissions from the CI combustion engines. They include: good combustion practices and the post-combustion control technologies of diesel oxidation catalysts.

7.10.1.1 Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The emergency generators are designed to achieve maximum combustion efficiency. The manufacturer provided operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

7.10.1.2 Diesel Oxidation Catalyst

A diesel oxidation catalyst (DOC) is a flow-through metal or ceramic substrate coated with platinum or other precious metals. The diesel oxidation catalyst sits in the exhaust stream and all exhaust from the engine passes through it. The catalyst promotes the oxidation of unburned CO and HC (as VOC) in the exhaust producing CO₂ and water. Diesel oxidation catalysts are commercially available and reliable for controlling VOC emissions from diesel engines.

7.10.2 Step 2 - Eliminate Technically Infeasible Options

The control technologies identified in Step 1 are technically feasible.

7.10.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The control effectiveness of each identified control technology is as follows:

- > Diesel oxidation catalyst – 95%
- > Combustion controls – baseline

7.10.4 Step 4 - Evaluate Impacts and Document Results

For diesel engines, oxidation catalysts are often combined with particulate filters. This can be done by applying the catalysts, which are typically platinum based, to a particulate filter. Another common approach is to located the oxidation catalyst separately, upstream of the particulate filter. The oxidation catalyst creates heat by oxidizing unburned hydrocarbons and shifts NO_x creating a favorable environment for the particulate filters to regenerate.

7.10.4.1 Energy, Environmental, and Economic Impacts

The highest ranking control option, DOC, can reduce VOC emissions up to 95%. A cost effectiveness evaluation for this top ranking option, in costs per ton of VOC removed, is presented in Table 7-13 and in Appendix B. Costs for DOCs were obtained from Wheeler Machinery.

Table 7-13 Cost Effectiveness of Installing DOC on Emergency Diesel Engines for VOC Control

Equipment	Cost Effectiveness (\$/Ton)
135 kW generator (east tank farm)	\$ 67,074
224 HP (water well #3)	\$ 1,481,981
393 HP Fire Pump #1	\$ 1,456,046
393 HP Fire Pump #2	\$ 1,456,046
220 HP plant air backup compressor #1	\$ 497,006
220 HP plant air backup compressor #2	\$ 497,006
220 HP plant air backup compressor #3	\$ 497,006
470 HP diesel generator (boiler house)	\$ 1,475,701
380 HP diesel generator (central control room)	\$ 1,466,543
540 HP standby generator	\$ 1,678,418

As seen from Table 7-13, it is not cost effective to install DOC on the emergency diesel generators.

7.10.5 Step 5 - Proposed BACM

As mentioned above, California has the most aggressive emission reduction standards for diesel engines. The MSC method includes the use of DOCs to reduce VOC emissions as well as the use of ultra-low sulfur fuel, limited hours of operation, and good combustion practices and engine maintenance. (See RBLC ID NJ-0085 and NJ-0084 which indicates these controls to be LAER).

40 CFR 60, Subpart IIII applies to engines which commenced construction after 7/11/2005 and are manufactured after 4/1/2006 (for non-fire-pump engines), or an engine modified or reconstructed after 7/11/2005. Subpart IIII applies to the emergency diesel equipment at the refinery. Records of maintenance and hours of operation are kept. A non-resettable totalizer is installed on each emergency diesel engine. Maintenance is performed on the engines in accordance with manufacturer specifications. Oil/filters are changed and belts/hoses inspected every 500 hours or annually.

Based on the economic evaluation presented in Table 7-13, DOC's are not cost effective for the emergency generators or the fire water pumps at the Woods Cross Refinery and have been eliminated from further consideration. The cost effectiveness of an oxidation catalyst includes general maintenance, assuming proper operation of the system. If poisoning of the catalyst occurs, replacement of the catalyst will occur more frequently which increases the cost of control. In addition, engine valves/heads beyond the typical maintenance schedule will add to the maintenance costs.

Thus, for the emergency diesel equipment at HollyFrontier, BACM was determined to be limited hours of operation of the diesel engines (50 hours per year for each engine with the exception of the East Tank Farm portable diesel generator which is permitted to operate 1,100 hours per year), the use of ultra-low sulfur diesel, good combustion practices, and best practice of periodic maintenance. Engines will be maintained and operated in accordance with manufacturer recommendations.

The most stringent measure identified was any engine certified or verified to achieve the CARB applicable standard, which, for units in the size of HollyFrontier's, is 4 g/KW-hr.

The proposed BACM, emission limitations, and monitoring methods for the emergency diesel engines are presented in Table 7-14.

Table 7-14 Proposed BACM Controls, VOC Emission Limitations, and Monitoring Methods for Emergency Diesel Engines

Pollutant	Units	Control Technology	Emission Limitations	Monitoring
VOC	All emer. Engines except ETF gen.	GCP	600 hours total rolling 12-month period	Non-resettable hour meter
	ETF portable generator		1100 hours per rolling 12-month period	

7.11 Emergency Natural Gas-Fired Engines

Combustion is a thermal oxidation process where carbon and hydrogen contained in the fuel combine with oxygen in the combustion zone to form H₂O and CO₂. VOC's are generated during the combustion process due to incomplete thermal oxidation of the carbon contained in the fuel. In properly designed and operated generators, low levels of VOC's are typically emitted.

7.11.1 Step 1- Identify all Control Technologies

Three potential control technologies were identified to reduce VOC emissions. They are:

- > good combustion practices,
- > oxidation catalysts, and
- > NSCR as an add-on control device.

7.11.1.1 Good Combustion Practices

Optimization of the design, operation, and maintenance of an engine is one way to reduce VOC emissions by maximizing the thermal oxidation of carbon which minimizes the formation of VOC.

7.11.1.2 Oxidation Catalysts

An oxidation catalyst is a flow through exhaust device that contains a honeycomb structure covered with a layer of chemical catalyst. This layer contains small amounts of precious metal-usually platinum or palladium-that interact with and oxidize pollutants in the exhaust stream (CO and unburned HCs), thereby reducing emissions.

7.11.1.3 Non-Selective Catalytic Reduction

NSCR is a catalytic reactor that simultaneously reduces VOC emissions. The catalytic reactor is placed in the exhaust stream of the engine and requires fuel-rich air-to-fuel ratios and low oxygen levels.

7.11.2 Step 2 - Eliminate Technically Infeasible Options

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich burn turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective VOC reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines cannot be retrofitted with NSCR control because of the reduced exhaust temperatures. Thus, NSCR was eliminated from consideration since the engines operated by HollyFrontier at the administration building are designed for lean burning. The remaining control technologies are technically feasible.

7.11.3 Step 3 - Rank Remaining Control Technologies by Effectiveness

The use of an oxidation catalyst is the remaining top ranking control technology which provides a 90% control efficiency for VOCs. Good combustion practice is the second ranking control technology for VOC reduction.

7.11.4 Step 4 - Evaluate Most Effective Controls

Combustion controls are integral in the combustion process as they are designed to achieve an optimum balance between thermal efficiency-related emissions (CO and VOC) and temperature related emissions (NO_x). Combustion controls will not create any energy impacts or significant environmental impacts. There are no economic impacts from combustion controls because they are part of the design for modern engines.

Natural gas generators are regulated by 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. Here, the EPA provides emissions standards manufacturers must meet, emissions standards owners/operators must meet, EPA certification requirements, testing requirements, and compliance requirements.

According to Subpart JJJJ, the VOC emission standards for stationary emergency engines >25 HP is 1.0 g/HP-hr or 86 ppmvd @ 15% O₂. The HollyFrontier natural-gas fired emergency generators were manufactured in 2012 and as such, meet the Subpart JJJJ VOC emission standard of 1.0 g/HP-hr.

7.11.4.1 Energy, Environmental, and Economic Costs

Catalytic oxidation is relatively expensive for the size of the engines and the frequency of their use at the Woods Cross Refinery. The capitol cost to install an oxidation catalysts is approximately \$59,000. Annual costs are approximately \$18,700. The cost in \$/ton of VOC removed is estimated to be over \$6 million dollars. (See Appendix B). Thus, it is not economically feasible to install oxidation catalysts on the emergency natural-gas fired generators at the Woods Cross Refinery. There are no additional energy or environmental costs associated with operating an oxidation catalyst on the natural-gas fired emergency generators. There is no fuel penalty associated with the use of an oxidation catalysts since this control technology does not increase the fuel usage in an SI engine.

7.11.5 Step 5 - Select BACT

The most stringent control measure identified is the use of an oxidation catalyst achieving a VOC emission rate of 0.15 g/bhp-hr. This emission rate has been achieved in practice.

BACT for VOC emissions from 2012 model year SI ICE generators at HollyFrontier is the application of a lean burn engine fired on natural gas, good combustion practices, limited operating hours, and operation in accordance to manufacturer's recommendations. The generators are EPA certified and the manufacturer lists a VOC emission rate of 1.0 g/HP-hr or 86 ppmvd @ 15% O₂. The engines are in compliance with the applicable emission limits of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ. The proposed controls satisfy BACM.

The proposed BACM controls, VOC emission limitations, and compliance monitoring method conducted by HollyFrontier for the emergency natural gas-fired engines are summarized in Table 7-15.

Table 7-15 Proposed BACM Controls, Emission Limitation, and Monitoring for Emergency Natural Gas Engines

Pollutant	Units	Control Technology	Emission Limitation	Monitoring Method
VOC	Nat. gas fired emergency engines	Work Practice Requirements, Good Combustion Practice	600 hours total rolling 12-month period for all emergency engines 1.0 g/HP-hr	Non-resettable hour meter

8.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR AMMONIA

BACM's were evaluated for ammonia emissions for certain emission units in operation or proposed at the Woods Cross Refinery. These emission units include: process heaters and boilers equipped with SCR, waste water treatment, FCCU, and sour water stripper.

8.1 Process Heaters and Boilers

Ammonia emissions from process heaters and boilers are a result of the ammonia slip from units that utilize SCR or SNCR to control NO_x emissions. Ammonia slip refers to emissions of unreacted ammonia that result from the incomplete reaction of the NO_x and the reagent.

8.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

A search of EPA's BACT/RACT/LAER Clearinghouse, state databases, and published literature did not identify application of emission controls to control ammonia emissions from process heaters and boilers. Ammonia slip emissions can occur when a process heater or boiler is equipped with an SCR and SNCR.

As discussed more fully in Section 4.1.1.4, SCR uses a catalyst to react injected ammonia to chemically reduce NO_x. It can achieve up to a 90% removal efficiency and is one of the most effective NO_x abatement techniques.

In SNCR, which is discussed in more detail in Section 4.1.1.5, ammonia or urea is injected within a boiler or in ducts in a region where temperature is between 900°C and 1100°C. This technology is based on temperature ionizing the ammonia or urea instead of using a catalyst. This temperature "window" is important because outside of it either more ammonia "slips" through or more NO_x is generated than is being chemically reduced. The temperature "window" is different for urea and ammonia. Reduction of the NO_x by SNCR can have up to a 50% removal efficiency.

8.1.2 Step 2 - Eliminate Technically Infeasible Options

There are no ammonia emissions from the combustion of natural gas or refinery gas from the boilers or process heaters except for those units that are equipped with a post-control add-on devices such as SCR or SNCR. As discussed above, SNCR was eliminated from due to the optimum exhaust gas temperature range for the boilers and process heaters were below implementation of SNCR which is 1,600 to 1,750°F for ammonia and from 1,000 to 1,900°F for urea-based reagents.

8.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

SCR is the remaining control technology that utilizes ammonia to reduce NO_x emissions. SCR is being utilized or proposed for certain large process heaters and boilers (10H2, 27H1, 30H1, 30H2, 33H1, and boilers #5, #8, #9, #10, #11) to reduce NO_x emissions at the Woods Cross Refinery.

8.1.4 Step 4 - Evaluate Impacts and Document Results

Ammonia slip associated with SCR system operation results from the gradual decline in catalyst activity over time, necessitating the use of increasing amounts of ammonia injection to maintain NO_x concentrations at or below the required emission limits. The parameters of NO_x concentration, ammonia slip limit, and catalyst life are integrally related. According to representative from Haldor Topsoe Inc., catalyst performance is generally specified as being a particular NO_x concentration guaranteed for 3 years. However, according to discussions with Topsoe, with burning natural gas or other clean fuels, catalyst life can be expected to last 6 to 8 years. With fresh catalyst, high performance is seen resulting in high NO_x reduction and low ammonia slip and as the catalysts deactivates, the ammonia injection rate will increase slightly and consequently also will the ammonia slip.

Stack testing on the boilers at the Woods Cross Refinery shows ammonia concentrations as non-detect. According to RBLC, an ammonia slip of 10 ppmv at 3% O₂ is a typical limit for process heaters and boilers equipped with SCR. Table 8-1 presents a summary of the BACM for ammonia for process heaters and boilers.

Table 8-1 Summary of BACM Determinations for Ammonia for Process Heaters and Boilers

Facility	Permit Date	Size (MMBtu/hr)	Limit (lb/MMBtu)	Control Technology
M&G Resins USA, LLC Project Jumbo, Texas	12/01/2014	142.82	10 ppmvd (hourly and annual)	Ammonia slip is 10 ppmvd – four heaters with LNB and SCR
Formosa Plastics Corp. Olefins Plant, Texas	08/08/2014	None listed	15 ppmvd (one-hour avg) 10 ppmvd (annual)	Ammonia slip is 15 ppmvd on an hourly basis and 10 ppmvd on an annual basis. Cracking furnaces and PDH reactors will use low-NO _x burners, Selective Catalytic Reduction (SCR), good engineering design/combustion practices.
Diamond Shamrock Refining Company, Valero Com McKee Refinery, Texas	12/30/2010	355.65	10 ppmv @3% O ₂	Ammonia slippage from SCR is limited to 10 ppmv at 3% oxygen.
Valero Delaware City Refinery, Delaware	02/26/2010	240, 446, 504	10 ppmvd@3% O ₂	Ammonia slip from SCR.

8.1.4.1 Energy, Environmental, and Economic Impacts

The environmental impacts of SCR include ammonia emissions and disposal of spent catalyst after a catalyst's lifetime. The catalysts typically used for SCR contain metals that may require special handling and disposal measures in accordance with Resource Conservation and Recovery Act (RCRA) regulations. Higher injection rates of ammonia are required to increase the control efficiency of SCR; however, these higher injection rates correspond with higher levels of ammonia slip, which can contribute to haze. Control of NO_x emissions should be balanced with limiting ammonia slip through proper catalyst use, ensuring good mixing of the ammonia reagent in the flue gas, and careful control of the ammonia injection rate when fuel loads change, thus changing the ammonia and flue gas NO_x reaction dynamics.

Ammonia storage and handling must be conducted with care because ammonia is a hazardous material. The use of SCR may cause a 1 to 2 percent increase in sulfur trioxide (SO₃) emissions as a result of the catalyst oxidizing SO₂ to SO₃. The SO₃ can further react with ammonia, forming ammonium sulfate and ammonium bisulfate salts, which can contribute to PM_{2.5} emissions.

8.1.5 Step 5 - Select BACT

As seen from table 8-1, an ammonia slip of 10 ppmvd @3% O₂ on an annual basis is considered BACM for process heaters and boilers utilizing SCR. HollyFrontier will maintain, analyze or replace the catalyst, as needed, to insure high NO_x emission reduction and low ammonia slip. Catalysts will be analyzed when ammonia injection rates are being increased to control NO_x within applicable limits. No other measures were identified as more stringent to control of ammonia slip from process heaters or boilers.

The cost of installing and operating an ammonia CEMS to measure slip from boilers with SCR was examined. From cost data provided by MSI/Mechanical Systems Inc. the estimated equipment cost including a shelter (estimated to be approximately \$50,000), the ammonia CEMS and affiliated equipment including installation is \$191,800 per system. Total annual operating costs were estimated to be approximately \$70,700. See Appendix B for a detailed cost analysis.

8.2 Wastewater Treatment

The Waste Water Treatment Plant (WWTP) (Unit 56) treats plant wastewater and storm water runoff from process areas. Wastewater is collected and routed through a grit collector then to a main process lift station. The main process lift station routes process waste water to two American Petroleum Institute (API) separators. Oil is skimmed off the separators and gravity fed to an API oil collection drum then to Tank 118. The sludge from the API separators is collected and dewatered in a sludge thickening vessel and later sent for disposal.

The effluent water from the API separators is pumped to two equalization tanks (Tanks 155 and 158). From the equalization tanks, waste water is pumped into two dissolved gas floatation units (DGF). The DGFs work to remove emulsified oil from the waste water by adding a polymer and inducing small N₂ bubbles into the water to bring oil to the surface. This skimmed oil, or float, is gravity fed to a storage tank before being pumped to the sludge thickening vessel.

Finally the waste water is sent to a series of moving bed bio-film reactors (MBBR) for biological polishing before being discharged to the South Davis County Public Owned Treatment Works (POTW). All process tanks and equipment at the WWTP are covered to control fugitive emissions.

8.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The minimum emission standards that would meet BACT requirements for ammonia emissions are equipment design and work practice requirements. The work practice requirements are presented in 40 CFR Part 60 Subpart QQQ and 40 CFR Part 61 Subpart FF.

Under Title 40 CFR Part 60, Subpart QQQ, performance standards have been established for individual drain systems, including:

- > Each drain shall be equipped with a water seal
- > Junction boxes shall be equipped with a cover and may have an open vent
- > Sewer lines shall not be open to the atmosphere
- > Regular inspection and maintenance requirements.

Also under Title 40 CFR Part 60, Subpart QQQ, performance standards have been established for closed vent systems and control devices, including:

- > Any control device shall operate with an efficiency of 95 percent or greater to reduce VOC emissions vented to them
- > All control devices shall be operated with no detectable emissions, as indicated by an instrument reading of 500 parts per million VOC above background.

Under 40 CFR Part 61, Subpart FF, the benzene NESHAP regulations require that petroleum refineries use maximum achievable control technology (MACT) to control emissions of benzene from waste operations, including certain wastewater systems. This includes use of carbon absorption or collection and venting of wastewater gases to the refinery flare system (vent flap system) to control benzene emissions from wastewater systems in compliance with the refinery NESHAP requirements.

VOC emissions from wastewater collection systems can be controlled in a variety of ways including enclosing or controlling all openings, changing the operation of the units that are feeding the wastewater collection system, having an inspection and maintenance (I&M) program, or a combination of controls.

8.2.2 Step 2 - Eliminate Technically Infeasible Options

Water stripping, floating roofs for treatment vessels, and incineration are technically infeasible for application to process drains. The requirements of Subpart QQQ and Subpart FF are technically feasible.

8.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Equipment control strategies can require the installation of new equipment or devices, or can include physical changes to the wastewater system. Potential control strategies include:

- > Enclosing open weirs and lines with hard piping is the most stringent control option and could result in the greatest amount of VOC emission reductions.
- > Collecting and venting the emissions to a control device can achieve a control efficiency of greater than 95 percent. Potential emission control devices for wastewater collection systems (predominately junction box vents) include: carbon absorption, thermal oxidation, catalytic oxidation, and condensation.
- > Installing water seals on process drains and vents open to the atmosphere would help prevent emissions from the downstream sewer lines from escaping back out of the drain or vent opening. The overall control efficiency of this method is estimated at an average of 65%, and varies depending on the proper maintenance of the water seal.
- > Some control measures, such as water seals, can require an extensive inspection and maintenance (I&M) program in order to be effective. An effective I&M program is designed to inspect (on a regular basis), maintain and repair (as necessary) the pertinent components of a pollution control system for proper operation.
- > By establishing performance-based standards, such as setting an emission limit of 500 ppm VOC from a drain or vent, equivalent emission reduction can be achieved without specifying a particular control technology.

8.2.4 Step 4 - Evaluate Impacts and Document Results

In 2015, HollyFrontier upgraded their wastewater treatment system to include covering oil-water separators with fixed roofs and venting VOC vapors that accumulate under the headspace of the fixed roofs through a closed system to carbon adsorption units, equipping new unit drains with water seals, and covering new junction boxes. Monthly visual inspections are performed on the individual drain systems and semi-annual inspections are performed on the closed vent system and sealed junction boxes and oil/water separators.

The waste water fugitives from the DGF's and MBBR are controlled through carbon adsorption. Carbon adsorber monitoring is performed at intervals no greater than 20 percent of the design carbon replacement intervals. Large carbon systems are in place on the DGF and MBBR units. Carbon is replaced within 24 hours if monthly monitoring detects a breakthrough of the carbon bed.

Performance based standards exist at the refinery with emission limits for VOC of 500 ppm above background for the American Petroleum Institute (API) carbon adsorber and the closed vent system.

8.2.4.1 Energy, Environmental, and Economic Impacts

No significant negative energy, environmental, or economic issues result from the wastewater treatment system meeting the requirements of 40 CFR Part 60 Subpart QQQ and 40 CFR Part 61 Subpart FF.

8.2.5 Step 5- Select BACT

Ammonia emissions from the wastewater treatment system built after the compliance date meet the requirements of 40 CFR 60 Subpart QQQ and 40 CFR Part 61 Subpart FF. Emissions from the wastewater system control device comply with Subpart QQQ and are monitored in accordance with 40 CFR 60.695. Subpart FF requires that the oil water separators be equipped with a fixed roof and vapors directed to a control device which HollyFrontier has installed. In addition, HollyFrontier has covered each new unit drain system opening and vapors from the drain system are vented from the drain to a control device. No more stringent control measures were found other than compliance with Subparts QQQ and FF.

8.3 FCCU

Fluidized catalytic cracking units (FCCUs) are complex processing units at refineries that convert heavy components of crude oil into light, high-octane products that are required in the production of gasoline. The FCCU is named because the catalyst comes in such small particles that it flows like a fluid. During the reaction phase, the catalyst becomes coated with petroleum coke, which must be burned off in the catalyst regenerator so that the catalyst can be reused. The catalyst regenerator exhaust contains ammonia, among several other pollutants including SO_2 , NO_x , $\text{PM}_{2.5}$ and VOC.

An FCCU consists of two vessels. In the reactor vessel, the conversion reaction occurs in the presence of a fine, powdered catalyst and steam. During the conversion reaction the catalyst becomes coated with petroleum coke. In the regenerator vessel, this coke is removed from the surface of the spent catalyst by burning it off in the presence of air so that the catalyst can be reused. The cracked products from the reactor vessel are separated in a fractionator column into intermediate streams for further processing.

FCCU particulate emissions (PM) can be classified as primary or secondary PM emissions. Secondary PM emissions are not particulate matter when emitted, but are precursors to the atmospheric formation of $\text{PM}_{2.5}$. Most of the secondary $\text{PM}_{2.5}$ formed consists of ammonium sulfate and ammonium nitrate particles formed by reactions between ammonia and NO_x and SO_2 in air.

8.3.1 Steps 1 - 4

No specific control technologies were identified for control of ammonia emissions from a FCCU. As such, the ammonia BACM is based on the reduction of secondary $\text{PM}_{2.5}$ emissions. $\text{PM}_{2.5}$ control strategies for an FCCU are presented in Section 6.5 above.

8.3.2 Step 5 - Select BACT

As presented in Section 6.5.5, according to the RBLC, wet scrubbers are used extensively as one method to reduce particulate from FCCUs and a wet gas scrubber are utilized by Holly to reduce PM and ammonia emissions from the FCCU's. Thus, a wet gas scrubber is considered BACM for reduction of ammonia from the FCCU regenerator stack. Stack testing has been performed for ammonia on the wet gas scrubbers and ammonia concentrations were between 0.4 to 0.6 ppm.

No more stringent measures were identified to control ammonia emissions from FCCU regenerator vents.

8.4 Sour Water Stripper and Ammonia Stripping Unit

Sour water containing ammonia is drained from process vessels throughout the refinery into an enclosed drain system which collects to storage Tank 166. Sour water is then pumped to the sour water stripper (Unit 18) where steam is used to strip the ammonia from the sour water. The ammonia vapors are sent to the ammonia stripping unit (Unit 22).

8.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

There are various control technologies available to control ammonia emissions which include both add-on control devices and pollution prevention techniques. The wet scrubber, specifically the packed tower scrubber, has been successfully used to control ammonia emissions, demonstrating control efficiencies up to 99%. Condensers are also used to remove ammonia by converting the gas to a liquid. With regards to ammonia leakage, good management practices can reduce the amount of ammonia that escapes.

8.4.2 Step 2 - Eliminate Technically Infeasible Options

Since the ammonia vapors from the sour water stripper are mixed with water to form ammonia liquid (35% aqua ammonia) at the ammonia stripping unit, no add-on control technologies are considered to be technically feasible and thus are eliminated from this analysis.

The remaining control, good management practices is considered to be technically feasible.

8.4.3 Steps 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Good management practices is the remaining top ranking control to reduce ammonia emissions from the ammonia stripping unit at HollyFrontier.

8.4.4 Step 4 - Evaluate Impacts and Document Results

As mentioned above, the ammonia vapors are mixed with water to form ammonia liquid which is further diluted with water to either 20% or 30% strength. This ammonia liquid is stored in Tanks 124 and 125 from which it is loaded for sale by truck. Tanks 124 and 125 are horizontal elliptical high pressure tanks with no anticipated emissions.

Best management practices are observed at the Woods Cross Refinery to reduce ammonia emissions from the sour water stripper and ammonia stripping unit. These practices include following manufacturer operation and maintenance recommendations, maintaining pumps and blowers, maintaining proper air and water flows, and safe guarding against potential hazards due to leaks and spills of ammonia.

8.4.4.1 Energy, Environmental, and Economic Impacts

No significant negative energy, environmental, or economic issues result from the use of best management practices for the control of fugitive ammonia emissions from the ammonia stripping unit.

8.4.5 Step 5 - Select BACT

The use of best management practices for control of ammonia emissions is considered best available control measures for the sour water stripper and ammonia stripping unit. No other measures were identified as more stringent to control ammonia emissions.

APPENDIX A

List of Refinery Permitted Equipment

Emission Unit Information - HollyFrontier Woods Cross Refinery

A.O. #	Source #	Source Description	Status	Capacity	Control Technology
II.A.3	4H1	FCC Feed Heater	In Service	68.4 MMbtu/hr	LNB
II.A.6	4V82	FCC Scrubber	In Service		
--	FCC 34"	FCC Flue gas bypass 34" stack	Decom.		
II.A.10	6H1	Reformer Reheat Furnace	In Service	54.7 MMbtu/hr	
II.A.11	6H2	Prefractionator Reboiler Heater	In Service	12.0 MMbtu/hr	
II.A.12	6H3	Reformer Reheat Furnace	In Service	37.7 MMbtu/hr	
II.A.16	7H1	HF Alkylation Regen. Furnace	In Service	4.4 MMbtu/hr	
II.A.17	7H3	HF Alkylation Deprop. Reboiler	In Service	33.3 MMbtu/hr	
--	8H1	Crude Furnace # 1	Decom.		
II.A.19	8H2	Crude Furnace # 1	In Service	99.0 MMbtu/hr	NGULNB
II.A.21	9H1	DHDS Reactor Charge Heater	In Service	8.1 MMbtu/hr	
II.A.22	9H2	DHDS Stripper Reboiler	In Service	4.1 MMbtu/hr	
II.A.24	10H1	Asphalt Mix Heater	In Service	13.2 MMbtu/hr	
II.A.25	10H2	Hot Oil Furnace	In Service	99.0 MMbtu/hr	LNB + SCR
II.A.27	11H1	SRGP Depentanizer Reboiler	In Service	24.2 MMbtu/hr	
II.A.30	12H1	NHDS Reactor Charge Furnace	In Service	50.2 MMbtu/hr	NGULNB
II.A.32	13H1	Isom. Reactor Feed Furnace	In Service	6.5 MMbtu/hr	
II.A.35	TGI-SRU	Tail Gas Incinerator - Sulfur Recovery Unit	In Service		
II.A.38	19H1	DHT Reactor Charge Heater	In Service	18.1 MMbtu/hr	LNB
II.A.40	20H1	Reactor Charge Heater	Decom.		
II.A.41	20H2	Fractionator Charge Heater	In Service	47.0 MMbtu/hr	ULNB
II.A.42	20H3	Fractionator Charge Heater	In Service	42.1 MMbtu/hr	ULNB
II.A.46	23H1	Reformate Splitter Reboiler Heater	In Service	21.0 MMbtu/hr	NGULNB
II.A.48	24H1	Crude Unit Furnace	In Service	60.0 MMbtu/hr	ULNB
II.A.50	25H1	FCC Feed Heater	In Service	45.0 MMbtu/hr	ULNB
II.A.51	25FCC	FCC Scrubber	In Service		
II.A.54	27H1	Reactor Charge Heater	Not Built	99.0 MMbtu/hr	LNB+SCR
II.A.57	30H1	Hydrogen Reformer Feed Furnace	Not Built	123.1 MMbtu/hr	LNB+SCR
II.A.58	30H2	Hydrogen Reformer Feed Furnace	Not Built	123.1 MMbtu/hr	LNB+SCR
II.A.60	33H1	Vacuum Furnace Heater	Not Built	130.0 MMbtu/hr	LNB+SCR, air preheat
II.A.78	66-1	Process Flare South	In Service		
II.A.79	66-2	Process Flare North	In Service		
II.A.81	68H2	North In-Tank Asphalt Heater	In Service	0.8 MMbtu/hr	
II.A.82	68H3	South In-Tank Asphalt Heater	In Service	0.8 MMbtu/hr	
II.A.83	68H4	Northwest In-Tank Asphalt Heater	In Service	0.8 MMbtu/hr	
II.A.84	68H5	North East In-Tank Asphalt Heater	In Service	0.8 MMbtu/hr	
II.A.85	68H6	South East In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.86	68H7	Southwest In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.87	68H10	North In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.88	68H11	South In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.89	68H12	North In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.90	68H13	South In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	

Emission Unit Information - HollyFrontier Woods Cross Refinery

Unit ID	Source ID	Source Description	Status	Capacity	Control Technology
II.A.63	Boiler #4	Boiler #4	In Service	35.6	
II.A.64	Boiler #5	Boiler #5	In Service	70.0	SCR
II.A.65	Boiler #8	Boiler #8	In Service	92.7	LNB+SCR
II.A.66	Boiler #9	Boiler #9	In Service	89.3	SCR
II.A.67	Boiler #10	Boiler #10	In Service	89.3	SCR
II.A.68	Boiler #11	Boiler #11	Not Built	89.3	LNB+SCR
II.A.70	CWT#4	Cooling Tower #4	In Service		
II.A.71	CWT#6	Cooling Tower #6	In Service		
II.A.72	CWT#7	Cooling Tower #7	In Service		
II.A.73	CWT#8	Cooling Tower #8	In Service		
II.A.74	CWT#10	Cooling Tower #10	In Service		
II.A.75	CWT#11	Cooling Tower #11	In Service		
II.A.219	ETF	East Tank Farm Portable Diesel Gen.	In Service		
II.A.223		Water Well #3	In Service	224 HP	
II.A.223		Fire Pump #1 (Caterpillar)	In Service	393 HP	
II.A.223		Fire Pump #2 (Caterpillar)	In Service	393 HP	
II.A.223		Fire Pump (Detroit Diesel)	In Service	180 HP	
II.A.223		Backup Diesel Compressor #1	In Service	220 HP	
II.A.223		Backup Diesel Compressor #2	In Service	220 HP	
II.A.223		Backup Diesel Compressor #3	In Service	220 HP	
II.A.223		Boiler House Cummins Generator	In Service	470 HP	
II.A.223		Central Control Generator	In Service	380 HP	
II.A.223		Standby Generator	In Service	540 HP	
II.A.224		Admin. Building Standby	In Service	142 KW	
II.A.224		Admin. Building Standby	In Service	142 KW	
II.A.220, II.A.221	Unit 87	Loading/Unloading	In Service		
II.A.76	Unit 56	Wastewater Treatment	In Service		
--	Tank 4		Removed		
II.A.91	Tank 11	Empty-Out of Service	No service	8,961 bbl	Vertical floating roof
II.A.92	Tank 12	Reformer Charge	In Service	9,868 bbl	Internal floating roof
II.A.93	Tank 14	K-1 Kerosene	In Service	2,539 bbl	Vertical floating roof
II.A.94	Tank 15	Fuel Oil #5 WX Input	In Service	4,692 bbl	Vertical floating roof
II.A.95	Tank 19	Stove Oil WX Input	In Service	6,986 bbl	Vertical floating roof
II.A.96	Tank 20	Stove Oil WX Input	In Service	7,372 bbl	Vertical floating roof
II.A.97	Tank 21	Olefin	In Service	--	--
II.A.98	Tank 23	Distillate fuel oil no. 2	In Service	10,481 bbl	Vertical floating roof
II.A.99	Tank 24	Distillate fuel oil no. 2	In Service	14,035 bbl	Vertical floating roof
II.A.100	Tank 28	Stove Oil WX Input	In Service	28,340 bbl	Vertical floating roof
II.A.101	Tank 29	Caustic	In Service	--	--
II.A.102	Tank 31	Residual oil no. 6	In Service	22,480 bbl	Vertical floating roof
II.A.103	Tank 35	Gas Oil	In Service	98,703 bbl	Vertical floating roof
II.A.104	Tank 37	Fuel Oil	In Service	2,865 bbl	Vertical floating roof
II.A.105	Tank 42A	Jet Fuel Additive	In Service	--	--
II.A.106	Tank 47	#2 ULSD	In Service	--	--

Emission Unit Information - HollyFrontier Woods Cross Refinery

A.O. ID	Source ID	Source Description	Status	Capacity	Control Technology
II.A.107	Tank 48	Light Cycle Oil	In Service	27,194 bbl	Vertical floating roof
--	Tank 49		Removed		
II.A.108	Tank 50	Empty-Out of Service	No Service	690 bbl	Horizontal
II.A.109	Tank 51	Empty-Out of Service	No Service	580 bbl	Horizontal
II.A.110	Tank 52	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.111	Tank 53	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.112	Tank 54	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.113	Tank 55	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.114	Tank 56	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.115	Tank 57	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.116	Tank 58	Residual oil no. 6	In Service	13,647 bbl	Vertical floating roof
II.A.117	Tank 59	Empty-Out of Service	No Service	24,656 bbl	Vertical floating roof
II.A.118	Tank 60	Caustic	In Service		Vertical floating roof
II.A.119	Tank 61	#2 ULSD	In Service		
II.A.120	Tank 63	Stove Oil WX Input	In Service	29,490 bbl	Vertical floating roof
II.A.121	Tank 64	#2 Raw Diesel	In Service		
II.A.122	Tank 65	#2 Raw Diesel	In Service		
II.A.123	Tank 70	Gas Oil	In Service	76,819 bbl	Vertical floating roof
II.A.124	Tank 71	Black Wax	In Service	79,944 bbl	Internal floating roof
II.A.125	Tank 72	Gasoline (RVP 8 WX Input)	In Service	124,381 bbl	Internal floating roof
II.A.126	Tank 73	#2 Raw Diesel	In Service		
II.A.127	Tank 74	#2 Raw Diesel	In Service		
II.A.128	Tank 75	#2 Raw Diesel	In Service		
II.A.129	Tank 76	#2 Raw Diesel	In Service		
II.A.130	Tank 77	Stove Oil WX Input	In Service	4,798 bbl	Vertical floating roof
II.A.131	Tank 78	Stove Oil WX Input	In Service	4,798 bbl	Vertical floating roof
II.A.132	Tank 79	Asphalt WX Input	In Service	9,400 bbl	Vertical floating roof
II.A.133	Tank 81	NaHS	In Service		
II.A.134	Tank 82	NaHS	In Service		
II.A.135	Tank 83	Caustic	In Service		
--	Tank 84	Chemical	Removed		
II.A.136	Tank 85	Poly Gasoline	Not Built		
II.A.137	Tank 86	Gas Oil	In Service		
II.A.138	Tank 87	Gas Oil	Not Built		
II.A.139	Tank 88	Hydroisom feed/lube	Not Built		
II.A.140	Tank 89	Hydroisom feed/lube	Not Built		
II.A.141	Tank 90	Hydroisom feed/lube	Not Built		
II.A.142	Tank 91	Hydroisom feed/lube	Not Built		
II.A.143	Tank 92	Hydroisom feed/lube	Not Built		
II.A.144	Tank 93	Hydroisom feed/lube	Not Built		
II.A.145	Tank 94	Hydroisom feed/lube	Not Built		
II.A.146	Tank 95	Hydroisom feed/lube	Not Built		
II.A.147	Tank 96	Hydroisom feed/lube	Not Built		
II.A.148	Tank 97	Hydroisom feed/lube	Not Built		
II.A.149	Tank 98	Gasoline Blendstock	Not Built		
II.A.150	Tank 99	Distillate fuel oil no. 2	In Service	72,821 bbl	Vertical floating roof

Emission Unit Information - HollyFrontier Woods Cross Refinery

A.O. ID	Source ID	Source Description	Status	Capacity	Control Technology
II.A.151	Tank 100	Gasoline (RVP 5 WX Input)	In Service	53,357 bbl	External floating roof
II.A.152	Tank 101	Gasoline (RVP 7 WX Input)	In Service	53,571 bbl	External floating roof
II.A.153	Tank 102	Gas Oil	In Service	53,000 bbl	External floating roof
II.A.154	Tank 103	Gas Oil	In Service	23,648 bbl	Vertical fixed roof
II.A.155	Tank 104	Gasoline (RVP 6)	In Service	24,429 bbl	External floating roof
II.A.156	Tank 105	Gasoline (RVP 6)	In Service	24,500 bbl	External floating roof
II.A.157	Tank 106	Gasoline (RVP 8 WX Input)	In Service	24,524 bbl	External floating roof
II.A.158	Tank 107	Gasoline (RVP 8 WX Input)	In Service	24,500 bbl	External floating roof
II.A.159	Tank 108	Gasoline (RVP 11 WX Input)	In Service	24,452 bbl	External floating roof
II.A.160	Tank 109	Gasoline (RVP 11 WX Input)	In Service	24,500 bbl	External floating roof
II.A.161	Tank 113	Caustic	In Service		
II.A.162	Tank 114	Caustic	In Service		
II.A.163	Tank 116	Caustic	In Service		
II.A.164	Tank 117	API Trap Sludge	In Service		
II.A.165	Tank 118	Recovered Slop	In Service		
II.A.166	Tank 121	Crude Oil (RVP 8 WX Input)	In Service	100,129 bbl	External floating roof
II.A.167	Tank 122	Propane	In Service		
II.A.168	Tank 123	Propane	In Service		
II.A.169	Tank 124	Ammonia	In Service		
II.A.170	Tank 125	Ammonia	In Service		
II.A.171	Tank 126	Crude Oil (RVP 4 WX Input)	In Service	64,667 bbl	External floating roof
II.A.172	Tank 127	Distillate fuel oil no. 2	In Service	29,504 bbl	Vertical fixed roof
II.A.173	Tank 128	Empty-Out of Service	No Service	10,095 bbl	External floating roof
II.A.174	Tank 129	NHDS Charge	In Service		
II.A.175	Tank 130	Caustic	In Service		
II.A.176	Tank 131	Stove Oil WX Input	In Service	64,537 bbl	Internal floating roof
II.A.177	Tank 132	Gasoline (RVP 8 WX Input)	In Service	24,548 bbl	External floating roof
II.A.178	Tank 133	Isobutane	In Service		
II.A.179	Tank 134	Isobutane	In Service		
II.A.180	Tank 135	Naptha WX Input	In Service	44,154 bbl	External floating roof
II.A.181	Tank 136	Propane	In Service		
II.A.182	Tank 138	Stove Oil WX Input	In Service	44,238 bbl	Internal floating roof
II.A.183	Tank 139	SDA Charge	In Service	15,022 bbl	Vertical fixed roof
II.A.184	Tank 140	SDA Charge	In Service	14,810 bbl	Vertical fixed roof
II.A.185	Tank 141	Solvent	In Service		
II.A.186	Tank 143	Empty-Out of Service	No Service	3,022 bbl	Vertical fixed roof
II.A.187	Tank 145	Gasoline (RVP 8 WX Input)	In Service	3,976 bbl	External floating roof
II.A.188	Tank 146	Gasoline (RVP 8 WX Input)	In Service	3,976 bbl	External floating roof
II.A.189	Tank 147	Propane	In Service		
II.A.190	Tank 148	Propane	In Service		
II.A.191	Tank 149	Butane	In Service		
II.A.192	Tank 150	Butane	In Service		
II.A.193	Tank 151	Butane	In Service		
II.A.194	Tank 152	Olefin	In Service		
II.A.195	Tank 153	Olefin	In Service		
II.A.196	Tank 159	NGL	In Service		

Emission Unit Information - HollyFrontier Woods Cross Refinery

A.O. ID	Source ID	Source Description	Status	Capacity	Control Technology
II.A.197	Tank 170	Finished Diesel	Not Built		
II.A.198	Tank 171	Propane	In Service		
II.A.199	Tank 172	Propane	In Service		
II.A.200	Tank 173	Propane	Not Built		
II.A.201	Tank 174	Propane	Not Built		
II.A.203	Tank 300	Chemical	In Service		
II.A.202	Tank 301	Chemical	In Service		
II.A.204	Tank 302	Chemical	In Service		
II.A.205	Tank 303	Chemical	In Service		
II.A.206	Tank 304	Chemical	In Service		
II.A.207	Tank 305	Chemical	In Service		
II.A.208	Tank 306	Chemical	In Service		
II.A.209	Tank 307	Chemical	In Service		
II.A.210	Tank 308	Chemical	In Service		
II.A.211	Tank 310	Chemical	In Service		
II.A.212	Tank 312	Chemical	In Service		
II.A.213	Tank 313	Chemical	In Service		
II.A.214	Tank 323	Ethanol	In Service		
II.A.215	Tank 324	Olefin	In Service		
II.A.216	Tank 54-V4	Chemical	In Service		
II.A.217	Tank 54-V5	Chemical	In Service		
II.A.218	Tank 54-V7	Chemical	In Service		
II.A.225	Tank W-2	Water	In Service		
II.A.225	Tank 167	Water	In Service		
II.A.225	Tank 155	Water	In Service		
II.A.225	Tank 157	Water	In Service		
II.A.225	Tank 158	Water	In Service		
II.A.225	Tank 154	Water	In Service		
II.A.225	Tank 166	Water	In Service		
II.A.225	Tank 119	Water	In Service		
II.A.225	Tank 156	Water	In Service		
II.A.225	Tank 62	Water	In Service		
II.A.225	Tank 168	Water	In Service		
II.A.225	Tank 111	Water	In Service		

APPENDIX B

Cost Analyses

Fixed Roof Tanks - HollyFrontier

Cost to Install Vapor Recovery System on Fixed Roof Tanks

DAO ID	Storage Vessel ID	SCC	Type of Material Stored	Storage Capacity (10 ³ gal)	Shell Height (ft)	Tank Diameter (ft)	Maximum Height (ft)	Average Height (ft)	Throughput		VOC Emissions (tons/yr)				Net Reduction - 75%	\$/ton VOC Removed
									Annual Turnovers	Annual Total (10 ³ gal)	Standing Loss	Working Loss	Total Loss			
6168	4	40399999	Diesel	34	14	21	13	9.4	0	0	0.000	0.000	0.000	0.00E+00		
6180	11	40399999	Fuel Oil	376	32	47	29	19.3	0	0	0.000	0.000	0.000	0.00E+00		
6631	14	40399999	Kerosene	98	20	30	18.5	10.2	1.84	154	0.000	0.000	0.000	4.75E-06		
6167	15	40399999	Fuel Oil	197	27	37	24.5	12.3	11.69	2082	0.000	0.008	0.008	6.39E-03		
6187	19	40399999	Jet/Stove Oil	294	37	38	34.6	16.8	5.28	1273	0.000	0.000	0.000	1.72E-04		
6177	20	40399999	Jet Kerosene	293	37	38	34.5	10.5	7.15	1742	0.000	0.000	0.000	3.67E-04		
6170	23	40399999	Diesel	381	35	45	32	23.3	97.33	51879	0.000	0.041	0.041	3.26E-02		
6179	24	40399999	Diesel	581	35	55	32.7	15.9	107.12	52500	0.000	0.039	0.039	3.15E-02		
6178	28	40399999	Stove Oil	1190	35	78	33.3	25.5	20.05	21272	0.000	0.013	0.014	1.10E-02		
6181	31	40399999	Fuel Oil	999	41	72	32.8	19.2	10.52	8109	0.000	0.005	0.005	3.83E-03		
6186	35	40399999	Gas Oil	2564	35	115	33	22.3	4.61	14112	0.002	0.021	0.022	1.77E-02		
6162	37	40399999	Fuel Oil	144	25	32	24	9.4	215.99	1725	0.000	0.010	0.010	7.97E-03		
6176	47	40399999	Diesel	1264	42	72	41.5	15.1	27.69	32381	0.000	0.022	0.022	1.76E-02		
6158	48	40399999	Light Cycle Oil	1142	42	72	37.5	19.5	3.68	3107	0.000	0.001	0.001	5.39E-04		
6189	49	40399999	Fuel Oil	2249	38	102	36.8	18.3	0.00	0	0.000	0.000	0.000	0.00E+00		
6183	52	40399999	Fuel Oil	38	32	15	29	16	15.33	339	0.000	0.003	0.003	2.47E-03		
6184	53	40399999	Fuel Oil	38	32	15	29	16	14.17	422	0.000	0.005	0.005	3.93E-03		
6163	54	40399999	Fuel Oil	38	32	15	29	16	14.16	401	0.000	0.003	0.003	2.32E-03		
6174	55	40399999	Fuel Oil	38	32	15	28.4	16	10.11	312	0.000	0.002	0.002	1.41E-03		
6195	56	40399999	Fuel Oil	38	32	15	28.4	16	15.71	433	0.000	0.005	0.005	3.98E-03		
6184	57	40399999	Fuel Oil	38	32	15	28.5	16	16.29	484	0.000	0.009	0.009	6.90E-03		
6185	58	40399999	Fuel Oil	573	32	58	29	16.8	14.17	7338	0.000	0.003	0.003	2.50E-03		
6190	59	40399999	Gas Oil/Fuel Oil	1179	41	72	38.7	18.2	0.00	0	0.000	0.000	0.000	0.00E+00		
6162	63	40399999	Jet Fuel/Naphtha	999	41	72	32.8	19.2	5.94	2349	0.000	0.002	0.002	2.00E-03		
6175	70	40399999	Gas Oil/Fuel Oil	2992	35	129	30.6	11.3	5.36	9020	0.000	0.003	0.003	2.08E-03		
172809	77	40399999	Stove Oil/Diesel	209	30	35	29	17	4.88	683	0.000	0.001	0.001	5.44E-04		
172810	78	40399999	Stove Oil/Diesel	209	30	35	29	17	7.70	1119	0.000	0.001	0.001	9.19E-04		
0	79	40399999	Asphalt	395	44	40	42	21	12.42	3018	0.000	0.044	0.044	3.50E-02		
6159	103	40399999	Gas Oil/Crude	1034	36	70	35.9	17.3	5.38	4867	0.000	0.004	0.004	3.12E-03		
6164	127	40399999	Diesel	1287	37	78	36	13.5	19.84	21069	0.000	0.013	0.013	1.02E-02		
6185	139	40399999	Fuel Oil/SDA Charge	631	36	55	35.5	19.1	2.14	376	0.000	0.001	0.001	1.11E-03		
6171	140	40399999	SDA Charge	631	36	55	35.5	19.1	4.11	1895	0.000	0.001	0.001	9.48E-04		
6169	143	40399999	Diesel	156	32	30	29.5	13.7	0.00	0	0.000	0.000	0.000	0.00E+00		
9643	137	40399999	Propane	4330	95	100	73.7	15			0.000	0.000	0.000	0.00E+00		

0.261

\$

6,337,724

Medium cost for less than 1 ton of VOC

\$

1,707,966

Assumptions:

2015 Actual Emission Estimates

Cost to Install IFR on Fixed Roof

Range - 337000 2164000 Reference: European Commission, Integrated Pollution Prevention and Control Report, Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries, 2003

Mean - 1,250,500.00 2003\$

Mean - 1,655,573.65 2017\$ 2003 dollars to reflect cost in 2017

Low - 446,164 2017\$

HollyFrontier**Cost to fire all units on natural gas**

NG cost	0.22 Mscf	based on company records
Usage	5,530,074 Mscf	2016 - total refinery fuel gas and purchased natural gas
Cost	\$ 1,216,616.28	annual cost
PM _{2.5} \$/ton	\$ 2,295,502.42	

Assumptions:

Emissions from 2015 Annual Inventory

Process Unit PM_{2.5} TPY

4-1	0.070
6-1	0.100
6-2	0.010
6-3	0.020
7-1	0.050
7-2	0.000
8-1	0.120
9-1	0.010
9-2	0.000
10-2	0.030
11-1	0.010
12-1	0.060
13-1	0.000
17-1	0.010
19-1	0.000
20-1	0.000
20-2	0.000
45-1	0.000
51-4	0.010
51-5	0.030
51-6	0.000
51-7	0.000
51-8	0.000
51-9	0.000
Total	0.53

Cost to Retrofit Emergency Diesel Engines with Diesel Particulate Filters, SCR, and Oxidation Catalysts
HollyFrontier Woods Cross Refinery

	Rating (HP)	Rating (KW)	DPF Retrofit ¹ (\$/KW)	SCR Retrofit ¹ (\$/KW)	OC Retrofit ¹ (\$/KW)	DPF Retrofit Cost	SCR Retrofit Cost	OC Retrofit Cost	Uncontrolled			Controlled			Emission Reduction				Cost Effectiveness (\$/ton)		
									PM _{2.5} PTE	NO _x PTE	VOC PTE	PM _{2.5} PTE	NO _x PTE	VOC PTE	PM _{2.5} PTE	NO _x PTE	VOC PTE	TPY	PM _{2.5}	NO _x	VOC
Diesel Emergency Equipment																					
135 kW generator (east tank farm)	181.0	135.0	47	350	118	\$ 6,345	\$ 47,250	\$ 15,930	0.220	3.070	0.250	0.0330	0.15350	0.0125	0.187	2.917	0.238	\$	33,930	\$ 16,201	\$ 67,074
224 HP (water well #3)	224.0	167.0	47	350	118	\$ 7,851	\$ 58,463	\$ 19,710	0.012	0.174	0.014	0.0018	0.00870	0.0007	0.010	0.165	0.013	\$	750,907	\$ 353,677	\$ 1,481,981
393 HP Fire Pump #1	393.0	293.1	47	350	118	\$ 13,774	\$ 102,571	\$ 34,581	0.022	0.305	0.025	0.0033	0.01525	0.0013	0.019	0.290	0.024	\$	736,568	\$ 353,998	\$ 1,456,046
393 HP Fire Pump #2	393.0	293.1	47	350	118	\$ 13,774	\$ 102,571	\$ 34,581	0.022	0.305	0.025	0.0033	0.01525	0.0013	0.019	0.290	0.024	\$	736,568	\$ 353,998	\$ 1,456,046
220 HP plant air backup compressor #1	220.0	164.1	47	350	118	\$ 7,711	\$ 57,419	\$ 19,358	0.012	0.171	0.041	0.0018	0.00855	0.0021	0.010	0.162	0.039	\$	755,935	\$ 353,456	\$ 497,006
220 HP plant air backup compressor #2	220.0	164.1	47	350	118	\$ 7,711	\$ 57,419	\$ 19,358	0.012	0.171	0.041	0.0018	0.00855	0.0021	0.010	0.162	0.039	\$	755,935	\$ 353,456	\$ 497,006
220 HP plant air backup compressor #3	220.0	164.1	47	350	118	\$ 7,711	\$ 57,419	\$ 19,358	0.012	0.171	0.041	0.0018	0.00855	0.0021	0.010	0.162	0.039	\$	755,935	\$ 353,456	\$ 497,006
470 HP diesel generator (boiler house)	470.0	350.5	47	350	118	\$ 16,473	\$ 122,668	\$ 41,357	0.026	0.364	0.030	0.0039	0.01820	0.0015	0.022	0.346	0.028	\$	745,363	\$ 354,736	\$ 1,475,701
380 HP diesel generator (central control room)	380.0	283.4	47	350	118	\$ 13,318	\$ 99,178	\$ 33,437	0.021	0.294	0.024	0.0032	0.01470	0.0012	0.018	0.279	0.023	\$	746,118	\$ 355,095	\$ 1,466,543
540 HP standby generator	540.0	402.7	47	350	118	\$ 18,926	\$ 140,937	\$ 47,516	0.001	0.205	0.030	0.0002	0.01025	0.0015	0.001	0.195	0.028	\$	22,265,725	\$ 723,683	\$ 1,678,418

Assumptions:

¹ Includes component and installation costs

Source - Discussion with Steve Loci on 3/27/2017, Wheeler Machinery, 801-974-0511

Diesel Particulate Filters - \$47/KW includes installation and labor costs

SCR - \$300 KW plus \$50 KW for installation and labor costs

Oxidation Catalysts - \$118 KW which includes installation and labor costs

Urea - \$1 KW

PTE emissions based on 50 operating hours per year and Title V permit application

DPF - 85% reduction, 95% VOC reduction

SCR - 95% NOx reduction

Assumed maintenance and labor costs to be unchanged

Cost to Retrofit Emergency NG Engines with Oxidation Catalyst
HollyFrontier Woods Cross Refinery

	Rating (HP)	OX Cat Retrofit Capitol Cost	OX Cat Retrofit Annual Cost	Uncontrolled VOC PTE TPY	Controlled VOC PTE TPY	Emission Reduction VOC PTE TPY	Cost Effectiveness (\$/ton) VOC
Diesel Emergency Equipment							
224 HP Generac MG150 Administration Bldg East	224.0	\$ 59,220	\$ 18,714	0.014	0.0042	0.010	\$ 6,018,665
224 HP Generac MG150 Administration Bldg West	224.0	\$ 59,220	\$ 18,714	0.014	0.0042	0.010	\$ 6,061,522

Assumptions:

Source - Memorandum - Control Costs for Existing Stationary SI Rice, June 29, 2010
 Contacted Generac who was unable/hesitant to provide actual cost estimates.
 PTE emissions based on 50 operating hours per year and Title V permit application
 Assumed maintenance and labor costs to be unchanged
 70% control efficiency with CO oxidation catalyst (EPA)

HollyFrontier Woods Cross Refinery

Cost Analysis - Upgrading Cooling Towers from Low Efficiency Drift Eliminators to High Efficiency Drift Eliminators

Drift Eliminator							Total Annual Cost ¹	PM _{2.5} Emissions Before Control (tn/yr)	PM _{2.5} Emissions After Control (tn/yr)	Emission Reduction (tn/yr)	PM _{2.5} Cost Effectiveness (\$/ton)
CT ID	Dimension 1	Dimension 2	Ft^2	30 \$/ft^2 for .0005 % circ	mobe/demobe/shipping	Capitol Cost					
4	63.0	36.0	2268.0	\$ 68,040.00	\$ 50,000.00	\$ 118,040	\$ 118,040	0.0014	0.0003	0.0010	\$ 116,335,401
6	36.0	36.0	1296.0	\$ 38,880.00	\$ 50,000.00	\$ 88,880	\$ 88,880	0.0013	0.0003	0.0010	\$ 93,020,814
7	50.2	28.2	1413.0	\$ 42,390.83	\$ 50,000.00	\$ 92,391	\$ 92,391	0.0012	0.0003	0.0009	\$ 105,542,074
8	61.0	38.0	2318.0	\$ 69,540.00	\$ 50,000.00	\$ 119,540	\$ 119,540	0.0025	0.0006	0.0019	\$ 63,609,192

Assumptions:

Maintenance, labor, and inspections costs would remain unchanged.

Cooling Towers (CT) would have to be upgraded one at a time or else the refinery would have to be shut down if all CT's were upgraded at once.

Cooling tower vendor recommended \$50,000 (+/- 20%) as number to demolish and build new towers. It will be less on the smaller towers and maybe a little more on the larger towers.

Existing cooling tower have 0.002% version drift eliminators in all cooling towers.

CF80's (0.0005%) run about \$30/sqft installed (quote from Cooling Tower Depot).

Cost information obtained from:

Brian S Fuqua

Regional Sales Director

Cooling Tower Depot, Inc.

517 D SE 2nd Street

Lees Summit, MO 64063

816-331-5536 Office

816-318-9493 Fax

816-585-3025 Cell

bfuqua@ctdinc.com

www.coolingtowerdepot.com



HollyFrontier Cost Analysis for Tanks
Cost of Vapor Control By Carbon Absorption

Cost Parameters	Consumer (1982 dollars)	Consumer (2017 dollars)	Comments
Capital Cost	\$ 631,000.00	\$ 993,935.41	
Annualized capital charges	\$ 114,000.00	\$ 179,572.80	
Annual taxes, insurance and administration	\$ 4,100.00	\$ 39,757.42	4% of capitol cost
Operating Costs			
Maintenance	\$ 31,600.00	\$ 49,696.77	5% of capitol cost
Labor	\$ 45,000.00	\$ 70,884.00	
Energy	\$ 60,000.00	\$ 94,512.00	
Total Annualized Cost	\$ 255,000.00	\$ 434,422.99	
Cost effectiveness in & per megagram of VOC emissions reduction	\$ 28,650.00	\$ 45,128.76	

Assumptions:

EPA 450/3-81-003, VOC Emissions from VOL Storage Tanks-Background Information for Proposed Standards, Table 8-12

CPI data found at: <http://www.usinflationcalculator.com/inflation/consumer-price-index-and-annual-percent-changes-from-1913-to-2008/>

HollyFrontier Cost Analysis for Tanks

Cost of Vapor Control By Incineration Techniques

Cost Parameters	Consumer (1982 dollars)	Consumer (2017 dollars)	Comments
Capital Cost	\$ 631,000.00	\$ 993,935.41	
Annualized capital charges	\$ 114,000.00	\$ 179,572.80	
Annual taxes, insurance and administration	\$ 4,100.00	\$ 39,757.42	4% of capitol cost
Operating Costs			
Maintenance	\$ 31,600.00	\$ 49,696.77	5% of capitol cost
Labor	\$ 27,200.00	\$ 42,845.44	
Energy	\$ 4,900.00	\$ 7,718.48	
Total Annualized Cost	\$ 181,800.00	\$ 319,590.91	
Cost effectiveness in & per megagram of VOC emissions reduction	\$ 20,700.00	\$ 32,606.12	

Assumptions:

EPA 450/3-81-003, VOC Emissions from VOL Storage Tanks-Background Information for Proposed Standards, Table 8-12

CPI data found at: <http://www.usinflationcalculator.com/inflation/consumer-price-index-and-annual-percent-changes-from-1913-to-2008/>

Total emissions all tanks for 2013 - 45.8 tons VOC

Tank 145 (gasoline) had the highest emissions in 2013 - 10.5 tons

HollyFrontier External Floating Roof Tanks
Cost to Install Dome on Fixed Roof Tanks

Storage Vessel ID	SCC	Type of Material Stored	Storage Capacity (10 ³ gal)	Tank Diameter (ft)	Shell			Tank Construction	Roof		Rim-Seal		Throughput		VOC Emissions (tons/yr)					96% Control - Net Reduction	\$/ton VOC Removed
					Condition	Paint Color/ Shade	Paint Condition		Type (pontoon or double deck)	Fitting Category	Primary Seal	Secondary Seal	Annual Turnovers	Annual Total (10 ³ gal)	Standing Loss	Withdrawal Loss	Total Loss				
100	40399999	Reformate	2241	110	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	18 14	24547	1 70	0 03	1 73	1.658	\$	104,650	
101	40399999	Cat Gas	2250	110	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	16 70	19904	3 87	0 02	3 89	3 737	\$	46,430	
102	40399999	Gas Oil	2226	110	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	8 42	13908	0 00	0 00	0 00	0.001	\$	171,887,160	
104	40399999	Isomorate	1028	70	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	13 88	10437	1 48	0 01	1 49	1 434	\$	120,985	
105	40399999	Hi Reformate	1029	70	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	15 26	11152	0 82	0 02	0 93	0.898	\$	193,341	
106	40399999	Gasoline	1030	70	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	31 18	24716	2 33	0 04	2 38	2 282	\$	76,046	
107	40399999	Gasoline	1029	70	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	23 95	18323	3 15	0 03	3 18	3.057	\$	56,771	
108	40399999	Gasoline	1027	70	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	22 05	16379	5 05	0 03	5 08	4 874	\$	35,604	
109	40399999	Alkylate	1029	70	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	23 50	16291	1 31	0 03	1 34	1 285	\$	135,010	
121	40399999	Crude Oil	4205	150	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Weather shield	8 24	26151	1 07	0 08	1 16	1.110	\$	156,276	
126	40399999	Crude Oil	2716	114	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Weather shield	13 19	24876	0 73	0 10	0 83	0.801	\$	216,602	
128	40399999	Out of Service	424	48	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	0 00	0	0 00	0 00	0 00	0.000			
129	40399999	Out of Service	2313	112	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	0 00	0	0 00	0 00	0 00	0.000			
132	40399999	Gasoline	1031	70	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	20 37	14161	3 13	0 02	3 15	3 025	\$	57,358	
135	40399999	NHDS Charge	1854	100	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	9 95	15888	24 75	0 01	24 76	23.772	\$	7,300	
145	40399999	Gasoline	167	32	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	11 91	1257	2 21	0 00	2 22	2 129	\$	81,489	
146	40399999	Gasoline	167	32	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	2 59	264	2 13	0 00	2 13	2.049	\$	84,676	

Cost to Install Dome:

2015 Actual Emission Estimates

Average Investment Cost = \$21,640 - \$240,500

Mean - \$ 131,070.00 2003 \$

\$ 173,527 42 2017 \$

Reference: European Commission, Integrated Pollution Prevention and Control Report, Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries, 2003

Fixed Roof Tanks - HollyFrontier
Cost to Install IFR on Fixed Roof Tanks

AQ ID	Storage Vessel ID	SCC	Type of Material Stored	Storage Capacity (10³ gal)	Shell Height (ft)	Tank Diameter (ft)	Maximum Height (ft)	Average Height (ft)	Shell		Roof			Throughput			VOC Emissions (tons/yr)						
									Color/ Shade	Paint Condition	Color/ Shade	Paint Condition	Type	Height (ft)	Radius (ft)	Slope (ft/ft)	Annual Turnovers	Annual Total (10³ gal)	Standing Loss	Working Loss	Total Loss	Net Reduction - 75%	\$/ton VOC Removed
0168	4	40399999	Diesel	34	14	21	13	9.4	White	Good	White	Good	Cone	0.7	10.5	0.07	0	0	0.000	0.000	0.000	0.00E+00	
0180	11	40399999	Fuel Oil	378	32	47	29	19.3	White	Good	White	Good	Cone	0.5	23.5	0.02	0	0	0.000	0.000	0.000	0.00E+00	
0031	14	40399999	Kerosene	98	20	30	18.5	10.2	White	Good	White	Good	Cone	0.5	15	0.03	1.84	154	0.000	0.000	0.000	4.46E-06	\$ 107,090,073,714
0167	15	40399999	Fuel Oil	197	27	37	24.5	12.3	White	Good	White	Good	Cone	0.5	18.5	0.03	11.69	2082	0.000	0.008	0.008	5.99E-03	\$ 79,634,022
0187	19	40399999	Jet/Stove Oil	294	37	38	34.6	16.8	White	Good	White	Good	Cone	1.2	19	0.06	5.28	1273	0.000	0.000	0.000	1.61E-04	\$ 2,958,631,266
0177	20	40399999	Jet Kerosene	293	37	38	34.5	10.5	White	Good	White	Good	Cone	1.2	19	0.06	7.15	1742	0.000	0.000	0.000	3.44E-04	\$ 1,385,277,891
0170	23	40399999	Diesel	381	35	45	32	23.3	White	Good	White	Good	Cone	1.4	22.5	0.08	97.33	51879	0.000	0.041	0.041	3.05E-02	\$ 15,627,837
0179	24	40399999	Diesel	581	35	55	32.7	15.9	White	Good	White	Good	Cone	1	27.5	0.04	107.12	52500	0.000	0.039	0.039	2.95E-02	\$ 16,160,255
0178	28	40399999	Stove Oil	1190	35	78	33.3	25.5	White	Good	White	Good	Cone	2.4	39	0.08	20.05	21272	0.000	0.013	0.014	1.03E-02	\$ 46,325,992
0181	31	40399999	Fuel Oil	989	41	72	32.8	19.2	White	Good	White	Good	Cone	1.2	36	0.03	10.52	8109	0.000	0.005	0.005	3.59E-03	\$ 132,960,672
0166	35	40399999	Gas Oil	2564	35	115	33	22.3	White	Good	White	Good	Cone	2.3	57.5	0.04	4.61	14112	0.002	0.021	0.022	1.66E-02	\$ 28,829,042
0182	37	40399999	Fuel Oil	144	25	32	24	9.4	White	Good	White	Good	Cone	1	16	0.06	215.99	1725	0.000	0.010	0.010	7.47E-03	\$ 63,873,048
0176	47	40399999	Diesel	1264	42	72	41.5	15.1	White	Good	White	Good	Cone	0.8	36	0.02	27.69	32381	0.000	0.022	0.022	1.65E-02	\$ 28,962,299
0158	48	40399999	Light Cycle Oil	1142	42	72	37.5	19.5	White	Good	White	Good	Cone	2.3	36	0.06	3.68	3107	0.000	0.001	0.001	5.05E-04	\$ 944,460,087
0180	49	40399999	Fuel Oil	2249	38	102	36.8	18.3	White	Good	White	Good	Cone	0.2	51	0	0.00	0	0.000	0.000	0.000	0.00E+00	
0183	52	40399999	Fuel Oil	38	32	15	29	16	White	Good	White	Good	Cone	0.2	7.5	0.03	15.33	339	0.000	0.003	0.003	2.31E-03	\$ 206,457,114
0184	53	40399999	Fuel Oil	38	32	15	29	16	White	Good	White	Good	Cone	0.2	7.5	0.03	14.17	422	0.000	0.005	0.005	3.69E-03	\$ 129,438,574
0183	54	40399999	Fuel Oil	38	32	15	29	16	White	Good	White	Good	Cone	0.2	7.5	0.03	14.16	401	0.000	0.003	0.003	2.17E-03	\$ 219,587,851
0174	55	40399999	Fuel Oil	38	32	15	28.4	16	White	Good	White	Good	Cone	0.2	7.5	0.03	10.11	312	0.000	0.002	0.002	1.32E-03	\$ 362,140,074
0185	56	40399999	Fuel Oil	38	32	15	28.4	16	White	Good	White	Good	Cone	0.2	7.5	0.03	15.71	433	0.000	0.005	0.005	3.73E-03	\$ 127,969,958
0184	57	40399999	Fuel Oil	38	32	15	28.5	16	White	Good	White	Good	Cone	0.2	7.5	0.03	16.29	484	0.000	0.009	0.009	6.47E-03	\$ 73,766,386
0185	58	40399999	Fuel Oil	573	32	58	29	16.8	White	Good	White	Good	Cone	0.5	29	0.02	14.17	7338	0.000	0.003	0.003	2.34E-03	\$ 203,549,123
0190	59	40399999	Gas Oil/Fuel Oil	1179	41	72	38.7	18.2	White	Good	White	Good	Cone	0.8	36	0.02	0.00	0	0.000	0.000	0.000	0.00E+00	
0182	63	40399999	et Fuel/Naphth	999	41	72	32.8	19.2	White	Good	White	Good	Cone	0.8	36	0.02	5.94	2349	0.000	0.002	0.002	1.87E-03	\$ 254,786,896
0175	70	40399999	Gas Oil/Fuel Oil	2992	35	129	30.6	11.3	White	Good	White	Good	Cone	1.3	64.5	0.02	5.36	9020	0.000	0.003	0.003	1.95E-03	\$ 244,740,749
0209	77	40399999	Stove Oil/Diesel	209	30	35	29	17	White	Good	White	Good	Cone	0.5	17.5	0.03	4.88	683	0.000	0.001	0.001	5.10E-04	\$ 935,154,735
02010	78	40399999	Stove Oil/Diesel	209	30	35	29	17	White	Good	White	Good	Cone	0.5	17.5	0.03	7.70	1119	0.000	0.001	0.001	8.61E-04	\$ 553,974,761
0	79	40399999	Asphalt	395	44	40	42	21	White	Good	White	Good	Cone	1.4	20	0.07	12.42	3018	0.000	0.044	0.044	3.29E-02	\$ 14,526,244
0159	103	40399999	Gas Oil/Crude	1034	36	70	35.9	17.3	White	Good	White	Good	Cone	2.2	35	0.06	5.38	4867	0.000	0.004	0.004	2.93E-03	\$ 163,092,919
0164	127	40399999	Diesel	1287	37	78	36	13.5	White	Good	White	Good	Cone	2.4	39	0.06	19.84	21069	0.000	0.013	0.013	9.52E-03	\$ 50,121,183
0185	139	40399999	il Oil/SDA Chs	631	36	55	35.5	19.1	White	Good	White	Good	Cone	0.6	27.5	0.02	2.14	378	0.000	0.001	0.001	1.04E-03	\$ 459,079,938
0171	140	40399999	SDA Charge	631	36	55	35.5	19.1	White	Good	White	Good	Cone	0.6	27.5	0.02	4.11	1895	0.000	0.001	0.001	8.89E-04	\$ 536,784,118
0169	143	40399999	Diesel	156	32	30	29.5	13.7	White	Good	White	Good	Cone	0.9	15	0.06	0.00	0	0.000	0.000	0.000	0.00E+00	
0043	137	40399999	Propane	4330	95	100	73.7	15	Earthen	Good	NA	NA	Dome	10	50	0.2			0.000	0.000	0.000	0.00E+00	

Assumptions:

2015 Actual Emission Estimates

Cost to Install IFR on Fixed Roof

Range - \$240,000 - \$480,900 Reference European Commission, Integrated Pollution Prevention and Control Report, Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries, 2003

Mean - 360450 2003\$

Mean - 477210 2017\$ 2003 dollars to reflect cost in 2017

HollyFrontier Cost Analysis for Installation of RTO for Product Loading

	RTO	Factor	Basis for Cost and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 146,220	EPA ¹ - Based on 2017 costs, 1000 scfm estimate	
Instrumentation	\$ 14,622	10% of PE	EPA
Sales Tax	\$ 4,387	3% of PE	
Freight	\$ 7,311	5% of PE	
Total Purchased Equipment Cost (PEC)	\$ 172,540		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 51,762	30% of PEC	
Total Direct Installation (DI)	\$ 51,762		
Total Direct Cost (DC)	\$ 224,301		
Indirect Installation Costs			
Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests,	\$ 106,975	62% of PEC	
Total Indirect Cost	\$ 106,975		
Total Installed Cost (TIC)	\$ 331,276		
VOC Emissions Before Control, tn/yr	3.57		
Control Efficiency (%)	98		
VOC Emissions After Control, tn/yr	1.47		
VOC Emission Reduction, tn/yr	2.10		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 9,938	3% of capitol cost	
Maintenance	\$ 9,938	3% of capitol cost	
Replacement Parts	\$ 9,938	3% of capitol cost	
Natural Gas	\$ 263,325	\$3.30/kft3	
Electricity	\$ 1,400	0.006/KWh	
Total Direct Costs, \$/year	\$ 294,540		
Indirect Costs			
Overhead	\$ 15,901	60% of labor costs	
Taxes, Insurance, and Administration	\$ 13,251	4% of total installed cost	
Capitol Recovery	\$ 43,553	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 72,705		
Total Annual Cost	\$ 367,245		
Cost Effectiveness, \$ per ton VOC reduction	\$ 174,995.23		
¹ EPA - CICA Fact Sheet Regenerative Thermal Oxidizer; EPA Cost Manual			

Assumptions:

Based on 1000 scfm - estimated

5.5 Lb/MMscf

VOC emission factor AP-42 Section 1.4

HollyFrontier Woods Cross Refinery
CEMS Installation and Monitoring Costs for NO₂, SO₂, and VOC

	CEMS	Factor	Basis for Cost and Factor
Direct Costs:			
Purchased Equipment:			
Primary Equipment (PE) and Monitoring Shelter	\$ 120,000	Estimate - Provided by HollyFrontier	
Sales Tax	\$ 8,400	7% of PE	Estimate based on monitoring experience
Freight	\$ 6,000	5% of PE	Estimate based on monitoring experience
Total Purchased Equipment Cost (PEC)	\$ 134,400		
Direct Installation	\$ 33,600	25% of PEC	Estimate based on monitoring experience
Total Direct Installation (DI)	\$ 33,600		
Total Direct Cost (DC)	\$ 168,000		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 33,600	25% of PEC	Estimate based on monitoring experience
Total Indirect Cost	\$ 33,600		
Total Installed Cost (TIC)	\$ 201,600		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 30,000	500 hours per year at @\$60/hr (includes benefits) ¹	
Raw materials	\$ -		
Replacement Parts	\$ 6,048	3% of capitol cost	
Total Direct Costs, \$/year	\$ 36,048		
Indirect Costs			
Taxes, Insurance, and Administration	\$ 8,064	4% of total installed cost	
Capitol Recovery	\$ 28,708	10%, 10 years, CRF-.1424	
Total Indirect Costs, \$/year	\$ 36,772		
Total Annual Cost	\$ 72,820		

¹ EPA estimate - SCR cost manual spreadsheet 2016
Shelter and equipment costs provided by HollyFrontier.

HollyFrontier Woods Cross Refinery
Ammonia CEMS Installation on SCR for Slip Monitoring

	CEMS	Factor	Basis for Cost
	Addition		and Factor
Direct Costs:			
Purchased Equipment:			
Primary Equipment (PE) and Monitoring Shelter	\$ 137,000	Estimate - Provided by MSI/Mechanical Systems including options	
Sales Tax	\$ 9,590	7% of PE	Estimate based on monitoring experience
Freight	\$ 6,850	5% of PE	Estimate based on monitoring experience
Total Purchased Equipment Cost (PEC)	\$ 153,440		
Direct Installation	\$ -		Included in cost estimate
Total Direct Installation (DI)	\$ -		
Total Direct Cost (DC)	\$ 153,440		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 38,360	25% of PEC	Estimate based on monitoring experience
Total Indirect Cost	\$ 38,360		
Total Installed Cost (TIC)	\$ 191,800		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 30,000	500 hours per year at @\$60/hr (includes benefits) ¹	
Raw materials	\$ -		
Replacement Parts	\$ 5,754	3% of capitol cost	
Total Direct Costs, \$/year	\$ 35,754		
Indirect Costs			
Taxes, Insurance, and Administration	\$ 7,672	4% of total installed cost	
Capitol Recovery	\$ 27,312	10%, 10 years, CRF-.1424	
Total Indirect Costs, \$/year	\$ 34,984		
Total Annual Cost	\$ 70,738		

¹ EPA estimate - SCR cost manual spreadsheet 2016

Cost estimate provided by MSI/Mechanical Systems Inc.



April 20, 2017

Meteorological Solutions, Inc.
4525 Wasatch Blvd.
Suite 200
Salt Lake City, Utah 84124

Attn: Ms. Linda Conger

Re: Ammonia Slip Monitoring – SCR outlet

Dear Ms. Conger:

MSI/Mechanical Systems, Inc. is pleased to provide a budgetary proposal for supplying an ammonia (NH₃) tunable diode laser (TDL) analyzer, optics, and associated ancillary equipment for ammonia slip measurement downstream of an SCR. Proposal is based on an installation location that provides a minimum 5 meter (17 feet) path length (stack diameter). Proposal is also based on installation in a non-rated electrical area.

Equipment Includes:

- Tunable Diode Laser Ammonia Analyzer (1)
 - Unisearch LASIR LAS-RR101-FC-NH₃ tunable diode laser analyzer
 - Internal flow through audit module (calibration cell)
 - Continuous laser background correction software
 - Continuous audit cell background subtraction software

- Unisearch SPSO24-15-F3-A single pass optics including
 - Launcher with 3" optics
 - Receiver with 3" optics
 - Fused silica windows (2)
 - NEMA 4X enclosures (2)
 - Aluminum mounting flanges (2)

MSI purge panel with blower failure and plugged filter alarms - launcher

MSI purge panel with blower failure and plugged filter alarms - receiver

Fiber optic cable from analyzer to launcher (250 feet maximum)

Coax cable from receiver to analyzer (200 feet)

Alarm cables from purge panels to site data system (200 + 250 = 450 feet)

Calibration Gas System

Cylinder bracket (1)
Calibration gas regulator (1) - Concoa 4322391
Teflon regulator outlet tubing - 20 feet

Services

Installation, startup, and informal training
Three days on site/one trip
Includes travel hours
Includes travel expenses
Includes all onsite expenses (lodging, meals, etc.)

Other Items

Operation and Maintenance Manuals (3)

Work by Others

1. Furnish and install two 6" NH₃ monitor ports on stack with Class 150 flanges and two holed mounting orientation. Alignment is critical on these ports. Installation must be verified on completion of port installation work.
2. Install NH₃ tunable diode laser purge panels on 6" mounting flanges. Tunable diode laser launcher and receiver optics will be installed on purge panels by MSI after blowers on purge panels are operational. Purge panels supplied by MSI. Purge panels must be energized prior to MSI startup technician arrival on site.
3. Run 120 Vac power circuits from local power source to:
NH₃ analyzer in rack
NH₃ launcher purge panel on stack
NH₃ receiver purge panel on stack
4. Install analyzer in rack. Analyzer rests on sliding tray provided by MSI. Tray has connections for zero air and three calibration gases.
5. Install NH₃ calibration regulator, cylinder bracket, and cylinder. Pipe regulator output to MSI NH₃ analyzer sliding tray using Teflon tubing provided by MSI.
6. Provide instrument air to MSI NH₃ analyzer sliding tray (0.3 scfm).

7. Install fiber optic cable from analyzer to launcher. Install coax cable from receiver to analyzer. Install alarm cable from each purge panel to data system.
8. Provide 4-20 mA stack temperature input to analyzer.
9. Provide 4-20 mA stack pressure input to analyzer.
10. Wire NH3 analyzer and purge panels to site compliance data system. The following inputs/outputs will be available:

Analog output from analyzer - 4-20 mA
NH3 ppm (0-10 ppm)
NH3 ppm (0-100 ppm)
NH3 laser power (0-100 percent)
Water (0-100 percent)

Digital output from analyzer
Malfunction
Power fail

Digital outputs from purge panels
Launcher purge panel blower failure
Launcher purge panel plugged filter
Receiver purge panel blower failure
Receiver purge panel plugged filter

11. Procure permanent NH3 calibration cylinders with ranges of 40 ppm, 100 ppm, and 160 ppm.

Total cost for work as described above is Seventy Two Thousand Three Hundred Dollars (\$72,300.00). Final pricing may vary slightly based on actual installation location of launcher and receiver and cannot be guaranteed until drawings of the proposed location of the optics are submitted for MSI review.

Payment terms are:

- 10% - contract award
- 10% - installation drawings
- 70% - shipment
- 10% - completion of startup

State and local sales taxes are not included. Freight to site is not included for purge panels and analyzer. Travel and living expenses for MSI startup technician are included.

MSI offers the following optional bids for consideration:

1. Provide laptop computer and Unisearch LasIRView software and key to interface with and make changes to the Unisearch NH3 analyzer - Add \$2,205.00.
2. Provide OPM-15 power meter for NH3 analyzer - Add \$1,050.00.
3. Provide VFL-2000 visible laser alignment tool for NH3 optics - Add \$825.00.
4. Provide safety shutters for purge panels that automatically close off and isolate optics in the event of purge air failure - Add \$6,920.00 total for two purge panels.
5. Provide weather hoods (2) for purge panels for outdoor installation of optics - Add \$1,220.00 total for two purge panels.
6. Provide two additional NH3 calibration gas regulators, cylinders brackets, outlet Teflon tubing to simplify quarterly linearity testing - Add \$2,480.00.
7. Add for additional footage of cables:
 - a. Fiber optic cable – No charge up to 300 feet
 - b. Coax cable – \$3.00/ft
 - c. Alarm cable – \$1.50/ft

We appreciate the opportunity to submit this proposal. If you have questions, feel free to email or call at any time.

Sincerely,

MSI/Mechanical Systems, Inc.



Chuck Arnold



HOLLYFRONTIER

HOLLYFRONTIER WOODS CROSS REFINING LLC

1070 West 500 South • West Bountiful, Utah 84087-1442
(801) 299-6600 • Fax (801) 299-6609

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

OCT 27 2017

DIVISION OF AIR

October 24, 2017

Bryce C. Bird, Director
Division of Air Quality
195 North 1950 West
Salt Lake City, Utah 84114-4820

CERTIFIED MAIL: 7013 3020 0001 4514 0706

RE: **Response to Request DAQE-066-17**

Dear Mr. Bird:

In response to your letter of September 21, 2017, we have reviewed our prior submittals to you related to the BACT analysis for control of PM_{2.5} and PM_{2.5} precursors. In the course of these analyses, there were no potential controls that we excluded because implementation could not occur prior to December 31, 2019. In addition, there were no potential controls that were eliminated due to an extended implementation timeframe. The measures that were considered included all those that were deemed feasible.

If you have any further questions regarding our submitted analyses, please don't hesitate to ask.

Sincerely,

Michael S. Astin, P.E.
Environmental Manager



HOLLYFRONTIER

HOLLYFRONTIER WOODS CROSS REFINING LLC

1070 West 500 South • West Bountiful, Utah 84087-1442
(801) 299-6600 • Fax (801) 299-6609

April 25, 2018

Mr. John Jenks
Environmental Engineer
Utah Division of Air Quality
195 North 1950 West
P.O. Box 144820
Salt Lake City, Utah 84114-4820

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

APR 27 2018

DIVISION OF AIR QUALITY

7017 0190 0000 7884 0134

RE: Letter – Best Available Control measure Analysis for Ammonia for HollyFrontier's Woods Cross Refinery

Dear Mr. Jenks:

In response to your letter dated April 9, 2018, HollyFrontier has prepared an addendum to the Best Available Control Measures (BACM) analysis requested in April 2017. Please find the attached response as prepared by MSI Trinity Consultants.

Please contact me at regina.harris@hollyfrontier.com or 801.397.7432 if you have any questions.

Sincerely,

Regina Harris
Environmental Specialist



4525 Wasatch Blvd | Suite 200 | Salt Lake City, UT 84124 | P (801) 272-3000 | F (801) 272-3040

trinityconsultants.com



April 24, 2018

Mr. John Jenks
Environmental Engineer
Utah Division of Air Quality
195 North 1950 West
P. O. Box 144820
Salt Lake City, Utah 84114-4820

RE: Addendum - Best Available Control Measure Analyses for Ammonia for HollyFrontier's Woods Cross Refinery

Dear Mr. Jenks:

HollyFrontier understands that at the time of the first request for Best Available Control Measures (BACM) information, the Utah Division of Air Quality (UDAQ) was under the assumption that emissions of ammonia (NH_3) did not significantly contribute to nonattainment. However, since that time, the results of the $\text{PM}_{2.5}$ precursor demonstration now indicate that ammonia does contribute to nonattainment in the Salt Lake Non-Attainment Area (NAA). Thus, this letter supplements the NH_3 BACM that was provided to the UDAQ in April 2017. As indicated in the original BACM analysis, the units that have the potential to emit NH_3 emissions include the process heaters, boilers and associated boiler pollutant control devices, wastewater treatment, fluidized catalytic cracking units (FCCUs), the sour water stripper, and ammonia stripping unit.

This addendum includes addition information regarding NH_3 emissions from combustion of natural gas in the process heaters, boilers, and natural gas-fired emergency engines.

Process Heaters and Boilers

While the original BACM indicated that ammonia emissions do not result from combustion of natural gas (Section 8.1.2), further research conducted in this area does indicate that NH_3 emissions may occur as a byproduct of incomplete combustion. From a review of current literature and EPA databases, two NH_3 emission factors were identified from combustion of natural gas. According to the EPA's WebFIRE database, the NH_3 emission factor presented for natural gas combustion is 0.0031 lb/MMBtu. In the August 1994 final report prepared for the EPA titled, Development and Selection of Ammonia Emission Factors, Table 7-4 lists the NH_3 emission factor from natural gas combustion as 3.2 lb/ 10^6 ft³.

Step 1 – Identify All Existing and Potential Emission Control Technologies

The various control technologies available to control ammonia emissions from the process boilers and heaters includes both pollution prevention techniques and add-on control devices. Control options for NH_3 consist of good combustion practices, fuel specifications (use of natural gas or refinery gas), thermal oxidation, and wet scrubbing (i.e. ammonia scrubber).

HEADQUARTERS >

12770 Merit Drive | Suite 900 | Dallas, TX 75251 | P (972) 661-8100 | F (972) 385-9203

North America | Europe | Middle East | Asia

Step 2 – Eliminate Technically Infeasible Options

Based on the emission factors presented above, the concentration of NH₃ from each process heater and boiler is estimated to be less than 1 ppm. In discussions with Gulf Coast Environmental Systems¹, waste streams with NH₃ concentrations of 100 ppm or greater are typically required for an add-on device, such as an ammonia scrubber or thermal oxidizer, to be technically and cost effective.

The ballpark equipment cost estimates provided by Gulf Coast Environmental Systems for an ammonia scrubber and thermal oxidizer for a 50 MMBtu/hr process heater/boiler were \$200,000 and \$350,000, respectively. Cost evaluations were prepared to determine the cost of control per ton of NH₃ removed from a 50 MMBtu/hr process heater/boiler. The \$/ton of NH₃ reduced with the use of an ammonia scrubber was approximately \$148,000, and approximately \$270,000 with the use of a thermal oxidizer which is economically not feasible (see Attachment 1). In addition, a review of the EPA's RBLC database and an internet search did not identify the use of any type of add-on device to control NH₃ emissions from natural gas or refinery fuel combustion from process heaters or boilers. Thus, for these reasons, add-on control devices such as an ammonia scrubber or thermal oxidizer were determined to be technically and economically infeasible for reducing NH₃ emissions from the process heaters/boilers at HollyFrontier's Woods Cross Refinery and as such were eliminated from further consideration.

Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control technologies include the use of good combustion practices and use of natural or refinery gas.

Step 4 – Evaluate Impacts and Document Results

Good combustion practices and natural and/or refinery fuel gas are utilized at the refinery. There are no energy, environmental or economic impacts associated with the use of good combustion practices and the use of natural or refinery gas.

Step 5 – Select BACT

The most stringent controls identified to reduce NH₃ emissions are the use of natural or refinery gas and good combustion practices which satisfy BACM for NH₃ for existing units 4H1, 6H1, 6H2, 6H3, 7H1, 7H3, 8H2, 9H1, 9H2, 10H1, 10H2, 11H1, 12H1, 13H1, 19H1, 20H2, 20H3, 24H1, 25H1, 68H2, 68H3, boilers #4, #5, #8, #9, and #10, and for proposed units 23H1, 27H1, 30H1, 30H2, 33H1, 68H2-H7, 68H10-H13, and boiler #11. Good combustion practices and the use of natural or refinery gas is currently being utilized at the Woods Cross Refinery to minimize pollutant emissions including emissions of NH₃. Good operating practices will be followed in order to minimize ammonia emissions during periods of startup and shutdown.

It should be noted that NO_x emissions on existing boilers #5, #8, #9, and #10 and for proposed units 10H2, 27H1, 30H1, 30H2, 33H1, and boiler #11 are (or will be) controlled through SCRs. A discussion of the ammonia slip from the SCR's can be found in Section 8.1 of the original BACM analysis.

¹ Conversation with Chad Clark, Technical Director Gulf Coast Environmental Systems on April 19, 2018.

Emergency Natural-Gas Fired Engines

HollyFrontier operates two natural gas-fired spark ignition emergency standby generators, each at 142 kW, at the Administration building. Emissions of NH_3 from the natural gas emergency generators are a byproduct of incomplete combustion of the natural gas.

Step 1 – Identify All Existing and Potential Emission Control Technologies

The control technologies available to minimize ammonia emissions include good combustion practices, the use of natural gas, and the add-on control technologies of SCR, and Non-selective Catalytic Reduction (NSCR).

Step 2 – Eliminate Technically Infeasible Options

As presented in the Section 4.6.2 of the original BACM analyses for NO_x submitted by HollyFrontier to the UDAQ in April 2017 and reiterated here, the NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich burn turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NO_x reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures. Thus, the add-on combustion control of NSCR is deemed technically infeasible.

SCR is a catalytic post-combustion control technology designed to control NO_x emissions. Ammonia is vaporized and injected directly into the exhaust stream, where it reacts with NO_x and oxygen in the presence of the catalyst to form N_2 and water vapor. Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream (ammonia slip). Since the operation of each generators is limited to 50 hours for testing (non-emergency) purposes, it is unlikely that the engines would reach the required operating temperature for a SCR to be effective. In addition, if SCR was feasible, increased NH_3 emissions would be likely. Thus, since it is unlikely that the natural gas emergency generators will achieve normal operating temperature for any period of time, the add-on control technology using SCR, which requires a consistent operating temperature to be effective, is technically not feasible and, if it were feasible, would result in increased NH_3 emissions.

Steps 3- 5

The remaining control technologies include good combustion practices and use of natural gas which are currently in use at the Refinery. There are no energy, environmental or economic impacts associated with these pollution control techniques. The proposed BACM for NH_3 for the emergency natural gas-fired engines is limited hours of operation, use of natural gas, and good combustion practices. Manufacturer specifications will be followed. Operating hours are tracked through non-resettable hour meters installed on each engine. Extremely low concentrations of NH_3 , based on the use of the emission factor of 3.2 lb/10⁶ scf for natural gas combustion, are expected.

If you have any questions concerning the information in this letter, feel free to contact me.

Mr. John Jenks - Page 4
April 24, 2018

Sincerely,

MSI TRINITY CONSULTANTS

A handwritten signature in black ink, appearing to read "Linda Conger". The signature is fluid and cursive, with the first name "Linda" and last name "Conger" clearly distinguishable.

Linda Conger
Managing Consultant

CL:\lec\\\MSI_SERVER_2012\msi_server\CONFIDENTIAL PROJECTS\HollyFrontier\Woods Cross\174501.0025 17-25 Holly Refining BACM
Analysis\04 Report\Addendum - NH3 BACM\NH3 BACM Addendum_HollyFrontier.docx

ATTACHMENT 1

Economic Viability Analysis for use of Ammonia Scrubber and Thermal Oxidizer

NH₃ Cost Analysis to Add Ammonia Scrubber

	Ammonia	Factor	Basis for Cost
	Scrubber Add-on		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 200,000.00	Estimate for 50 MMBtu/hr heater/boiler	
Instrumentation and Controls	\$ 20,000	10% of PE	EPA ¹
Sales Tax	\$ 6,000	3% of PE	EPA ¹
Freight	\$ 10,000	5% of PE	EPA ¹
Total Purchased Equipment Cost (PEC)	\$ 236,000		
Direct Installation			
Foundations	\$ 28,320	12% of PEC	EPA ¹
Handling and Erection	\$ 94,400	40% of PEC	EPA ¹
Electrical	\$ 2,360	1% of PEC	EPA ¹
Piping	\$ 4,720	2% of PEC	EPA ¹
Insulation and Ductwork	\$ 2,360	1% of PEC	EPA ¹
Painting	\$ 2,360	1% of PEC	EPA ¹
Total Direct Installation (DI)	\$ 134,520		
Total Direct Cost (DC)	\$ 370,520		
Indirect Installation Costs			
Engineering and Project Management	\$ 23,600	10% of PEC	EPA ¹
Construction and Field Expenses	\$ 23,600	10% of PEC	EPA ¹
Contractor Fees	\$ -	0% of PEC	EPA ¹
Startup Expenses	\$ 2,360	1% of PEC	EPA ¹
Performance Tests	\$ 2,360	1% of PEC	EPA ¹
Contingencies	\$ 7,080	3% of PEC	EPA ¹
Total Indirect Cost	\$ 59,000		
Total Installed Cost (TIC)	\$ 429,520		
Assumptions:			
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002.			

NH₃ Cost Analysis to Add Ammonia Scrubber

	Ammonia	Basis for Cost and Factor
	Scrubber Add-on	
Total Installed Cost	\$ 429,520	
NH3 Emissions Before Control, lb/MMBtu	0.0031	
Annual Capacity Factor	100%	
NH3 Emissions Before Control, tn/yr	0.680	
NH3 Emissions After Control, lb/MMBtu	0.00003	
Control Efficiency (%)	99	
NH3 Emissions After Control, tn/yr	0.01	
NH3 Emission Reduction, tn/yr	0.67	
Annual Costs, \$/year (Direct + Indirect)		
Direct Costs		
Operating Labor	\$ 8,590	2% of capitol cost
Raw materials	\$ -	
Replacement Parts	\$ 8,590	2% of capitol cost
Total Direct Costs, \$/year	\$ 17,181	
Indirect Costs		
Overhead	\$ 6,872	80% of labor costs
Taxes, Insurance, and Administration	\$ 17,181	4% of total installed cost - EPA ¹
Capitol Recovery	\$ 58,372	6%, 10 years, CRF-.1359
Total Indirect Costs, \$/year	\$ 82,425	
Total Annual Cost	\$ 99,606	
Cost Effectiveness, \$ per ton NH3 reduction	\$ 147,958.54	
Assumptions:		
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002. Table		

NH₃ Cost Analysis to Add Thermal Oxidizer

	Thermal	Factor	Basis for Cost
	Oxidizer Add-on		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 350,000.00	Estimate for 50 MMBtu/hr heater/boiler	
Instrumentation and Controls	\$ 35,000	10% of PE	EPA ¹
Sales Tax	\$ 10,500	3% of PE	EPA ¹
Freight	\$ 17,500	5% of PE	EPA ¹
Total Purchased Equipment Cost (PEC)	\$ 413,000		
Direct Installation			
Foundations	\$ 49,560	12% of PEC	EPA ¹
Handling and Erection	\$ 165,200	40% of PEC	EPA ¹
Electrical	\$ 4,130	1% of PEC	EPA ¹
Piping	\$ 8,260	2% of PEC	EPA ¹
Insulation and Ductwork	\$ 4,130	1% of PEC	EPA ¹
Painting	\$ 4,130	1% of PEC	EPA ¹
Total Direct Installation (DI)	\$ 235,410		
Total Direct Cost (DC)	\$ 648,410		
Indirect Installation Costs			
Engineering and Project Management	\$ 41,300	10% of PEC	EPA ¹
Construction and Field Expenses	\$ 41,300	10% of PEC	EPA ¹
Contractor Fees	\$ -	0% of PEC	EPA ¹
Startup Expenses	\$ 4,130	1% of PEC	EPA ¹
Performance Tests	\$ 4,130	1% of PEC	EPA ¹
Contingencies	\$ 12,390	3% of PEC	EPA ¹
Total Indirect Cost	\$ 103,250		
Total Installed Cost (TIC)	\$ 751,660		
Assumptions:			
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002.			

NH₃ Cost Analysis to Add Thermal Oxidizer

	Thermal	Basis for Cost and Factor
	Oxidizer Add-on	
Total Installed Cost	\$ 751,660	
NH3 Emissions Before Control, lb/MMBtu	0.0031	
Annual Capacity Factor	100%	
NH3 Emissions Before Control, tn/yr	0.680	
NH3 Emissions After Control, lb/MMBtu	0.00016	
Control Efficiency (%)	95	
NH3 Emissions After Control, tn/yr	0.03	
NH3 Emission Reduction, tn/yr	0.65	
Annual Costs, \$/year (Direct + Indirect)		
Direct Costs		
Operating Labor	\$ 15,033	2% of capitol cost
Raw materials	\$ -	
Replacement Parts	\$ 15,033	2% of capitol cost
Total Direct Costs, \$/year	\$ 30,066	
Indirect Costs		
Overhead	\$ 12,027	80% of labor costs
Taxes, Insurance, and Administration	\$ 30,066	4% of total installed cost - EPA ¹
Capitol Recovery	\$ 102,151	6%, 10 years, CRF-.1359
Total Indirect Costs, \$/year	\$ 144,244	
Total Annual Cost	\$ 174,310	
Cost Effectiveness, \$ per ton NH3 reduction	\$ 269,829.65	
Assumptions:		
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002. Table		