NOTICE OF INTENT
HOLLY REFINING & MARKETING COMPANY
HEAVY CRUDE PROCESSING PROJECT
MAY 2012

Prepared for:

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By

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Project No. 041211133

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TABLE OF CONTENTS

Section **Page**

1.0 INTRODUCTION 1-1
1.1 Facility Description 1-4
1.2 Company Information 1-4

2.0 PROJECT DESCRIPTION 2-1
2.1 Heavy Crude Processing Project 2-1
2.1.1 Existing Crude Unit Expansion 2-4
2.1.2 New Crude Unit 2-4
2.1.3 Vacuum Unit 2-5
2.1.4 Gas Oil Hydrocracking Unit and Distillate Hydrotreater 2-5
2.1.5 Fluid Catalytic Cracking Unit 2-6
2.1.6 Poly Gasoline Unit 2-6
2.1.7 Hydrocracker/Hydroisom Unit 2-7
2.1.8 Boiler #11 2-7
2.1.9 Sour Water Stripper 2-7
2.1.10 Emergency Generator 2-7
2.2 Permitted Equipment to be Removed from Air Approval Order 2-8
2.3 Process Support Units 2-9
2.3.1 Fuel Gas 2-10
2.3.2 Cooling Towers 2-10
2.3.3 Flare 2-10
2.3.4 Loading/Unloading Facilities 2-10
2.3.5 Storage Tanks 2-11
2.3.6 Wastewater Treatment and Sewer 2-13
2.3.7 Removal of Frozen Earth Propane Storage 2-13

3.0 HEAVY CRUDE PROCESSING PROJECT EMISSIONS 3-1
3.1 NSR/PSD Applicability Test 3-1
3.1.1 Baseline Actual Emissions 3-3
3.1.2 PSD Netting Analysis 3-7
3.2 PSD Applicability Determination 3-16
3.3 Non-Attainment Area New Source Review 3-17
3.4 Emission Calculation Methodologies 3-19
3.4.1 Process Heaters, Furnaces, and Steam Boiler 3-19
3.4.2 Emergency Equipment 3-20

Table of Contents
Continued

Section **Page**

3.4.3 Cooling Towers 3-21
3.4.4 Flare 3-24
3.4.5 Storage Tanks 3-25
3.4.6 Fluid Catalytic Cracking Unit 3-25
3.4.7 Fugitives 3-26
3.4.8 Product Loading/Unloading 3-27
3.4.9 Wastewater Treatment 3-27
3.4.10 Greenhouse Gases 3-28
3.4.10.1 Stationary Fuel Combustion Sources 3-28
3.4.10.2 Flare 3-29
3.4.10.3 Fluid Catalytic Cracking Unit 3-31
3.4.10.4 Fugitive Sources Including Equipment Leaks 3-32
3.4.10.5 Storage Tanks 3-33
3.4.10.6 Suppliers of Petroleum Products 3-33
3.5 Startup and Shutdown Emissions 3-35
3.6 Flaring Emissions Due to Upsets 3-37
3.7 Potential to Emit Emissions for Entire Refinery 3-37

4.0 REGULATORY REVIEW 4-1

4.1 Federal Regulations 4-1
4.1.1 New Source Performance Standards (NSPS) 4-1
4.1.1.1 40 CFR Part 60 Subpart A 4-2
4.1.1.2 40 CFR Part 60 Subpart Dc 4-2
4.1.1.3 40 CFR Part 60 Subpart Ja 4-3
4.1.1.4 40 CFR Part 60 Subpart Kb 4-4
4.1.1.5 40 CFR Part 60 Subpart GGGa 4-4
4.1.1.6 40 CFR Part 60 Subpart IIII 4-5
4.1.2 National Emission Standards for Hazardous Air Pollutants (NESHAP) 4-5
4.1.3 National Ambient Air Quality Standards (NAAQS) 4-7
4.1.4 Prevention of Significant Deterioration 4-9
4.1.4.1 Best Available Control Technology Analysis 4-12
4.1.4.2 Air Quality Monitoring Requirements 4-12
4.1.4.3 Air Quality Impact Analysis 4-13
4.1.4.4 Additional Impact Analysis 4-15
4.1.5 Good Engineering Stack Height Analysis 4-15
4.1.6 40 CFR Part 70 Operating Permit Program (Title V) 4-16
4.1.7 40 CFR Part 98- Mandatory Greenhouse Gas Reporting 4-16
4.2 Utah Administrative Codes 4-17

Table of Contents
Continued

Section **Page**

4.2.1 R307-101 General Requirements 4-18
4.2.2 R307-107 General Requirements: Unavoidable Breakdown 4-18
4.2.3 R307-150 Emission Inventories 4-19
4.2.4 R307-165 Emission Testing 4-19
4.2.5 R307-170 Continuous Emission Monitoring Program 4-19
4.2.6 R307-210 Stationary Sources 4-20
4.2.7 R307-214 National Emission Standards for Hazardous Air Pollutants (NESHAPS) 4-20
4.2.8 R307-305 Nonattainment and Maintenance Areas for PM_{10}: Emission Standards 4-20
4.2.9 R307-326 Ozone Nonattainment and Maintenance Areas: Control Of Hydrocarbon Emissions in Petroleum Refineries 4-21
4.2.10 R307-401 Permit: New and Modified Sources 4-21
4.2.11 R307-405 Permits: Major Sources in Attainment or Unclassified Areas (PSD) 4-21
4.2.12 R307-406 Permits: Visibility 4-22
4.2.13 R307-410 Permits: Emission Impact Analysis 4-23
4.2.14 R307-414 Permits: Fees for Approval Orders 4-23
4.2.15 R307-415 Permits: Operating Permit Requirements 4-24

5.0 BEST AVAILABLE CONTROL TECHNOLOGY DEMONSTRATION 5-1
5.1 BACT for Process Heaters 5-3
5.1.1 BACT for CO 5-4
5.1.1.1 Step 1 – Identify All Available Control Technologies 5-4
5.1.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-6
5.1.1.3 Step 3 – Rank Remaining Control Options 5-7
5.1.1.4 Step 4 – Evaluate Remaining Control Options 5-7
5.1.1.5 Step 5 – Select BACT 5-8
5.1.2 BACT for PM_{10} and $PM_{2.5}$ 5-10
5.1.2.1 Step 1 – Identify All Available Control Technologies 5-11
5.1.2.2 Step 2 – Eliminate Technically Infeasible Control Options 5-12
5.1.2.3 Step 3 – Rank Remaining Control Options 5-13
5.1.2.4 Step 4 – Evaluate Remaining Control Options 5-13
5.1.2.5 Step 5 – Select BACT 5-13
5.1.3 BACT for SO_2 5-14
5.1.3.1 Step 1 – Identify All Available Control Technologies 5-14
5.1.3.2 Step 2 – Eliminate Technically Infeasible Control Options 5-15
5.1.2.3 Step 3 – Rank Remaining Control Options 5-15
5.1.2.4 Step 4 – Evaluate Remaining Control Options 5-16

Table of Contents
Continued

Section **Page**

5.1.2.5 Step 5 – Select BACT 5-16
5.1.4 BACT for NO_x 5-17
5.1.4.1 Step 1 – Identify All Available Control Technologies 5-17
5.1.4.2 Step 2 – Eliminate Technically Infeasible Control Options 5-18
5.1.4.3 Step 3 – Rank Remaining Control Options 5-18
5.1.4.4 Step 4 – Evaluate Remaining Control Options 5-19
5.1.4.5 Step 5 – Select BACT 5-23
5.1.5 BACT for VOC 5-24
5.1.5.1 Step 1 – Identify All Available Control Technologies 5-24
5.1.5.2 Step 2 – Eliminate Technically Infeasible Control Options 5-25
5.1.5.3 Steps 3 – 5 5-25
5.2 BACT for Power Boiler 5-27
5.2.1 BACT for CO and VOC 5-27
5.2.1.1 Step 1 – Identify All Available Control Technologies 5-27
5.2.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-28
5.2.1.3 Steps 3 – 5 5-29
5.2.2 BACT for PM_{10} and $PM_{2.5}$ 5-30
5.2.2.1 Step 1 – Identify All Available Control Technologies 5-30
5.2.2.2 Step 2 – Eliminate Technically Infeasible Control Options 5-30
5.2.2.3 Steps 3 – 5 5-31
5.2.3 BACT for SO_2 5-31
5.2.3.1 Step 1 – Identify All Available Control Technologies 5-31
5.2.3.2 Step 2 – Eliminate Technically Infeasible Control Options 5-32
5.2.3.3 Step 3 – Rank Remaining Control Options 5-32
5.2.3.4 Step 4 – Evaluate Remaining Control Options 5-32
5.2.3.5 Step 5 – Select BACT 5-33
5.2.4 BACT for NO_x 5-33
5.2.4.1 Step 1 – Identify All Available Control Technologies 5-33
5.2.4.2 Step 2 – Eliminate Technically Infeasible Control Options 5-34
5.2.4.3 Step 3 – Rank Remaining Control Options 5-34
5.2.4.4 Step 4 – Evaluate Remaining Control Options 5-34
5.2.4.5 Step 5 – Select BACT 5-36
5.3 BACT for Cooling Tower 5-37
5.3.1 BACT for $PM_{10}/PM_{2.5}$ 5-38
5.3.1.1 Step 1 – Identify All Available Control Technologies 5-38
5.3.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-39
5.3.1.3 Step 3 – Rank Remaining Control Options 5-39
5.3.1.4 Step 4 – Evaluate Remaining Control Options 5-40
5.3.1.5 Step 5 – Select BACT 5-40

Table of Contents
Continued

Section **Page**

5.3.2 BACT for VOC 5-40
5.3.2.1 Step 1 – Identify All Available Control Technologies 5-40
5.3.2.2 Step 2 – Eliminate Technically Infeasible Control Options 5-41
5.3.2.3 Steps 3 – 5 5-41
5.4 BACT for Fluid Catalytic Cracking Unit 5-41
5.4.1 BACT for CO 5-42
5.4.1.1 Step 1 – Identify All Available Control Technologies 5-42
5.4.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-42
5.4.1.3 Steps 3 – 5 5-43
5.4.2 BACT for PM_{10} and $PM_{2.5}$ 5-44
5.4.2.1 Step 1 – Identify All Available Control Technologies 5-44
5.4.2.2 Step 2 – Eliminate Technically Infeasible Control Options 5-44
5.4.2.3 Step 3 – Rank Remaining Control Options 5-44
5.4.2.4 Step 4 – Evaluate Remaining Control Options 5-45
5.4.2.5 Step 5 – Select BACT 5-46
5.4.3 BACT for SO_2 5-46
5.4.3.1 Step 1 – Identify All Available Control Technologies 5-46
5.4.3.2 Step 2 – Eliminate Technically Infeasible Control Options 5-47
5.4.3.3 Step 3 – Rank Remaining Control Options 5-48
5.4.3.4 Step 4 – Evaluate Remaining Control Options 5-48
5.4.3.5 Step 5 – Select BACT 5-49
5.4.4 BACT for NO_x 5-50
5.4.4.1 Step 1 – Identify All Available Control Technologies 5-50
5.4.4.2 Step 2 – Eliminate Technically Infeasible Control Options 5-50
5.4.4.3 Step 3 – Rank Remaining Control Options 5-50
5.4.4.4 Step 4 – Evaluate Remaining Control Options 5-52
5.4.4.5 Step 5 – Select BACT 5-53
5.5 BACT for Storage Tanks 5-55
5.5.1 BACT for VOC 5-55
5.5.1.1 Step 1 – Identify All Available Control Technologies 5-56
5.5.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-56
5.5.1.3 Step 3 – Rank Remaining Control Options 5-57
5.5.1.4 Step 4 – Evaluate Remaining Control Options 5-58
5.5.1.5 Step 5 – Select BACT 5-59
5.6 BACT for Product Loading Racks 5-59
5.6.1 BACT for VOC 5-59
5.6.1.1 Step 1 – Identify All Available Control Technologies 5-59
5.6.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-59
5.6.1.3 Steps 3 – 5 5-60

Table of Contents
Continued

Section **Page**

5.7 BACT for Emergency Generator 5-60
5.7.1 BACT for NO_x 5-60
5.7.1.1 Step 1 – Identify All Available Control Technologies 5-61
5.7.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-63
5.7.1.3 Step 3 – Rank Remaining Control Options 5-63
5.7.1.4 Step 4 – Evaluate Remaining Control Options 5-63
5.7.1.5 Step 5 – Select BACT 5-64
5.7.2 BACT for CO and VOC 5-65
5.7.2.1 Step 1 – Identify All Available Control Technologies 5-65
5.7.2.2 Step 2 – Eliminate Technically Infeasible Control Options 5-66
5.7.2.3 Step 3 – Rank Remaining Control Options 5-66
5.7.2.4 Step 4 – Evaluate Remaining Control Options 5-66
5.7.2.5 Step 5 – Select BACT 5-67
5.7.3 BACT for $PM_{10}/PM_{2.5}$ 5-67
5.7.3.1 Step 1 – Identify All Available Control Technologies 5-67
5.7.3.2 Step 2 – Eliminate Technically Infeasible Control Options 5-68
5.7.3.3 Step 3 – Rank Remaining Control Options 5-68
5.7.3.4 Step 4 – Evaluate Remaining Control Options 5-69
5.7.3.5 Step 5 – Select BACT 5-69
5.7.4 BACT for SO_2 5-70
5.7.4.1 Step 1 – Identify All Available Control Technologies 5-70
5.7.4.2 Step 2 – Eliminate Technically Infeasible Control Options 5-70
5.7.4.3 Steps 3 – 5 5-70
5.8 BACT for Leaks 5-70
5.8.1 BACT for VOC 5-71
5.8.1.1 Step 1 – Identify All Available Control Technologies 5-71
5.8.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-71
5.8.1.3 Steps 3 – 5 5-71
5.9 BACT for Flare 5-72
5.9.1 BACT for NO_x, SO_2, CO, VOC, and PM 5-72
5.9.1.1 Step 1 – Identify All Available Control Technologies 5-72
5.9.1.2 Step 2 – Eliminate Technically Infeasible Control Options 5-72
5.9.1.3 Step 3 – Rank Remaining Control Options 5-72
5.9.1.4 Step 4 – Evaluate Remaining Control Options 5-73
5.9.1.5 Step 5 – Select BACT 5-73
5.10 BACT for Process Heaters for Greenhouse Gases 5-74
5.10.1 Step 1 – Identify All Available Control Technologies 5-74
5.10.1.1 Good Combustion Practices 5-74
5.10.1.2 Low-Carbon Fuel 5-75

Table of Contents
Continued

Section **Page**

5.10.1.3 Energy Efficient Design 5-75
5.10.1.4 Carbon Capture and Subsequent Sequestration 5-75
5.10.2 Step 2 – Eliminate Technically Infeasible Control Options 5-76
5.10.3 Step 3 – Rank Remaining Control Options 5-78
5.10.4 Step 4 – Evaluate Remaining Control Options 5-79
5.10.5 Step 5 – Select BACT 5-81
5.11 BACT for Steam Boiler for Greenhouse Gases 5-81
5.11.1 Step 1 – Identify All Available Control Technologies 5-81
5.11.1.1 Energy Efficient Processes and Technologies 5-82
5.11.1.2 Carbon Capture and Subsequent Sequestration 5-82
5.11.2 Step 2 – Eliminate Technically Infeasible Control Options 5-82
5.11.3 Steps 3 – 5 5-83
5.12 BACT for Equipment Leaks for Greenhouse Gases 5-85
5.12.1 Step 1 – Identify All Available Control Technologies 5-85
5.12.2 Step 2 – Eliminate Technically Infeasible Control Options 5-85
5.12.3 Step 3-5 5-85
5.13 BACT for Flare for Greenhouse Gases 5-85
5.13.1 Step 1 - Identify All Available Control Technologies 5-86
5.13.2 Step 2 - Eliminate Technically Infeasible Control Options 5-86
5.13.3 Step 3 - Rank Remaining Control Options 5-86
5.13.4 Step 4 – Evaluate Remaining Control Options 5-86
5.13.5 Step 5 – Select BACT 5-87
5.14 BACT for Fluid Catalytic Cracking Unit for Greenhouse Gases 5-87
5.14.1 Step 1 – Identify All Available Control Technologies 5-87
5.14.2 Step 2 – Eliminate Technically Infeasible Control Options 5-87
5.14.3 Step 3 – Rank Remaining Control Options 5-88
5.14.4 Step 4 – Evaluate Remaining Control Options 5-88
5.14.5 Step 5 – Select BACT 5-89
6.0 PSD CLASS II AREA AMBIENT AIR QUALITY ANALYSIS 6-1
6.1 Near-Field Dispersion Modeling Analyses 6-1
6.1.1 Regional Description 6-1
6.2 Background Ambient Air Quality 6-3
6.3 Model Selection 6-4
6.3.1 AERMET 6-4
6.3.2 AERMAP 6-5
6.3.3 AERSURFACE 6-5
6.4 Meteorological Data 6-9
6.5 Treatment of Calms or Near-Calms 6-12
6.6 Receptor Grid for Near-Field Modeling 6-12

Table of Contents
Continued

Section **Page**

6.7 Source Parameters and Technical Input Options 6-14
6.9 Good Engineering Practice (GEP) Stack Height 6-22
6.10 Downwash 6-22
6.11 PVMRM 6-24
6.12 Urban Roughness 6-24
6.13 Near-Field Modeling Results 6-26
6.14 Significant Impact Levels 6-35
6.15 Full Impact Analysis 6-35
6.16 Near-by Source Inventory 6-36
6.17 National Ambient Air Quality Standard Compliance 6-38
6.18 PSD Class II Increment Compliance 6-41
6.19 Hazardous Air Pollutant Air Quality Analysis 6-41
6.20 Preconstruction Monitoring 6-42

7.0 ADDITIONAL IMPACT ANALYSES 7-1
7.1 Soils and Vegetation Analysis 7-1
7.2 Growth Analysis 7-2

8.0 REFERENCES 8-1

Table

2-1 Summary of Storage Tank Changes 2-12
3-1 NSR/PSD Significant Emission Rates 3-2
3-2 Baseline Actual 24-Month Period 3-4
3-3 Proposed PTE Emissions from Heavy crude Processing Project New and Modified Equipment Only 3-6
3-4 Contemporaneous Project Emissions and NSR Applicability (TPY) 3-14
3-5 Additional Proposed Refinery Changes and Corresponding Emissions 3-15
3-6 PTE Greenhouse Gas Emission Estimates for Proposed Heavy Crude Processing Project at Holly Refining & Marketing Company Woods Cross Refinery 3-16
3-7 PSD Applicability Results 3-17
3-8 Net Emission Change for $PM_{2.5}$ and VOC Emissions 3-17
3-9 Net Emissions from New and Project-Affected Sources 3-18
3-10 Average Startup/Shutdowns Per Year 3-35
3-11 PTE Startup Emissions per Event 3-36
3-12 PTE Shutdown Emissions per Event 3-36
3-13 Total Startup/Shutdown Emissions in Tons Per Year 3-36

Table of Contents
Continued

Table		Page
3-14	Potential to Emit Emissions for Holly Refining & Marketing Company Woods Cross Refinery	3-37
4-1	National Ambient Air Quality Standards	4-8
4-2	PSD Significant Emission Rates	4-10
4-3	PSD De Minimis Monitoring Concentrations	4-13
4-4	PSD Increments and Significant Impact Levels in Micrograms per Cubic Meter	4-14
5-1	Summary of BACT Determinations for CO for Process Heaters	5-9
5-2	Summary of BACT Determinations for PM_{10} for Process Heaters	5-14
5-3	Control Efficiencies for NO_x Control Devices	5-18
5-4	Summary of BACT Determinations for NO_x for Process Heaters	5-24
5-5	Summary of BACT Determinations for VOC for Process Heaters	5-26
5-6	Summary of BACT Determination for CO for Power Boilers < 100 MMBtu/hr	5-29
5-7	Summary of BACT Determinations for PM_{10} for Power Boilers < 100 MMBtu/hr	5-31
5-8	Summary of BACT Determinations for NO_x for Power Boilers < 100 MMBtu/hr	5-37
5-9	$LoTO_x$™ NO_x Reduction Technology Installations	5-54
6-1	Background Pollutant Concentrations	6-3
6-2	Surface Characteristics used in AERMET for Holly Marketing & Refining Company	6-7
6-3	Modeled PTE Emission Rates and Stack Parameters for Proposed Holly Heavy Crude Processing Project Sources – Short Term	6-15
6-4	Modeled PTE Emission Rates and Stack Parameters for Existing or Modified Holly Sources – Short Term	6-16
6-5	Modeled PTE NO_2 Annual Emission Rates and Stack Parameters for Proposed Holly Holly Heavy Crude Processing Project Sources	6-18
6-6	Modeled PTE NO_2 -Annual Emission Rates and Stack Parameters for Existing or Modified Holly Sources	6-19
6-7	Building Dimensions used in AERMOD	6-23
6-8	Surrounding City Population Densities	6-25
6-9	Modeled Maximum and High-Second-High Near-Field Pollutant Concentrations for Proposed Holly Refining & Marketing Company Heavy Crude Processing Project	6-27
6-10	Modeled Maximum and High-Second-High Near-Field Pollutant Concentrations for Proposed Holly Refining & Marketing Company Sources	6-28
6-11	PSD Class II Area Significant Air Quality Impact Levels	6-35
6-12	Comparison of Modeled Maximum Concentrations for Holly's Proposed Heavy Crude Processing Project to Significant Impact Levels	6-36
6-13	Full Impact Analysis Sources	6-37
6-14	Full Impact Analysis AERMOD Results	6-37
6-15	NAAQS Compliance Demonstration for Holly Proposed Heavy Crude Project and Existing Holly Sources Only	6-38
6-16	NAAQS Compliance Demonstration for Full Impact Analysis Sources	6-39

Table of Contents
Continued

Table **Page**

6-17 PSD Class II Increment Compliance for Full Impact Analysis Sources 6-41
6-18 Modeled Maximum HAP Concentrations 6-42
7-1 SPC Annual Emissions 7-2
7-2 Default CALMET Land Use Categories and Associated Geophysical Parameters Based on USGS Classification System..... 7-10
7-3 Class I Area Receptors..... 7-11
7-4 PSD Class I SILs and Increments 7-13
7-5 Modeled Maximum Class I Area Concentrations Compared to Significant Impact Levels and PSD Class I Increments 7-37
7-6 VISCREEN Level 1 Model Input Parameters 7-44
7-7 Maximum Predicted Visual Impact - VISCREEN 7-45

Figure **Page**

1.1 Location of Holly Refining & Marketing Company's Woods Cross Refinery 1-5
2.1 Holly Refining & Marketing Company Facility Layout..... 2-3
2.2 Crude Unit Process Schematic..... 2-4
2.3 Fluid Catalytic Cracking Unit Process Schematic 2-6
2.4 SRU Incinerator Emission Reduction Process Flow Diagram 2-9
6.1 Map Showing Location of Holly Refinery and Terrain Data used in AERMOD 6-2
6.2 2006 Annual Wind Rose (Syracuse, Utah)..... 6-10
6.3 2007 Annual Wind Rose (Syracuse, Utah)..... 6-10
6.4 2008 Annual Wind Rose (Syracuse, Utah)..... 6-11
6.5 2009 Annual Wind Rose (Syracuse, Utah)..... 6-11
6.6 AERMOD Discrete Receptor Grid 6-13
6.7 Land Use Surrounding Holly Refinery 6-25
6.8 Cities/Population Densities Surrounding Holly..... 6-26
6.9 Modeled 98th Percentile One-hour NO_2 Concentration Isopleth Plot Based on Three-Year Average 6-29
6.10 Modeled Maximum Annual NO_2 Concentration Isopleth Plot..... 6-30
6.11 Modeled Maximum One-hour CO Concentration Isopleth Plot..... 6-31
6.12 Modeled Maximum Eight-hour CO Concentration Isopleth Plot..... 6-32
6.13 Modeled 99th Percentile One-hour SO_2 Concentration Isopleth Plot Based on Three-Year Average 6-33
6.14 Modeled High-Second-High 24-hour PM_{10} Concentration Isopleth Plot..... 6-34
6.15 Modeled 98th Percentile One-Hour NO_2 Concentration Isopleth Plot – Full Impact Analysis – Entire Modeling Domain Based on Three-Year Average..... 6-40
6.15 Modeled Maximum Annual NO_2 Concentration Isopleth Plot – Full Impact Analysis Entire Modeling Domain 6-34

Table of Contents
Continued

Figure **Page**

6.16 Modeled 99th Percentile One-hour SO_2 Concentration Isopleth Plot-Full Impact Analysis Based on Three-Year Average 6-35
6.16 Modeled Maximum Annual NO_2 Concentration Isopleth Plot – Full Impact Analysis Around SPC Facility 6-37
6.17 Modeled HSH 24-hour PM_{10} Concentration Isopleth Plot – Full Impact Analysis Around SPC Facility 6-38

Appendices

A Baseline Emission Estimates
B PTE Emission Estimates for Heavy Crude Expansion Project
C PTE Holly Refining & Marketing Operations
D Modeling Protocol Approval Letter
E Cost Analysis for Flare Gas Recovery System
F GHG Cost Analysis for Flare Gas Recovery System
G In-Stack NO_x/NO_2 Ratio Test Results
H Near-Field Analysis AERMOD Results – Existing and Proposed Holly Refining & Marketing Operations
I Full Impact Source Parameters and Emissions Information
J Full Impact Analysis AERMOD Results
K HAPS Spreadsheet
L HAPS AERMOD Analyses Results
M Soils and Vegetation Analysis

NOTICE OF INTENT

HOLLY REFINING & MARKETING COMPANY-WOODS CROSS REFINERY

HEAVY CRUDE PROCESSING PROJECT

MAY 2012

1.0 INTRODUCTION

Meteorological Solutions Inc. (MSI) was retained by Holly Refining & Marketing Company, referred to as "Holly", to prepare a Notice of Intent (NOI) to accommodate for the processing of heavy black and yellow wax crudes at Holly's Woods Cross Refinery. As part of the increase in crude processing, from the currently permitted 40,000 barrels per day (BPD) to 60,000 BPD, changes to refinery operations including the installation of new equipment, and decommissioning or replacement of, and/or modifications to existing equipment are needed. This facility is an existing major source under Prevention of Significant Deterioration (PSD) and estimated net emission increases for carbon monoxide (CO) will be above the PSD major modification thresholds. Therefore, the requested changes require PSD review for CO.

On July 10, 2012 in a show of support for Gov. Gary R. Herbert's U-CAIR initiative to improve air quality, Holly plans to add pollution control equipment that reduces sulfur dioxide (SO_2) emissions and its corresponding SO_2 State Implementation Plan (SIP) cap by 150 tons per year. This reduction is primarily due to emissions from the existing sulfur recovery incinerator routed to wet scrubber (an estimated reduction of 138 tons) as well as other SO_2 emission reductions that have taken place at the Refinery over the past ten years.

In 2007, the Refinery permitted a number of changes to modernize the refinery and expand processing capacity. Many of those changes have been implemented or are in the process of being implemented. Due to market forces, the Refinery is seeking to modify implementation of certain previously permitted changes. Central to these changes is a revision in the planned nature of the crude oil feed to the refinery. The former modernization included a significant increase in processing of heavier crude oil with higher sulfur content.

This revision replaces that heavier crude with local production primarily from eastern Utah (black wax and yellow wax). This local production is a highly-paraffinic crude oil with lower sulfur content.

For this project, the following changes are proposed as part of the facilities modifications to process black and yellow wax crudes:

- The existing crude unit's capacity will be expanded with the addition of a preflash tower. A previously permitted 35 MMBtu/hr crude feed heater (8H2) will not be constructed.
- A second crude unit with a capacity of 15,000 barrels per day of crude will be installed along with a 60 MMBtu/hr crude heater (24H1).
- To improve recovery of gas oil from the crude distillation bottoms, a vacuum tower and vacuum furnace, with a rating of 130 MMBtu/hr will be installed. A previously permitted 15.2 MMBtu/hr vacuum furnace heater (33H1) will not be constructed. Emissions from the new heater will be controlled using Selective Catalytic Reduction (SCR).
- The existing charge heater on the Gas Oil Hydrocracking Unit (GHC) will be replaced with a 42.1 MMBtu/hr reactor charge heater.
- The Distillate Hydrotreater (DHT) will be expanded to handle the additional distillate by utilizing the GHC charge heater.
- A Fluid Catalytic Cracking Unit (FCCU) with a capacity of processing 8500 barrels per day will be constructed along with a 45 MMBtu/hr feed heater. Emissions from the FCCU will be controlled by a wet gas scrubber.
- A poly gasoline unit equipped with a 14 MMBtu/hr hot oil heater will be constructed to convert olefin to a high octane gasoline blend stock.
- A Hydrocracker/Hydroisom Unit which will produce high-quality lubricants and ultra-low sulfur diesel will be constructed. This unit will be equipped with a 99 MMBtu/hr reactor charge heater. Emissions from this heater will be controlled using SCR.
- An 89.3 MMBtu/hr steam boiler will be installed. Emissions from this boiler will be controlled through Selective Catalytic Reduction (SCR).

- A sour water stripper with a capacity of handling 100 gallons per minute will be constructed. Emissions from this unit will be controlled through the existing sour water stripper/ammonia stripping unit prior to treatment in the existing sulfur recovery unit.
- One new cooling tower will be constructed and one existing cooling tower will be expanded by adding a cell.
- Two previously permitted amine units will not be constructed.
- Two previously permitted Claus sulfur recovery units and tail gas treatment units will not be constructed.
- The 60 MMBtu/hr CO boiler will be decommissioned.
- A previously permitted 15.3 MMBtu/hr asphalt mix heater will no longer be used.
- The previously permitted heaters for the Hydrogen Plant will be controlled using SCR to reduce oxides of nitrogen emissions.
- The previously permitted heater for the Deasphalting Unit hot oil heater will be controlled using SCR to reduce NO_x emissions.
- The previously permitted boiler #8 will be controlled using SCR to reduce NO_x emissions.
- Emissions from existing sulfur recovery incinerator will be routed to a wet gas scrubber.
- 40 previously permitted rail spots for loading fuel oil will be revised to 16 for fuel oil and 24 for lube oil. The 16 fuel oil spots will be reconfigured to load fuel oil or asphalt.
- Two existing biodiesel loading spots will be moved to the west track in the East Tank Farm. The existing biodiesel spots will be converted to fuel oil/asphalt loading.
- An existing LPG rail loading spot on the west track will be converted to load propane.
- The crude truck unloading facilities will be expanded for twelve more truck bays.
- Several storage tanks will be modified, reconstructed or removed as part of this project. Ten (10) new tanks for lubes feed/product, two (2) for gas oil, one (1) for poly gasoline, one (1) for gasoline, two (2) for diesel, four (4) for propane, one (1) for wastewater, and one (1) for sour water feed will be constructed.
- Three asphalt tanks will be equipped with two to four 0.8 MMBtu/hr stab-in heaters each.
- The frozen earth propane storage will be removed.

1.1 Facility Description

The Holly Refining & Marketing Company refinery is located at 393 South 800 West 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. The refinery is located in Davis County which is non-attainment area for $PM_{2.5}$, maintenance for ozone (O_3) and particulate matter (PM_{10}), and attainment for sulfur dioxide (SO_2), 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 $PM_{2.5}$, PM_{10}, and SO_2, and a maintenance area for O_3. A map showing the location of the facility is presented as Figure 1.1.

1.2 Company Information

All correspondence regarding this NOI should be directed to:

Mr. Michael S. Astin. P.E.
Environmental Manager
393 South 800 West
West Bountiful, Utah 84087-1435
Phone No. (801) 299-6625
Fax No. (801) 299-6609

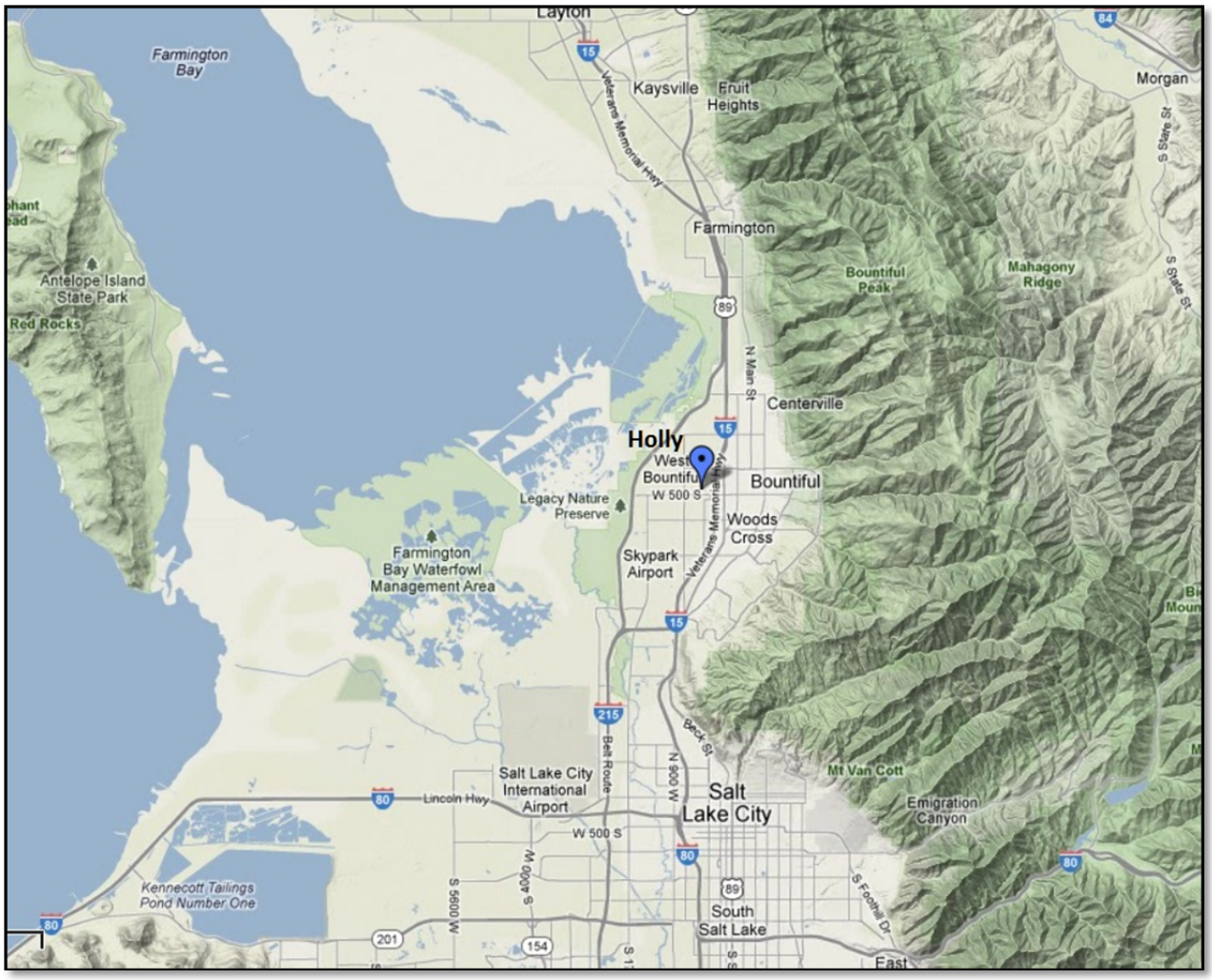


Figure 1.1 Location of Holly Refining & Marketing Company's Woods Cross Refinery

This permit application is organized into the following sections:

- **Section 2.0 – Project Description**. This section contains information including process descriptions, changes to existing operations, new or modified equipment, and equipment to be removed.

- **Section 3.0 – Heavy Crude Processing Project Emissions**. This section presents a detailed review of the Potential to Emit (PTE) emissions from the proposed Heavy Crude Processing Project and existing sources as well as actual to future potential emission estimates.

- **Section 4.0 – Regulatory Review**. This section presents an assessment of applicable state and federal regulations. This section focuses on which regulations are directly applicable to the proposed equipment and how compliance will be demonstrated.

- **Section 5.0 – Best Available Control Technology Demonstration**. This section is a substantial requirement of the Notice of Intent (NOI)/PSD application. A detailed evaluation of control technologies and emission rates is provided. EPA's "top down" best available control technology (BACT) approach was used for these determinations. Lowest achievable emission rate (LAER) controls were reviewed for $PM_{2.5}$ emission sources.

- **Section 6.0 – Near-Field Dispersion Modeling Analyses**. This section summarizes the near-field dispersion modeling conducted to evaluate the potential increased emission impacts on the Significant Impact Levels (SILs), National Ambient Air Quality Standards (NAAQS), PSD Class II increments, and at near-by non-attainment areas. Specifically, this section discusses the modeling input data and the various modeling scenarios evaluated. This section also presents the results of the Class II area analyses performed and compares the calculated impacts to the applicable standards.

- **Section 7.0 – Additional Impact Analyses.** This section summarizes the impact from carbon monoxide emissions on soils and vegetation.
- **Section 8.0 – References**. This section summarizes the references that were used in the preparation of the NOI.

Site work for construction is scheduled to begin as soon as approval to proceed is obtained. Startup of the earliest portions of this project is anticipated to begin in April 2014. Completion of the entire project is projected by December 2016.

2.0 PROCESS DESCRIPTION

The Uinta Basin in Eastern Utah contains abundant resources of black-wax and yellow-wax crude, which are both desirable for their low sulfur content and are suitable for the creation of various refined petroleum products. Because of the paraffinic nature and high pour point of these unique crudes, they become solid wax at ambient temperatures and must be transported to Salt Lake City refineries via insulated tanker trucks and trailers. To be able to accommodate for the additional crude, Holly is expanding its refining capabilities. Thus, the following sections discuss the proposed new equipment and modifications to the existing equipment as part of Holly's Heavy Crude Processing Project.

2.1 Heavy Crude Processing Project

The heavy crude processing project involves changes to existing refinery operations and addition of new process units at the facility including:

1) Expansion of existing crude unit through addition of preflash tower;
2) Installation of second crude unit;
3) Installation of second fluid catalytic cracking unit (FCCU);
4) Installation of Poly Gasoline Unit:
5) Installation of Hydrocracker/Hydroisom Unit;
6) Installation of new and expansion to existing cooling towers;
7) Installation of several process heaters and furnaces; and
8) Installation of a steam boiler.

Other existing facility process units will be modified/removed to accommodate the black and yellow wax crudes. These consist of:

1) Installation of new or modification to existing tanks;
2) Installation of additional truck bays for crude unloading; and

3) Changes to rail loading and unloading locations.
4) Removal of frozen earth propane storage.

A facility-wide plot plan for the heavy crude processing project is presented as Figure 2.1.

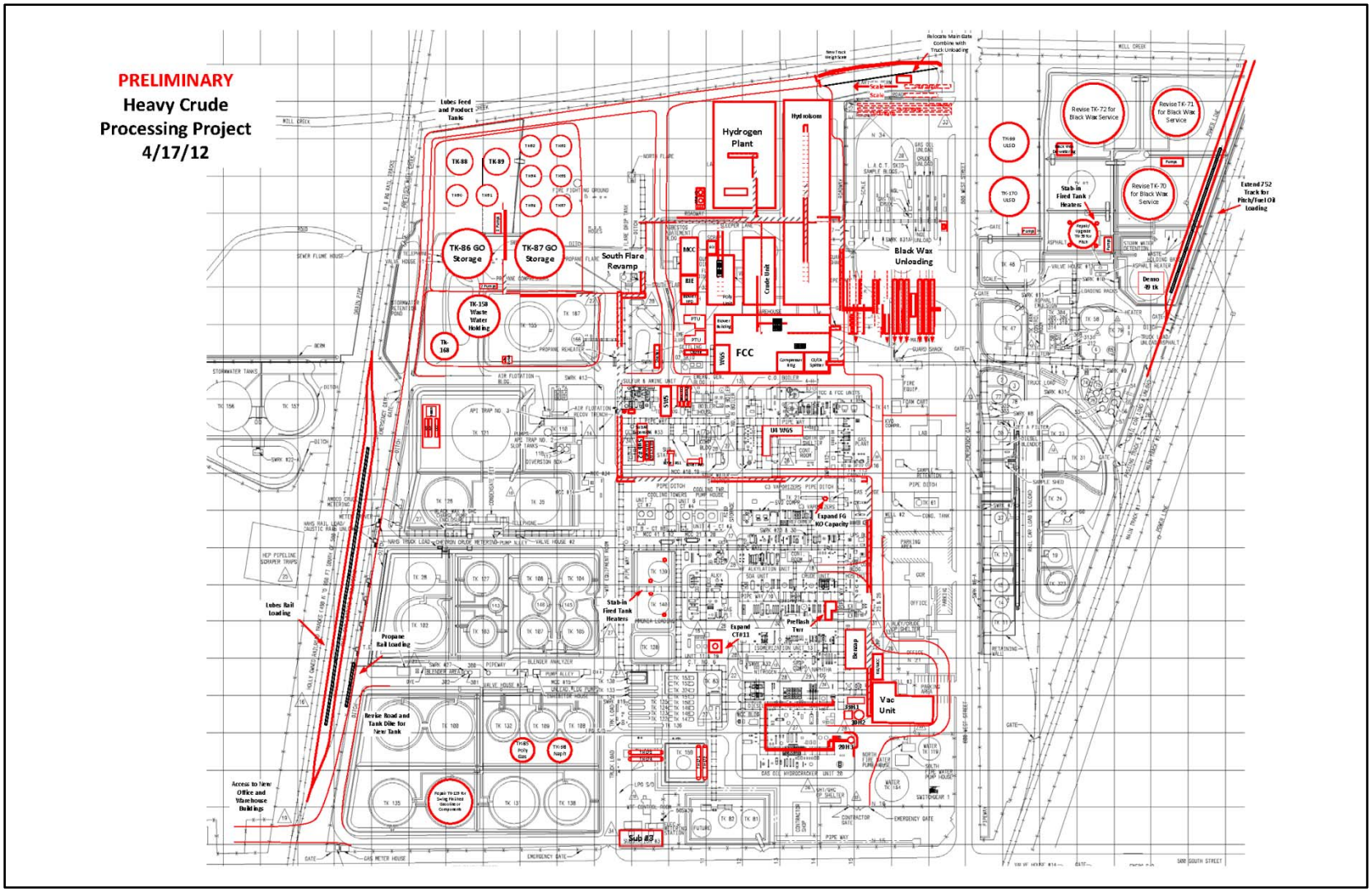


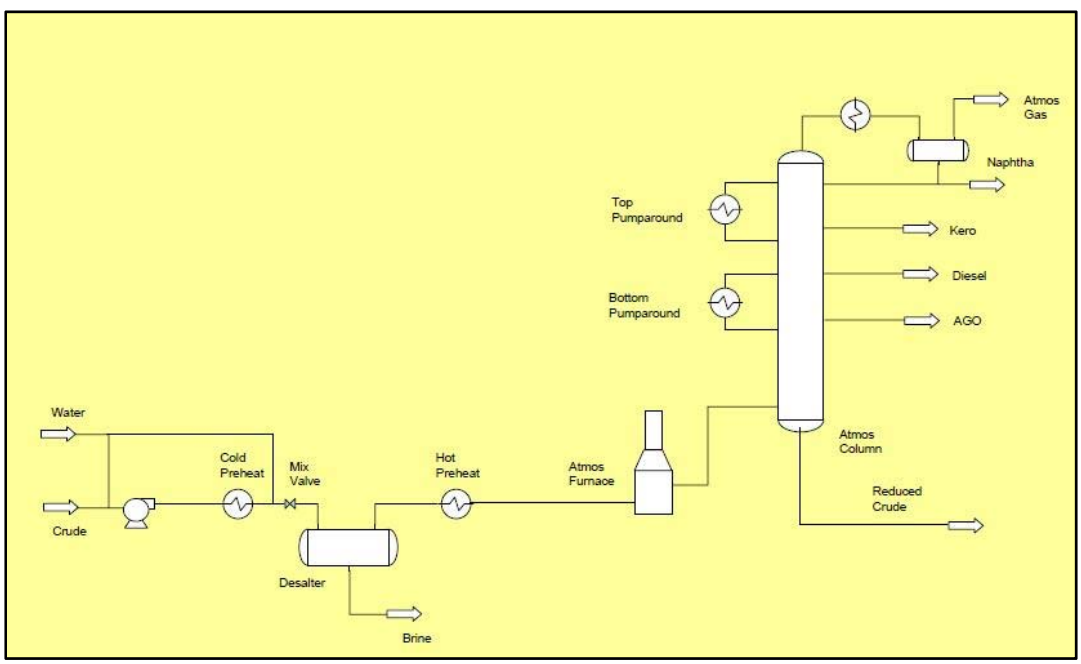
Figure 2.1 Holly Refining & Marketing Company Facility Layout

2.1.1 Existing Crude Unit Expansion

The crude unit is used to pre-treat crude and distill it into several hydrocarbon fractions that are used for sale, blending into sales products, or for further processing to produce saleable products. Holly's existing crude unit (Unit 8) processes 26,000 barrels per day (BPD) of crude. With the proposed change to include the throughput of black wax crude, a preflash tower will be installed on the existing crude unit which will increase the processing capacity of the existing crude unit to 45,000 BPD. A previously permitted 35.0 MMBtu/hr (HHV) crude feed heater (ID 8H2) will not be constructed due to the change in feedstock.

2.1.2 New Crude Unit

A second crude unit capable of processing 15,000 BPD of crude will be installed at the Woods Cross refinery. A 60 MMBtu/hr crude heater (ID 24H1), equipped with ultra-low NO_x burners and fired on refinery plant fuel gas, will be installed on this new crude unit. A general process schematic for a crude unit is presented in Figure 2.2.



Source: www.processengr.com

Figure 2.2 Crude Unit Process Schematic

2.1.3 Vacuum Unit

In order to further improve the recovery of gas oil from the crude distillation bottoms, a vacuum tower and vacuum furnace heater will be installed. The previously permitted vacuum tower unit (Unit 33) will have a capacity of 25,000 BPD. The resulting vacuum tower bottoms will be fed to the existing Solvent Deasphalting (SDA) Unit (Unit 10).

Previously, a 15.2 MMBtu/hr (HHV) vacuum furnace heater (ID 33H1) was proposed to be installed on the vacuum tower. This heater was not constructed. With the change in feedstock, a larger vacuum furnace heater (130 MMBtu/hr (HHV)), to be equipped with low NO_x burners and fired on refinery plant gas, will be installed on the vacuum tower unit. Emissions from the proposed vacuum heater will be controlled by selective catalytic reduction (SCR).

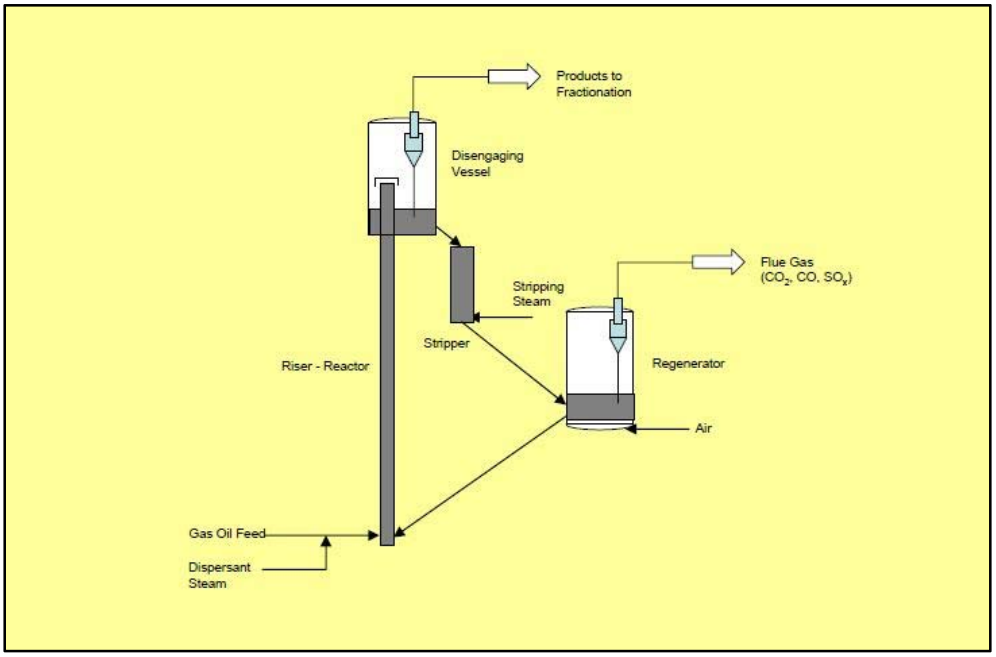
2.1.4 Gas Oil Hydrocracking Unit and Distillate Hydrotreater

With the change to include the processing of black and yellow wax crudes, the existing charge heater (ID 20H1) on the Gas Oil Hydrocracking (GHC) Unit (Unit 20) will be insufficient to run the GHC unit at full capacity. Thus, a larger 42.1 MMBtu/hr (HHV) reactor charge heater (ID 20H3) equipped with ultra-low NO_x burners fired on refinery plant gas will be installed on the GHC.

The Distillate Hydrotreater (DHT) will be expanded to handle the additional distillate that will be produced under the proposed modifications. The existing 14.9 MMBtu/hr (HHV) GHC charge heater (20H1) will be re-piped to provide additional charge heating for the DHT.

2.1.5 Fluid Catalytic Cracking Unit

A Fluid Catalytic Cracking Unit (FCCU) from an idled New Mexico refinery will be relocated to the Woods Cross Refinery. This unit is capable of processing 8500 barrels of gas oil per day and is similar in size to the existing FCCU. This new FCCU will include a 45 MMBtu/hr (HHV) feed heater (ID 25H1) and will be equipped with ultra-low NO_x burners fired on refinery plant gas. A wet gas scrubber will be installed on this unit for emissions control. A general process diagram for a FCCU is presented as Figure 2.3.



Source: www.processengr.com

Figure 2.3 Fluid Catalytic Cracking Unit Process Schematic

2.1.6 Poly Gasoline Unit

A Poly Gasoline Unit will also be relocated to the Woods Cross Refinery. This unit will take olefin produced by both the relocated FCCU and the existing FCCU and convert it to a high octane gasoline blend stock. A 14 MMBtu/hr (HHV) hot oil heater (ID 26H1), equipped with ultra- low NO_x burners and fired on refinery plant gas, will be installed to provide process heat for the poly gasoline unit.

2.1.7 Hydrocracker/Hydroisom Unit

A new Hydrocracker/Hydroisom Unit, that will produce high-quality lubricants and ultra-low sulfur diesel, will be constructed at the Woods Cross refinery. The hydrocracker/hydroisom unit will include a 99 MMBtu/hr reactor charge heater (ID 27H1). This heater will be equipped with low NO_x burners and fired on refinery plant gas. Emissions from the proposed reactor charge heater will be controlled by SCR.

2.1.8 Boiler #11

An 89.3 MMBtu/hr boiler (Boiler #11), equipped with low NO_x burners and fired on refinery plant gas as the primary fuel will be installed to provide steam for the facility. Emissions from this boiler will be controlled by SCR.

2.1.9 Sour Water Stripper

With the additional sour water streams that will be generated, a third sour water stripper, capable of handling up to 100 gallons per minute, will be constructed. The off-gas from the new stripper will be sent to the existing sour water stripper/ammonia stripping unit (Unit 22) to remove ammonia prior to treatment in the existing SRU.

2.1.10 Emergency Generator

A 540 HP diesel-driven emergency generator will be installed to provide support system power to critical systems in the event that electric power is not available from the grid. The diesel engine will meet Tier 3 emissions standards which minimize the NO_x, CO, VOC, and PM emissions by using good combustion controls. The SO_2 emissions from the diesel engines will be minimized by using ultra-low sulfur diesel fuel. Maintenance and readiness testing checks of the diesel engine are necessary to ensure the reliability of the engine. It is anticipated that the emergency diesel generator would be operated 50 hours per year for maintenance and readiness testing purposes.

2.2 Permitted Equipment to be Removed from Air Approval Order

As mentioned previously, the 35.0 MMBtu/hr (HHV) crude feed heater (ID 8H2) and 15.2 MMBtu/hr (HHV) vacuum furnace heater (ID 33H1) will not be installed. With the proposed change to black wax crude processing, Amine Units #2 and #3 (Unit 32 and Unit 35) are no longer necessary and will not be constructed. The existing Sulfur Recovery Unit #1 (Unit 17) and NaSH sour gas treatment Unit (Unit 21) are sized to handle all sulfur removal requirements from the heavy crude processing project.

In addition, two (2) previously permitted Claus sulfur recovery units (SRU) and Tail Gas Treatment Units (TGTU), Units 31 and 34, will also no longer be necessary and will not be constructed. Since ammonia stripping capability is part of the sour water stripper (Unit 22) that has been installed, the modifications to the existing SRU which included the addition of oxygen enrichment will not be made. The effluent from the existing SRU incinerator will, however, be routed to the wet scrubbers for emissions control.

SRU incinerator effluent gases will be hard piped from the SRU incinerator stack to the inlet of the wet gas scrubber. The wet gas scrubber will treat the SO_2 in the effluent gas by reaction with reagent to form an aqueous solution of sodium sulfite that will in turn be treated by the waste water plant. The treatment of the SRU Incinerator effluent gases will be routed to the wet gas scrubber during normal operation and unit upsets. A SRU incinerator emission reduction process flow diagram is presented as Figure 2.4.

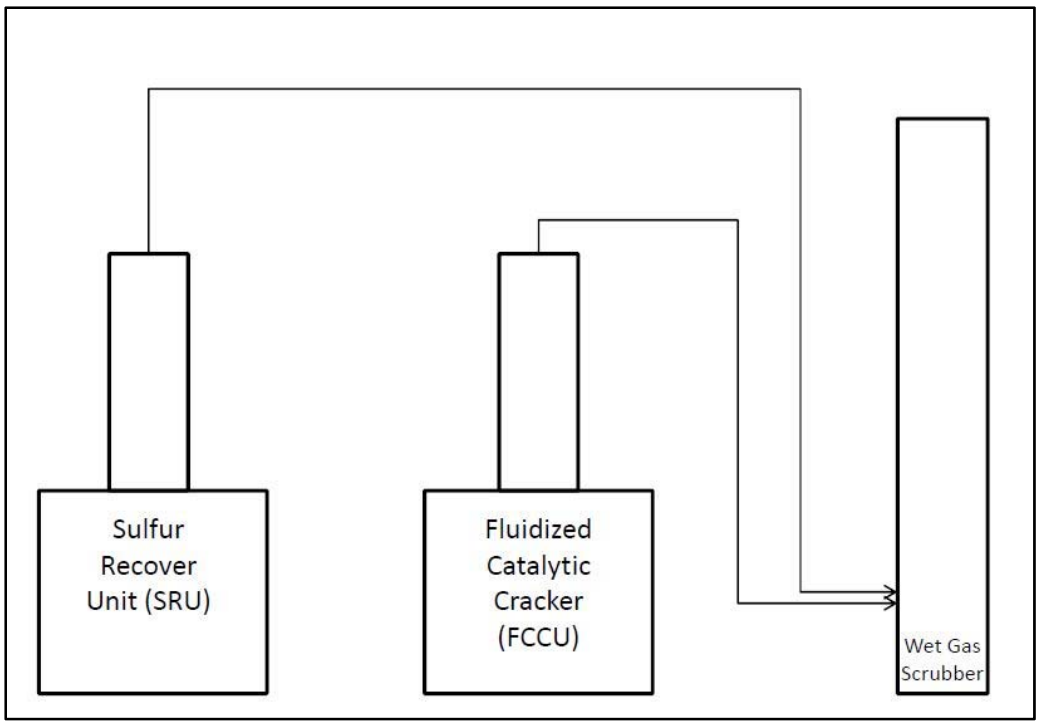


Figure 2.4 SRU Incinerator Emission Reduction Process Flow Diagram

The 60 MMBtu/hr CO boiler (Boiler #6) will be decommissioned because it is beyond its useful life and when the wet gas scrubber becomes operational. An asphalt mix heater (45H1), a 15.3 MMBtu/hr process furnace will also no longer be used.

2.3 Process Support Units

The installation and operation of the proposed new or modified equipment at the Holly Refinery will impact some of the refinery's current operation and existing equipment. The following sections discuss the impacted areas.

2.3.1 Fuel Gas

The new process heaters will use fuel gas that has been treated to contain no more than 162 ppm H_2S based on a three-hour average and 60 ppm H_2S based on an annual average. The majority of fuel gas that is used at the refinery is generated within the refinery process. If the amount generated within the refinery process is inadequate, pipeline-quality natural gas will be utilized.

2.3.2 Cooling Towers

As part of the heavy crude processing project, there will be a new 8,500 gallon per minute cooling tower (cooling tower #10) and expansion of existing cooling tower #11 with the addition of an 8,500 gallon per minute cell. The new and expanded cooling towers will be induced draft, multi-cell counter flow type cooling towers equipped with drift eliminators to control particulate emissions.

2.3.3 Flare

The south flare will be reconstructed and reconfigured as part of the heavy crude processing project.

2.3.4 Loading/Unloading Facilities

The current permit includes 40 rail spots for loading fuel oil. This will be revised to 16 for fuel oil and 24 for lube oil. The 16 rail spots will be reconfigured to load fuel oil or asphalt. Two (2) existing biodiesel loading spots will be moved to the west track in the East Tank Farm and their prior locations will be converted to fuel oil/asphalt loading. One existing LPG rail loading spot on the west track will be converted to load propane. One additional rail spot for loading propane will be constructed on the west track.

A small electric-driven compressor will be added to control loading emissions by recovering displaced relief gas from loading propane into rail cars. In addition, the crude truck unloading facilities will be expanded to accommodate twelve (12) more truck bays.

2.3.5 Storage Tanks

There will be eighteen new tanks (Tanks 89-99, 158, 168), two tanks removed (Tanks 4 and 49), and five existing tanks (Tanks 59, 70-72, 139, and 140) modified as part heavy crude processing project. Four tanks previously permitted (Tanks 85-88) will still be constructed. Two tanks previously permitted, Tanks 80 and 84, will not be constructed. A summary of the tanks to be added, modified or removed as part of the heavy crude processing project is presented in Table 2-1.

Tank 168, a sour water tank, is being added to accommodate the additional sour water that will be generated by the project.

Table 2-1
Summary of Storage Tank Changes

Tank ID	Tank Status	Capacity (barrels)	Type	Description
4	Existing	851	Fixed Roof	To be removed.
49	Existing	55,877	Fixed Roof	To be removed.
59	Existing	30,019	Fixed Roof	To be reconstructed for asphalt storage. Four (4) stab-in heaters to be added.
70	Existing	80,306	Fixed Roof	Tank to be put into black wax crude storage.
71	Existing	67,155	This tank is currently equipped with IFR and primary and secondary seals.	This tank will be converted to black wax crude storage and the IFR removed[1].
72	Existing	106,811	This tank is currently equipped with IFR and primary and secondary seals.	This tank will be converted to black wax crude storage and the IFR removed[1].
80	Will not be built	10,000	Fixed Roof	Two (2) stab-in heaters.
84	Will not be built	10,000	Fixed Roof	Chemical storage.
85	To be constructed	19,600[2]	Previously permitted for heavy HC but will be constructed with IFR.	Poly gas storage.
86	To be constructed	109,660[2]	Cone Roof	Gasoil storage.
87	To be constructed	109,660[3]	Cone Roof	Gasoil storage.
88	To be constructed	26,730[4]	Cone Roof	Lubes feed/product storage.
89	New	26,730	Cone Roof	Lubes feed/product storage.
90-97	New	13,600	Cone Roof	Lubes feed/product storage.
98	New	19,600	IFR	Gasoline
99	New	66,000	Cone Roof	Diesel
139	Existing	14,957	Fixed roof	Two (2) stab-in heaters to be added. Vacuum bottoms stored.
140	Existing	14,857	Fixed roof	Two (2) stab-in heaters to be added. Vacuum bottoms stored.
158	New	64,315	Floating Roof	Waste water storage.
168	New	30,952	Floating Roof	Sour water feed.
170	New	66,000	Cone Roof	Diesel
171-174	New	1,600	Horizontal Elliptical	Propane

[1] IFR – Internal floating roof. Holly proposes to remove the floating roofs on Tanks 71 and 72 and use these tanks for storage of black and yellow wax crude. However, Holly may initially leave the floating roofs in place, because there has been some variation in the vapor pressure of this crude, and although it has not varied enough to require vapor control, further monitoring of the vapor pressure will be conducted prior to removal of the roofs. If the vapor pressure of delivered crude appears to drop to levels that would require vapor controls, the roofs will be left in these tanks, and Holly will address the need to install controls on the remaining waxy crude storage tanks.
[2] Previously permitted for 80,000 bbl.
[3] Previously permitted for 50,000 bbl.
[4] Previously permitted for 13,638 bbl.

2.3.6 Wastewater Treatment and Sewer

As part of the project to increase refinery throughput, a study is being conducted on water conservation and wastewater reduction. Based on the preliminary results of that study, it is anticipated that installation and operation of the proposed new process units will not increase the overall throughput of the existing wastewater treatment plant. The current water supply from existing onsite deep wells will be utilized more efficiently to meet the demand of the existing as well as the new units.

Most of the new or relocated process facilities will be constructed on the north of the existing process units and new process drains will be routed connected to existing drain systems.

A wastewater storage tank (Tanks 158) will be added to provide additional holding time for further separation of oils from the wastewater as well as additional capacity during high water events.

2.3.7 Removal of Frozen Earth Propane Storage

In conjunction with the other changes described herein, Holly will decommission the Frozen Earth Storage (FES) unit that has been used to store liquid propane. This decommissioning will include removal of all stored material and backfilling with suitable material to protect groundwater resources and provide adequate support for future use.

3.0 HEAVY CRUDE PROCESSING PROJECT EMISSIONS

Emission estimates were derived for the proposed heavy crude processing project as well as other proposed changes at the refinery on existing equipment. Emission estimates were based on manufacturer data, EPA guidance as published in *Compilation of Air Pollution Emission Factors, Volume I: Stationary Point and Area Sources or AP-42*, fuel type, and anticipated operating hours. The derived emission estimates presented in this application were used to determine New Source Review (NSR)/PSD and non-attainment NSR (NNSR) applicability.

The NSR permitting program for major sources is implemented in the Utah Rules. Utah Rules R407-403 and R07-405 implement both the federal PSD and NNSR permitting programs. Holly is considered a major PSD source as defined in R307-405 and is located in a non-attainment area for $PM_{2.5}$ and a maintenance area for ozone.

3.1 NSR/PSD Applicability Test

A PSD applicability analysis was conducted to determine if emissions from the proposed heavy crude processing project would be considered a “major modification” under NSR regulations. Because this project involves proposed modifications to existing emission units and addition of new emissions units, the applicability test was conducted to determine if a “significant emissions increase” and a “significant net emissions increase” of a regulated pollutant will occur. An increase is considered “significant” if it exceeds the annual ton per year thresholds which are presented in Table 3-1. For determining applicability as a major modification, the NSR pollutants covered either by PSD or NNSR permitting programs and their associated significant thresholds (Table 3-1) are the same.

Table 3-1

NSR/PSD Significant Emission Rates

Pollutant	Significant Emission Rate (TPY)
PM	25
PM_{10}	15
$PM_{2.5}$	10
SO_2	40
NO_x	40
CO	100
O_3 (VOC)	40
Sulfuric Acid Mist	7
Greenhouse gases (mass basis)	0
Greenhouse gases as carbon dioxide equivalents	75,000

Per the PSD regulation as found in 40 CFR 52.21(a)(2)(v)(f), a hybrid test can be conducted to determine if the sum of the emissions increases for each emission unit, using the methods specified in 40 CFR Part 52.21(a)(2)(iv)(c) through (d) equals or exceeds the significant amount for each pollutant. 40 CFR Part 52.21(a)(2)(iv)(c) through (d) are defined as follows:

> (c) Actual-to-projected-actual applicability test for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline actual emissions (defined below), for each existing emissions unit, equals or exceeds the significant amount for that pollutant;
>
> (d) Actual-to-potential test for projects that only involve construction of a new emissions unit(s). A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit from each new emissions unit following completion of the project and the baseline actual emissions of these units before the project equals or exceeds the significant amount for that pollutant.

3.1.1 Baseline Actual Emissions

Calculation of baseline actual emissions for the Holly Refining project followed 40 CFR 52.21 (b)(48)(ii) which states: "For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(a) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(b) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(c) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period.

However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of §51.165(a)(3)(ii)(G) of this chapter.

(d) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for all the emissions units being changed. A different consecutive 24-month period can be used for each regulated NSR pollutant.

(e) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (b)(48)(ii)(b) and (c) of this section."

For this permit, baseline actual emissions from project-affected sources were based on the average annual emissions that occurred during any consecutive two-year period in the past 10 years as reported in the required Holly annual emissions inventories. The existing sources to be affected by the heavy crude processing project include: the crude unit (8H1); the vacuum unit (33H1); the gas oil hydrocracker heater (20H1); the hydrogen reformer feed furnaces (30H1 and 30H2); the asphalt furnace (45H1); the south flare; existing FCCU; CO boiler; the existing sulfur recovery unit; cooling towers; propane pit flare; and tanks 4, 49, 59, 70-72, 139 and 140. The consecutive 24-month period baseline periods that were determined for the proposed project are presented in Table 3-2. The baseline actual emissions for the project-affected sources based on the time period presented in Table 3-2 are presented in Appendix A.

Table 3-2

Baseline Actual 24-Month Period

Pollutant	Consecutive 24-month Period
PM_{10}	January 2005 - December 2006
$PM_{2.5}$	January 2009- December 2010
SO_2	January 2006 – December 2007
NO_x	January 2010 – December 2011
CO	January 2009 – December 2010
VOC	January 2008- December 2009

According to 40 CFR Part 52.21, an emissions increase with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

> (a) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(2)(iv) of this section; and
>
> (b) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. Baseline actual emissions for calculating increases and decreases under this paragraph (b)(3)(i)(b) shall be determined as provided in paragraph (b)(48) of this section, except that paragraphs (b)(48)(i)(c) and (b)(48)(ii)(d) of this section shall not apply.

The emissions increase was calculated as the sum of emissions increases from new and modified existing units that are impacted by this project. If the project emissions increase for a regulated pollutant is less than the significant emission rate, NSR is not required for that pollutant. Table 3-3 and Appendix B presents the proposed PTE emissions for new or modified equipment as part of the heavy crude processing project.

Table 3-3

Proposed PTE Emissions from Heavy Crude Processing Project New and Modified Equipment Only

Emission Unit	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	SO_2 (TPY)	NO_x (TPY)	VOC (TPY)	CO (TPY)	Total HAPS (TPY)
24H1 Crude Furnace #3 (new)	1.97	1.97	2.61	10.51	1.42	21.02	0.49
25H1 FCC#2 Feed Heater (new)	1.48	1.48	1.96	7.88	1.06	15.77	0.36
FCCU #2 Wet Scrubber (new)	13.58	13.58	17.70	19.91	--	154.85	--
26H1 Hot Oil Furnace (new)	0.46	0.46	0.61	2.45	0.33	4.91	0.11
27H1 Reactor Charge Heater (new)	3.25	3.25	4.31	8.67	2.34	34.69	0.80
20H3 Reactor Charge Heater (new)	1.38	1.38	1.83	7.38	1.00	14.75	0.34
Boiler #11 (new)	3.91	3.91	3.88	7.82	1.56	14.47	0.72
Sour Water Stripper	--	--	--	--	--	--	--
Cooling Tower #10 (new)	0.09	0.001	--	--	1.56	--	2.07
Cooling Tower #11 (modified)	0.09	0.001	--	--	1.56	--	2.07
33H1 Vacuum Furnace Heater (new)	4.27	4.27	5.65	11.39	3.07	45.6	1.05
540 HP Diesel Generator (new)	0.01	0.001	0.03	0.20	0.03	0.25	0.0004
Stab-in Asphalt Tank Heaters (new)	0.16	0.16	0.21	2.06	0.11	1.68	0.04
Tanks (See Table 2-1)	--	--	--	--	1.46	--	0.02
Fugitives from leaks (new)	--	--	--	--	14.6	--	0.85
South Flare (modified)	--	--	-2.3	5.8	-2.8	29.5	0.40
12 Additional Truck Bays for Black Wax Crude	--	--	--	--	--	--	--
Project Total	30.6	30.5	36.5	84.1	27.3	337.5	9.3
NSR/Significant Emissions Rate	15	10	40	40	40	100	NA
Significant	Yes	Yes[1]	No	Yes	No[1]	Yes	--

[1] Davis County is non-attainment for $PM_{2.5}$ and maintenance for ozone; thus, $PM_{2.5}$ and VOC emissions are subject to NNSR permitting requirements provisions.

From Table 3-3, the emission projections from the heavy crude processing project only indicate that emissions for PM_{10}, NO_2, and CO are significant under PSD. However, if the emissions increase is greater than the NSR/PSD significant emission rate, then a source has several options which include:

1. Accept limits on new or existing units impacted by the project to obtain an project emissions increase less the significant emission rate;
2. Conduct a netting analysis of contemporaneous creditable increases and decreases to determine if the net emission emissions increase is less than the NSR significant emissions rate;
3. Use a combination of 1 and 2 to maintain the net emissions increase to a level less than the significant emission rate, or
4. Undergo NSR review for the project.

3.1.2 PSD Netting Analysis

A netting analysis was performed by Holly since the heavy crude processing project emissions increase of PM_{10}, NO_2 and CO exceeded the PSD significant emission rates. The netting analysis was performed following the steps listed below:

Step 1 – Determine the emissions increases from the proposed project

The emission increases expected to results from the proposed project were examined. This included emissions from the new and modified emissions units and any other plant-wide emissions increases that will occur as a result of the proposed project.

Step 2 – Determine the Beginning and Ending Dates of the Contemporaneous Period as it Relates to the Proposed Modification

The contemporaneous period starts five years from the date of the NOI until the AO is signed, that is May 25, 2007.

Step 3 – Determine which emissions Units at the Source have experienced an Increase or Decrease in Emissions during the Contemporaneous Period

Credible emission increases are associated with a physical change or change in the method of operation at a source which did not require a PSD permit. Decreases are credible reductions in actual emissions from an emissions unit that are, or can be made, federally-enforceable. A physical change or change in the method of operation is also associated with the types of decreases that are credible.

Step 4 – Determine which Emissions Changes are Credible

There are several rules that apply when determining if the emission changes are credible. The applicable ones for this project are:

1. An increase or decrease in emissions is credible if the reviewing authority had not relied upon it in previously issuing a PSD permit and the permit is in effect when the increase from the proposed modification occurs.
2. A decrease is credible only to the extent that it is "federally enforceable" from the moment that the actual construction begins on the proposed modification to the source. The proposed decrease must occur before the proposed emissions increase occurs. An increase occurs when the emissions units on which construction occurred becomes operational and begins to emit a particular pollutant.
3. A decrease is credible only to the extent that it has the same health and welfare significance as the proposed increase from the source.
4. A source cannot take credit for a decrease that it has to make or will have to make in order to bring an emissions unit into compliance.
5. A source cannot take credit for an emissions reduction from potential emissions from an emission unit which was permitted but never was built or operated.

Step 5 – Determine, on a Pollutant-by-Pollutant Basis, the Amount of each Contemporaneous and Creditable Emissions Increase and Decrease

An emissions increase is the amount by which the new level of "actual emissions" at the emissions unit exceeds the old level or level prior to the physical or operational change. An emissions decrease is the amount by which the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of "actual" emissions. Both emissions increases and decreases are calculated, in most cases, from a two-year period that directly preceded the physical change. A contemporaneous emissions increase is calculated as the positive difference between an emissions unit's potential to emit just after a physical or operation change and the unit's actual emissions just prior to the change. A decrease is the amount by which the old level of actual emissions exceeds the new level of "actual" emissions.

Step 6 – Sum all Contemporaneous and Credible Increases and Decreases

The proposed project will be subject to PSD review for each regulated pollutant for which the sum of all creditable emission increases and decreases results in a significant net emissions increase.

1. The emissions increase from the proposed project only was determined. (See Table 3-3).
2. The contemporaneous period was defined. Under federal PSD regulations, an emissions change is contemporaneous to a given project if it occurred within the five years preceding the start of construction of the project or if it will occur between the time construction commences and operation begins. The contemporaneous period for this project begins on May 25, 2007.
3. Sum the emission change to determine the net emissions increase. Compare the net emissions increase to the PSD significant emission rate. All creditable contemporaneous actual emission increases and decreases that were a result of physical changes in the method of operation at the plant site were summed together.

For the emissions change to be credible, it must not have been relied upon in the issuance of a PSD permit, the new level of actual emissions exceeds the old. An emissions decrease is credible if it: (1) the old level of actual or allowable emissions, whichever is lower, exceeds the new level of actual emissions; (2) is federally enforceable; and (3) it has approximately the same qualitative significance for public health and welfare as that attributed to the increase from a particular change.

On June 8, 2007, Holly received an approval order for a modernization project. With the modernization project, changes in equipment and operations were proposed to handle heavier crude (Canadian crude) with higher sulfur content. The portions of the refinery that were to handle the heavier fractions needed to be expanded. In addition, several measures were proposed to significantly reduce emissions of criteria pollutants including the replacement of existing equipment and addition of new control equipment. The net emission changes from the 2007 modernization project were determined to be:

- NO_x – reduction of 79.8 TPY;
- SO_2 – reduction of 81.9 TPY
- PM_{10} – reduction of 83.9 TPY
- CO – increase of 172.8 TPY
- VOC – increase of 16.8 TPY.

The contemporaneous period starts five years from the date of the NOI until the AO is signed, that is May 25, 2007. However, the contemporaneous period will likely slide by several months since the review of the NOI has not been completed as of this date and an approval order would not likely be granted until late Fall 2012 at the earliest. Holly is unable to begin construction until an approval order is granted.

Although several of the changes proposed in the modernization project have been implemented, primarily those associated with reducing refinery air emissions through additional pollution controls, due to market forces, Holly is now seeking to modify implementation of certain previously permitted changes. These modifications are summarized in Section 1.0 of the NOI. Central to these changes is a revision in the planned nature of the crude oil feed to the refinery.

The 2007 modernization project included a significant increase in processing of heavier crude oil with higher sulfur content. Now Holly is proposing to replace that heavier crude with local eastern Utah crude, which is a highly-paraffinic crude oil with lower sulfur content.

Thus, Holly feels that since an approval order for the current proposed project will not be issued until Fall of 2012 at the earliest and that the AO for the modernization project was dated June 8, 2007, the emissions from the modernization project fall outside the five years before construction can commence and are not considered contemporaneous.

The approval order issued on November 3, 2009 was to incorporate CD requirements including new permit limits on heaters 8H1 and 12H1 based on performance tests conducted in October 2008 and the inclusion of a small portable electric generator for use an as emergency power supply with an associated hours of operation limitation. The results of the performance testing results indicated higher NO_x emissions of approximately 39.3 tons using the EPA mandated NGULNB or equivalent burners. Thus, since the use of NGULNB or equivalent burners was a mandate of the CD, credit was not taken for these emissions in part of the netting analysis.

Table 3-4 presents a summary of the contemporaneous project emission estimates that were obtained from a review of projects undertaken or proposed at Holly Refinery since May 25, 2007. Emissions presented for the equipment identified in approval orders or NOI's are based on PTE emission estimates.

Table 3-5 presents additional proposed changes at the Refinery. These changes are considered "side projects" and not necessarily associated with the heavy crude processing project. As can be seen in Table 3-5, several sources will not be constructed; thus no emissions are presented for these sources. 10H2, 30H1 and 30H2 hydrogen reformer furnaces will be built and additional NO_x control will be added through the use of SCR's. Since these sources have not been built, credit for reducing NO_x emissions was not taken. Boiler #8 emissions are based on the difference between an emissions unit's potential to emit just after a physical or operation change and the unit's actual emissions (average of 2010/2011) just prior to the change.

In Section VI.143.a of the Holly Refinery Consent Decree, EPA indicates that the prohibition of Holly Refinery to be able to generate emission reductions that result from the consent decree was not intended to prohibit Holly Refinery from *"utilizing or generate netting reduction or emissions offset credits from refinery units that are covered by this Consent Decree to the extent that the proposed netting reductions or emission offset credits represent the difference between the emissions limitations set forth in this Consent Decree for these refinery units and the more stringent emissons limitations that Holly may elect to accept for these refinery units in a permitting process*". As it applies to Boiler 6, this is interpreted that the removal of the boiler would be a more stringent emission limitation.

In Section V.A.14 of the Consent Decree, Holly Refinery is required to minimize NOx emissions to the maximum extent practicable without interfering with interfering with conversion or process rates beginning by no later than April 1, 2009. The Consent Decree includes Boiler 6 in this requirement if it is in operation at that time. This boiler was in operation at that time and is still in operation until such time an Approval Order removes it from service. In accordance with 40 CFR Per 40 CFR 52.21(b)(48)(ii)(c), in determining baseline actual emissions for NO_x for the CO Boiler, the average rate can be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had the major stationary source been required to comply with such limitations during the consecutive 24-month period.

The DAQ determined that the April 1, 2009 is the baseline for the required NO_x reduction for Boiler 6. A contemporaneous time period that began after March 31, 2009 (January 1, 2010 through December 31, 2011) was chosen for the CO boiler. Actual NO_x emissions from the CO boiler for 2010 and 2011 were 72.08 tons and 58.05 tons, respectively, for an average of 65.07 tons per the 24-month period.

Table 3-4

Contemporaneous Project Emissions and NSR Applicability (TPY)

Project	Emissions Change					Source
	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	NO_2 (TPY)	CO TPY	VOC TPY	
Install 250 gpm charge pump	--	--	--	--	0.03	DAQE-AN101230040-11
Install 3 dedicated ethanol unload areas	--	--	--	--	0.05	DAQE-101230039-11
Incorporation of FCCU NO_x and SO_2 Limits from CD	--	--	--	--	--	DAQE-AN101230038-10
Install Benzene Sat Unit #23 and boiler #5 NOx limit	0.69	0.69	3.7	7.57	0.50	NOI Dated April 29, 2010
Incorporate NSPS Subpart A & J for CO Emissions to FCCU	--	--	--	--	--	DAQE-AN101230032-10
Addition of Boilers #9 and #10	7.82	7.82	15.65	28.94	3.13	NOI dated Oct. 14, 2009
Incorporate CD Requirements & Add 135 KW diesel generator	0.02	0.02	0.66[1]	0.12	0.01	DAQE-AN101230027-09
Total Changes	8.5	8.5	20.0	36.6	3.7	

CD - July 2008 Consent Decree

[1] The NO_2 emissions do not include the increase of 39.3 tons of NO_2 emissions listed in DAQE-AN101230027-09 abstract for heaters 8H1 and 12H1. This emission increase was based on October 8, 2009 performance test results. These tests were conducted in compliance with the CD after the replacement of the original heater burners with NGULNB or equivalent.

Table 3-5

Additional Proposed Refinery Changes and Corresponding Emissions

Project	Emissions Change				Comment
	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	NO_2 (TPY)	CO TPY	
10H2 Hot Oil Furnace (existing)	--	--	--	--	SCR will be added once constructed
8H2 35 MMBtu/hr Crude Feed Heater	--	--	--	--	Unit will not be constructed
33H1 15 MMBtu/hr Vacuum Furnace Heater	--	--	--	--	Unit will not be constructed
Unit 32 Amine Unit #2	--	--	--	--	Unit will not be constructed
Unit 35 Amine Unit #3	--	--	--	--	Unit will not be constructed
Unit 31 SRU with TGTU	--	--	--	--	Unit will not be constructed
Unit 35 SRU with TGTU	--	--	--	--	Unit will not be constructed
Power Boiler #8	--	--	-7.61	--	SCR will be added for NOx control
Emergency Equipment (modified)	0.06	0.06	0.84	0.18	Additional operating hours
CO Boiler (existing)	-55.75	-36.55	-65.07	-18.98	Unit will be removed
45H1 15.3 MMBtu/hr asphalt mix heater	--	--	--	--	Unit will be removed
30H1 & 30H2 Hydrogen Reformer Feed Furnaces (existing)	--	--	--	--	SCR's will be added for NO_x control once furnaces are constructed
Propane Pit Flare (existing)	-0.86	-2.6	-23.76	-129.28	Flare will be removed
Total	-40.90	-38.23	-95.60	-158.61	

Projected greenhouse gas emissions (GHG) in metric tons per year for the new sources only (MTPY) are presented in Table 3-6 and Appendix B.

Table 3-6

PTE Greenhouse Gas Emission Estimates for Proposed Heavy Crude Processing Project at Holly Refining & Marketing Company Woods Cross Refinery

Equipment	CO_2 (MTPY)	CH_4 (MTPY)	N_2O (MTPY)
20H3 Reactor Charge Heater	17,660.6	0.35	0.03
24H1 Crude Furnace #3	25,169.6	0.49	0.05
25H1 FCC#2 Feed Heater	18,877.2	0.37	0.04
FCC	53,846.7	1.58	0.32
26H1 Hot Oil Furnace	5,872.9	0.12	0.01
27H1 Reactor Charge Heater	41,529.8	0.82	0.08
33 H1 Vacuum Furnace Heater	54,534.0	1.07	0.11
#11 Boiler	37,460.7	0.74	0.07
Process Flare (South)	10,070.0	30.40	0.101
Asphalt Heaters (6 total)	2,013.5	0.06	0.004
Tanks	NA	1.00	NA
Fugitives (Leaks)	NA	9.60	NA
Product Combustion	5,102,318.7	NA	NA
Total	5,369,353.7	46.6	0.815
Total CO_2e			**5,370,584**

3.2 PSD Applicability Determination

Table 3-7 and Appendix B presents a summary of net emissions expected from the proposed heavy crude refinery project, contemporaneous emission estimates, and additional proposed refinery changes and the applicability of PSD. As seen from Table 3-7, the only pollutants with a significant emissions increase are CO and GHG.

Table 3-7

PSD Applicability Results

Equipment	PM_{10} (TPY)	NO_x (TPY)	CO (TPY)	GHG (MTPY)
Heavy Crude Proc. Project	30.6	84.1	337.5	5,370,584[1]
Contemporaneous Emissions	8.5	20.0	36.6	--
Additional Proposed Changes	-40.9	-95.6	-158.6	--
Net Emissions	-1.8	8.5	215.5	
Significant Emissions Rate	15	40	100	
Significant	No	No	Yes	Yes

[1] As CO_2e

3.3 Non-Attainment Area New Source Review

As mentioned previously, Holly's Woods Cross refinery is located in Davis County which is in non-attainment for $PM_{2.5}$ and ozone. Proposed VOC and $PM_{2.5}$ emissions are presented in Table 3-8. Both $PM_{2.5}$ and ozone (VOC) emissions are less than significant (i.e. 40 tons). Based on Table 3-8, emission offsets are not required.

Table 3-8

Net Emission Change for $PM_{2.5}$ and VOC Emissions

Equipment	$PM_{2.5}$ (TPY)	VOC (TPY)
Heavy Crude Proc. Project	30.5	27.3
Contemporaneous Emissions	8.5	3.7
Additional Proposed Changes	-38.2	-50.4
Net Emissions	0.77	-19.4
Significant Emissions Rate	10	40
Offsets Required	No	No

Overall net emissions from new and project-affected sources are presented in Table 3-8. As seen from Table 3-9, overall emissions of PM_{10}, $PM_{2.5}$, SO_2, and VOC of will be reduced. Appendix C contains the PTE emissions from entire refinery operations (existing and proposed).

Table 3-9

Net Emissions from New and Project-Affected Sources

Emission Unit	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	SO_2 (TPY)	NO_x (TPY)	VOC (TPY)	CO (TPY)	Total HAPS (TPY)
24H1 Crude Furnace #3 (new)	2.0	2.0	2.6	10.5	1.4	21.0	0.49
25H1 FCC#2 Feed Heater (new)	1.5	1.5	2.0	7.9	1.1	15.8	0.36
FCCU #2 Wet Scrubber (new)	13.6	13.6	17.7	19.9	--	154.9	--
26H1 Hot Oil Furnace (new)	0.5	0.5	0.6	2.5	0.3	4.9	0.11
27H1 Reactor Charge Heater (new)	3.3	3.3	4.3	8.7	2.3	34.7	0.80
20H3 Reactor Charge Heater (new)	1.4	1.4	1.8	7.4	1.0	14.8	0.34
Boiler #8 (existing)				-7.6			
Boiler #11 (new)	3.9	3.9	3.9	7.8	1.6	14.5	0.72
Cooling Tower #10 (new)	0.1	0.001	--	--	1.6	--	2.07
Cooling Tower #11 (modified)	0.1	0.001	--	--	1.6	--	2.07
Cooling Tower 4-8 (existing)	--	--	--	--	-48.1	--	--
33H1 Vacuum Furnace Heater (new)	4.3	4.3	5.7	11.4	3.1	45.6	1.1
540 HP Diesel Generator (new)	0.01	0.001	0.03	0.20	0.03	0.25	0.0004
Emergency Equipment (existing)	0.06	0.06	0.06	0.84	0.07	0.18	0.0005
Stab-in Asphalt Tank Heaters (new)	0.16	0.16	0.21	2.1	0.11	1.7	0.04
Tanks (new and modified)	--	--	--	--	1.5	--	0.02
Fugitives from leaks (new)	--	--	--	--	14.6	--	0.85
South Flare (modified)	--	--	-2.3	5.8	-2.8	29.5	0.40
CO Boiler (existing)	-55.8	-36.6	-297.9	-65.0	-0.8	-19.0	-0.31
Propane Pit Flare (existing)	-0.9	-2.6	0.0	-23.8	-1.6	-130.0	--
SRU Incinerator (existing)	--	--	-138.3	--	--	--	--
Net Emissions	-25.8	-8.5	-399.6	-11.3	-23.0	188.8	9.1

3.4 Emission Calculation Methodologies

Emission estimates were derived for the proposed new and modified equipment and are based on manufacturer data, facility testing data, fuel type, anticipated operating hours, and published emission factors and emission calculation guidance presented in publications such as EPA's *Compilation of Air Pollution Emission Factors (AP-42), Volume I: Stationary Point and Area Sources*. The calculation methodologies for each proposed source type are presented in the following sections.

3.4.1 Process Heaters, Furnaces, and Steam Boiler

With the proposed heavy crude processing project, six process heaters and furnaces (reactor charge heater, crude furnace #3, FCC #2 feed heater, hot oil furnace, 27H1 reactor charge furnace, vacuum furnace heater), six asphalt tank heaters, and one steam boiler (boiler #11) will be added. Natural gas/plant gas is one of the major combustion fuels used throughout industry. It is mainly used to generate industrial process steam and heat. Refinery plant gas/natural gas to be used to fire the above mentioned equipment consists of a high percentage of methane and varying amounts of ethane, propane, butane, and inerts. The emissions from refinery plant gas/natural gas-fired boilers and furnaces include nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), sulfur dioxide (SO_2), particulate matter of sizes 10 and 2.5 microns (PM_{10}, $PM_{2.5}$), and hazardous air pollutants (HAPs).

The emission factors for criteria and hazardous air pollutants from the process heaters/furnaces and steam boiler are based on AP-42, Tables 1.4-1, 1.4-2, and 1.4-3 with the exception of NO_x and SO_2. NO_x emission factors are based on assumed performance using ultra low-NO_x burners with the exception of the vacuum furnace heater (33H1), hot oil furnace (10H2), hydroisom charge heater (27H1), hydrogen reformer feed furnaces (30H1 and 30H2), and boilers #8 and #11. This later equipment will utilize low NO_x burners and NO_x emissions will be controlled by SCR. NO_x emissions from the FCC flue gas will be controlled by a wet gas scrubber. SO_2 emissions are based on a 60 ppm average of H_2S in plant gas.

An example PTE calculation methodology for the process heaters and furnaces is presented in Equation 1 and the assumptions below:

$$\boxed{NO_x = Burner_{\max} \div GHV \times EF_{NOxC} \times 8760 \div 2000}$$

(Eq. 1)

Where:
NO_x= Annual potential NO_x emissions from combustion of natural gas/plant gas (tons/year).
$Burner_{max}$ = Maximum burner rating for the combustion unit (MMBtu/hr).
GHV = Gross heating value of natural gas/plant gas (Btu/scf). An average gross heating value of 1020 BTU/scf for natural gas was used.
EF_{NOxC} = Emission factor for NO_x from controlled burners (lb/mmscf). The current Holly Woods Cross Refinery operating permit emission factor for ULNB and NGULNB NO_x from is 41 lb/mmscf or 0.04 lb/MMbtu.
EF_{NOxC} = Emission factor for NO_x from LNB with SCR is 0.02 lb/MMbtu.
8760 = Conversion factor from hours to years based on 24 hours per day, 7 days per week, 52 weeks per year.
2000 = Conversion factor from pounds to tons.

3.4.2 Emergency Equipment

As part of the heavy crude processing project, Holly is proposing the addition of a 540 HP diesel emergency generator to be used for emergency power supply. The proposed emergency generator will meet EPA Tier 3 emission limitations as found in 40 CFR Part 60 Subpart IIII for NO_x, non-methane hydrocarbons, CO, and PM. Hours of operation for this generator will be limited to 50 hours annually for testing and maintenance purposes only.

For other criteria and HAPS, emission factors found in EPA's AP-42 Section 3.3, Gasoline and Diesel Engines were utilized. Per AP-42, all PM emissions are expected to be ≤ 1 μ in size. An example PTE calculation methodology for the emergency generator is presented in Equation 2 and the assumptions below:

$$\boxed{VOC = HP_{\max} \times EF_{VOC} \times Operation_{Permitted} \div 2000}$$

(Eq. 2)

Where:
VOC = Annual potential VOC emissions from combustion of diesel fuel (tons/year).

HP_{max} = Maximum horsepower rating for the unit (HP) and based on the highest rated emergency engine.
EF_{VOC} = Emission factor for VOCs from engines in lb/HP-hr. Reference: AP-42, Section 3.3 Gasoline and Diesel Engines, Table 3.3-1, uncontrolled diesel industrial engines.
$Operation_{Permitted}$ = Permitted hours for non-emergency use (50 hours).
2000 = Conversion factor from pounds to tons.

3.4.3 Cooling Towers

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. In the cooling tower, warm cooling water returning from refinery processes is contacted with air by cascading through packing. Cooling tower emissions include "drift" crystallized solid particles that are considered PM_{10} emissions.

VOCs from cooling towers will be monitored and controlled via the Modified El Paso Method for Determination of Volatile Organic Compound Emissions from Water Sources. The methods requires a continuous stream of cooling water, process water, or wastewater to be supplied via a hard pipe or direct interface to an air stripping column apparatus for analysis. Air flowing countercurrent to the water strips volatile organic compounds from the water for analysis. Concentrations of air stripped compounds in the air exhaust, along with the air and water flow rates, are used to determine concentrations of strippable volatile compounds in the water. A FID analyzer will be used to determine the valve of "combined" or "total" strippable volatile organic compounds. The method is presented in Appendix P -Texas Commission on Environmental Quality – Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources.

Since the Modified El Paso method was going to be implemented, it was felt to be appropriate to use the "controlled" emission factor of 0.7 lb/10^6 gallons cooling water as found in AP-42, Section 5.1 for VOC's from cooling towers. Previously, VOC emissions were calculated using the "uncontrolled" emission factor of 6 lb/10^6 gal cooling water which is also found in AP-42, Section 5.1. Thus, the use of the controlled emission factor accounts for the estimated VOC reductions.

Air emissions from the cooling tower also consist of fugitive VOCs and gases stripped from the cooling water as the air and water come into contact. These contaminants enter the cooling water system from leaking heat exchangers and condensers. VOC and PM emissions from the proposed cooling tower 10 and additional cell for cooling tower 11 were based on the following equations and assumptions below:

$$\boxed{VOC = Feed \times 42 \times EF_{Water} \div 10^6 \times EF_{VOC} \div 2000}$$

(Eq. 4)

Where:
VOC = Annual potential VOC emissions from cooling towers (tons/year).
Feed = Annual refinery crude feed (bbls) based on 3-year average (2008-2010) +3 standard deviations.
42 = Conversion factor from barrels to gallons.
EF_{Water} = Emission factor for cooling water used per crude feed (40 gallons cooling water to 1 gallon crude feed). Reference: AP-42, Section 5.1.
10^6 = Conversion from gallons to million gallons (gal/10^6 gal).
EF_{VOC} = Controlled emission factor for VOCs from cooling towers (0.7 lb/10^6 gal). Reference: AP-42, Table 5.1-2.
2000 = Conversion factor from pounds to tons.

The PM PTE calculation methodology is presented in Equation 5. PM emissions were estimated based on the methodology and particle size distributions presented by Joel Reisman and Gordon Frisbie's paper titled, Calculating Realistic PM_{10} Emissions from Cooling Towers.

$$\boxed{PM = Circulation_Rate \times \frac{TDS}{10^6} \times \frac{Drift_Rate}{100} \times \rho \times 60 \times 8760 \div 2000}$$

(Eq. 5)

Where:
PM = Annual potential PM emissions from cooling towers (tons/year).
Circulation Rate = Water circulation rate of the cooling tower (gal/min).
TDS = Based on average of total dissolved solids (TDS) measurements collected from existing cooling tower water.
10^6 = Conversion factor from ppm.
Drift Rate = Drift loss of circulating water (%).
ρ = density of water (lbs/gal).
60 = Conversion factor from minutes to hours.
8760 = Conversion factor from hours to years based on 24 hours per day, 7 days per week, 52 weeks per year.
2000 = Conversion factor from pounds to tons.

In the above mentioned paper, a linear relationship, based on research data between solid particle diameter size and Electric Power Research Institute (EPRI) % mass, at a constant TDS is established. Therefore, percentages of PM_{10} and $PM_{2.5}$ can be calculated using the interpolation equation below in Equation 6. Equations 7 and 8 present the PM_{10} and $PM_{2.5}$ PTE methodologies, respectively.

$$y_2 = y_0 + \left(\frac{y_1 - y_0}{x_1 - x_0}\right) \times (x_2 - x_0)$$

(Eq. 6)

$$PM_{10} = PM \times \frac{EPRI\%_{10}}{100}$$

(Eq. 7)

$$PM_{2.5} = PM \times \frac{EPRI\%_{2.5}}{100}$$

(Eq. 8)

Where:
PM_{10}/ $PM_{2.5}$ = Annual potential PM_{10}/$PM_{2.5}$ emissions from cooling towers (tons/year).
PM = Annual potential PM emissions from cooling towers (tons/year).
$EPRI\%_{10}$ = EPRI% Mass % at solid particle diameter 10 or 2.5 microns.

HAP emissions were also calculated for the cooling towers based on Equation 9 and the assumptions below:

$$HAPs = \frac{VOC_{CoolingTowers}}{VOC_{Fugitives}} \times HAPs_{StorageTanks}$$

(Eq. 9)

Where:
HAPs = Annual potential organic HAPs emissions from cooling towers (tons/year).
$VOC_{CoolingTowers}$ = Annual potential VOC emissions from cooling towers (tons/year).
$VOC_{Fugitives}$ = Annual potential VOC fugitive emissions from valves and fittings (lbs/year).
$HAPs_{Storage\ Tanks}$ = Annual HAPs emissions from storage tanks (lbs/year). Storage tank HAPs emissions determined using the TANKS software, averaging the last 8 years, and multiplying by 2 standard deviations.

3.4.4 Flare

Flaring is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, of waste gases from industrial operations. Natural gas, propane, ethylene, propylene, butadiene and butane constitute over 95 percent of the waste gases flared.

Emissions from flaring include unburned hydrocarbons, CO, and other partially burned and altered hydrocarbons. Also emitted are NO_x and, if sulfur-containing material such as hydrogen sulfide or mercaptans is flared, SO_2. The quantities of hydrocarbon emissions generated relate to the degree of combustion. The degree of combustion depends largely on the rate and extent of fuel-air mixing and on the flame temperatures achieved and maintained.

The average non-upset throughput to the south flare is estimated to be 17,000 standard cubic feet per hour (scf/h) and was based on 2011 flow monitoring data. The efficiency of the flare was estimated to be 98% and the average methane concentration of the flare is 55%. The higher heating value of the flare gas was assumed to be 1150 BTU/scf. Flare HAP emissions were based on California Air Resource Board (CARB) species profiles which were applied to the EPAs' TOC emission factor, as found in AP-42 for flares. Criteria pollutant emission factors used were based on AP-42 Section 13.5 Industrial Flares and Wyoming Department of Environmental Quality suggested emission factors. PM_{10} and $PM_{2.5}$ emissions for the Woods Cross refinery flares were assumed to be zero. An example flare calculation is presented in Equation 3 below:

$$\boxed{NO_x = Flare_{Average} \times HHV \times EF_{NOx} \times 10^{-6} \times 8760 \div 2000}$$

(Eq. 3)

Where:
NO_x = Annual potential NO_x emissions from normal flaring (tons/year).
$Flare_{Average}$ = Average non-upset flare throughput (scf/hr) which is based on 2011 monitored flow to flare.
HHV = Average higher heating value of flared gas (Btu/scf) which is based on 2011 monitored flow to flare.

EF_{NOx} = Emission factor for NO_x from industrial flares in lb/mmBtu. Reference: AP-42 Section 13.5 Industrial Flares, Table 13.5-1. The VOC emission factor utilized was from Wyoming Department of Environmental Quality and HAPS emission factors from CARB.
10^{-6} = Conversion factor from Btu to MMBtu.
8760 = Conversion factor from hours to years based on 24 hours per day, 7 days per week, 52 weeks per year.
2000 = Conversion factor from pounds to tons.

3.4.5 Storage Tanks

Storage tanks are used in the oil and gas industry 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 and HAPs.

All PTE VOC and HAPs emissions for the proposed or modified storage tanks at the Woods Cross Refinery were calculated using the average emissions for the last five years generated by the TANKS program, Version 4.09D, plus two standard deviations. Copies of the TANKS program output are included in Appendix B. HAPs emissions were developed based on published or assay data for the crude and other products, if available.

3.4.6 Fluid Catalytic Cracking Unit

Emissions from the new FCCU will be controlled by a wet gas scrubber. NO_x and SO_2 emissions were based on Holly Consent Decree limits for the existing FCCU (with a wet gas scrubber) of 40 ppm and 25 ppm, respectively based on 0% O_2 and a 365 day averaging period. PM_{10} emissions were based on Consent Decree PM limit of 0.5 lb/1000 lb coke. All PM_{10} was assumed to be $PM_{2.5}$. CO emissions were based on engineering calculations of 23 mmscf/day and the existing FCCU limit of 500 ppm based on a one-hour average and 0% O_2. VOC emissions were assumed to be negligible. Annual emissions were based on 8760 operating hours.

3.4.7 Fugitives

Fugitive emission sources include leaks of hydrocarbon vapors from process equipment and evaporation of hydrocarbons from open areas, rather than through a stack or vent. Fugitive emission sources include valves of all types, flanges, pump and compressor seals, process drains, cooling towers, and oil/water separators.

Fugitive emissions are attributable to the evaporation of leaked or spilled petroleum liquids and gases. Normally, control of fugitive emissions involves minimizing leaks and spills through equipment changes, procedure changes, and improved monitoring, housekeeping, and maintenance practices.

The following assumptions were made for the fugitive sources:

- only relief valves that vent to atmosphere are counted;
- same number of heavy liquid components as light liquid components;
- twice as many connectors as valves;
- leak rate is greater than 10,000 ppm;
- 2% of all components leaking; and
- year-long continuous leak.

The VOC calculation methodology to estimate fugitive emissions from leaks is presented in Equation 10.

$$\boxed{VOC = \#Components \times EF_{source} \times 0.02 \times 24 \times 2.205 \times 365 \div 2000}$$

(Eq. 10)

Where:
VOC = Potential VOC emissions from fugitive sources (tons/year).
#Components = Number of components in a source group (gas valves, light liquid valves, heavy liquid valves, light liquid pump seals, heavy liquid pump seals, compressor seals, pressure relief valves, connectors, open-ended lines, sampling connections).
EF_{source} = Emission factor for source group (kg/hr/source). Reference: Protocol for Equipment Leak Emission Estimates, Table 2-2.
0.02 = 2% assumed leak rate of all components in a source group.

24 = Conversion factor from hours to days.
2.205 = Conversion from kilograms to pounds.
365 = Conversion factor from days to year.
2000 = Conversion factor from pounds to tons.

3.4.8 Product Loading/Unloading

Although a reconfiguration of loading spots is anticipated from the heavy crude processing project, no additional air emissions are expected. Air emissions from the converted or new propane loading spots will be controlled through a small electric-driven compressor which will recover displaced relief gas from loading propane into rail cars. Since emissions from fuel oil and asphalt rail loading are negligible due to the heavy nature of these products, no vapor controls are proposed.

The black wax unloading bays will be constructed with a heated closed sump. Black wax product collected in the sump will be piped to one of the proposed black wax crude storage tanks. Emissions from the black wax unloading bays will be negligible due to the crude being a solid at average ambient conditions.

3.4.9 Wastewater Treatment

As mentioned in Section 2, based on the preliminary results of the water conservation and wastewater reduction study that Holly undertook, it is anticipated that installation and operation of the proposed new process units will not increase the overall throughput of the existing wastewater treatment plant. Thus, no increased air emissions are expected from wastewater treatment.

3.4.10 Greenhouse Gases

Emissions of greenhouse gases (GHG) for the stationary fuel combustion sources were determined based on the calculation methodologies found in 40 CFR Part 98. Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter.

3.4.10.1 Stationary Fuel Combustion Sources

Stationary fuel combustion sources at Holly include boilers and process heaters. Emergency generators and emergency equipment are not included per §98.30(b)(2). The calculation methodologies for GHG are the same for plant fuel gas and/or natural gas fired combustion units.

For calculating CO_2 emissions from the stationary fuel combustion sources, the equation as found in 40 CFR 98.33(a)(3)(iii), and presented as Equation 11 below was used.

$$\boxed{CO_2 = \frac{44}{12} \times Fuel \times CC \times \frac{MW}{MVC} \times 0.001}$$

(Eq. 11)

Where:
CO_2= Annual CO_2 mass emissions from combustion of plant fuel gas or natural gas (metric tons).
Fuel = Annual volume of the gaseous fuel combusted (scf). This was based on a gas heating value of 1020 Btu/scf and maximum heater duty.
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel or 0.7135 based on average value from Holly's 2011 GHG annual inventory calculation.
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole) or 15.9 based on average value from Holly's 2011 GHG annual inventory calculation.
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6, or 849.5 scf per kg mole at 68 °F and 836.6 scf per kg mole at 60 °F standard temperature.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

For the calculation of CH_4 and N_2O emissions, the following equation (Equation 12) as presented in 40 CFR 98.33(c)(1) was used.

$$CH_4 \text{ or } N_2O = 0.001 \times Fuel \times HHV \times EF$$

(Eq. 12)

Where:
CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).
Fuel = Annual volume of the gaseous fuel combusted (scf). This was based on a gas heating value of 1020 Btu/scf and maximum heater duty.
HHV = Default high heat value of the fuel from 40 CFR Part 98, Table C–1.
EF = Fuel-specific default emission factor for CH_4or N_2O from 40 CFR Part 98, Table C–2.
1×10^{-3}= Conversion factor from kilograms to metric tons.

The equation for HHV as found in 40 CFR 98.33(a)(2)(ii) is as follows.

$$(HHV)_{annual} = \frac{\sum_{i=1}^{n} (HHV)_i \times (Fuel)_i}{\sum_{i=1}^{n} (Fuel)_i}$$

(Eq. 13)

Where:
$(HHV)_{annual}$= Weighted annual average high heat value of the fuel (mmBtu per mass or volume).
$(HHV)_I$= Based on average value from Holly's 2011 GHG annual inventory calculation.
$(Fuel)_I$= Annual volume of the gaseous fuel combusted (scf) determined by month. This was based on a gas heating value of 1020 Btu/scf and maximum heater duty.
n = Number of months in the year that the fuel is burned in the unit.

3.4.10.2 Flare

40 CFR 98.253(b)(1)(iii)(C) presents the calculation (Equation 14) that was used to determine CO_2 emissions from normal operations for the south flare. Startup, shutdown, malfunction events were considered to be zero.

$$CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)$$

(Eq. 14)

CO_2= Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98 = Assumed combustion efficiency of a flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
$Flare_{Norm}$= Annual volume of flare gas combusted during normal operations based on 17,000 scfh.
HHV = Higher heating value for fuel gas or 1150 Btu/scf.
EmF = Default CO_2 emission factor for flare gas of 60 kilograms CO_2/MMBtu (HHV basis).
n = Number of start-up, shutdown, and malfunction events which was assumed to be zero.
p = Start-up, shutdown, and malfunction event index which was assumed to be zero.
44 = Molecular weight of CO_2(kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).

For calculation of CH_4, the equation found in 40 CFR 98.253(b)(2) and presented as Equation 16 below was used:

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

(Eq. 16)

Where:
CH_4= Annual methane emissions from flared gas (metric tons CH_4/year).
CO_2= Emission rate of CO_2 from flared gas (metric tons/year).
EmF_{CH4}= Default CH_4emission factor for "Petroleum Products", 40 CFR Part 98 Table C–2.
EmF = Default CO_2emission factor for flare gas or 60 kg CO_2/MMBtu (HHV basis).
0.02/0.98 = Correction factor for flare combustion efficiency.
16/44 = Correction factor ratio of the molecular weight of CH_4 to CO_2.
f_{CH4}= Weight fraction of carbon in the flare gas prior to combustion. Default of 0.4 was used.

For calculation of N_2O, the following equation was used:

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

(Eq. 17)

Where:
N_2O = Annual nitrous oxide emissions from flared gas (metric tons N_2O/year).
CO_2= Emission rate of CO_2 from flared gas (metric tons/year).
EmF_{N2O}= Default N_2O emission factor for "Petroleum Products", 40 CFR Part 98 Table C–2.
EmF = Default CO_2 emission factor for flare gas or 60 kg CO_2/MMBtu (HHV basis).

3.4.10.3 Fluid Catalytic Cracking Unit

The GHG emissions for the proposed FCCU are presented below. For calculation of CO_2 emissions, the equation as found in 40 CFR 98.253(c)(2)(i) (Equation 18) was used.

$$CO_2 = \sum_{p-1}^{n}\left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001\right]$$

(Eq. 18)

Where:
CO_2= Annual CO_2mass emissions (metric tons/year).
Q_r= Volumetric flow rate of exhaust gas from the FCCU regenerator estimated to be 766681.72 dscf/hr.
$\%CO_2$= Hourly average percent CO_2 concentration in the exhaust gas stream from FCCU regenerator estimated to be 16.2 based on November 2011data.
%CO = Hourly average percent CO concentration in the exhaust gas stream FCCU regenerator estimated to be 0.015 based on November 2011 data.
44 = Molecular weight of CO_2 (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia at 60 °F)
0.001 = Conversion factor (metric ton/kg).
n = Number of hours in calendar year.

Per 40 CFR 98.253(c)(2)(ii) and 40 CFR 98.253(c)(4), the following equation (19) was used to calculate CH_4 emissions:

$$CH_4 = \left(CO_2 \times \frac{EmF_2}{EmF_1}\right)$$

(Eq. 19)

Where:
CH_4= Annual methane emissions from coke burn-off (metric tons CH_4/year).
CO_2= Emission rate of CO_2 (Equation 18).
EmF_1= Default CO_2emission factor for "Petroleum Coke" of 102.41 kg CO_2/MMBtu from 40 CFR Part 98, Table C–1.
EmF_2= Default CH_4emission factor for "Petroleum Products" of 0.003 kg CH_4/MMBtu from 40 CFR Part 98, Table C–1.

N_2O was calculated using the following equation (Eq. 20) as found in 40 CFR 98.253(c)(5).

$$N_2O = \left(CO_2 \times \frac{EmF_3}{EmF_1} \right)$$

(Eq. 20)

Where:
N_2O = Annual nitrous oxide emissions from coke burn-off (mt N_2O/year).
CO_2= Emission rate of CO_2 (Equation 18).
EmF_1= Default CO_2emission factor for "Petroleum Coke" of 102.41 kg CO_2/MMBtu from 40 CFR Part 98, Table C–1.
EmF3 =Default N_2O emission factor for "Petroleum Products" 0.0006 kg N_2O/MMBtu from 40 CFR Part 98, Table C–1.

3.4.10.4 Fugitive Sources including Equipment Leaks

For the determination of GHG from equipment leaks, the equation as found in 40 CFR 98.253(l)(2) was used.

$$CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS})$$

(Eq. 21)

Where:
CH_4= Annual methane emissions from equipment leaks (metric tons/year).
N_{CD}= Number of atmospheric crude oil distillation columns at the facility.
N_{PU1}= Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
N_{PU2}= Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
N_{H2}= Total number of hydrogen plants at the facility.
N_{FGS}= Total number of fuel gas systems at the facility.

3.4.10.5 Storage Tanks

Per 40 CFR 98.253(m)(1), CH_4 was calculated for storage tanks in accordance with Equation 22 as follows:

$$\boxed{CH_4 = \left(0.1 \times Q_{\mathrm{Ref}}\right)}$$

(Eq. 22)

Where:
CH_4= Annual methane emissions from storage tanks (metric tons/year).
0.1 = Default emission factor for storage tanks (metric ton CH_4/MMbbl).
Q_{Ref}= Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

3.4.10.6 Suppliers of Petroleum Products

A petroleum refinery for the purpose of 40 CFR Part 98 Subpart MM is any facility engaged in producing petroleum products through the distillation of crude oil. For calculation of CO_2 emissions from products produced, imported, or exported, the following equation, as found in in 40 CFR 98.393(a)(1) was used.

$$\boxed{CO_{2i} = \left(\mathrm{Pr}\,oduct_i \times EF_i\right)}$$

(Eq. 23)

Where:
CO_{2i}= Annual CO_2emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).
$Product_i$= Annual volume of product "i" produced, imported, or exported by the reporting party (barrels).
EF_i= Product-specific CO_2emission factor (metric tons CO_2per barrel).

For calculation of CO_2 emissions from non-crude feedstock products that enter the refinery, per 40 CFR 98.393(b)(1), Equation 24 below was utilized.

$$\boxed{CO_{2j} = \left(\mathrm{Pr}\,oduct_j \times EF_j\right)}$$

(Eq. 24)

Where:
CO_{2j}= Annual CO_2emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).
$Feedstock_j$= Annual volume of a petroleum product or natural gas liquid "j" that enters the refinery to be further refined or otherwise used on site (barrels). For natural gas liquids, volumes shall reflect the individual components of the product as listed in table MM–1 of this subpart.
EF_j= Feedstock-specific CO_2emission factor (metric tons CO_2per barrel).

For the calculation of CO_2 emissions from non-crude feedstock products that enter the refinery, Equation 25, as found in 40 CFR 98.393(c)(1) was used.

$$\boxed{CO_{2m} = \left(Biomass_m \times EF_m\right)}$$

(Eq. 25)

Where:
CO_{2m}= Annual CO_2emissions that would result from the complete combustion or oxidation of each type of biomass "m" (metric tons).
$Biomass_m$= Annual volume of a specific type of biomass that enters the refinery and is co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (barrels).
EF_m= Biomass-specific CO_2emission factor (metric tons CO_2per barrel).

To summarize CO_2 for refinery products, the following calculation as found in 40 CFR 98.393(d) was used.

$$\boxed{CO_r = \sum\left(CO_{2i}\right) - \sum\left(CO_{2j}\right) - \sum\left(CO_{2m}\right)}$$

(Eq. 26)

Where:
CO_{2r}= Annual CO_2 emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids minus non-crude feedstocks and any biomass to be co-processed with petroleum feedstocks.
CO_{2i}= Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).
CO_{2j}= Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).
CO_{2m}= Annual CO_2 emissions that would result from the complete combustion or oxidation of each type of biomass "m" (metric tons).

3.5 Startup and Shutdown Emissions

The average number of startups (SU) and shutdowns (SD) for the new process units are presented in Table 3-10 and are based on the average shutdowns per year for the existing units at Holly from 2007 through 2011. Potential-to-emit startup and shutdown emissions, per startup event and on an annual basis are presented in Tables 3-11 and 3-12, respectively, for the proposed new equipment. Annual SU/SD emissions, presented in Table 3-13 and in Appendix B, are based on the projected number of SU and SD as presented in Table 3-10.

"Torch oil" is a term which is usually applied to gas oil that is burned in FCC regenerators, to supply necessary heat requirements during startup and shutdown. Torch oil and refinery plant gas will be used for the new FCCU.

At Holly, it will be the standard operating procedure that the wet gas scrubber will be online prior to the start up or shutdown of the FCCU. It was also assumed that the wet gas scrubber will be online during any malfunction or maintenance event of the FCCU. There is no change in emission due to start up, shut down, or malfunction. It should be noted that the startup, shutdown and malfunction estimates provided in this section are overly conservative and have assumed that the wet gas scrubber was not in operation.

Table 3-10

Average Startup/Shutdowns Per Year

Process	Number of SU/SD
New Crude Unit	3.4
New FCC Unit	2.6
New Poly Gas Unit	2.6
New Hydrocracker/Hydroisom Unit	4.2

Table 3-11

PTE Startup Emissions per Event

Pollutant	New Crude (lbs)	New FCC (lbs)	Poly Gas (lbs)	Hydrocracker/Hydroisom Unit (lbs)
NO_x	28.2	182.2	8.0	32.1
CO	153.7	991.6	43.3	174.4
SO_x	1.0	6.5	0.3	1.1
PM_{10}	2.9	18.5	0.8	3.3
$PM_{2.5}$	2.9	18.5	0.8	3.3
VOC	2.1	13.4	0.6	2.4

Table 3-12

PTE Shutdown Emissions per Event

Pollutant	New Crude (lbs)	New FCC (lbs)	Poly Gas (lbs)	Hydrocracker/Hydroisom Unit (lbs)
NO_x	62.3	170.5	256.2	429.1
CO	338.8	927.7	1394.1	2334.9
SO_x	1.5	4.1	6.2	10.4
PM_{10}	4.2	11.7	17.4	29.4
$PM_{2.5}$	4.2	11.7	17.4	29.4
VOC	3.1	8.5	12.6	21.3

Table 3-13

Total Startup/Shutdown Emissions in Tons Per Year

Pollutant	New Crude (TPY)	New FCC (TPY)	Poly Gas (TPY)	Hydrocracker/Hydroisom Unit (TPY)
NO_x	0.15	0.46	0.34	0.97
CO	0.84	2.50	1.87	5.27
SO_x	0.00	0.01	0.01	0.02
PM_{10}	0.01	0.04	0.02	0.07
$PM_{2.5}$	0.01	0.04	0.02	0.07
VOC	0.01	0.03	0.02	0.05

3.6 Flaring Emissions Due to Upsets

Flaring emissions from upset conditions were calculated based on the average emissions calculated for flaring events from 2005 through 2008 from the existing north and south flares. Three standards deviations were applied to the average emission estimates so that a conservative emissions estimate could be obtained. Proposed flare emissions from upsets for the north and south flare are as follows:

- SO_2 – 120 TPY per flare
- NO_x – 4 TPY per flare
- VOC – 8 TPY per flare
- CO – 21 TPY per flare

3.7 Potential to Emit Emissions for Entire Refinery

Based on the above calculation methodologies, PTE emissions for the entire refinery which includes existing operations and proposed changes were determined. These PTE emissions are presented in Table 3-14.

Table 3-14
Potential to Emit Emissions for
Holly Refining & Marketing Company Woods Cross Refinery

Equipment	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	SO_2 (TPY)	NO_x (TPY)	VOC (TPY)	CO (TPY)
All combustion sources (SIP sources)	84.4	84.4	109.5	364.9	42.7	912.2
All other sources (Non-SIP sources)	101.7	1.9	4.5	12.9	207.9	67.1
All Sources	186.1	86.3	114.1[1]	377.7	2621.7[2]	979.3

[1] Value does not include flaring upset emissions.
[2] Total includes fugitives including emissions from tank cleaning.

4.0 REGULATORY REVIEW

The following sections contain an assessment of federal and State of Utah air regulations that are potentially applicable for the proposed heavy crude processing project at Holly's Woods Cross refinery.

4.1 Federal Regulations

For the purposes of this permit application the following federal regulations have been reviewed for potential applicability to the Project:

- New Source Performance Standards (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- National Ambient Air Quality Standards (NAAQS)
- Prevention of Significant Deterioration (PSD)
- Good Engineering Stack Height Analysis
- Operating Permit (Title V)
- Mandatory Greenhouse Gas Reporting

A review of each specific federal requirement is presented below.

4.1.1 New Source Performance Standards (NSPS)

The United States Environmental Protection Agency (EPA) has promulgated standards of performance for specific sources of air pollution. These standards have been codified in 40 CFR Part 60, Subparts A through KKKK. NSPS apply to certain categories of new, modified, or reconstructed sources after a given applicability date as specified in the applicable standard. The following Subparts are applicable to the proposed project:

- Subpart A - General Provisions

- Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
- Subpart Ja - Standards of Performance for Petroleum Refineries
- Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984
- Subpart GGGa – Equipment Leaks of VOC in petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006
- Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

4.1.1.1 40 CFR Part 60 Subpart A

Certain provisions of 40 CFR Part 60 Subpart A applies to the owner or operator of any stationary source subject to a NSPS. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions.

4.1.1.2 40 CFR Part 60 Subpart Dc

40 CFR 60 Subpart Dc applies to each steam generating unit that commences construction, modification, or reconstruction after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). The requirements of Subpart Dc apply to the proposed 89.3 MMBtu/hr boiler #11.

4.1.1.3 40 CFR Part 60 Subpart Ja

The provisions of this subpart apply to the new FCCU and fuel gas combustion devices, including flares and process heaters. Holly will comply with the following emission limitations:

- 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for the newly constructed FCCU.
- NO_x in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis for the FCCU.
- SO_2 in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis for the FCCU.
- CO in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.
- The wet scrubber's three-hour rolling average pressure drop must not fall below the level established during the most recent performance test.
- The wet scrubber's three-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

For each new fuel gas combustion device, Holly will comply with either the emission limits or fuel gas concentration limit as presented below:

- Holly shall not burn in any new fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a three-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

- For each new process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr), Holly shall not discharge to the atmosphere any emissions of NO_x in excess of 40 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis.

4.1.1.4 40 CFR Part 60 Subpart Kb

Storage tanks to be added or modified as part of the heavy crude processing project, with a capacity greater than or equal to 75 cubic meters (m^3) and that will be used to store volatile organic liquids for which construction commenced after July 23, 1984 are subject to the requirements of 40 CFR Part Kb. This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa. The new tanks, as well as any existing tanks that are "reconstructed," will meet NSPS Subpart Kb technology standards (e.g., roof requirements, vent requirements, inspection schedules, etc.).

4.1.1.5 40 CFR Part 60 Subpart GGGa

40 CFR 60 Subpart GGGa applies to the Holly Refining affected process units (valves, pumps, pressure relief devices, sampling connections, etc.) constructed after November 7, 2006. Subpart GGGa requires minimum performance specifications, routine inspection and repair of all such fugitive components consistent with §60.482-1 through 60.482-10 under NSPS Subpart VV (NSPS LDAR program).

4.1.1.6 40 CFR Part 60 Subpart IIII

40 CFR Part 60 Subpart IIII applies to stationary, compression ignition, internal combustion engines. The diesel engine in the proposed emergency generator falls under this rule. Holly will purchase an engine that is certified to the emission standards (Tier III) specified in the rule and will install a non-resettable hour meter on the engine prior to startup. In addition, SO_2 emissions are required to be minimized by burning only ultra-low sulfur diesel fuel with a maximum sulfur content of 15 ppmw.

Holly is proposing limiting the non-emergency operation of the new generator to 50 hours per year for maintenance and testing. In addition, Holly is proposing an increase to the existing operating hours for the remaining emergency equipment from an average of 30 to 50 hours per year for maintenance and testing purposes, or a total for all emergency equipment of 500 hours per year. This would be offset by a reduction in the permitted use of the ETF portable diesel generator by 200 hours to 1100 hours per year.

4.1.2 National Emission Standards for Hazardous Air Pollutants (NESHAP)

The Clean Air Act requires the US EPA to regulate emission of hazardous air pollutants under regulations know as Maximum Achievable Control Technologies (MACTs). These MACTs are embodied in National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR Part 61 and for source categories as found in 40 CFR Part 63. The following Subparts are determined to be applicable to the proposed project.

- 40 CFR Part 63 Subpart A - General Provisions
- 40 CFR Part 61 Subpart FF - National Emission Standard for Benzene Waste Operations

- 40 CFR 63 Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units
- 40 CFR Part 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Boilers and Process Heaters
- 40 CFR Part 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

The provisions of 40 CFR Part 63 Subpart A apply to certain proposed facility operations and contain general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions.

Part 61, Subpart FF applies to all petroleum refineries, regardless of the quantity of benzene processed. Refinery operators must determine the Total Annual Benzene (TAB) generated, as prescribed under §61.342(a). Refineries with a TAB greater than 10 Megagrams/year (Mg/yr) must comply with Subpart FF control requirements. Facilities with a TAB less than 10 Mg/yr, but greater than 1 Mg/yr must update their TAB calculations annually, and report these values to the US EPA. Facilities with a TAB less than 1 Mg/yr are required to submit to EPA an initial report, and are only required to submit future reports if there are changes in the waste-generating processes that could cause the TAB to increase to 1 Mg/yr or more.

40 CFR Part 63 Subpart UUU establishes national emission standards for HAPs emitted from petroleum refineries. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

40 CFR 63 Subpart DDDDD governs process heaters and boilers with a heat input of greater than 10 MMBtu/hr. The work practice standards and compliance requirements established in DDDDD may be applicable for the proposed process heaters or furnaces. Holly will comply with this standard following the final resolution of this proposed rule.

The applicable requirements of 40 CFR 63 Subpart CC relates to all heat exchange systems such as the proposed new cooling tower associated with petroleum refining process units. Samples from the cooling tower return line will be collected and analyzed to determine the total strippable VOC concentration (as methane) from the air stripping testing system using "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources" Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003.

4.1.3 National Ambient Air Quality Standards (NAAQS)

The 1970 Clean Air Act (CAA) gave EPA authority to establish the minimum level of air quality that all states would be required to achieve. These minimum standards were developed to protect the public health and welfare. Thus, National Ambient Air Quality Standards (NAAQS) have been established for several pollutants (referred to as criteria pollutants) and are presented in Table 4-1.

As part of this permit application, Holly is required to demonstrate that its facility and associated processes will not cause or contribute to a violation of the NAAQS.

Table 4-1

National Ambient Air Quality Standards [1]

Pollutant	Averaging Period	Primary Standard ($\mu g/m^3$)	Secondary Standard ($\mu g/m^3$)
SO_2	1-hour	197[1]	NA[2]
	3-hour	NA[2]	1,300
	24-hour	365[3]	NA[2]
	annual	80	NA[2]
PM_{10}	24-hour	150[4]	Same as primary
$PM_{2.5}$	24-hour	35[5]	Same as primary
	Annual	15[6]	Same as primary
CO	1-hour	40,000[3]	NA[2]
	8-hour	10,000[3]	NA[2]
NO_2	1-hour	188[9]	None
	Annual	100	Same as primary
O_3	8-hour (2008 standard)	0.075[7]	Same as primary
	8-hour (1997 standard)	0.08[8]	Same as primary
Lead	3-Month	1.5	NA[2]

1) To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.
2) No ambient standard for this pollutant and/or averaging time.
3) Not to be exceeded more than once per year.
4) Not to be exceeded more than once per year on average over three years.
5) To attain this standard, the three-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceeds 35 $\mu g/m^3$.
6) To attain this standard, the three-year average of the weighted annual mean $PM_{2.5}$concentrations from single or multiple community-oriented monitors must not exceed 15 $\mu g/m^3$.
7) To attain this standard, the three-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm.
8) To attain this standard, the three-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm.
9) To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 100 ppb.

[1] http://www.epa.gov/air/criteria.html

The 1990 CAA amendments called for a review of the ambient air quality of all regions of the United States. States were required to file with EPA designations of all areas as attainment, non-attainment, and unclassifiable. An area that is in attainment indicates that air quality concentrations are less than the NAAQS; non-attainment areas are areas where monitoring data has indicated air quality concentrations that are greater than the standards. Unclassifiable areas are areas where there is insufficient monitoring data to prove that the area has attained the federal standards; however, these areas are treated as attainment areas.

The current air quality classification for Davis is non-attainment area for $PM_{2.5}$, maintenance for ozone (O_3) and PM_{10}, and attainment for SO_2, NO_2, VOC, and CO. New major sources or major modifications to existing major sources in attainment areas are required to obtain a PSD permit prior to initiation of construction.

4.1.4 Prevention of Significant Deterioration

Major new sources located in attainment areas are required to obtain a PSD permit prior to construction. A "major" stationary source, as defined by 40 CFR 52.21(b)(1)(i)(a) is any stationary source with the potential to emit 250 tons per year of a regulated air pollutant or any stationary source defined as one of the 28 source categories listed in 40 CFR 52.21(b)(1)(i)(a) with the potential to emit 100 tons per year of any regulated pollutant. Holly, as a petroleum refinery, would fall under one of the named 28 listed source categories and, as such, the applicable PSD threshold is 100 tons per year.

A major modification is defined as "any physical change in or change in the method of operation of a major stationary source that would result in: (1) a significant emissions increase of a regulated NSR pollutant; and (2) a significant net emissions increase of that pollutant from the major stationary source." EPA rules specify what amount of emissions increase is "significant" for listed regulated NSR pollutants and these significant emission rates are presented in Table 4-2.

Table 4-2

PSD Significant Emission Rates

Pollutant	Significant Emission Rate (TPY)
CO	100
NO_x	40
SO_2	40
PM_{10}	15
$PM_{2.5}$	10
O_3	40 (VOCs)
Lead	0.6
Fluorides	3
Sulfuric acid mist (H_2SO_4)	7
Total reduced sulfur (including H_2S)	10
Reduced sulfur compounds (including H_2S)	10
H_2S	10

For proposed modifications at existing major sources, PSD applies to each regulated NSR pollutant for which the proposed emissions increase resulting from the modification both is significant and results in a significant net emissions increase. This is true even if the increased pollutant is different than the pollutant for which the source is major. Thus, the regulations quoted above require a two-step applicability process for modifications. Step 1 involves determining if the modification by itself results in a significant increase. No emissions decreases are considered in Step 1.

If there is a significant increase in Step 1, then Step 2 applies, which involves determining if the modification results in a significant net emissions increase. The Step 2 calculation includes creditable emissions increases and decreases from the modification by itself and also includes creditable emissions increases and decreases at the existing source over a “contemporaneous period.”

A contemporaneous period is defined in the federal regulations as the period that extends back 5 years prior to the date that construction commences on the modification and forward to the date that the increase from the modification occurs.

To determine PSD applicability of an existing stationary source, one of two tests may be used to determine the emissions increase from an existing emissions unit: the actual-to-projected-actual" emissions test or the "actual-to-potential" emissions test. If the emissions unit at an existing source is new, the owner or operator must use the "actual-to potential" emissions test to calculate emissions increases. Also, the "baseline actual emissions" for existing emissions units are generally the actual emissions in TPY from the unit for any consecutive 24-month period (selected by the applicant) in the prior 10 years.

For Holly, CO emissions will be significant and as such are subject to PSD. PSD permitting requirements also cover new construction projects that emit GHG emissions of at least 75,000 tons per year CO_2e (carbon dioxide equivalent). Holly will also be significant for GHG.

The PSD application for this project includes the following analyses for each pollutant subject to PSD:

- Best Available Control Technology (BACT) analysis,
- Air Quality Monitoring Requirements,
- Air Quality Impact Analysis,
- Additional Impact analyses, and
- PSD Class I analysis.

4.1.4.1 Best Available Control Technology Analysis

A PSD source must conduct an analysis to ensure the application of the Best Available Control Technology (BACT) to emissions of pollutants subject to PSD review. To determine BACT, the "Top Down" methodology is recommended by EPA. A detailed explanation of the "Top Down" BACT analysis is presented in Section 5.0 of this permit application.

4.1.4.2 Air Quality Monitoring Requirements

In accordance with 40 CFR 52.21(m), a PSD permit application must contain an analysis of the existing ambient air quality data in the area which could be affected by the proposed project if the project would result in a net significant emissions increase. To define the existing air quality, a pre-construction monitoring program that is specifically designed to collected data in the area of the proposed source can be initiated or else data collected from either a state or privately-operated monitoring program may be used. The condition for monitoring can be waived if the proposed project would cause an impact less than EPA-specified de minimis monitoring levels as established by the EPA. PSD de minimis monitoring concentration levels are presented in Table 4-3.

Table 4-3

PSD De Minimis Monitoring Concentrations

Pollutant	Averaging Period	Threshold Concentration ($\mu g/m^3$)
CO	8-hour	575
NO_2	annual	14
SO_2	24-hour	13
PM_{10}	24-hour	10
$PM_{2.5}$	24-hour	4
O_3	NA	Exempt if VOC emissions are less than 100 TPY
Lead	3-month	0.1
Fluorides	24-hour	0.25
Total reduced sulfur	1-hour	10
H_2S	1-hour	0.2
Reduced sulfur compounds	1-hour	10

4.1.4.3 Air Quality Impact Analysis

An air quality impact analysis must be performed for the proposed modification subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate to demonstrate that the project will not cause or contribute to a exceedance of any applicable NAAQS or PSD increment. Usually, the analysis will involve: (1) the assessment of existing air quality which may include ambient monitoring data and air quality dispersion modeling results; and (2) using dispersion modeling, the prediction of ambient concentrations that will result from the applicants proposed project and future growth associated with the project. To determine the air quality impact, atmospheric dispersion modeling is performed in accordance with EPA's Guideline on Air Quality Models[2] and Utah modeling requirements[3].

[2] 40 CFR Part 51, Appendix W
[3] Utah Division of Air Quality Emissions Impact Assessment Guidelines

Federal PSD increments have been established for SO_2, NO_2, PM_{10} and $PM_{2.5}$ for the Class I and Class II areas. Class I areas are those federally protected areas in which the least amount of incremental impact can occur such as National Parks and Wilderness areas. Nearly all other areas are defined as Class II where higher increments are specified. As part of the PSD regulations, an ambient air quality analysis is required to demonstrate that the PSD increment consumed does not exceed or contribute to a concentration that exceeds allowable PSD increments.

As part of the air quality impact analysis, a preliminary dispersion modeling analysis was performed for those pollutants which were expected to be emitted in significant amounts. Per a request from the UDAQ, modeling was performed for existing and proposed Holly sources of NO_2, SO2, PM_{10}, $PM_{2.5}$, and CO.

An impact analysis may be limited to Holly sources only if modeled impacts are below the significant impact levels (SILs). The preliminary modeling indicated that SO_2 and NO_2 were the only two pollutants above the PSD Class II SILs which required a full impact analysis to be performed for these pollutants. The allowable PSD increments and SILs are presented in Table 4-4. SIL's for the one-hour NO_2 and SO_2 standards have not been established.

Table 4-4

PSD Increments and Significant Impact Levels in Micrograms per Cubic Meter

Pollutant	Averaging Time	PSD Increments		SILs	
		Class 1	Class II	Class 1	Class II
NO_2	Annual	2.5	25	0.1	1
SO_2	3-hour	25	512	1	25
	24-hour	5	91	0.2	5
	annual	2	20	0.1	1
CO	1-hour	---	---	---	2000
	8-hour	---	---	---	500
PM_{10}	24-hour	8	30	0.3	5
	annual	4	17	0.2	1
$PM_{2.5}$	24-hour	1	4	0.07	1.2
	annual	2	9	0.06	0.3

All air quality impact analyses were performed in accordance with an UDAQ approved modeling protocol which was designed specifically for the proposed project. A copy of the modeling protocol approval letter is presented in Appendix D.

4.1.4.4 Additional Impact Analyses

Per 40 CFR 52.21, a PSD permit application must contain an additional impacts analysis. These analyses provide an analysis of the impairment to visibility, acid deposition, soils and vegetation that would occur as a result of the source and general commercial, residential, industrial, and other growth associated with the source. The applicant need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

4.1.5 Good Engineering Stack Height Analysis

The CAA requires that the degree of emission limitation required for control of any pollutant not by affected by a stack which exceeds good engineering practice (GEP) height. GEP stack height is defined as the highest of:

- 65 meters,
- A height established by applying the formula: HGEP = H + 1.5 L where H is the height of the structure or nearby structure and L is the lesser dimension (height or projected width) of the nearby structure, and
- A height demonstrated by fluid modeling or field study.

A structure is considered nearby a stack if it is within a distance of five times the structures height or maximum projected width. Only the smaller value of the height or projected width is used and the distance to the structure cannot be greater than 0.8 kilometers. Although GEP stack height regulations require that the stack height used in modeling not exceed GEP stack height, the actual stack height may be greater.

The regulations (40 CFR Part 51) also increase stack height beyond that resulting from the formula in cases where plume impaction occurs. Plume impaction occurs when a plume of exhaust gases emitted from a stack hits a higher hill or mountain (elevated terrain) downwind of the stack. Elevated terrain is terrain that exceeds the height calculated by the GEP stack height formula.

Per 40 CFR Part 51 and the results of BPIP-PRIME show there is no significant terrain that would induce downwash with ½ kilometer at least a 10% height relative to the distance from the source. Thus, plume impaction was not considered.

All stacks for the proposed Holly heavy crude processing project will be less than 65 meters and will be modeled at their actual stack elevation. The modeling complies with GEP regulations.

4.1.6 40 CFR Part 70 Operating Permit Program (Title V)

In accordance with the CAA of 1990, the proposed Holly project sources will be subject to the requirements of 40 CFR Part 70.

4.1.7 40 CFR Part 98 - Mandatory Greenhouse Gas Reporting

On September 22, 2009, EPA finalized the mandatory reporting of greenhouse gases rule. This rule establishes the first federal requirement to report and monitor GHG emissions. The reporting threshold is 25,000 metric tons CO_2e/year based on actual emissions or capacity-based thresholds depending on sector type. The final rule requires reporting of annual emissions of carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, perfluorocarbons, and other fluorinated greenhouse gases, as applicable, to the reporting facility. Monitoring, reporting, and recordkeeping activities will be required for Holly Refining.

4.2 Utah Administrative Codes

The air quality regulations, codified in Title R307 of the Utah Administrative Code, which are potentially applicable to this project, are as follows:

- R301-101. General Requirements
- R301-102. General Requirements: Broadly Applicable Requirements
- R307-107. General Requirements: Unavoidable Breakdown
- R307-150. Emission Inventories
- R307-165. Emission Testing
- R307-170. Continuous Emission Monitoring Program
- R307-210. Stationary Sources
- R307-214. National Emission Standards for Hazardous Air Pollutants
- R307-305. Nonattainment and Maintenance Areas for PM_{10}: Emission Standards
- R307-326. Ozone Nonattainment and Maintenance Areas: Control of Hydrocarbon Emissions in Petroleum Refineries
- R307-401. Permits: New and Modified Sources
- R307-403. Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas
- R307-405. Permits: Major Sources in Attainment or Unclassified Areas (PSD)
- R307-406. Permits: Visibility
- R307-410. Permits: Emissions Impact Analysis
- R307-414. Permits: Fees for Approval Orders
- R307-415. Permits: Operating Permit Requirements

4.2.1 R307-102 General Requirements: Broadly Applicable Requirements

The definitions and general requirements found in E307-102 will apply to Holly Refining and Marketing Company including penalties for violations of state statutes and providing periodic reports and other information as necessary to determine compliance with state and federal standards.

4.2.2 R307-107 General Requirements: Unavoidable Breakdown

The unavoidable breakdown provisions of R307-107 will apply to the Holly Heavy Crude Processing Project. A breakdown for any period longer than 2 hours will be reported to the Executive Secretary within 3 hours of the beginning of the breakdown if reasonable, but in no case longer than 18 hours after the beginning of the breakdown.

During times other than normal office hours, breakdowns for any period longer than 2 hours shall be initially reported to the Environmental Health Emergency Response Coordinator.

Within 7 calendar days of the beginning of any breakdown of longer than 2 hours, a written report will be submitted to the Executive Secretary which shall include the cause and nature of the event, estimated quantity of pollutant (total and excess), time of emissions and steps taken to control the emissions and to prevent recurrence.

The submittal of such information shall be used by the Executive Secretary in determining whether a violation has occurred and/or the need of further enforcement action.

Breakdowns that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown will not be considered unavoidable and are not covered by R307-107.

4.2.3 R307-150 Emission Inventories

The emission inventory provision of R307-150 will apply to Holly since it is anticipated that the proposed project will be considered a major modification. Holly shall submit an inventory annually for all emissions units including fugitive emissions. The inventory shall include PM_{10}, $PM_{2.5}$, oxides of sulfur, oxides of nitrogen, CO, VOC, ammonia, other chargeable pollutants, and non-exempted HAPS.

For each pollutant, the emissions inventory data shall include the rate and period of emissions, startup and shut down emissions, the specific emissions unit which is the source of the air pollution, composition of air contaminant, type and efficiency of the air pollution control equipment, and other information necessary to quantify operation and emissions and to evaluate pollution control. The emissions of a pollutant shall be calculated using the source's actual operating hours, production rates, and types of materials processed, stored, or combusted during the inventoried time period.

4.2.4 R307-165 Emission Testing

Holly will be subject to the emission testing requirements that are listed in R307-165. Emission testing will be required of the Holly project sources within six months of start-up and at least once every five years or more frequently as determined by the Executive Secretary.

4.2.5 R307-170 Continuous Emission Monitoring Program

The proposed Holly project will be required to operate a continuous monitoring system that is subject to the requirements of 40 CFR 60.13 (d) through (j). Performance specification tests and audits, record keeping, and electronic data reports are also required as part of this regulation.

4.2.6 R307-210 Stationary Sources

The provisions of 40 Code of Federal Regulations (CFR) Part 60, effective on July 1, 2006, except for Subparts Cb, Cc, Cd, Ce, BBBB, DDDD,and HHHH, are incorporated by reference into these rules with the exception that references in 40 CFR to "Administrator" shall mean "executive secretary" unless by federal law the authority referenced is specific to the Administrator and cannot be delegated. With the proposed heavy crude processing project, several of the proposed sources will be subject to New Source Performance Standards as found in 40 CFR Part 60, specifically, Subparts A, Dc, Ja, Kb, GGGa, and IIII.

4.2.7 R307-214 National Emission Standards for Hazardous Air Pollutants (NESHAPS)

The provisions of 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories, effective as of July 1, 2010, are incorporated into the air rules by reference. With the proposed modification, sources at the refinery will be subject to the requirements of the NESHAPs, including notification, monitoring, performance testing, reporting, recordkeeping, operation and maintenance provisions, as well as the applicable requirements of Subpart UUU.

4.2.8 R307-305 Nonattainment and Maintenance Areas for PM_{10}: Emission Standards

Since Holly is located in a PM_{10} maintenance area, Holly will be subject to the emission limitations and operating parameters as specified in Section IX, Part H, of the Utah state implementation.

4.2.9 R307-326 Ozone Nonattainment and Maintenance Areas: Control of Hydrocarbon Emissions in Petroleum Refineries

This rule requires that Reasonably Available Control Technology (RACT) be applied to control hydrocarbon emissions from Holly's refinery since it is located in ozone maintenance area. This rule would include the application of RACT to control emissions from the new FCCU as well as the monitoring of leaks from refinery equipment.

4.2.10 R307-401 Permit: New and Modified Sources

This rule, which applies to the proposed Holly heavy crude processing project, establishes the application and permitting requirements for new installations and modifications to existing installations throughout the State of Utah. According to R307-401 any person intending to construct a new installation which will or might reasonably be expected to become a source or an indirect source of air pollution shall submit to the executive secretary a NOI and receive an approval order prior to initiation of construction. The NOI shall include the information described in R307-401-5 to determine whether the proposed construction will be in accord with applicable requirements of these rules. Within 30 days after receipt of a NOI, or any additional information necessary to the review, the executive secretary shall advise the applicant of any deficiency in the NOI or the information submitted.

4.2.11 R307-405 Permits: Major Sources in Attainment or Unclassified Areas (PSD)

R307-405 implements the federal PSD permitting program for major sources and major modifications in attainment areas and maintenance areas as required by 40 CFR 51.166. This rule does not include the routine maintenance, repair and replacement provisions that were vacated by the DC Circuit Court of Appeals on March 17, 2006.

The proposed CO emissions from Holly's heavy crude processing project meets the definition of a "major modification" as found in R307-405 and will be subject to PSD requirements. A major modification is a physical change or change in the method of operation at an existing major source that causes a significant "net emissions increase" at that source of any pollutant regulated under the Clean Air Act.

Every new major source must be reviewed by the Executive Secretary to determine the air quality impact of the source to include a determination whether the source will cause or contribute to a violation of the maximum allowable increases or the NAAQS in any area. The determination of air quality impact will be made as of the source's projected start-up date.

Such determination shall take into account all allowable emissions of approved sources and, to the extent practicable, the cumulative effect on air quality of all sources and growth in the affected area.

4.2.12 R307-406 Permits: Visibility

R307-406 establishes the requirements for evaluating the impact of emissions on visibility in any mandatory Class I area from any new major source or major modification proposed in either an attainment area or area of nonattainment area. In determining visibility impact by a major new source or major modification, the Executive Secretary shall use, the procedures identified in the EPA publication "Workbook For Estimating Visibility Impacts" (EPA 450-4- 80-031) November 1980, or equivalent. Federal land managers will be notified as appropriate.

4.2.13 R307-410 Permits: Emissions Impact Analysis

R307-410 establishes the procedures and requirements for evaluating the emissions impact of new or modified sources that require an approval order under R307-401 to ensure that the source will not interfere with the attainment or maintenance of any NAAQS. The rule also establishes the procedures and requirements for evaluating the emissions impact of hazardous air pollutants. The rule also establishes the procedures for establishing an emission rate based on the good engineering practice stack height as required by 40 CFR 51.118.

Prior to receiving an approval order under R307- 401, a modification to an existing source located in an attainment area which increases the total controlled emission rate per pollutant of the source in an amount greater than or equal to those specified in Table 1 of R307-410, shall conduct air quality modeling, as identified in R307-410-3, to estimate the impact of the new or modified source on air quality unless previously performed air quality modeling for the source indicates that the addition of the proposed emissions increase would not violate a National Ambient Air Quality Standard, as determined by the Executive Secretary.

4.2.14 R307-414 Permits: Fees for Approval Orders

The owner and operator of each new major source or major modification is required to pay a fee to the Department sufficient to cover the reasonable costs of reviewing and acting upon the notice of intent required pursuant to R307-401 for each new major source or major modification and implementing and enforcing requirements placed on such source by any approval order issued pursuant to such notice (not including any court costs associated with any enforcement action). R307-414 will apply to Holly since a NOI will be submitted prior to construction.

4.2.15 R307-415 Permits: Operating Permit Requirements

Title V of the CAA requires States to develop and implement a comprehensive air quality permitting program. Title V does not impose new substantive requirements. Title V does require that sources subject to R307-415 pay a fee and obtain a renewable operating permit that clarifies, in a single document, which requirements apply to a source and assures the source's compliance with those requirements.

R307-415 establishes the procedures and elements of the Title V program. Since the Holly project is a major modification and a Part 70 source, Holly will be subject to R307-415.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY DEMONSTRATION

As presented in Utah Air Quality Rule R307-401-2 (d), "Best available control technology (BACT)" means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each air contaminant which would be emitted from any proposed stationary source or modification which the executive secretary, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. The BACT analysis was conducted in accordance with EPA's recommended "top-down" methodology which is:

- Step 1 – Identify All Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Controls
- Step 5 – Select BACT.

In Step 1 in a "top down" analysis, all available control options for the emission unit in question are identified. Identifying all potential available control options consists of those air pollution control technologies or control techniques with a practical potential for application to the emission unit and the regulated pollutant being evaluated.

In Step 2, the technical feasibility of the control options identified in Step 1 are evaluated and the control options that are determined to be technically infeasible are eliminated. Technically infeasible is defined where a control option, based on physical, chemical, and engineering principles, would preclude the successful use of the control option on the emissions unit under review due to technical difficulties. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

The third step of the "top-down" analysis is to rank all the remaining control options not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information.

Once the control effectiveness is established in Step 3 for all feasible control technologies identified in Step 2, additional evaluations of each technology, based on energy, environmental, and economic impacts, are considered to make a BACT determination in Step 4. 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.

The second evaluation to be reviewed for each control technology remaining in Step 4 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.

The third evaluation addresses the economic evaluation of the remaining control technologies. The cost to purchase and to operate the control technology is analyzed. The capitol 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.

In Step 5, BACT is selected for the pollutant and emission unit under review. BACT is the highest ranked control technology not eliminated in Step 4.

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

Beginning in July 2011, UDAQ rules regulate GHG emissions where physical changes at an existing stationary source will result in an emissions increase of 75,000 tons per year CO_2e or more (see UAC R307-405-3(9)9d)). The required BACT reviews for GHG emissions are found in Section 5.10 through 5.14 of this NOI.

5.1 BACT for Process Heaters

The proposed process heaters at the Holly Refining & Marketing facility include:

- 60 MMBtu/hr Crude Heater:
- 42.1 MMBtu/hr Reactor Charge Heater;
- 45 MMBtu/hr FCCU #2 Feed Heater;
- 14 MMBtu/hr Hot Oil Furnace;
- 99 MMBtu/hr Reactor Charge Furnace;
- 0.8 MMBtu/hr Asphalt Heaters (6 heaters); and
- 130 MMBtu/hr Vacuum Furnace Heater.

These process heaters will be fired on either natural gas or refinery fuel gas.

5.1.1 BACT for CO

The EPA's top-down process was used to determine the best available control technology for control of CO emissions from the proposed process heaters. Carbon monoxide is a product of the chemical reaction between carbonaceous fuels and oxygen. CO occurs as the product of combustion in fuel-rich mixtures. In fuel-lean mixtures, CO can result due to poor mixing of fuel and air or because of very high temperatures in the combustion zone.

5.1.1.1 Step 1 – Identify All Available Control Technologies

A search of the EPA's RACT/BACT/LAER (RBLC) Clearinghouse[4] and California Air Resources Board (CARB) BACT Clearinghouses[7] as well as other data sources found combustion controls, catalytic oxidation, and thermal oxidation as technically feasible for reducing CO emissions from refinery process heaters/boilers. EM_x™ was identified as a control alternative.

The first control technology identified to reduce CO emissions is through good engineering design of the equipment utilizing good combustion practices. Good combustion practices for CO include adequate fuel residence times, proper fuel-air mixing, and temperature control. For the proposed process heaters, there will be adequate turbulence in the flue gas which will ensure good mixing, a high temperature zone (greater than 1800°F) that will ensure complete burnout along with a sufficient residence time (one to two seconds) at high temperature which will lead to minimized CO emissions. Higher combustion zone temperatures favor the complete oxidation of carbon-containing compounds to carbon dioxide (CO_2) and water. Therefore, emissions of carbon monoxide would be expected to decrease at higher temperatures.

4 California Air Resources Board BACT Clearinghouse at http:/www.arb.ca.gov/bact/bact.htm

A second control technology identified for controlling CO emission from process heaters is catalytic oxidation. Catalytic oxidation allows 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 (fps). Catalytic oxidizers typically operate at a narrow temperature range of approximately 600 to 1100 °F. At lower temperatures, the CO conversion efficiency falls off rapidly.

Catalytic oxidizers are similar to a Selective Catalytic Reduction (SCR) system in that a catalyst bed facilitates the conversion of a CO to CO_2. Unlike SCR, catalytic oxidizers do not use additional chemicals such as ammonia to facilitate the conversion.

The third control technology identified is thermal oxidizers or thermal incineration. 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. The waste gas is passed through burners, where the gas is heated above its ignition temperature. Additional fuel is required to reach this higher temperature. The hot gases then pass through one or more residence chambers to ensure complete combustion.

Thermal oxidizers require operating temperatures in the 1200 to 2000°F range to ensure conversion of CO to CO_2. The combustion process occurs in two separate stages: (1) the combustion of fuels, and (2) the combustion of pollutants. The combustion process in the first stage is extremely rapid and is an irreversible chemical reaction. The oxygen supplied by the primary air may be in excess or obtained directly from the process gas stream. In the second stage, the heated gases from the burners pass through residence chambers where the CO is oxidized. Residence time, heating value of the gas stream, and operating temperatures determine the efficiency of the process.

A control alternative, supplied by Emera Chem is EM_x^{TM}. EM_x^{TM} is a developing add-on technology with the potential to reduce NO_x and CO emissions from combustion sources. EM_x^{TM} utilizes a catalytic technique that simultaneously oxidizes NO to NO_2 and CO to CO_2, then absorbs the NO_2 onto the surface of a catalyst through the use of a potassium carbonate coating. The CO_2 is passes through the catalyst unchanged.

5.1.1.2 Step 2 - Eliminate Technically Infeasible Control Options

Oxidation catalyst is not a technically feasible option for control of CO emissions from process heaters. The Holly Refinery plant gas contains sulfur.

In flue gas containing more than trace levels of SO_2, poisoning and deactivation of the catalyst by sulfur-containing compounds occurs as well. In addition, SO_2 would be converted to SO_3 which will form sulfuric acid increasing the emissions of this acid gas and will increase both condensable particulate emissions and flue gas system corrosion rates.

A typical oxidation catalyst for CO is platinum or rhodium on an alumina support material. Acceptable catalyst operating temperatures range from 400 to 1,250°F with an optimal operating range of 850 to 1,100°F. In process heaters, the catalyst would have to be installed upstream of any air preheat or waste heat recovery equipment to achieve this temperature range.

The EPA's RBLC and recent issued permits were reviewed and catalytic oxidation was not identified as a CO technically feasible control option for natural gas or refinery-fuel gas-fired boilers and heaters.

EM_x was also identified as not a technically feasible option. EM_x™ is a multi-pollutant catalyst that does not require ammonia. EM_x™ technology is available for gas turbine, reciprocating engines, and industrial/utility boilers[5] firing pipeline quality natural gas; however, there is no practical experience with operating on flue gas streams from refinery gas-fired equipment. At this time, EM_x™ is not being used in any commercial refinery situation with equipment using a sulfur-bearing fuel gas stream such as refinery fuel gas because SO_x will contaminate the catalyst and reduce efficiency over time.

Because of the lack of commercial refinery experience and the catalyst's sensitivity to sulfur compounds, EM_x™ is deemed to be technically infeasible for the refinery process heaters and is rejected for further consideration.

5.1.1.3 Step 3 - Rank Remaining Control Options

The following lists the ranking of the remaining control options:

1) Thermal oxidation – 90% reduction
2) Good combustion practice

5.1.1.4 Step 4 - Evaluate Remaining Control Options

The remaining control options were reviewed in consideration with energy, environmental, and economic impacts.

Thermal oxidation is considered a technically feasible add-on control option. Flue gases from the combustion equipment could be routed through a thermal oxidizer where gases could be heated to an operating range of 1200 - 2000°F. At this temperature, CO will be burned to CO_2. Raising the exit gas to the appropriate temperature range will require a significant amount of energy and generate increased combustion emissions.

5 http://murcal.com/11.emerachem/11.emerachem.catalysts.html

Heaters and boilers can be considered as thermal oxidizers themselves and adding another thermal oxidizer downstream of a heater or boiler to control CO is impractical. Thermal oxidation did not result as BACT and was eliminated from consideration.

CO emissions can be controlled using proper equipment design and operation, good combustion practices, and gaseous fuels, which are usually less efficient than the oxidation technologies, but have minimal environmental and economic impacts.

5.1.1.5 Step 5 - Select BACT

Based on the information presented in EPA's RBLC, combustion controls, based on modern boiler and burner designs to optimize residence time, fuel/air mixing, and combustion temperature are the industry standards for CO reduction from refinery process heaters. Table 5-1 presents a summary of previous BACT determinations for CO. This table is not exhaustive, rather lists the lowest emission rates identified in approximately the past six years from select plants.

Table 5-1

Summary of BACT Determinations for CO for Process Heaters

Facility	Permit Date	Size (MMBtu/hr)	Primary Fuel	Limit (lb/MMBtu)	Technology
Total Refining – Port Arthur	11/06/2009	68 and 90	Refinery Gas	0.08 (one-hour average)	Proper equipment design and operation, good combustion practices, use of gaseous fuels.
St. Charles Refinery Valero Refining	11/17/2009	15-95	Refinery Gas	0.08 (one-hour average)	Proper equipment design and operation, good combustion practices, use of gaseous fuels.
Marathon Petroleum CO LLC Garyville Refinery	7/16/2008	73.8 - 85.1	Refinery gas	0.04 (3-run average)	Proper design, operation, and good engineering practices
St. Charles Refinery Valero Refining	02/08/2007	15-95	Refinery Gas	0.08	Proper equipment design and operation, good combustion practices, use of gaseous fuels.
Marathon Petroleum CO LLC Garyville Refinery	12/27/2006	73.8 - 85.1	Refinery gas	0.04	Proper design, operation, and good engineering practices
Arizona Clean Fuels Yuma LLC	04/14/2005	23.2 - 346	Refinery gas	0.04	Proper design, operation, and good engineering practices

The lowest CO emission factor for process heaters and boilers firing refinery fuel gas found in the database searches ranged from 0.08 based on a one-hour average and to 0.04 lb/MMBtu based on three-hour average. The proposed CO BACT emission limit for proposed Holly process heaters is based on the heat input utilizing proper equipment design and operation, good combustion practices, and the use of gaseous fuels. A BACT CO emission limit of 0.08 lb/MMBtu is proposed for the crude heater, reactor charge heater, FCCU #2 feed heater, hot oil furnace, reactor charge heater, stab-in heaters, and vacuum heater.

5.1.2 BACT for PM_{10} and $PM_{2.5}$

PM_{10} is particulate matter (PM) less than 10 microns in diameter produced by combustion. PM_{10} consists of two parts, filterable and condensable. Filterable PM_{10} is the material that is captured on the filter used in the EPA Reference Method 5 test; Condensable PM_{10} is particulate that passes through the filter as a gas and is measured using EPA Reference Method 202. According to AP-42, filterable PM emissions from gaseous fuels such as refinery fuel gas are typically lower than emissions from solid fuels. Particulate matter from refinery gas or natural gas combustion is usually composed of larger molecular weight hydrocarbons that have not been fully combusted.

$PM_{2.5}$ is particulate matter 2.5 microns or smaller. According to John Zink, emissions from the process heaters are in the PM_{10} range. In addition, this is collaborated by the publication, *$PM_{2.5}$ Speciation Profiles and Emission Factors from Petroleum Industry Gas-Fired Sources*[6] which indicates that "measured emissions of primary fine particulate from the gas-fired boiler, process heater, and steam generator were extremely low". Thus the BACT analysis for the process heaters will focus on PM_{10}.

[6] http://www.epa.gov/ttn/chief/conference/ei10/poster/wien.pdf

5.1.2.1 Step 1 - Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling PM_{10} 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.

By maintaining the heaters in good working order per manufacturer specifications with low sulfur gaseous fuels, emissions of PM_{10} are reduced.

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

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

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.

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. Cyclones are generally used to reduce dust loading and collect large particles.

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations.

5.1.2.2 Step 2 - Eliminate Technically Infeasible Control Options

None of the add-on control devices were identified as being suitable for the process heaters burning gaseous fuels due to both the extremely low concentration of small particulates expected in gas streams from this type of equipment. PM/PM_{10} concentrations in the refinery fuel and natural gas-fired boilers and heaters are even less than the concentrations guaranteed by the cyclones, EPS's, fabric filters, and wet scrubbers.

Therefore, wet scrubbers, EPS's, cyclones, and fabric filtration (baghouses) were rejected as BACT for PM/PM_{10} emissions from heaters and boilers.

5.1.2.3 Step 3 - Rank Remaining Control Options

The remaining control option is the utilization of good combustion practices.

5.1.2.4 Step 4 - Evaluate Remaining Control Options

The concept of applying combustion controls and appropriate furnace design or "proper combustion" to minimize PM_{10} 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_{10} 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 is a work practice requirement to adhere to good combustion practices and use of low sulfur gaseous fuel. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

5.1.2.5 Step 5 - Select BACT

A review of the RBLC as well as other databases indicated that the most stringent control technologies for PM_{10} are good combustion practices and use of gaseous fuel. The proposed PM_{10} BACT emission limit for the proposed new process heaters is based on manufacturer data at 0.0075 lb/MMBtu utilizing proper equipment design and operation, good combustion practices, and gaseous fuels. Table 5-2 presents a summary of previous BACT determinations for PM_{10}. This table is not exhaustive, rather lists the lowest emission rates identified in the past several years from select plants.

Table 5-2

Summary of BACT Determinations for PM_{10} for Process Heaters

Facility	Permit Date	Size (MMBtu/hr)	Primary Fuel	Limit (lb/MMBtu)	Technology
St. Charles Refinery Valero Refining	11/17/2009	15-95	Refinery Gas	0.0074 (Annual avg.)	Proper equipment design and operation, good combustion practices, gaseous fuels
Hunt Refinery Co.	09/28/2009	34.7-254	Refinery gas	0.0075	None listed.
Marathon Petroleum CO LLC Garyville Refinery	12/27/2006	63.7-183.3	Refinery gas	0.0075 (3-hr avg.)	Proper design, operations and good engineering practices
Arizona Clean Fuels Yuma LLC	04/14/2005	23.2 - 346	Refinery gas	0.0075	None listed.
ExxonMobil Refining & Supply Baton Rouge Refinery	02/18/2004	22-82	Gaseous fuels	0.0080	Good engineering design and proper combustion practices

5.1.3 BACT for SO_2

Sulfur dioxide (SO_2) emissions come from the sulfur in the fuel gas. Both refinery gas and natural gas contain sulfur, mostly in the form of hydrogen sulfide (H_2S). In general, refinery fuel has higher sulfur content than natural gas supplied by a pipeline. When burned in a boiler or heater, essentially all the sulfur in the fuel is oxidized to SO_2.

5.1.3.1 Step 1 - Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling SO_2 emissions:

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

Nearly all of the sulfur combusted in the fuel will be converted to SO_2. By limiting the sulfur content of the fuel, emissions of SO_2 will be reduced.

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 AFGD process accomplishes SO_2 removal by utilizing a single absorber which performs three functions which are prequenching the flue gas, adsorption of SO_2, 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 SO_2 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 SO_2 is absorbed by the slurry forming calcium sulfite and calcium sulfate. The liquid-to-gas ration 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 ESP.

5.1.3.2 Step 2 - Eliminate Technically Infeasible Control Options

All listed control options are technically feasible.

5.1.3.3 Step 3- Rank Remaining Control Options

The following lists the ranking of the control options:

1) AFGD – 95 – 99.5% reduction;
2) Wet FGD – 90 - 99% reduction;
3) Dry FGD – 90-95% reduction; and
4) Low sulfur fuels – base case.

The NSPS fuel specification for low sulfur fuels is limited to 162 ppmv or less.

5.1.3.4 Step 4 - Evaluate Remaining Control Options

A review of the recent literature, recent permits, and the RBLC database did not result in AFGD, 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 which included cost information, these control options were not cost effective in terms of dollars per ton removal. Hence, these three options were eliminated from consideration.

The only control strategy identified for the fuel gas-fired process heaters is adherence to fuel specifications - low sulfur fuel. This control strategy is technically feasible and will not cause adverse energy, environmental, or economic impacts.

5.1.3.5 Step 5 - Select BACT

BACT limits for SO_2 can be expressed as the total sulfur or H_2S content of the fuel or as emissions limit that specify the type of fuel.

Holly has a fuel gas sulfur content of 162 or less ppmv which is the proposed BACT emission limit from refinery fuel gas-fired process heaters. In addition to the fuel gas sulfur content limit, equipment design and work practice requirements will be implemented to minimize, to the greatest extent possible, emissions that would occur due to upsets.

5.1.4 BACT for NO_x

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.

5.1.4.1 Step 1 - Identify All Available Control Technologies

There are a variety of options available for control of NO_x emissions from combustion sources. These include modifications that reduce NO_x formation, add-on control devices, or combinations of both. The control technologies and techniques for NO_x emissions that were identified include:

- low NO_x burners (LNB),
- next or current generation ultra-low NO_x burners (ULNB)
- flue gas recirculation (FGR),
- selective non-catalytic reduction (SNCR),
- selective catalytic reduction (SCR),
- low NO_x burners and flue gas recirculation (LNB +FGR),
- next or current generation ultra-low NO_x burners and flue gas recirculation (ULNB + FGR)
- low NO_x burners and selective non-catalytic reduction (LNB + SNCR),
- next or current generation ultra-low NO_x burners and selective non-catalytic reduction (ULNB + SNCR),
- low NO_x burners and selective catalytic reduction (LNB + SCR),
- next or current generation ultra-low NO_x burners and selective catalytic reduction (ULNB + SCR),

- EM_x™ (formerly $SCONO_x$),
- low NO_x burners and EM_x™, and
- next or current generation ultra-low NO_x burners and EM_x™.

5.1.4.2 Step 2 - Eliminate Technically Infeasible Control Options

All of the individual controls or combinations of controls were determined to be technically feasible. All controls except the combination of SNCR and LNB or ULNB have been demonstrated on process heaters.

5.1.4.3 Step 3 - Rank Remaining Control Options

Table 5-3 lists a range of control efficiencies for the NO_x control devices.

Table 5-3

Control Efficiencies for NO_x Control Devices [7]

Technology	Range of Control (%)
ULNB + SCR	85-99
LNB + SCR	80-99
EM_x™	90-95
ULNB + SNCR	75-95
SCR	80-95
ULNB (including FGR)	75-90
LNB + SNCR	50-89
LNB+FGR (with or without FGR)	50-72
SNCR	30-75
LNB	50-72
FGR	30
No control	---

7 Petroleum Refinery Tier 2 BACT Analysis Report, Draft, US EPA, March 14, 2000.

5.1.4.4 Step 4 - Evaluate Remaining Control Options

The top-ranked control option for the process heaters involves the use next generation ULNB or current ULNB with SCR as the post-combustion control device. Next generation ULNB can reduce NO_x emissions at refineries by 90%. 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 catalysts[8].

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.

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

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.

There are also safety issues associated with the transportation, handling, and storage of aqueous ammonia. The storage of ammonia is regulated under Occupational Safety and Health Act (OSHA) regulations and Section 112(2), Risk Management Planning provisions of the Clean Air Act. Aqueous ammonia is made at Holly which will be used in the SCR system.

EM_x™, formerly $SCONO_x$, is a post combustion control system produced by EmeraChem LLC. 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. The emissions of NO_x are oxidized to NO_2 and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to regenerate the catalyst. This gas absorbs the NO_2 from the catalyst and reduces N_2 before it exits the stack.

EM_x™ operates in a temperature range between 300°F to 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrites and nitrates on the surface of the catalyst. 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^{TM} has not been demonstrated for refinery fuel gas-fired process heaters. This technology has not been demonstrated to function efficiently on combustion sources burning fuels other than natural gas. In addition, there are significant technical differences between the proposed refinery's combustion sources and those few sources where EM_x^{TM} has been demonstrated in practice. These significant technical differences preclude a determination that EMx^{TM} has been demonstrated to function efficiently on sources that are similar or identical to the proposed process heaters. Thus, EM_x^{TM} has been eliminated as BACT for process heaters.

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 1600°F to 2100°F[9]. 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.

There are two advantages of an SNCR system over a SCR system. These include lower capital costs and there are no liquid or solid wastes generated with a SNCR system.

The exhaust temperatures of the proposed process heaters are estimated to be 900° F or less. Therefore, SNCR was eliminated as BACT for use as a post-combustion control for NO_x emissions from the proposed process heaters.

Next and current generation ultra-low NO_x burners may incorporate a variety of techniques including staged fuel injection, internal flue gas recirculation, lean flame technology, steam injection, or a combination of techniques.

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

Several next generation ULNB have been developed over the past few years. Callidus has developed ULNB that use reduced oxygen concentrations in the flame which enables the flame to burn at a lower temperature without compromising burner efficient. Hamworthy has developed a series of advanced low-NO_x burners which operates in a low excess air environment incorporating air-staging techniques. The John Zink Company has developed several new ULNB which use staged fuel injection combined with internal furnace gas recirculation and lean flame technology or a lean premix primary flame with staged combustion.

Many current ULNB combine the benefits of flue gas recirculation and low-NO_x burner control technologies. The ULNB is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. By doing this, the average oxygen concentration is reduced in the flame without reducing the flame temperatures below that which is necessary for optimal combustion efficiency. Reducing oxygen concentrations in the flame impacts the amount of fuel NO_x generated. ULNB designs have a control efficiency of up to 85% and coupling them with SCR, the control efficiency can range from 85-97 percent.

Low-NO_x burner 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.

Staged fuel LNB's are well suited for process heaters and boilers burning process or natural gas which generate higher thermal NO_x. By increasing residence times, staged-air LNBs provide reducing conditions which has a greater impact on fuel NO_x than staged fuel burners.

Flue gas recirculation is another combustion control used to reduce NOx. FGR involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. Internal FGR, used primarily in ULNB, involves recirculation of the hot O_2-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner windbox.

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. There are significant technical differences between the proposed process heaters and those combustion sources where flue gas recirculation has been demonstrated in practice. Thus, FGR has been eliminated as BACT for NO_x reduction for the process heaters proposed by Holly.

In summary, based on the above discussion, SNCR, SCR, ULNB+SCR, LNB+SCR, ULNB+SNCR, LNB + SNCR, FGR, LNB + FGR, and EM_x™ were eliminated due to technical, economic, energy and environmental impacts.

5.1.4.5 Step 5 - Select BACT

SCR's do have significant environmental and energy impacts when compared to next or current generation ULNB and LNB. For the proposed process heaters, ULNB and LNB's and good combustion control will not cause any adverse energy, environmental, or economic impacts. The highest-ranked control option (ULNB + SCR) when considered in comparison to the use of ULNB and LNB's, will cause energy and economic impacts and will yield both beneficial and adverse environmental impacts.

Table 5-4 presents a summary of previous BACT determinations for NO_x for process heaters. This table is not exhaustive, rather lists the lowest emission rates identified in the past several years from select plants. As can be seen from Table 5-4, the use of LNB and ULNB is BACT for the industry with NO_x emission limits ranging from 0.03 to 0.05 lb/MMBtu.

Thus, for Holly's new process heaters with the exception of the reactor charge furnace (27H1) and the vacuum furnace heater (33H1), ULNB's will be utilized with a proposed emission rate of 0.04 lb/MMBtu based on a three-hour average. For the reactor charge furnace (27H1) and the vacuum furnace heater (33H1), LNB with SCR will be utilized with a proposed emission rate of 0.02 lb/MMBtu.

Table 5-4

Summary of BACT Determinations for NO_x for Process Heaters

Facility	Permit Date	Size (MMBtu/hr)	Primary Fuel	Limit (lb/MMBtu)	Technology
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	CPF Heater H-39-03 & H-39-02 (94-28 & 94-30)	Refinery gas	0.05 (3 - one-hr test avg.)	Low NO_x burners
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	Heaters/ reboilers	Refinery gas	0.04 (3 - one-hr test avg.)	Ultra low NO_x burners
Chevron Products Company, Pascagoula Refinery	4/14/2009	73.25, 73.95, 54.53	Refinery gas	0.03 (30-day rolling avg.)	Ultra low NO_x burners
Navajo Refining Company, Artesia Refinery	12/14/2007	9.6, 35	Refinery gas	0.03 (3-hour rolling avg.)	Ultra low NO_x burners
Arizona Clean Fuels Yuma LLC	04/14/2005	25, 23.2, 99.5	Refinery gas	0.04 (3-hour average)	Low NO_x burners

5.1.5 BACT for VOC

Emissions of volatile organic compounds (VOCs) results from the incomplete combustion of carbon and organic compounds and are a function of oxygen availability, temperature, residence time, and turbulence.

5.1.5.1 Step 1 - Identify All Available Control Technologies

Two control technologies were identified for controlling VOC emissions. These control technologies are good combustion practice and catalytic oxidation.

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.

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.

5.1.5.2 Step 2 - Eliminate Technically Infeasible Control Options

With the use of oxidation catalysts, emissions of acid gases increase as does the need for additional heat input and power. Sulfur and other compounds in the exhaust can lead to fouling of the catalyst, leading to decreased activity. Furthermore, a review of the RBLC and other state databases did not indicate that this technology has been used as a VOC control for process heaters. Therefore, the use of oxidation catalysts for control of VOC emissions from process heaters at the Holly refinery is not technically feasible.

Based on the review of the available literature, RBLC and state databases, good combustion practices were identified as BACT for reducing VOC emissions.

5.1.5.3 Steps 3 - 5

The only control strategy identified for the refinery fuel gas-fired process heaters is adherence to good combustion practices. This control strategy is technically feasible and will not cause adverse energy, environmental, or economic impacts.

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 5-5 presents a summary of previous BACT determinations for VOC for process heaters. This table is not exhaustive, rather lists the lowest emission rates identified in the past several years from select plants.

Table 5-5

Summary of BACT Determinations for VOC for Process Heaters

Facility	Permit Date	Size (MMBtu/hr)	Primary Fuel	Limit (lb/MMBtu)	Technology
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	Heaters/ reboilers	Refinery gas	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	Refinery gas	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	Refinery gas	0.015(3-hr average)	Proper design operation, and good engineering practices

The proposed BACT emission limit for the Holly process heaters is based on utilizing good combustion practices, proper equipment design, and gaseous fuels. The estimated VOC emission rate from these heaters is 0.0054 lb/MMBtu which represents BACT.

5.2 BACT for Power Boiler

Holly Refining is proposing the addition Boiler #11, an 89.3 MMBtu/hr refinery- or natural gas-fired boiler.

5.2.1 BACT for CO and VOC

EPA's top-down process was used to determine the best available control technology for control of CO and VOC emissions from the proposed boiler. As mentioned previously, CO and VOC's are products of the chemical reaction between carbonaceous fuels and oxygen. The primary factors influencing generation of CO and VOC are temperature and residence time in the combustion zone. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions.

5.2.1.1 Step 1 - Identify All Control Technologies

Two control options, good combustion practice and catalytic oxidation, were identified for the control of CO and VOC emissions from the proposed boiler.

The first control technology identified to reduce CO and VOC emissions is through good engineering design of the equipment utilizing good combustion practice. Good combustion practices for CO and VOC include adequate fuel residence times, proper fuel-air mixing, and temperature control. For the proposed boiler, there will be adequate turbulence in the flue gas which will ensure good mixing, a high temperature zone (greater than 1800°F) that will ensure complete burnout along with a sufficient residence time (one to two seconds) at high temperature which will lead to minimized CO and VOC emissions. Higher combustion zone temperatures favor the complete oxidation of carbon-containing compounds to CO_2 and water. Therefore, emissions of CO and VOC would be expected to decrease at higher temperatures.

Catalytic oxidation allows 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 (fps). Catalytic oxidizers typically operate at a narrow temperature range of approximately 600ºF to 1100ºF. At lower temperatures, the CO conversion efficiency decreases rapidly.

Catalytic oxidizers are similar to a SCR system in that a catalyst bed facilitates the conversion of a CO to CO_2. Unlike SCR, catalytic oxidizers do not use additional chemicals such as ammonia to facilitate the conversion.

5.2.1.2 Step 2 – Eliminate Technically Infeasible Options

Oxidation catalyst is not a technically feasible option for control of CO and VOC emissions from the proposed boiler. The Holly Refinery plant gas contains sulfur. In flue gas containing more than trace levels of SO_2, poisoning and deactivation of the catalyst by sulfur-containing compounds occurs as well. In addition, SO_2 would be converted to SO_3 which will form sulfuric acid increasing the emissions of this acid gas and will increase both condensable particulate emissions and flue gas system corrosion rates.

The EPA's RBLC and recent issued permits were reviewed and catalytic oxidation was not identified as a CO and VOC technically feasible control option for refinery-fuel gas-fired boilers.

5.2.1.3 Steps 3- 5

CO and VOC emissions can be controlled by using good combustion practice, including providing adequate fuel residence time, excess oxygen and high temperature combustion zone to ensure complete combustion. Thus, the only identified control technology, good combustion practice, is considered technically feasible for refinery or natural gas fired boilers. With the use of GCP, no adverse economic, energy, or collateral environmental impacts are identified that preclude the use of this control option.

Table 5-6 presents a summary of previous BACT determinations for power boilers that are similar sized to the proposed Holly boiler. This table is not exhaustive, rather lists the lowest emission rates identified in the past several years from select plants.

Table 5-6

Summary of BACT Determinations for CO for Power Boilers <100 MMBtu/hr

Facility	Permit Date	Boiler Name	Size MMbtu/hr	Primary Fuel	Limit lb/MMBtu	Technology
St. Charles Refinery Valero Refining	12/31/2010	EQT0323-Boiler 401F	99	Refinery Gas	8.15 lb/hr	Good combustion practices, proper equipment design and operation, use of gaseous fuels
Conoco Phillips Ponca City Refinery	2/09/2009	Leased boiler #1 and TB-1, TB-2, TB-3	95	Natural gas	0.04	Ultra low NOx burners and good combustion practices
Williams Refining and Marketing LLC.	4/3/2002	Boiler 9	95	Natural gas	0.09	None given in database

Holly Refining & Marketing will utilize good combustion practices to reduce CO emissions from the proposed boiler. Holly has obtained performance guarantee of 50 ppm or approximately 0.037 lb/MMBtu for CO and 10 ppm for VOC or approximately 0.004 lb/MMBtu. The use of good combustion practices and estimated emissions of 50 ppm for CO and 10 ppm for VOC represents BACT.

5.2.2 BACT for PM_{10} and $PM_{2.5}$

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

5.2.2.1 Step 1 - Identify All Available Control Technologies

The list of control technologies that were identified for controlling PM_{10} and $PM_{2.5}$ emissions from the power boiler are as follows:

- good combustion practice;
- wet gas scrubber;
- electrostatic precipitator (ESP);
- cyclone; and
- baghouse/fabric filters.

Like the process heaters, information obtained from vendors indicated that particulate emissions are in the PM_{10} range. Thus, the BACT analysis focused on PM_{10}.

5.2.2.2 Step 2 - Eliminate Technically Infeasible Control Options

None of the add-on control devices were identified as the proposed boiler burning gaseous fuels due to the extremely low concentration of small particulates expected in gas streams from this type of equipment. PM/PM_{10} concentrations in the refinery fuel and natural gas-fired boilers are even less than the concentrations guaranteed by the cyclones, ESP's, fabric filters, and wet gas scrubbers. Therefore, wet gas scrubbers, ESP's, cyclones, and fabric filtration (baghouses) were rejected as BACT for PM/PM_{10} emissions from the proposed boiler.

5.2.2.3 Steps 3 -5

The remaining control option is the utilization of good combustion practices. The proposed PM_{10} and $PM_{2.5}$ emission limit for the proposed Holly boiler is based on manufacturer specifications and 0.010 lb/MMBtu utilizing proper equipment design and operation, good combustion practices, and the use of gaseous fuels. This represents BACT for PM_{10} and $PM_{2.5}$.

Table 5-7 presents a summary of previous BACT determinations for PM_{10}. This table is not exhaustive, rather lists the lowest emission rates identified in the past four years from select plants.

Table 5-7

Summary of BACT Determinations for PM_{10} for Power Boilers <100 MMBtu/hr

Facility	Permit Date	Boiler Name	Size MMBtu/hr	Primary Fuel	Limit lb/MMBtu	Technology
St. Charles Refinery Valero Refining	12/31/2010	EQT0323-Boiler 401F	99	Refinery Gas	0.74 lb/hr	Good combustion practices, proper equipment design and operation, use of gaseous fuels
Williams Refining and Marketing LLC.	4/3/2002	Boiler 9	95	Natural gas	0.0075	None given in database

5.2.3 BACT for SO_2

The quantity of SO_2 emissions from the proposed boiler depends on the sulfur content of the fuels combusted. In general, refinery fuel has a higher sulfur content that natural gas supplied by a pipeline. When burned in a boiler, essentially all the sulfur in the fuel is oxidized to SO_2.

5.2.3.1 Step 1 - Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling SO_2 emissions:

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

5.2.3.2 Step 2 - Eliminate Technically Infeasible Control Options

All listed control options are technically feasible.

5.2.3.3 Step 3- Rank Remaining Control Options

The following lists the ranking of the control options:

1) AFGD – 95 – 99.5% reduction;
2) Wet FGD – 90 - 99% reduction;
3) Dry FGD – 90-95% reduction; and
4) Low sulfur fuels – base case.

5.2.3.4 Step 4 - Evaluate Remaining Control Options

A review of the recent literature, recent permits, and the RBLC database did not result in AFGD, wet FGD, or dry FGD as BACT for large boilers. These three options were eliminated from further consideration.

The only control strategy identified for the fuel gas-fired boiler is adherence to fuel specifications. This control strategy is technically feasible and will not cause adverse energy, environmental, or economic impacts.

5.2.3.5 Step 5 - Select BACT

Holly has a fuel gas sulfur content limit of 162 ppmv or less which is proposed as the BACT emission limit for the boiler. In addition to the fuel gas sulfur content limit, equipment design and work practice requirements will be implemented to minimize, to the greatest extent possible, emissions that would occur due to upsets.

5.2.4 BACT for NO_x

Oxides of nitrogen 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.

5.2.4.1 Step 1 - Identify All Available Control Technologies

There are a variety of options available for control of NO_x emissions from combustion sources. These include modifications that reduce NO_x formation, add-on control devices, or combinations of both. The same control technologies and techniques for NO_x emissions that were identified for the process heaters are applicable to the boiler. They include:

- low NO_x burners (LNB),
- ultra-low NO_x burners (ULNB)
- flue gas recirculation (FGR),
- selective non-catalytic reduction (SNCR),
- selective catalytic reduction (SCR),
- low NO_x burners and flue gas recirculation (LNB +FGR),
- ultra-low NO_x burners and flue gas recirculation (ULNB + FGR)
- low NO_x burners and selective non-catalytic reduction (LNB + SNCR),
- ultra-low NO_x burners and selective non-catalytic reduction (ULNB + SNCR),
- low NO_x burners and selective catalytic reduction (LNB + SCR),
- ultra-low NO_x burners and selective catalytic reduction (ULNB + SCR),

- EM_x™ (formerly $SCONO_x$),
- low NO_x burners and EM_x™,
- ultra-low NO_x burners and EM_x™, and
- good combustion practices.

5.2.4.2 Step 2 - Eliminate Technically Infeasible Control Options

All of the individual controls or combinations of controls were determined to be technically feasible.

5.2.4.3 Step 3 - Rank Remaining Control Options

The range of control efficiencies for the NO_x control devices is presented in Table 5-3 above.

5.2.4.4 Step 4 - Evaluate Remaining Control Options

With SCR, ammonia is injected as the flue gas passes through a catalyst bed (see Section 5.1.4.4 for a comprehensive discussion).

SNCR consists of injecting ammonia or urea into the combustion unit flue gases in a specific temperature zone between 1600ºF to 2100ºF. The exhaust temperature of the proposed boiler is estimated to be 900º F or less. This would require additional energy input and therefore, additional exhaust emissions to raise the temperature of the power boiler exhaust to the operating temperature of the SNCR. Therefore, SNCR was eliminated as BACT for use as a post-combustion control for NO_x emissions from the proposed boiler. SNCR+LNB and SNCR+ULNB were also eliminated.

Ultra-low NO_x and low NO_x are burner designs that reduce NO_x formation. The ULNB is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. By doing this, the average oxygen concentration is reduced in the flame without reducing the flame temperatures below that which is necessary for optimal combustion efficiency. Low-NO_x burner technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time.

Flue gas recirculation is another combustion control used to reduce NO_x. FGR involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame.

Internal FGR, used primarily in ULNB, involves recirculation of the hot O_2-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner windbox.

EM_x is an add-on technology that utilizes a catalyst to absorb the SO_2 in the flue gas. The catalyst is periodically regenerated using hydrogen. This technology has only been used on a small number of natural gas combustion turbines for NO_x control and not on power boilers. Thus, it was eliminated from further BACT consideration.

In summary, based on the above discussion, SNCR, ULNB+SNCR, LNB + SNCR, EM_x™, EM_{Xx}™ +LNB and EM_x™+ULNB were eliminated due to technical, economic, energy and environmental impacts.

ULNB, LNB, and ULNB or LNB with SCR are all viable options to control NO_x emissions.

With the use of an SCR, adverse energy impacts occur. The adverse energy impact is due to the electrical requirements of the SCR system operation and to the reduction in energy efficiency attributable to the pressure drop across the catalyst.

The adverse environmental impacts attributable to the use of an SCR system includes the use of ammonia reagent, the handling and disposal of a spend catalyst as a solid waste stream, and ammonia emissions. The ammonia needed for the SCR will be available from other on-site operations and will not be trucked to the facility. Industry experience with SCR systems indicates that the removal and disposal of the spent catalyst can be conducted safely with insignificant risk to the environment.

With the use of addition energy and the SCR system, additional costs are incurred. The average cost effectiveness of this control option was justified by the air quality benefit gained through the use of an SCR system. Thus, although the use of an SCR has adverse energy, environmental and economic impacts, the beneficial environmental impacts outweigh the adverse impacts.

5.2.4.5 Step 5 - Select BACT

Table 5-8 presents a summary of previous BACT determinations for NO_x for similar sized boilers as proposed by Holly for refineries. This table is not exhaustive, rather lists the lowest emission rates identified in the past four years from select plants.

Table 5-8

Summary of BACT Determinations for NO_x for Power Boilers <100 MMBtu/hr

Facility	Permit Date	Boiler Name	Size MMBtu/hr	Primary Fuel	Limit lb/MMBtu	Technology
Valero Energy Corp. Valero Delaware City Refinery	02/26/2010	Four package boilers	99.9	Refinery Gas	0.015	SCR and LNB
St. Charles Refinery Valero Refining	12/31/2010	EQT032 3-Boiler 401F	99	Refinery Gas	0.040	Ultra low NO_x burners and good combustion practices
Conoco Phillips Ponca City Refinery	2/09/2009	Leased boiler #1 and TB-1, TB-2, TB-3	95	Natural gas	0.036	Ultra low NO_x burners
Williams Refining and Marketing LLC.	4/3/2002	Boiler 9	95	Natural gas	0.084	None given in database

Hence, with the combination of LNB and a SCR with combustion control for controlling NO_x emissions, this option is the highest ranking control option and has been chosen for the proposed boiler #11 at Holly and is considered BACT. The proposed NO_x emission rate is 0.02 lb/MMBtu based on a three-hour average.

5.3 BACT for Cooling Tower

The cooling system proposed for the Holly Refining heavy crude processing project consists of the addition of cooling tower #10 and the addition of a cell to existing cooling tower #11.

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. $PM_{10}/PM_{2.5}$ and VOC emissions are expected from the cooling towers.

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.

VOC emissions are due 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.

5.3.1 BACT for $PM_{10}/PM_{2.5}$

Particulate matter is emitted from the cooling towers due to the presence of dissolved and suspended solids in the water droplets from the drift from the cooling tower.

5.3.1.1 Step 1- Identify All Available Control Technologies

Four control technologies were identified to limit $PM_{10}/PM_{2.5}$ 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.

5.3.1.2 Step 2 - Eliminate Technically Infeasible Control 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.

5.3.1.3 Step 3 - Rank Remaining Control Options

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.

5.3.1.4 Step 4 - Evaluate Remaining Control Options

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%.

The only identified, technically feasible control option is the use of high-efficiency drift eliminators in conjunction with the proposed wet cooling tower and additional cell. In using the drift eliminators, no significant energy, environmental, or economic impacts are expected.

5.3.1.5 Step 5 - Select BACT

The cooling towers will be equipped with drift eliminators with a vendor-guaranteed maximum total liquid drift of 0.0005 percent of the circulating water flow rate. This is equivalent to the most stringent identified equipment specification for wet cooling tower and represents BACT.

5.3.2 BACT for VOC

Emissions of VOC can also occur due to evaporation of volatile organic compounds that may be present in the cooling water due to leaks from heat exchangers.

5.3.2.1 Step 1- Identify All Available Control Technologies

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

5.3.2.2 Step 2 - Eliminate Technically Infeasible Control Options

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

5.3.2.3 Steps 3 - 5

The only identified, technically feasible control option is to implement a heat exchanger leak detection and repair program for the proposed wet and expanded 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.

Therefore, to satisfy BACT, Holly will install and maintain an in-line hydrocarbon monitor in the return water steam entering the cooling tower to detect unusual levels of hydrocarbons. This determination is expressed as a work practice requirement rather than an emission limitation.

5.4 BACT for Fluid Catalytic Cracking Unit

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

Emissions from the burning of coke off the catalyst in the FCCU regenerator vessel are released out the regenerator stack. The emissions include: NO_x, CO, PM, and SO_2.

5.4.1 BACT for CO

CO will be present in the FCCU regenerator flue gas. The FCCU will be run in "full burn" operation. In full burn, the FCCU regenerator, when properly designed and operated, will convert nearly all of the coke to CO_2, thereby limiting CO emissions.

5.4.1.1 Step 1 – Identify All Available Control Technologies

Three control technologies were identified as potentially able to control CO emissions from a full burn FCCU regenerator. These technologies are: catalytic oxidation, CO combustion promoters, and good combustion practices.

5.4.1.2 Step 2 - Eliminate Technically Infeasible Control Options

Catalytic oxidizers, a post-emission control technology, are designed so that the waste gases pass through a flame area and then through a catalyst bed where CO is oxidized to CO_2 at temperatures of 650 to 1100°F. The regenerator flue gas will exit the wet gas scrubber at approximately 150°F. The process of reheating the flue gas would result in increased CO. In addition, catalytic oxidation cannot be used on waste gas streams that contain particulate due to the potential for fouling the catalyst which prohibits oxidation. Thus, catalytic oxidizers are technically infeasible and are eliminated from further consideration.

CO combustion promoters and good combustion practices are technically feasible and will be considered further.

5.4.1.3 Steps 3 - 5

One remaining CO control technology is CO 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 CO burning, reduce emissions of CO 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 Corporations OxyClean™, Intercat, and Grace Davison's XNO_x all of which are effective in reducing CO emissions while controlling NO_x emissions.

A second control technology for reducing CO emissions is good combustion practices. Full burn regenerators operate with excess oxygen in the flue gas, typically 1-3 volume percent on a dry basis. The minimum excess oxygen required to promote complete CO oxidation is a function of bed temperature, gas residence time in the bed, and how efficiently the regenerator design utilizes the available oxygen. If the full burn unit is properly designed and operated, with sufficient oxygen present, the oxidation of CO to CO_2 should be complete. Therefore, good combustion design and operation will effectively control CO emissions present in the FCCU regenerator exhaust gas.

Good combustion practices and a CO promoter will be used by Holly to minimize CO emissions from the new FCCU. Using these control options, there are no anticipated additional environmental or energy impacts associated with this unit. Thus, the FCCU in full burn, the use of CO promoters and good combustion practices are considered BACT for CO. CO emissions will be limited to 500 ppmvd based on a one-hour average at 0% O_2.

5.4.2 BACT for PM_{10} and $PM_{2.5}$

The main source of PM_{10} and $PM_{2.5}$ is catalyst fines and products of incomplete combustion that are released in the regenerator exhaust stack.

5.4.2.1 Step 1 - Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling PM_{10} and $PM_{2.5}$ emissions from the FCCU regenerator stack:

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

Descriptions of the ESP and the wet gas scrubber are presented in Section 5.1.2.1. 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.

5.4.2.2 Step 2 - Eliminate Technically Infeasible Control Options.

Each of the technologies is technically feasible.

5.4.2.3 Step 3 - Rank Remaining Control Options

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.

5.4.2.4 Step 4 - Evaluate Remaining Control Options

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 EPS 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.

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 0.5lb/1000lb coke burned.

5.4.2.5 Step 5 - Select BACT

According to the RBLC, wet scrubbers are used extensively as one method to reduce particulate from FCCUs and a wet gas scrubber is proposed by Holly to reduce PM emissions from the new FCCU. Thus, a wet gas scrubber is considered BACT for reduction of particulate from the FCCU regenerator stack. The emissions of PM_{10} and $PM_{2.5}$ will be well controlled below the 0.5 lbs/1000 lbs of coke burn-off limit.

5.4.3 BACT for SO_2

Depending on the feed sulfur content and FCCU design, sulfur emissions in the form of SO_2 and SO_3 from the regenerator can vary significantly. Black wax crude is inherently low in sulfur. 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 H_2S. 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.

5.4.3.1 Step 1 - Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling SO_2 emissions from the FCCU:

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

As mentioned previously, black and yellow wax crudes are inherently low in sulfur.

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 SO_2 can be reduced by up to 90 percent with the additional benefit of reductions in nitrogen compound and trace metal emissions.

Wet gas scrubbers are principally defined in Section 5.1.2.1. The water used in a wet gas scrubber is mixed with an alkaline reagent to react with the SO_2 to form sulfate and sulfite salts. These compounds are captured as a wet solid in the filtering section of the wet gas scrubber. The SO_2 removal efficiencies typically range from 95 to 99.9%.

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 SO_2 removal efficiency using this process is between 85 to 98%.

$DeSO_x$ additives are typically metal oxide catalysts that are added to the regenerator to convert SO_2 to SO_3. The metal oxide catalyst is introduced to the feed in the riser with the regenerated catalyst. The SO_3 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 H_2S which is controlled by a refineries sulfur plant.

5.4.3.2 Step 2 - Eliminate Technically Infeasible Control Options

All options are technically feasible with the exception of feedstock hydrotreatment.

The feedstock hydrotreatment requires a large number of process units to take the sulfur out of the feed to the FCCU. This equipment includes a hydrogen plant, a high pressure hydrotreater, approximately three additional heaters, a fractionation tower, and a gas plant. This sulfur removal technique is larger than the FCCU process itself. The three additional process heaters would operate full time and each heater would have additional emissions. In addition, there are additional environmental concerns with catalyst removal and disposal from the hydrotreater.

The catalyst beds in the hydrotreater are layers of catalyst inside high pressure vessels. The feedstock flows through these beds where the reactions take place. The Black Wax crude has a heavy residual bottoms fraction. This fraction is too heavy for the catalyst beds to efficiently crack into lighter fractions. It would plug up the catalyst beds in the hydrotreater. This issue makes it technically infeasible to hydrotreat the Black Wax feedstock to the FCCU without removing the bottoms fraction first. Thus, this option has been determined to be technically infeasible.

5.4.3.3 Step 3 - Rank Remaining Control Options

The following lists the ranking of the remaining control options:

- Wet Gas Scrubbers - 95-99.9%
- Wellman-Lord Flue Gas Desulfurization Process - 85-98%
- $DeSO_x$ additives – 30%

5.4.3.4 Step 4 - Evaluate Remaining Control Options

According to EPA's RBLC, wet scrubbers have been successfully applied to several refinery FCCUs to control emissions of SO_2 and PM. Recent consent decrees will require several refineries to install wet gas scrubbers to reduce SO_2 emissions. Several designs of wet scrubbers are available (plate or tray towers, spray chambers, and venturi) and emission control levels for SO_2 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 SO_2 in the regenerator to SO_3 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 H_2S 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 extremely low and the amount of SO_2 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.

5.4.3.5 Step 5 - Select BACT

The top control option, a wet gas scrubber with a control efficiency of up to 99% will be utilized by Holly Refining to reduce SO_2 emissions from the proposed FCCU. The use of a wet gas scrubber represents BACT. SO_2 emissions from the wet gas scrubber are estimated to be 25 ppmvd at 0% O_2 based on a 365-day average.

5.4.4 BACT for NO_x

The FCCU regenerator is proposed as a full-burn unit 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 NO_2 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.

5.4.4.1 Step 1 - Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling NO_X emissions from a FCCU:

- Selective Non-Catalytic Reduction (SNCR);
- Selective Catalytic Reduction (SCR);
- LoTOx; and
- Catalyst additives and low NO_x combustion promoters.

5.4.4.2 Step 2 - Eliminate Technically Infeasible Control Options

All the options are technically feasible.

5.4.4.3 Step 3 - Rank Remaining Control Options

The remaining control options were ranked in order of reduction:

- Selective Non Catalytic Reduction (SNCR) – 60 to 80% reduction
- Selective Catalytic Reduction (SCR) - > 90% reduction
- LoTox - >90% reduction with SCR
- Catalyst additives and low NO_x combustion promoters – 45-95% reduction.

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 N_2 and H_2O. The typical operating temperature range for an SNCR is 1,600ºF to 2,000ºF. 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 NH_3 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 1,400ºF. In full burn units, such is proposed by Holly, the flue gas must be heated to 1,600 to 1,800ºF to achieve NO_x removal rates of 50% and greater.

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 600ºF to 750ºF 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.

The Belco $LoTO_x$™ 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 $LoTO_x$™ technology does not use a fixed catalyst bed, it can handle unit upsets without impacting overall reliability and mechanical availability.

The $LoTO_x$™ 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%.

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%. Engelhards 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 easily 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.

5.4.4.4 Step 4 – Evaluate Remaining Control Options

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 conditions.[10] A drawback of using SNCR technology is the potential formation of ammonium sulfate salts and resultant fouling. These salts will exist as small particulates.

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

SCRs operate in the temperature range of the regenerator flue gas coming out of the FCC. 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. Holly is not proposing either a third stage separator or ESP as part of the heavy crude processing project.

$LoTO_x$™ 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.

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

5.4.4.5 Step 5 – Select BACT

A review of the literature and the EPA's RBLC indicate that SCRs, and $LoTO_x$™ in conjunction with wet scrubbing systems are used for the reduction of NO_x in a number of FCCUs. However, Holly is concerned about potential SCR problems such as fouling, plugging, poisoning and/or thermal degradation of the catalyst which could result in potential downtime for the SCR and possible the process. Addition concerns with the use of a SCR include conversion of SO_2 to SO_3 and formation of ammonium sulfate/sulfite particles that could deposit in the catalyst or ductwork.

Thus, Holly Refining has chosen a LoTOx™ system in conjunction with a wet gas scrubber to reduce NO_x emissions in the regenerator flue gas. This is considered to represent BACT. NO_x emissions from the FCCU regenerator will not exceed 110 ppm per 365-day rolling average and 180 ppm per 7-day rolling average. BELCO, a subsidiary of DuPont, has provided a list of locations where the LoTOx ™ technology has been installed or is projected to be installed in FCCU regenerator applications. Table 5-9 presents a list of a few of these facilities.

Table 5-9

LoTOx™ NO_x Reduction Technology Installations

Application	Location	Capacity	Start-up
Refinery FCCU (New EDV scrubber with LoTOx technology)	Valero, Houston,	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,	130,000 bpsd	June 2007
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	7,000 m^3/day	2009
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 (New EDV Scrubber with LoTOx technology	Holly Refining, Woods Cross, NJ	Confidential	2013
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

5.5 BACT for Storage Tanks

Due to the processing of heavy crude at the refinery, several new tanks will be added or existing tanks modified to store the black and yellow wax crude or resultant products. Fugitive VOC emissions result from vapor expansion and contraction due to diurnal temperature and pressure variations, vapor losses at roof tank seals, and vapor losses due to filling and emptying tanks. The amount of VOC loss is dependent on the tanks roof design and vapor pressure of the stored liquid.

Internal floating roof (IFR) tanks are used to store high vapor pressure volatile organic liquid products at a refiner. Internal floating roof tanks use a fixed cone roof covering over the top of the tank along with an internal floating roof having at least a single seal system between the tank wall and floating roof cover.

5.5.1 BACT for VOC

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 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.

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.

5.5.1.1 Step 1 - Identify All Available Control Technologies

The available control technologies for tanks storing organic liquids include control equipment designed to minimize leakage from tanks, air pollution control equipment, less polluting processes, and combinations of each. The nominal requirements relating to control of VOC emissions from storage tanks are outlined in the above mentioned regulations. The control options that were identified include:

1) Operating the tank under pressure such that it operates with no emissions;
2) Routing the vapors to a process or a fuel gas system via piping such that the tank has no emissions;
3) Fixed roof in combination with an internal roof and with a vapor collection system in a closed vent system routed to a control device;
4) Fixed roof in combination with an internal floating roof;
5) An external floating roof; and
6) A fixed roof with vapor collection by a closed vent system routed to a control device.

5.5.1.2 Step 2 - Eliminate Technically Infeasible Control Options

The two most effective control options, operating the tank with no emissions by operating the tank under pressure or by routing the sweep gases to a process or fuel gas system, are only feasible for tanks storing certain petroleum products. Butane and propane are materials that are stored in tanks under pressure and for the proposed changes, no new pressurized tanks are proposed. Thus, this option is eliminated from further discussion and is technically infeasible.

The second option, routing the vapors to a process or a fuel gas system via piping such that the tank has no emissions, is feasible for tanks storing petroleum products that are compatible with the process or fuel gas system into which the gases would be routed. For the proposed heavy crude processing project, none of the proposed tanks fall under this option. Thus, this option is eliminated from further discussion and is technically infeasible. The remaining options are technically feasible.

5.5.1.3 Step 3 - Rank Remaining Control Options

The control options for the storage tanks are listed in decreasing order of control effectiveness.

The 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 which eliminates working losses. 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 tank are carried with the sweep gas to add on control device such as a thermal oxidizer or carbon adsorption unit.

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

The third option used to control VOC emissions from storage tanks includes the use of an external floating roof with dual rim seals. This type of tank is similar to the internal floating roof configuration without the enclosed headspace. The floating roof and seals act to reduce VOC losses. This control option has overall effectiveness equivalent to a tank which is equipped with an internal floating roof and dual rim seals. The external floating roof design is commonly accepted control technology for tanks storing liquids with relatively low volatility.

The fourth option includes a fixed roof with vapor collection by a closed vent system routed to a control device. This design omits any control equipment such as a floating roof and relies on an end-of-pipe air pollution control device. Holly is not proposing any tanks with this configuration as part of the heavy crude processing project.

5.5.1.4 Step 4 - Evaluate Remaining Control Options

Vapor losses from fixed roof vertical tanks are primarily due to changes in the atmospheric temperature and pressure as well as liquid level changes inside the tank. Due to the low volatility of the products to be stored, black wax and gas oil, Holly is proposing fixed roof tanks with no vapor recovery.

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. The total annualized costs of installing a vapor control system by incineration is approximately $425,000 (based on EPA estimates adjusted to 2011 dollars). If carbon adsorption were used for vapor control, the projected annualized costs would be approximately $595,000. The volume of VOC vapors, expected to be approximately 6,242 pounds for the proposed tanks is insufficient to justify the installation of a vapor recovery system.

Because of the low volatility off the products being stored, the installation of internal floating roofs and seals or an external floating roof is also not warranted. The capitol cost to install internal floating roof and controlled deck fittings is approximately $30,000 per tank. For an external floating roof, the estimated capitol cost would be over $210,000.

In addition, if a vapor recovery system were utilized, energy usage will increase. If an incineration device is used, increased emissions would be expected from flaring. If activated carbon were used, a solid waste could also be generated.

5.5.1.5 Step 5 - Select BACT

Holly is proposing fixed roof tanks as a means of controlling VOC emissions for Tanks 89-97, 99, and 139 and 140. Tank turnovers will be minimized as much as reasonable. Tank 98 will be equipped with an internal floating roof with primary and secondary seals. The maximum true vapor pressure of the liquids stored in 1.5 psia. Tank emissions were estimated to be 3.1 TPY. Tanks 158 and 168 will store wastewater and sour water, respectively. These tanks will be equipped with an external floating roof which is BACT for tanks storing liquids with relatively low volatility.

5.6 BACT for Product Loading Racks

With the proposed heavy crude processing project, one existing LPG rail loading spot on the west track will be converted to load propane and one additional rail spot for loading propane will be constructed on the west track. The crude truck unloading facilities will be expanded to accommodate six (6) more truck bays.

5.6.1 BACT for VOC

The product loading racks will be a source of VOC emissions.

5.6.1.1 Step 1 - Identify All Available Control Technologies

Three control technologies were identified to reduce VOC emissions from product loading racks. These technologies include: carbon adsorption, condensation, and incineration.

5.6.1.2 Step 2 - Eliminate Technically Infeasible Control Options

Due to the makeup of the black wax crude, these options are not technically feasible. Black wax crude becomes a solid with insignificant VOC emissions at ambient temperatures.

5.6.1.3 Steps 3 – 5

The new truck unloading bays for the black wax crude will utilize a sump that can be pumped out. The sump will be heated and appropriately sized to accommodate a spill. Transfer piping from the new unloading bays to Tank 126 will be installed. A small electric-driven compressor will be added to control loading emissions by recovering displaced relief gas from loading propane into rail cars.

5.7 BACT for Emergency Generator

The emergency diesel generator will be operated only during interruptions in normal electrical power supply or for maintenance, testing, and operator training. The emergency generator will be limited to 50 hours of operation per year for maintenance and testing.

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 primary pollutants in the exhaust gases include NO_x, CO, VOC, and particulate matter.

5.7.1 BACT for NO_x

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.

5.7.1.1 Step 1 - Identify All Available Control Technologies

The following control options were evaluated for controlling NO_x emissions from the emergency generator. 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.

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.

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.

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

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 (200ºC to 500ºC) 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.

A non-selective catalytic reduction system (NSCR) is used to reduce emissions 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.

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.

5.7.1.2 Step 2 - Eliminate Technically Infeasible Control Options

Combustion modifications and SCR have been demonstrated and are technically feasible technologies that will be further considered for BACT. 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 engine is inherently a lean-burn engine; 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 RBLC RACT/BACT/LAER Clearinghouse databases as being employed on stationary emergency generators. 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[11].

5.7.1.3 Step 3- Rank Remaining Control Options

The remaining control options, combustion modification 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%.

5.7.1.4 Step 4 - Evaluate Remaining Control Options

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 N_2. 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.

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11 http://www.poweronsite.org/AppGuide/Chapters/Chap4/4-1_Recip_Engines.htm

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. In addition, cost evaluations were performed to determine the cost of control per ton of NO_x removed from an SCR for the emergency generator. Per EPA's cost effectiveness evaluation[12], cost per ton of NO_x removed is $396,886 for the emergency generator.

Thus, based on the economic impact prepared by EPA, the post-combustion NO_x control utilizing SCR is not cost effective for the emergency generator and has been eliminated from further consideration.

Thus, the only control technology for the emergency generator is a work practice requirement to adhere to GCP. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

5.7.1.5 Step 5 - Select BACT

Holly is proposing a generator that incorporates in its design injection timing retard, turbocharging and aftercooling. The generator will be operated and maintained in accordance with GCP. The hours of operation will be restricted to 50 hours per year for maintenance and testing. The combustion controls, ultra-low sulfur diesel fuel and limited annual hours of operation as BACT for the emergency diesel generator. The emergency generator will be Tier III compliant. The use of good combustion controls including ignition timing retard, air-to-fuel ratio, and derating will be based on manufacturer recommendations.

12 Memorandum from Tanya Parise, Alpha-Gamma Technologies to Sims Roy, EPA OAQPS ESD Combustion Group, June 9, 2005.

5.7.2 BACT for CO and VOC

Carbon monoxide and 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.

5.7.2.1 Step 1 - Identify All Available Control Technologies

The following control options were evaluated for controlling CO and VOC emissions from the CI combustion engines. They include: good combustion practices and the post-combustion control technologies of diesel oxidation catalysts and non-selective catalytic reduction (NSCR) catalysts.

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The proposed emergency generator engine is designed to achieve maximum combustion efficiency. The manufacturers will provide operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

A diesel oxidation catalyst 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 CO_2 and water. Diesel oxidation catalysts are commercially available and reliable for controlling CO and HC emissions from diesel engines.

NSCR technology uses three-way catalysts to promote the reduction of NO_x to nitrogen and water. CO and hydrocarbons are simultaneously oxidized to carbon dioxide and water. NSCR is applicable only to rich burn engines. NSCR catalytic reactions require that O_2 levels be kept low and that the engine be operated at fuel-rich air-to fuel-ratios. The proposed emergency generator is a lean-burn engine which is characterized by an oxygen-rich exhaust which minimizes the potential for CO reduction.

5.7.2.2 Step 2 - Eliminate Technically Infeasible Control Options

Good combustion practices and diesel oxidation catalysts have been demonstrated and are technically feasible technologies that will be further considered for BACT. NSCR catalysts are effective to reduce CO and VOC emissions when applied to rich-burn engine that are fired on natural gas, propane or gasoline. The proposed diesel engines are inherently lean-burn engines; thus, NSCR is eliminated from further consideration.

5.7.2.3 Step 3- Rank Remaining Control Options

The remaining control options, good combustion practices and the post-combustion control using a diesel oxidation catalyst will be examined further. Combustion controls have been demonstrated to reduce CO emissions from CI engines by approximately 50%; the use of a diesel oxidation catalyst can reduce CO emissions in the range of 60 to 85% and 35 to 50% for VOC emissions.

5.7.2.4 Step 4 - Evaluate Remaining Control Options

Diesel oxidation catalysts can significantly reduce CO and VOC emissions. However, due to the limited hours of proposed operation for the emergency generator, this add-on control is not practical. The cost effectiveness of installing and operating standard diesel oxidation catalysts on each of the proposed engines was evaluated.

The cost effectiveness of a standard diesel oxidation catalyst on the emergency generator was estimated to be in excess of the $500,000 per ton for both CO and VOC removed[13]. Thus, based on the economic impact, the post-combustion CO and VOC control utilizing diesel oxidation catalysts is not cost effective for the emergency generator and has been eliminated from further consideration.

5.7.2.5 Step 5 - Select BACT

Holly is proposing combustion controls, ultra-low sulfur diesel fuel and limited annual hours of operation as BACT for the emergency diesel generator. The emergency generator will be Tier III compliant and will meet a CO emission standard of 3.5 g/kW-hr. The emergency generator hours of operation will be restricted to 50 hours per year for maintenance and testing. The use of good combustion controls will be based on manufacturer recommendations.

5.7.3 BACT for $PM_{10}/PM_{2.5}$

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.

5.7.3.1 Step 1 - Identify All Available Control Technologies

The following control options were evaluated for controlling $PM_{10}/PM_{2.5}$ emissions from the CI combustion engines. They include: GCP, use of low sulfur fuels, diesel particulate filters, and diesel oxidation catalysts.

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion.

The proposed emergency generator engine is designed to achieve maximum combustion efficiency. The manufacturers will provide operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

Limiting the sulfur content of diesel fuel is a pollution prevention method to reduce the sulfate fraction (25-25%) of diesel particulate matter. The literature suggests that the use of low sulfur fuels, such as ultra-low sulfur diesel, can reduce particulate emissions by 10-20%.

Diesel particulate filters are add-on devices that filter out particulate matter. Diesel particulate filters are add-on devices that include both passive and active diesel particulate filters, depending on the method used to clean the filters. Some filters are single-use, while others are designed to burn off the accumulated particulate, either through the use of a catalyst (passive), or through an active technology, such as a fuel burner which heats the filter to soot combustion temperatures, through engine modifications. The use of diesel particulate filters has been demonstrated to reduce particulate emissions by up to 85%.

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 up to 30% from diesel engines.

5.7.3.2 Step 2 - Eliminate Technically Infeasible Control Options

All proposed control options are technically feasible and will be reviewed further.

5.7.3.3 Step 3- Rank Remaining Control Options

The proposed control options are ranked in descending order based on control efficiency:

- Diesel particulate filters – 85%
- Diesel oxidation catalysts – 30%
- Low sulfur fuels – 10-20%

- Good combustion practices - baseline

5.7.3.4 Step 4 - Evaluate Remaining Control Options

The top ranked control options, diesel particulate filters and diesel oxidation catalysts can significantly reduce $PM_{10}/PM_{2.5}$ emissions. However, due to the limited hours of proposed operation for the emergency generator, these add-on controls are not practical. Per EPA's cost effectiveness evaluation, the cost per ton of PM removed from an emergency generator with a catalyzed diesel particulate filter was $348,278. EPA also determined the cost effectiveness utilizing an oxidation catalyst to reduce particulate matter emissions. Per EPA's cost effectiveness evaluation, the cost per ton of PM removed from an emergency generator was $163,458[12]. Thus, based on the economic impact prepared by EPA, the post-combustion add-on devices are not cost effective for the emergency generator and have been eliminated from further consideration.

5.7.3.5 Step 5 - Select BACT

Holly is proposing good combustion practices, ultra-low sulfur diesel fuel, and limited annual hours of operation as BACT for the emergency diesel generator. The emergency generator will be Tier III compliant and will meet a PM emission standard of 0.2 g/kW-hr. The emergency generator hours of operation will be restricted to 50 hours per year for maintenance and testing.

The use of good combustion practices will be based on manufacturer recommendations; ultra-low sulfur diesel fuel (15 ppm sulfur) will also be utilized.

5.7.4 BACT for SO_2

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.

5.7.4.1 Step 1 - Identify All Available Control Technologies

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

5.7.4.2 Step 2 - Eliminate Technically Infeasible Control Options

All proposed control option is technically feasible and will be reviewed further.

5.7.4.3 Steps 3 – 5

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 proposed emergency generator. There is no adverse energy, environmental or cost impact associated with the use of these control technologies. Thus, no further analysis is required under EPA's top-down BACT approach.

5.8 BACT for Leaks

With the proposed changes at the refinery, piping, valves, connectors, pumps, compressors and other components will be installed for the movement of gas and liquid raw materials, etc. Leakage from this equipment is a potential source of fugitive VOC emissions.

5.8.1 BACT for VOC

Several leak control programs were reviewed for this analysis. Emissions from leaking equipment are reduced through a combination of repair and equipment modifications and leak detection.

5.8.1.1 Step 1 - Identify All Available Control Technologies

Common strategies for VOC emissions from equipment leaks are based on work practices known as leak detection and repair (LDAR) programs. The requirements for the LDAQ program for the Holly heavy crude processing project is set forth in 40 CFR Part 60 Subpart GGGa. These requirements apply to each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

5.8.1.2 Step 2 - Eliminate Technically Infeasible Control Options

The identified control strategy for leak control (the regulation in this case) is technically feasible.

5.8.1.3 Steps 3 – 5

For VOC emissions, compliance with the leak control program will be equivalent to the requirements of 40 CFR Part 60 Subpart GGGa. Each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other VOC connector in VOC service will be subject to the requirements which include lower leak definitions for pumps (2000 ppm) and valves (500 ppm). Holly will incorporate these leak control requirements into their existing LDAR.

5.9 BACT for Flare

The flare system at Holly provides for the safe disposal of hydrocarbon gases which are vented automatically from process units through pressure relief valves, control valves or are manually vented. As part of the heavy crude processing project, the south flare at Holly will be reconstructed.

5.9.1 BACT for NO_x, SO_2, CO, and VOC

EPA's top-down process was used to determine the best available control technology for control of flare emissions. Emissions from flaring include carbon particles (soot), unburned hydrocarbons, NO_x, SO_2, CO, and VOC.

5.9.1.1 Step 1 - Identify All Available Control Technologies

Flares operate primarily as air pollution control devices. The only technically feasible control options for emissions of all pollutants from flares are: (1) equipment design specifications and good combustion work practices such as minimization of exit velocity, ensuring adequate heat value of combusted gases, and minimizing the quantity of gases combusted; and (2) flare gas recovery systems.

5.9.1.2 Step 2 - Eliminate Technically Infeasible Control Options

Both control options are technically feasible.

5.9.1.3 Step 3- Rank Remaining Control Options

Where feasible, a flare gas recovery system is the most effective control method. Good combustion practices and design specifications are also effective methods for controlling emissions from a flare.

5.9.1.4 Step 4 - Evaluate Remaining Control Options

A flare gas recovery system typically is installed upstream of the flare. 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 the vapors are sent 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 are combusted in other devices that operate using fuel gas.

Normally, the flare gas recovery system recovers all of the vent gas. There are conditions where the flare gas recovery system may not be sufficient to prevent flaring are process unit startup and shutdown events where large volume of process gases will be sent to the flare. Holly makes every effort to eliminate flaring from startups and shutdowns.

For the top control technology, the use of a flare gas recovery system would involve economic and energy impacts. Cost analyses were prepared for NO_x, CO and VOC to determine the economic feasibility of adding a flare gas recovery system. SO_2 emissions are estimated to less 0.1 ton per year; hence, no cost analysis was performed for this pollutant. These analyses are presented in Appendix E. In summary, based on these cost analyses, the cost effectiveness ($ per ton pollutant reduction) was over $365,000 for NO_x, $67,000 for CO, and $390,000 for VOC.

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 flare is located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja.

5.9.1.5 Step 5 - Select BACT

Thus, BACT for the Holly proposed flare is proper equipment design and good combustion practices that meet the requirements of the NSPS and recommended industry practices.

5.10 BACT for Process Heaters for Greenhouse Gases

Potential GHG emissions from the stationary combustion sources such as process heaters and furnaces include primarily carbon dioxide (CO_2) with lesser amounts of nitrous oxide (N_2O) and methane (CH_4). The majority of the total GHG emissions, expressed at CO_2e are CO_2 emissions. CO_2 is a product of combustion of fuel containing carbon, such as refinery fuel gas and natural gas. Refinery fuel gas is a mixture of light C1 to C4 hydrocarbons, hydrogen, hydrogen sulfide (H_2S), and other gases.

5.10.1 Step 1 - Identify All Available Control Technologies

Several control technologies were identified for reducing GHG emissions from stationary combustion sources which include energy efficiency programs and systems, good combustion controls, low-carbon fuel, energy efficient design, and carbon capture and subsequent sequestration.

5.10.1.1 Good Combustion Practices

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

Combustion control is an effective means for reducing CH_4 emissions. Combustion efficiency is related to time, temperature, and turbulence and these three items are designed into the process heater so that fuel efficiency is maximized and operating costs are reduced. Thus, combustion control is accomplished through process heater burner design and operation.

Changes in excess air affect the availability of oxygen and combustion efficiency. Extremely high and low levels of excess air will result in high CH_4 levels. Higher CH_4 levels can also affect NO_x formation. If too much excess air is introduced, combustion temperatures will decrease and the efficiency of the process heater will be negatively affected. Low excess air also lowers combustion temperatures which do not allow for sufficient oxygen an efficient combustion.

5.10.1.2 Low-Carbon Fuel

Gaseous fuels such as refinery fuel gas and natural gas reduces the CO_2 emissions during the combustion process relative to burning other solid fuels such as coal or distillate oils. Holly is proposing the use of refinery fuel gas or natural gas in the process heaters.

5.10.1.3 Energy Efficient Design

A highly efficient energy design requires less fuel for the process heaters. Elements of a highly energy-efficient design include combustion air controls by limiting excess air and combustion air preheat. Excessive amounts of combustion air in process heaters reduced the efficiency of process heat burners. This can be eliminated by installing instrumentation for monitoring and control the excess air levels in the combustion process. Air preheat is a method of recovering heat from the hot exhaust gas of a combustion process by heat exchange with the combustion air before it enters the combustion chamber. Preheating the combustion air reduces the amount of fuel required and ultimately lowers GHG emissions since less fuel is being combusted.

5.10.1.4 Carbon Capture and Subsequent Sequestration

The purpose of CO_2 capture is to produce a concentrated stream that can be readily transported to a CO_2 storage site.

CO_2 emissions can be captured through oxy-combustion and post-combustion methods. In oxy-combustion carbon capture, nearly pure oxygen is used for combustion instead of air which results in an exhaust gas that is comprised of mainly H_2O and concentrated CO_2.

The process used an air separation unit to remove the nitrogen component from the air. The oxygen-rich stream is fed to the combustion unit so the resulting exhaust gas contains a concentration of CO_2 of 80% or higher. This technology is still in the research stage (EPA).

Post-combustion capture systems using solvent scrubbing and high temperature sorbents, ionic liquids, biological capture using algae ponds, and membrane technology were also identified as possible CO_2 control technologies. Post combustion capture is an "end of pipe" technology which involves separating CO_2 from flue gas consisting mainly of nitrogen, water, CO_2 and other impurities.

If a carbon capture technology could be utilized, after capture, a compression system to compress the CO_2 is needed to prepare the CO_2 for transport to a permanent geological storage site such as oil and gas reserves and underground saline formations and to inject the captured CO_2 into the storage site.

5.10.2 Step 2 – Eliminate Technically Infeasible Control Options

The identified control options of good combustion practice, low-carbon fuels, and energy efficient design are technically feasible and will be reviewed further.

As mentioned above, the oxy-combustion CO_2 capture method involves substituting pure oxygen for air in the combustion process. Since no refinery was identified that has applied this process to process heaters and the EPA states that this technology is still in the research phase, oxy-combustion CO_2 capture was eliminated from further review.

Through the use of chemical or physical absorption/adsorption processes, there are several sorbents and solvents under development for the separation of CO_2 from combustion flue gases. The most commercial of these processes uses monoethanolamine (MEA). In typical post-combustion capture solvent-based scrubbing, the flue gas is cooled and cleaned of dust and other impurities before contacting with solvent, such as MEA. A CO_2 scrubbing column removes the CO_2 through absorption. Next, the CO_2 rich solvent is passed to a solvent regeneration column where heat transfer with hot steam releases CO_2 from the solvent, which results in solvent regeneration through the desorption process. Since MEA or other alkanolamines are used in certain processes for separation of CO_2, this control technology will be examined further.

The use of high temperature solid sorbents is also a promising technology for removal of CO_2 from flue gas. Extensive research is on-going evaluating the use of solid sorbents as a means of chemical adsorption, physical adsorption, or a combination of the two. However, some of the research has shown that the degradation of the sorbent over repeated cycles, particularly in the presence of sulfur and ash is a potential problem. The use of sorbents for capturing CO_2 at refineries has not been commercially demonstrated; thus, these post combustion control technologies have been eliminated for further review.

Ionic liquids are material with low melting points and high boiling points and are composed entirely of ions. Currently, ionic liquids are prohibitively expensive and their manufacture is very complicated. The use of these liquids has not been commercially demonstrated to capture CO_2 from refinery operations. Thus, this control technology has been eliminated for further review.

The use of biological capture systems using algae to remove CO_2 from industrial flue gas is an area of active research. The general concept involves using the exhausted CO_2 and waste heat from combustion, in the presence of water and sunlight, to cultivate algae populations. The cultivation of algae represents a valuable source of biomass which may be used to produce additional energy, including liquid fuels such as bio-diesel.

However, it should be noted that the re-use of CO_2 as a liquid bio-fuel only displaces the use of fossil fuels and limits the CO_2 mitigation potential. Biological capture processes suffer from inherent scale-up issues because of the limited rate at which algae can grow. Like the other post-combustion technologies identified above, the use of this CO_2 capture technology has not been demonstrated commercially at a refinery. Thus, the use of biological capture systems using algae has been eliminated from further review.

Membranes are manufactured to allow the selective permeation of a gas to flow through them. There are several types of membrane materials (ceramic, polymeric, metallic) that may be used in CO_2 capture systems. Although the use of membrane technology may be available in the future for use to separate or absorb CO_2 in an exhaust stream, this technology is primarily in the research phase and industrial application is at least 10 years away (EPA)[13]. Major challenges need to be overcome including the cost of the membrane materials, the life-time of membrane and membrane reliability. [14] Thus, since this technology has not been demonstrated commercially at a refinery, this technology was eliminated from further consideration.

5.10.3 Step 3 - Rank Remaining Control Options

The use of good combustion practices, low-carbon fuels, and energy-efficient design to reduce GHG emissions from the proposed process heaters at Holly is inherent in the heater's design; this option is considered to be the baseline. Chemical absorption using a solvent such as MEA is assumed to represent the best CO_2 capture option. The use of a geological storage site is assumed to represent the best option for long-term CO_2 storage.

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13 US EPA. Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry.

14 Figueroa JD, Fout T., Plasynski D., et al. Advances in Co2 capture technology – The US Department of Energy's Carbon Sequestration Program International Journal of Greenhouse Gas Control 2 (2008).

5.10.4 Step 4 - Evaluate Remaining Control Options

All commercial post-combustion CO_2 capture plants identified for this NOI use chemical absorption processes generally using MEA-based solvents. MEA was developed over 70 years ago as a general, non-selective solvent to remove acid gases, CO_2, and hydrogen sulfide, from natural gas streams where it is readied for transport and sequestration. MEA scrubbing is considered state-of-the-art for fossil fuel-fired systems such as gas turbines. In a typical process, flue gas contacts MEA solution in an absorber. The MEA selectively absorbs the CO_2 and is then sent to a stripper. In the stripper, the CO_2-rich MEA solution is heated to release almost pure CO_2.

The MEA process requires a significant amount of power to operate pumps and blowers for gas and solvent circulation. Additional issues with the use of MEA are equipment corrosion, solvent degradation caused by the presence of dissolved O_2 and impurities, or reaction with SO_2, SO_3, and NO_x to produce non-regenerable heat-stable salts. The cost of capture in 2008 using MEA solvent absorption was estimated to be over $100 per ton CO_2 avoided for oil refineries.[15] A study presented in the International Journal of Greenhouse Gas Control explored the cost of routing refinery emission sources to a CO_2 capture plant. The study found that a typical refinery, CO_2 point sources are scattered around the site. The study concluded that "many kilometers of additional ducting would be required to collect the CO_2. Both the capitol costs as well as the required blower duty will be of such a magnitude that this does not appear to be a feasible opportunity."[16]

If CO_2 were captured, it would have to be transported for subsequent sequestration. CO_2 can be transported in three states: gas, liquid, and solid. Applicable commercial-scale transport of CO_2 for Holly would consist of tanker trucks and/or pipeline.

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15 Ho.M., Allinson. GW, and Wiley, D. Comparison of MEA capture cost for low CO_2 emissions.
16 Straelena, Jiri Van et al. CO_2 Capture for Refineries, A Practical Approach. International Journal of Greenhouse Gas Control.

Transport by tanker trucks is not practical due to the large number of trucks needed and their associated exhaust emissions which include CO_2. Also, tank truck and rail options cost more than twice as much as a pipeline.[12] Pipelines routinely carry large volumes of natural gas, oil, and water, for example, over large distances. Pipelines would be the best avenue for transport of CO_2 to a sequestration site although safety issues are of concern with a pipeline especially in populated areas. Pipeline leak or rupture would have significant safety, environmental and health impacts.

Currently, the pipeline infrastructure in the area of the Holly plant does not exist for CO_2 transport. The nearest CO_2 pipeline in northeastern Utah is over 125 miles from the Holly refinery. The cost to build a pipeline would be extreme; the labor and steel costs alone are estimated to be $57,500 per mile per inch pipeline diameter.[17]

CO_2 injection and storage into geological formations is a mitigation option. Injecting CO_2 into deep geological formations at carefully selected sites can store it underground for long periods of time. The cost of geological storage of CO_2 is highly site-specific, depending on factors such as the depth of the storage formation and the number of wells needed for injection. Costs for storage, including monitoring, appear to lie in the range of 0.6–8.3 US$/t$CO_2$ stored[18]. However, current and planned CO_2 geological storage locations in the United States are limited. The closest CO_2 storage project is proposed near Teapot Dome, Wyoming. CO_2 injection is also being used to enhance oil recovery in western and central Wyoming.

Since current cost and energy penalties are relatively high, CO_2 capture has not been demonstrated commercially at a refinery at full scale, CO_2 transport infrastructure in the vicinity of Holly refinery is not available, and the experience with large-scale geological CO_2 storage is limited, CO_2 capture, transport, and sequestration is not considered BACT and has been eliminated from further consideration.

17 http://www.powerplantccs.com/ccs/tra/tra_pipe_cost.html

5.10.5 Step 5 - Select BACT

Thus, at this point in time, the only practical way to reduce the amount of CO_2 generated from stationary combustion sources such as process heaters is good combustion practices including good air/fuel mixing in the combustion zone, good burner maintenance and operation, sufficient residence time to complete combustion, high temperatures and low oxygen levels in the primary combustion zone, proper fuel gas supply system design and operation, and excess oxygen levels high enough to complete combustion while maximizing thermal efficiency. Oxygen monitors and intake air flow monitors will be used to optimize the fuel/air mixture and limit excess air. Air preheater packages, consisting of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convection section exchange heat with the incoming combustion air will be installed on the vacuum unit furnace and crude unit furnace #2.

5.11 BACT for Steam Boiler for Greenhouse Gases

Potential GHG emissions from the refinery fuel or natural gas fired boiler include CO_2, N_2O, and CH_4. The majority of the total GHG emissions, expressed at CO_2e are CO_2 emissions. CO_2 is a product of combustion of fuel containing carbon, such as natural gas. Since CO_2 is created as part of the chemical reaction between oxygen and the fuel when burned, there is no way to reduce the amount of CO_2 generated from combustion. Methane emissions result from incomplete combustion. Nitrous oxide emission results primarily from low temperature combustion.

5.11.1 Step 1 - Identify All Control Available Technologies

Three control options identified as potential CO_2, CH_4, and N_2O controls include low carbon fuels, energy efficient processes and technologies including good combustion practices, and carbon capture and sequestration.

5.11.1.1 Energy Efficient Processes and Technologies

EPA has found that low carbon fuels, such as refinery fuel and natural gas produce half the amount of CO_2 when compared to other fossil fuels.

Good combustion practices generally include the following components: (1) Proper air/fuel mixing in the combustion zone; (2) High temperatures and low oxygen levels in the primary combustion zone; (3)Overall excess oxygen levels high enough to complete combustion while maximizing boiler thermal efficiency, and (4) Sufficient residence time to complete combustion. Good combustion practices is accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it relates to excess oxygen levels.

5.11.1.2 Carbon Capture and Sequestration

Carbon capture and sequestration is considered an add-on technology. Carbon sequestration is an engineering technique where CO_2 is removed from the exhaust gas, injected and stored permanently underground in a geological formation of some type for a long period of time.

5.11.3 Step 2 – Eliminate Technically Infeasible Control Options

The identified control options of low carbon fuels and energy efficient processes and technologies including good combustion practices are technically feasible and will be reviewed further.

Carbon capture and sequestration from the boiler is not technically feasible for the reasons stated in Section 5.10.4 above and have been eliminated from further consideration.

5.11.3 Steps 3 – 5

Refinery fuel and/or natural gas will be utilized by the boiler and has the lowest CO_2 emission rate of all fossil fuels. According to AP-42, natural gas has a CO_2 emission rate of 120 lb/MMBtu compared to distillate oil which has a CO_2 emission rate of 150 lb/MMBtu. Thus, natural gas is a top ranked low carbon containing fuel.

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, CH_4 and N_2O emissions will be minimized. To improve boiler efficiency and reduce GHG emissions by 3 to 13 percent, insulation will be installed on the new boiler (boiler #11) and improved insulation will be added to the existing boilers and distribution pipes. The reuse of steam condensate, which reduces the amount of feed water and the amount of energy needed since the condensate is preheated will be employed at the refinery. The estimated efficiency improvement by the installation of steam condensate return lines is up to 10%.

For proposed boiler #11, Holly is proposing the use of a Nebraska Boiler Model NOS-2A/S-55. Other boiler configurations are available and were examined for this project but due to the larger cabin space, those boilers did not produce steam as efficiently as the proposed make/model for boiler #11. The proposed boiler utilizes high efficiency TODD VARIFLAME burners and a welded-membrane wall design that creates a gas-tight furnace area. The burners are designed to use advanced fuel-staging and to provide the proper-air-to-fuel mixture throughout the full range of firing rates which maximizes combustion efficiency while minimizing the release of emissions. This proposed boiler design allows for higher steam generation and heat utilization with less fuel consumption, thus resulting in lower GHG emissions. The boiler also features a single-source integrated boiler and burner controls for more efficient operator-free handling of the boiler.

Boiler #11 will be equipped with instrumentation and controls that can achieve up to a 4% reduction in CO_2 emissions. Boiler #11 will be equipped with an O_2 analyzer and O_2 concentrations will be monitored and documented each shift. This boiler will also be equipped with a mechanical linkage that can be adjusted by a factory representative. This linkage increases/decreases air flow and fuel gas simultaneously keeping the excess percent O_2 constant.

Tuning of the burners will be performed periodically to insure efficient boiler operation. Through burner tuning, up to a 3% reduction of CO_2 emissions can be obtained.

Routine maintenance will be performed on the boiler to insure it is operating at maximum efficiency. The system will be periodically checked for air leaks since too much excess air leads to energy loss. Indications of air leakage will be present in higher O_2 levels as well as increased fuel consumption. Improved efficiency improvement from reducing air leakage problems can reduce CO_2 emissions ranging from 1 to 4 percent.

Available control technologies for the control of CH_4 and N_2O emissions are the same controls used for CO and VOC emissions (Section 5.2.1). These controls include good combustion practices including the use of LNB and FGR for the boiler. LNB are designed to control the mixing of air and fuel to reduce the peak temperatures of combustion. The use of LNB and FGR for the boiler is expected to achieve a CH_4 emission rate of 0.001 kg/MMBtu and a N_2O emission rate of 0.0001 kg/MMBtu.

With the above-listed controls, no adverse economic, energy, or collateral environmental impacts were identified that would preclude using these technologies.

The use of low carbon containing fuels including natural gas in combination with the use of efficient steam boiler and good combustion practices represents BACT for control of GHG.

5.12 BACT for Equipment Leaks for Greenhouse Gases

With the proposed Holly heavy crude processing project, piping with a large number of connectors, valves, pumps, and similar components will be installed for movement of gas and liquid materials. These components are potential sources of CO_2 and CH_4 emissions due to leakage.

5.12.1 Step 1 - Identify All Available Control Technologies

Like VOC emissions, GHG emissions from equipment leaks will occur and Holly's LDAR program will provide effective control of GHG emissions. The requirements of the LDAR program use CH_4 as the reference compound for performing the required monitoring for leaks. Thus, the LDAR program already established as BACT for VOC emissions relies on a GHG as the basis for the monitoring and control requirements.

5.12.2 Step 2 – Eliminate Technically Infeasible Control Options

The identified control option is technically feasible.

5.12.3 Steps 3 – 5

The most effective control strategy identified for GHG emissions from equipment leaks is a LDAR program. Identified leaks will be repaired as soon as practical. The use of this system will not result in any adverse energy or environmental impacts.

5.13 BACT for Flare for Greenhouse Gases

The south flare will be used at the Holly refinery to manage the disposal of hydrocarbon products from upsets or emergencies via combustion.

5.13.1 Step 1 - Identify All Available Control Technologies

Two control technologies were identified for minimizing GHG emissions from flaring activities. These are: proper flare operation and flare gas recovery systems. Proper flare operation leads to lower methane emissions and lower overall GHG emissions. The installation of a flare gas recovery system can reduce flaring by approximately 95 percent which offers the highest amount of emission reduction potential.

5.13.2 Step 2 – Eliminate Technically Infeasible Control Options

Both identified control technologies are technically feasible.

5.13.3 Step 3 - Rank Remaining Control Options

The use of a flare recovery system is the most effective option followed by proper flare operation.

5.13.4 Step 4 - Evaluate Remaining Control Options

Flaring can be reduced by installation of a commercially available flare gas recovery system. The cost of installing a flare gas recovery system was looked at in reference to CO_2 and CH_4 which have global warming potentials of 1 and 21, respectively. For the top control technology, the use of a flare gas recovery system would involve an economic impact. Appendix F presents the cost analysis for reduction of CO_2 and CH_4 emissions using a flare gas recovery system. As seen in Appendix F, the cost is considerable, in excess of $220 per ton CO_2 and $73,000 per ton of CH_4 emissions controlled. Like the analysis presented in Section 5.9.1.4, the use of a flare gas recovery system is extremely high for control of criteria pollutant as well as for control of GHG emissions.

Since the cost-effectiveness (cost per ton of CO_2 and CH_4 avoided) from flaring operations at a refinery (or any facility) could not be ascertained from available literature, and that it was demonstrated in Section 5.9.1.4 that the cost of criteria pollutant avoidance from flares was considerable, due to these considerations, this control technology has been eliminated from further consideration. Thus, the remaining control technology, proper flare operation is considered the most effective control from flaring at Holly's Woods Cross Utah refinery.

5.13.5 Step 5 – Select BACT

To insure proper flare operation, Holly will install flow meters and gas combustion monitors on the flare gas line which allows for improved flare gas combustion control and minimizes periods of poor flare combustion efficiencies. The combustion efficiency of the flare will be maintained by controlling the heat content of flare gas and steam or air-assist rates.

5.14 BACT for Fluid Catalytic Cracking Unit for Greenhouse Gases

In a refinery, the FCC unit converts heavy, lower-value hydrocarbon feedstock into lighter, more valuable products. FCC units account for 15-20% of refinery energy consumption and can be a significant source of CO_2 emissions.

5.14.1 Step 1 - Identify All Available Control Technologies

Several control technologies were identified for reducing CO_2 emissions from a FCCU. These include power/waste heat recovery, high-efficiency regenerators, post-combustion capture solvent-based scrubbing, and oxy-combustion.

5.14.2 Step 2 – Eliminate Technically Infeasible Control Options

The identified control options are technically feasible and will be reviewed further.

5.14.3 Step 3 - Rank Remaining Control Options

Traditionally at power plants utilizing a post-combustion control technology with a formulated amine solvent such as MEA can achieve CO_2 recovery between 85-95%. Similar percentages of CO_2 recovery are can be achieved utilizing the oxy-combustion control technology. Power/waste heat recovery and high efficient regenerators are inherent in the design and operation of the equipment at Holly and is considered the baseline condition.

5.14.4 Step 4 - Evaluate Remaining Control Options

Post-combustion capture using an amine solvent such as MEA has been demonstrated to reduce CO_2 emissions from coal-, oil-, and natural gas-fired units mainly at electrical generation facilities. MEA is used as a scrubbing agent to absorb CO_2 in the flue gas and then release it in a steam-heated regenerator. The released CO_2 gas is routed to the CO_2 compressor station for export.

A similar CO_2 capture efficiency can be obtained using oxy-combustion. Traditionally in a FCCU, air is used to regenerate the catalyst by burning off coke deposited on the catalyst during the conversion process. In the oxy-combustion mode, air is replaced by pure oxygen which is diluted with recycled CO_2 so that thermal balance and catalyst fluidization is maintained.

Both post-combustion capture using an amine solvent such as MEA and oxy-combustion are promising technologies but are challenging in a FCCU. A techno-economic evaluation was conducted of post-combustion amine absorption and oxy-combustion for CO_2 capture from a FCC regenerator by the CO_2 Capture Project sponsors. They determined that both processes were able to achieve the required recovery levels. The post-combustion option had lower capital costs and the oxy-combustion had lower operational costs leading to lower overall capture costs. However, with both of these control options, several technical issues still need to be resolved.

With post-combustion capture using an amine solvent such as MEA, the operating experience of existing plants shows a fairly high operating cost due to a high steam consumption and high MEA makeup. Because of the CO_2 scrubber, power usage is increased. Additional issues with the process include equipment corrosion, solvent degeneration caused by the presence of dissolved O_2 and other impurities or reaction with SO_2, SO_3 and NO_x to produce non-regenerable, heat-stable salts.

Although oxy-combustion may be preferred in regards to operating costs, a number of issues need to be addressed using this control technology for CO_2 capture. These issues include corrosion of equipment, thermal balance, catalyst attrition, and coke burn rate. Also health and safety issues need to be assessed due to the presence of gaseous oxygen on-site.

Even if these technologies were cost effective and energy efficient for capturing CO_2, the CO_2 would need to be transported and ultimately sequestered. As mentioned above, the transport by tanker trucks is not practical due to the large number of trucks needed and their associated exhaust emissions which include CO_2. Also, tank truck and rail options cost more than twice as much as a pipeline. While pipelines would be the best avenue for transport of CO_2 to a sequestration site although safety issues are of concern with a pipeline especially in populated areas, the nearest CO_2 pipeline in northeastern Utah is over 125 miles from the Holly refinery. The cost to build a pipeline would be extreme.

Thus, while field demonstrations are being conducted on CO_2 capture technologies such as oxy-combustion, at this point in time, these control technologies are not cost effective, have not been demonstrated at full scale, have energy penalties, and pose environmental and safety risks. Due to these reasons, these CO_2 capture control technologies do not represent BACT.

Power/waste heat recovery and high-efficiency regenerators will be employed to reduce fuel consumption and ensure complete combustion thus lowering GHG emissions.

5.14.5 Step 5 – Select BACT

Holly will install or upgrade power recovery or waste heat boilers to recover latent heat from the FCCU regenerator exhaust as a means of reducing GHG emissions. In addition, Holly will install specially designed FCCU regenerators for high efficiency, complete combustion of catalyst coke deposits. Thus, energy recovery and high efficiency regenerators which allow for complete combustion of coke deposits are considered BACT for GHG emissions from the FCCU.

6.0 PSD CLASS II AREA AMBIENT AIR QUALITY ANALYSIS

This section presents the air quality impacts associated with the emissions from Holly Refining & Marketing Companies proposed heavy crude processing project. Consistent with the procedures presented in 40 CFR Part 51 Appendix W *Guideline on Air Quality Models*, the air dispersion model used to demonstrate compliance with the NAAQS and PSD Class II area increments was the EPA approved model AERMOD. A modeling protocol developed for this project was accepted by the UDAQ and forwarded to the FLMs. The near-field modeling and full-impact analysis input and output files are contained on an external hard drive that accompanies this permit application.

6.1 Near-Field Dispersion Modeling Analyses

Analyses of air quality impacts within designated PSD Class II areas were performed in accordance with Utah Titles R307-405 and R307-410. These analyses consisted of dispersion modeling of criteria and hazardous air pollutants.

6.1.1 Regional Description

The Holly' Woods Cross refinery is located approximately 5 kilometers (3.2 miles) east of Farmington Bay. Elevated terrain, the Wasatch Mountains, is located approximately 4 kilometers (2.5 miles) to the east of the facility. Figure 6.1 presents the location of the refinery and surrounding terrain.

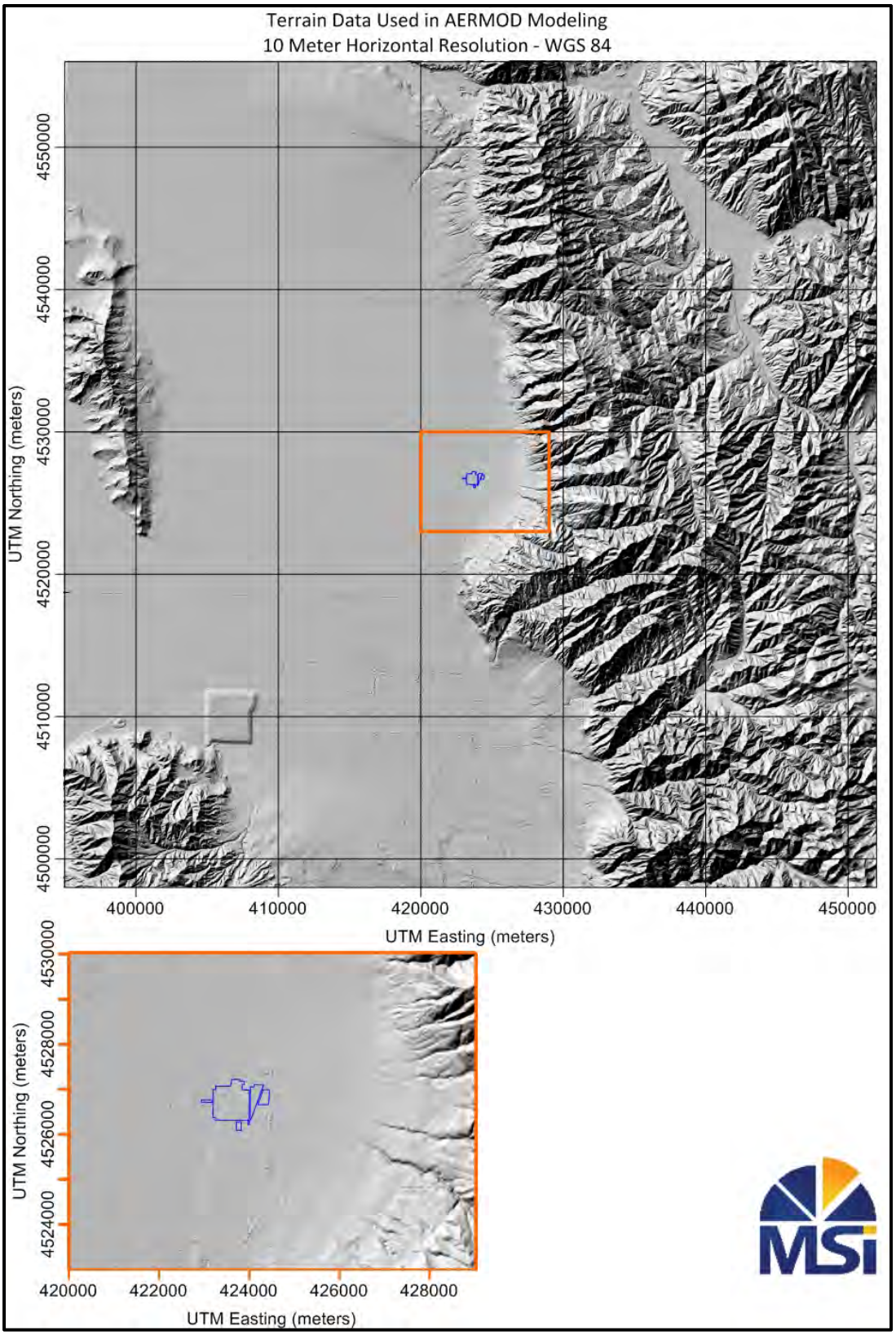

Figure 6.1 Map Showing Location of Holly Refinery and Terrain used in AERMOD

6.2 Background Ambient Air Quality

Background air quality includes pollutant concentrations due to natural sources, nearby sources other than the one(s) currently under consideration, and unidentified sources. Davis County, where the refinery is located, is non-attainment area for $PM_{2.5}$, maintenance for O_3 and PM_{10}, and attainment for SO_2, NO_2, VOC, and CO. The refinery is located within four miles of Salt Lake County, which is in non-attainment for $PM_{2.5}$, PM_{10}, and SO_2, and a maintenance area for O_3.

Background concentrations of NO_2, SO_2, PM_{10}, and CO were derived based on three years of monitoring data obtained from UDAQ's Bountiful ambient air quality monitoring station. The background values used for the SO_2, PM_{10}, CO and NO_2 analyses are presented in Table 6-1. For the one-hour NO_2 full impact analysis, concurrent hourly NO_2 data obtained from the UDAQ Bountiful ambient air quality station for 2006-2009 was formatted for input into AERMOD as temporally varying background concentrations.

Table 6-1

Background Pollutant Concentrations

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)
NO_2	1-hour	89.7[1]
	Annual	35.5
SO_2	1-hour	26.2
PM_{10}	24-hour	56.3
CO	1-hour	4,122
	8-hour	2,484

[1] One hour background concentrations used with Holly sources only.

6.3 Model Selection

To address the near-field impacts from the new and modified sources from Holly's heavy crude processing project and for the entire refinery, the latest version of the AERMOD modeling system (AERMOD 12060, AERMET 11059, AERSURFACE 08009, AERMAP 11103) was utilized.

AERMOD is a steady-state plume dispersion model that is used for assessment of pollutant concentrations from a variety of sources. AERMOD uses Gaussian distributions in the vertical and horizontal for stable conditions, and in the horizontal for convective conditions. The vertical concentration distribution for convective conditions results from an assumed bi-Gaussian probability density function of the vertical velocity. AERMOD accounts for plume downwash based on the PRIME building downwash algorithms. The model uses hourly sequential preprocessed meteorological data to estimate pollutant concentrations for various averaging times.

The AERMOD modeling system consists of two pre-processors and the dispersion model. AERMET is the meteorological pre-processor and AERMAP is the terrain pre-processor that characterizes the terrain and generates receptor elevations. These pre-processors were utilized to generate the required AERMOD files. In addition, in 2008 EPA released AERSURFACE which prepares required land-use information inputs for AERMET.

6.3.1 AERMET

The AERMET preprocessor was used to prepare the meteorological data for AERMOD. AERMET is designed to accept National Weather Service (NWS) one-hour surface observations, NWS twice-daily upper air soundings, and data from an on-site meteorological measurement system. The AERMOD model utilizes a file of boundary layer parameters and a file of profile variables including wind speed, wind direction, and turbulence parameters.

6.3.2 AERMAP

The AERMAP terrain preprocessor was used to extract elevation data from 7.5-minute USGS digital elevation data (DEM). Elevations were based on WGS-84 datum. AERMAP produces receptor heights and related parameters that are input into AERMOD. AERMAP determines the base elevation at each receptor and source. For complex terrain situations, AERMOD captures the essential physics of dispersion in complex terrain and needs elevation data that convey the features of the surrounding terrain. To satisfy this need, AERMAP searches for the terrain height and location that has the greatest influence on dispersion for each individual receptor, within a 10% slope of the facility. This height is then referred to as the hill height scale. Both the base elevation and hill height scale data are produced by AERMAP as a file or files which can be directly accessed by AERMOD.

6.3.3 AERSURFACE

The AERMOD Implementation Guide recommends that the surface characteristics be determined using digital land cover data. The current version of AERSURFACE supports the use of land cover from the United States Geological Survey (USGS) National Land Cover archives. These data were used to determine site characteristics surrounding the meteorological tower. AERSURFACE was used to calculate the surface roughness, albedo and Bowen ratio for 12 sectors around a one-kilometer radius centered at the location of the meteorological tower used in AERMET.

The surface roughness length is related to the height of obstacles to the wind flow. The surface roughness length influences the surface shear stress and is an important in the determination of the magnitude of mechanical turbulence and the stability of the boundary layer. Albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption. The daytime Bowen ratio, an indicator of surface moisture, is the ratio of sensible heat flux to latent heat flux and was used for determining planetary boundary layer parameters for convective conditions driven by the surface sensible heat flux. Table 6-2 presents the albedo, Bowen ratio, and surface roughness, by month that was used for Holly's near-field dispersion modeling analysis.

Table 6-2

Surface Characteristics used in AERMET for Holly Refining & Marketing Company

Months		Sectors											
		1	2	3	4	5	6	7	8	9	10	11	12
January	Alb.	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Bo	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Zo	0.056	0.046	0.037	0.05	0.065	0.121	0.086	0.012	0.009	0.02	0.036	0.088
February	Alb.	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Bo	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Zo	0.056	0.046	0.037	0.05	0.065	0.121	0.086	0.012	0.009	0.02	0.036	0.088
March	Alb.	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
	Bo	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
	Zo	0.084	0.072	0.062	0.079	0.108	0.182	0.086	0.012	0.009	0.02	0.037	0.124
April	Alb.	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
	Bo	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
	Zo	0.084	0.072	0.062	0.079	0.108	0.182	0.086	0.012	0.009	0.02	0.037	0.124
May	Alb.	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
	Bo	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
	Zo	0.084	0.072	0.062	0.079	0.108	0.182	0.086	0.012	0.009	0.02	0.037	0.124
June	Alb.	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
	Bo	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
	Zo	0.084	0.072	0.062	0.079	0.108	0.182	0.086	0.012	0.009	0.02	0.037	0.124
July	Alb.	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Bo	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Zo	0.173	0.184	0.184	0.159	0.151	0.235	0.086	0.012	0.009	0.02	0.037	0.182
August	Alb.	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Bo	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Zo	0.173	0.184	0.184	0.159	0.151	0.235	0.086	0.012	0.009	0.02	0.037	0.182

Table 6-2 (Continued)

Surface Characteristics used in AERMET for Holly Refining & Marketing Company

Months		Sectors											
		1	2	3	4	5	6	7	8	9	10	11	12
September	Alb.	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Bo	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Zo	0.173	0.184	0.184	0.159	0.151	0.235	0.086	0.012	0.009	0.02	0.037	0.182
October	Alb.	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Bo	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Zo	0.173	0.184	0.184	0.159	0.151	0.235	0.086	0.012	0.009	0.02	0.037	0.182
November	Alb.	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Bo	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Zo	0.056	0.046	0.037	0.05	0.065	0.121	0.086	0.012	0.009	0.02	0.036	0.088
December	Alb.	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Bo	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Zo	0.056	0.046	0.037	0.05	0.065	0.121	0.086	0.012	0.009	0.02	0.036	0.088

6.4 Meteorological Data

The meteorological data input files were prepared using AERMET and were approved by UDAQ for use in this analysis. These files consist of four years (2006 through 2009) of surface meteorological data collected by the UDAQ at Syracuse, Utah . Cloud cover and atmospheric sounding data were obtained from NWS Salt Lake City, Utah observations for the corresponding surface data period (2006-2009).

The AERMET meteorological processor required full upper air soundings (radiosonde data) representing the vertical potential temperature profile near sunrise in order to calculate convective mixing heights. For Holly, the early morning soundings collected at 12Z (or UTC/GMT) by the NWS for the period coinciding with the surface meteorological data were used. Annual wind roses for 2006 through 2009, for Syracuse, Utah are presented in Figures 6.2 through 6.5.

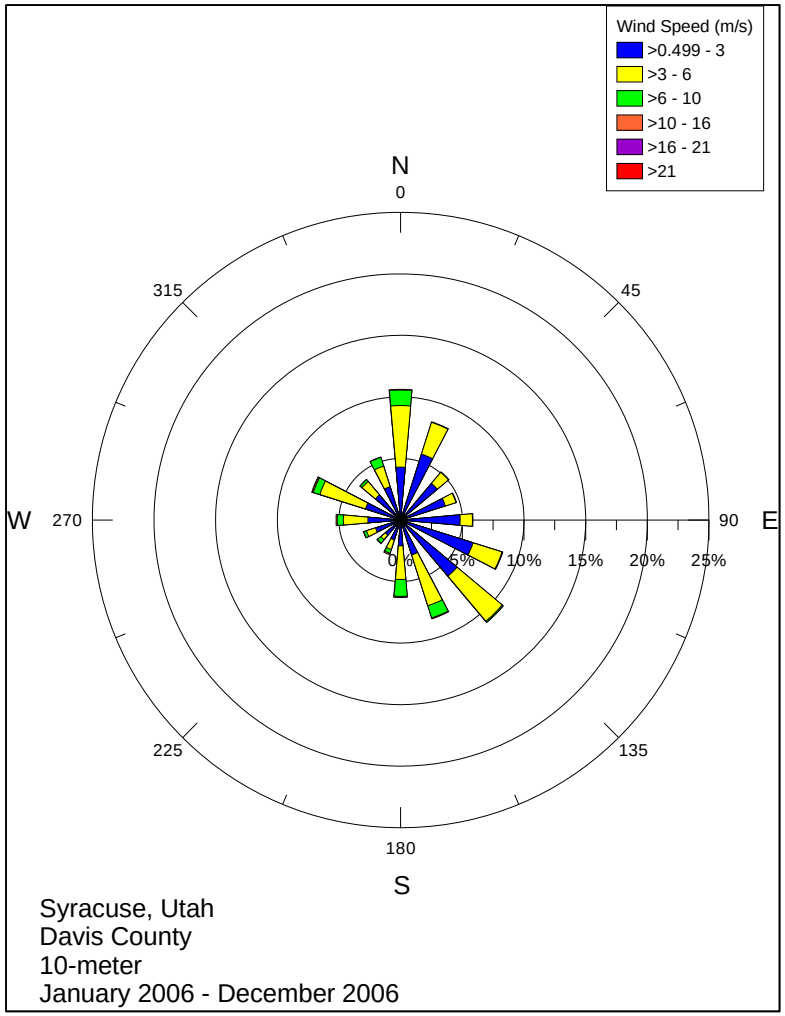

Figure 6.2 2006 Annual Wind Rose (Syracuse, Utah)

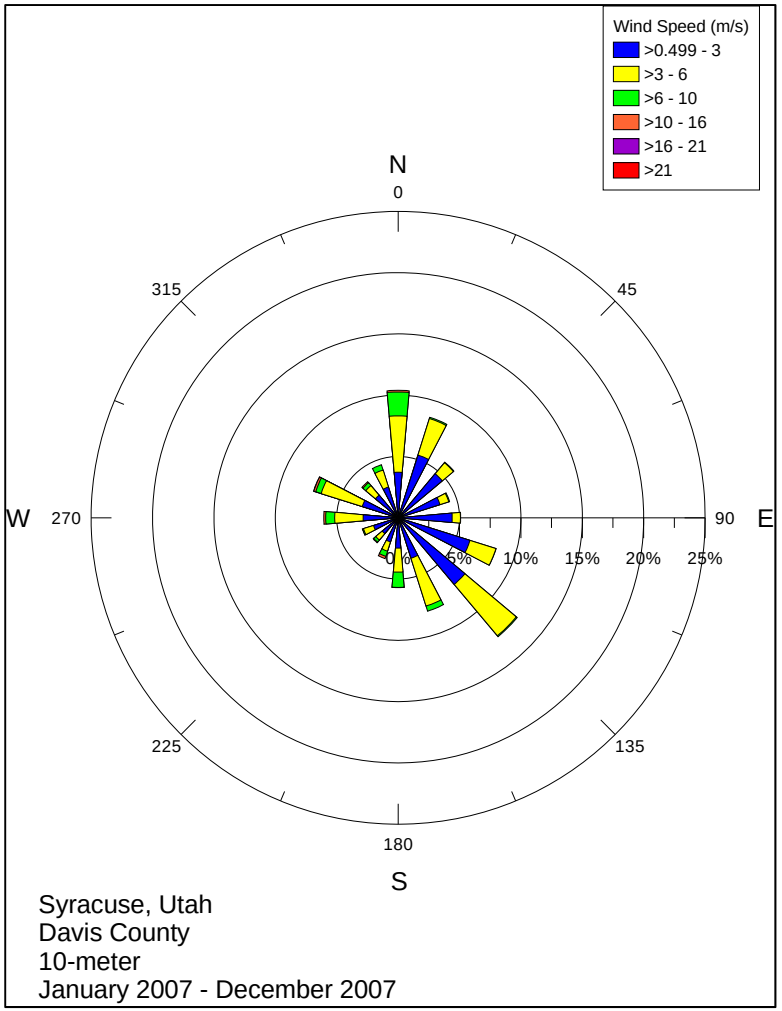

Figure 6.3 2007 Annual Wind Rose (Syracuse, Utah)

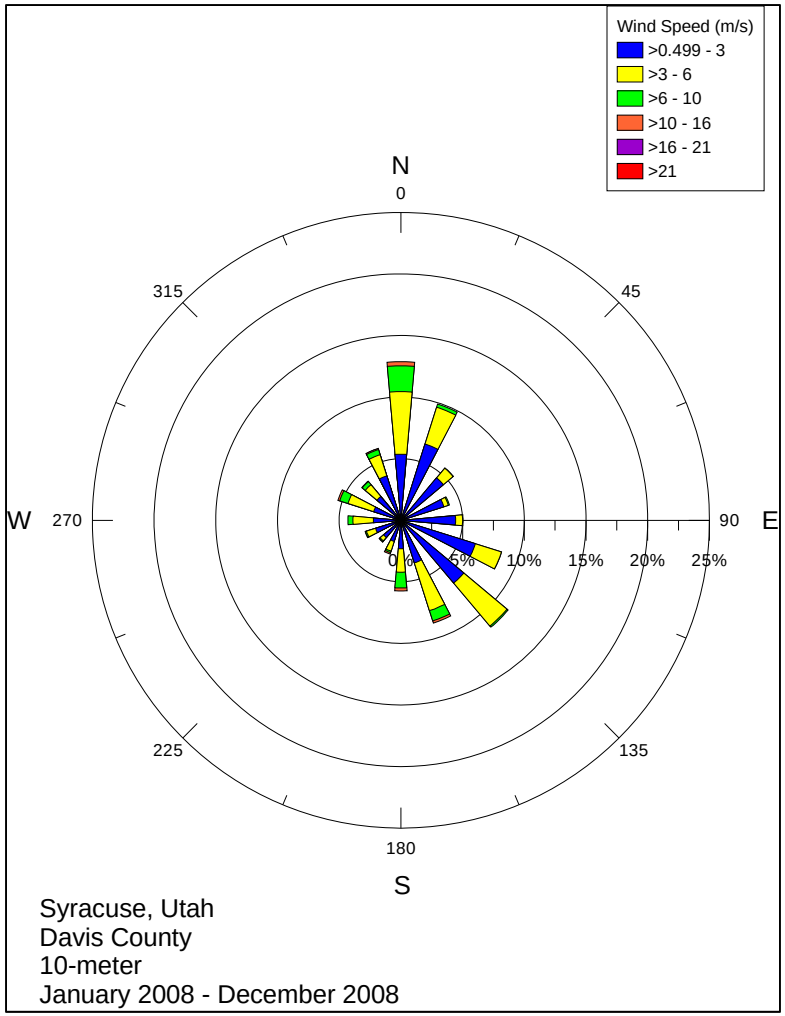

Figure 6.4 2008 Annual Wind Rose (Syracuse, Utah)

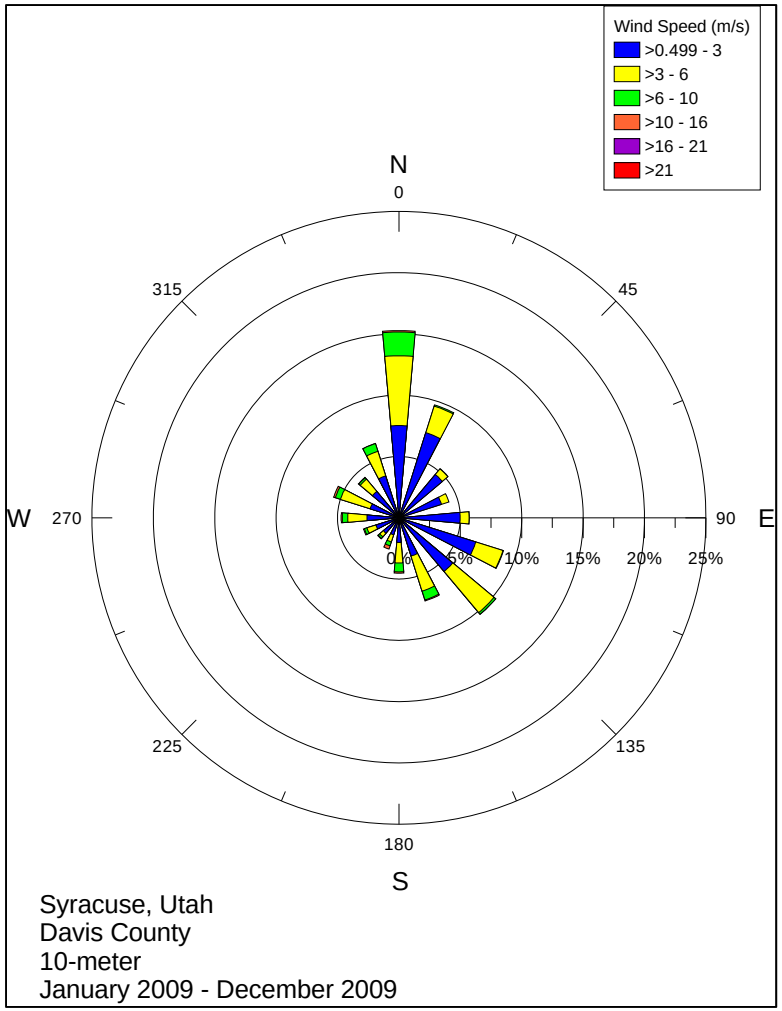

Figure 6.5 2009 Annual Wind Rose (Syracuse, Utah)

6.5 Treatment of Calms or Near-Calms

AERMOD contains algorithms for dealing with low wind speed (near calm) conditions. AERMOD can produce model concentrations for conditions when the wind speed may be less than 1 m/s but still greater than the instrument threshold. The threshold wind speed is typically the threshold of the instrument used to collect the wind information.

6.6 Receptor Grid for Near-Field Modeling

A modeling domain was developed for the near-field analysis that encompassed the location of the maximum modeled concentration from the Holly heavy crude processing project. Discrete receptors based on Universal Transverse Coordinates (UTM) and elevations derived from in-house 10-meter DEM data were used in AERMOD.

The receptor grid was developed to insure that maximum pollutant concentrations were determined by the model. The grid consisted of 10,024 receptors with 25-meter spacing around the fence line, 50-meter spacing for receptors extending out to 500 meters; from 500 meters to 1 kilometer, 100-meter spacing was used. Two hundred-meter spacing was used from 1 to 5 kilometers, and from 5 kilometers out to 10 kilometers 500-meter spacing was used. From 10 kilometers to 25 kilometers, receptor spacing of 1 kilometer (or 1,000 meters) was used. Figure 6.6 presents the receptor grid that was used in the near-field analysis. Receptors were also placed along the Salt Lake County line.

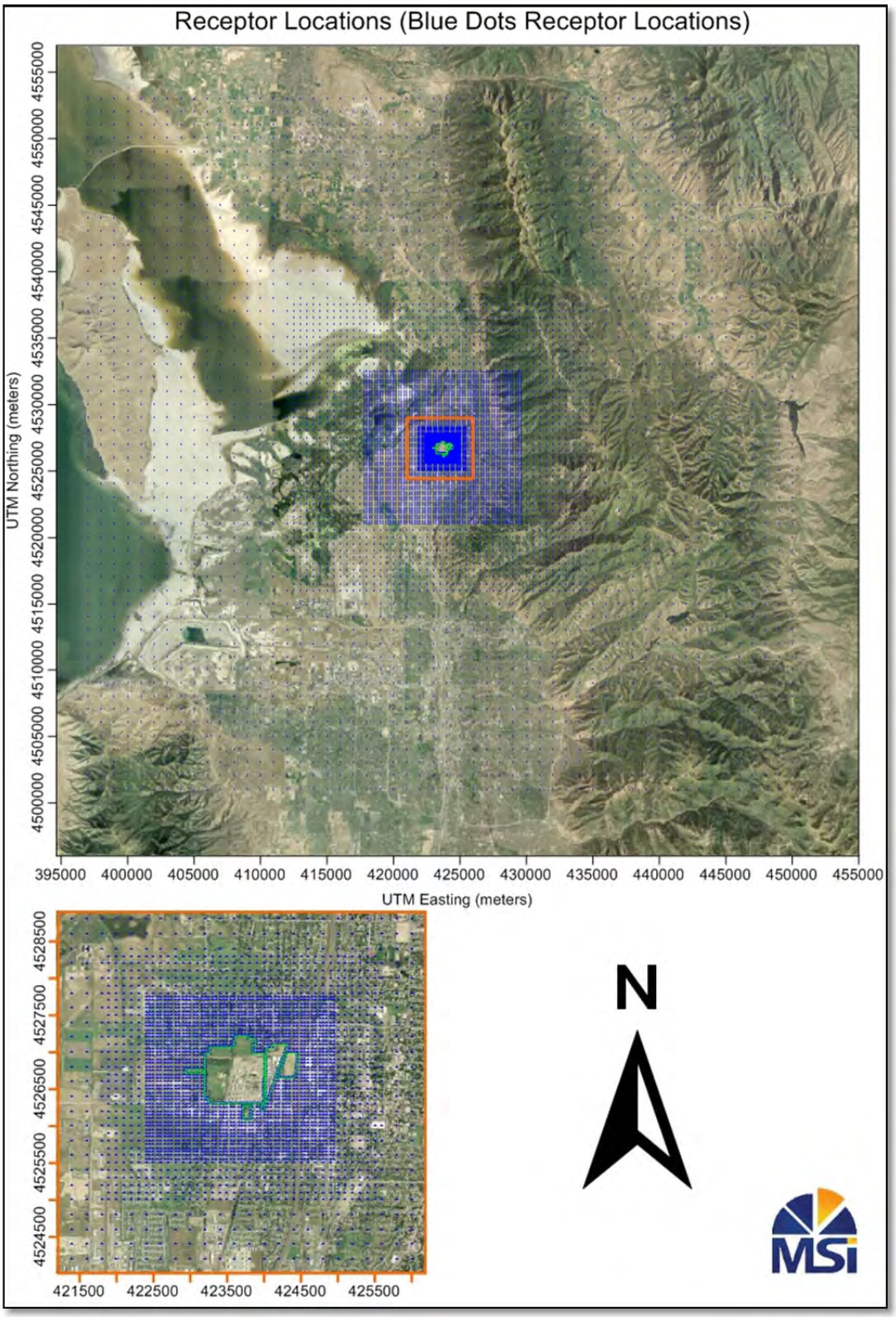

Figure 6.6 AERMOD Discrete Receptor Grid

6.7 Source Parameters and Technical Input Options

The stack parameters and PTE emission rates were used in AERMOD to insure that emissions from Holly' proposed heavy crude processing project and existing operations would meet all applicable air quality standards. The short-term emission estimate rates and source parameters including UTM coordinates, stack base elevations, and source release parameters for each point were modeled are presented in Tables 6-3 and 6-4, respectively. Emissions from the emergency generators were not modeled per the UDAQ.

Long-term (annual) emission rates were also modeled. Tables 6-6 presents the annual emission rates for NO_2 for proposed and existing Holly sources.

Table 6-3

Modeled PTE Emission Rates and Stack Parameters for Proposed Holly Heavy Crude Processing Project Sources – Short Term

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Stack Exit Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO_X (g/s)	SO_2 (g/s)	PM_{10} (g/s)	CO (g/s)
20H3 Reactor Charge Heater	423909.2	4526400.9	1305.7	35.1	772.0	4.20	1.55	0.2129	0.0529	0.0391	0.4372
24H1 Crude Furnace #3	423841.1	4526834.6	1300.3	36.6	772.0	7.49	1.65	0.3039	0.0751	0.0563	0.6226
25H1 FCC #2 Feed Heater	423836.8	4526768.1	1301.0	35.5	772.0	6.06	1.58	0.2279	0.0563	0.0422	0.4669
FCC #2 Scrubber	423801.2	4526732.1	1300.8	60.7	338.7	10.26	1.01	0.5727	0.5091	0.3906	4.4545
26H1 Hot Oil Furnace	423802.9	4526783.7	1300.0	24.4	772.0	6.06	0.88	0.0709	0.0175	0.0131	0.1453
27H1 Reactor Charge Furnace	423885.7	4526788.6	1301.0	39.6	772.0	10.01	1.83	0.2446	0.1235	0.0932	1.0269
30H1 Hydrogen Reformer Feed Furnace	423851.5	4526891.3	1301.4	29.9	772.0	7.00	2.44	0.3042	0.1540	0.1156	1.2774
30H2 Hydrogen Reformer Feed Furnace	423851.4	4526886.9	1301.3	29.9	772.0	7.00	2.44	0.3042	0.1540	0.1156	1.2774
33H1 Vacuum Furnace Heater	423911.2	4526432.7	1305.2	39.6	772.0	13.14	1.83	0.3212	0.1627	0.1221	1.3489
#11 Boiler	423780.3	4526634.1	1302.0	15.2	588.7	8.99	1.60	0.2250	0.1118	0.0838	0.9266
SE In-Tank Asphalt Heater	424116.4	4526802.3	1305.2	13.4	616.5	1.03	0.46	0.0099	0.0010	0.0008	0.0083
SW In-Tank Asphalt Heater	424102.4	4526801.9	1305.0	13.4	616.5	1.03	0.46	0.0099	0.0010	0.0008	0.0083
North In-Tank Asphalt Heater	423763.5	4526544.5	1302.0	18.3	616.5	8.72	0.46	0.0099	0.0010	0.0008	0.0083
South In-Tank Asphalt Heater	423751.2	4526533.7	1302.0	18.3	616.5	8.72	0.46	0.0099	0.0010	0.0008	0.0083
North In-Tank Asphalt Heater	423761.9	4526519.5	1301.5	18.3	616.5	8.72	0.46	0.0099	0.0010	0.0008	0.0083
South In-Tank Asphalt Heater	423750.3	4526506.9	1302.0	18.3	616.5	8.72	0.46	0.0099	0.0010	0.0008	0.0083
Cooling Tower # 10	423880.6	4526843.2	1301.0	10.7	310.9	1.83	7.92			0.0027	
Cooling Tower # 11	423788.2	4526478.0	1303.2	10.7	310.9	1.83	7.92			0.0040	

Table 6-4

Modeled PTE Emission Rates and Stack Parameters for Existing or Modified Holly Sources - Short Term

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Stack Exit Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO_X (g/s)	SO_2 (g/s)	PM_{10} (g/s)	CO (g/s)
4H1 FCC Furnace	423849.4	4526682.2	1303.0	42.7	799.8	7.70	1.35	0.2021	0.0499	0.0375	0.4140
KVG Compressor (West)	423909.7	4526680.9	1303.0	9.1	727.6	10.24	0.46	0.1790	0.0001	0.0021	0.1178
KVG Compressor (East)	423917.0	4526681.0	1303.0	9.1	727.6	10.24	0.46	0.1790	0.0001	0.0021	0.1178
FCC Scrubber	423858.3	4526654.3	1303.0	60.7	338.7	10.26	1.02	0.5727	0.5091	0.3906	4.4545
6H1 Reformer Reheat Furnace	423927.8	4526591.5	1304.0	18.5	1088.7	13.86	1.37	0.6757	0.0684	0.0514	0.5676
6H3 Reformer Reheater	423926.9	4526577.6	1304.0	38.1	672.0	8.49	1.14	0.4657	0.4716	0.0354	0.3912
6H2 Reformer Reboiler	423914.1	4526562.8	1304.0	18.1	797.0	3.68	1.07	0.1482	0.0150	0.0113	0.1245
SVG Compressor (East)	423846.6	4526590.7	1302.6	10.7	727.6	25.28	0.20	0.2020	0.0001	0.0050	0.0402
SVG Compressor (West)	423839.5	4526591.1	1303.0	10.7	727.6	25.28	0.20	0.2020	0.0001	0.0050	0.0402
7H3 H. F. Alkylation Reboiler	423798.7	4526547.2	1302.9	38.4	672.0	6.59	1.22	0.4114	0.0417	0.0313	0.3455
7H1 Alky Regen Furnace	423802.3	4526569.9	1302.5	10.8	699.8	2.74	0.70	0.0543	0.0055	0.0042	0.0456
8H1 Crude Furnace # 1	423913.8	4526505.6	1304.0	36.9	649.8	5.39	2.29	0.9979	0.1239	0.0930	1.0273
9H1 DHDS Reactor Charge Heater	423919.6	4526529.6	1304.0	22.3	549.8	2.33	0.91	0.1000	0.0101	0.0076	0.0840
9H2 DHDS Stripper Reboiler	423919.5	4526523.9	1304.0	13.3	738.7	5.58	0.49	0.0507	0.0051	0.0039	0.0426
10H1 Asphalt Mix Heater	423826.1	4526508.7	1303.0	25.3	577.6	5.75	0.76	0.1630	0.0165	0.0124	0.1370
10H2 Hot Oil Furnace	423931.3	4526444.2	1305.3	29.9	772.0	6.41	2.29	0.2446	0.1239	0.0930	1.0273
11H1 SRGP Depentanizer Reboiler	423797.8	4526558.0	1302.5	24.4	810.9	7.55	1.07	0.2990	0.0303	0.0227	0.2511
12H1 NHDS Reactor Charge Furnace	423919.7	4526441.1	1305.0	37.9	1088.7	12.72	1.37	0.4428	0.0628	0.0471	0.5209
13H1 Isomerization Reactor Feed Furnace	423926.2	4526442.5	1305.1	17.4	533.2	5.65	0.52	0.0803	0.0081	0.0061	0.0674
19H1 DHT Reactor Charge Heater	423898.8	4526434.1	1305.0	29.9	772.0	6.99	0.94	0.0917	0.0226	0.0170	0.1879
20H1: Reactor Charge Heater	423903.7	4526402.4	1305.4	29.9	772.0	6.02	0.91	0.0755	0.0186	0.0140	0.1546
20H2: Fractionator Charge Heater	423903.2	4526381.6	1305.8	29.9	772.0	6.63	1.55	0.2380	0.0588	0.0441	0.4877
23H1 Reformate Splitter Reboiler Heater	423924.4	4526478.3	1304.6	29.9	772.0	6.24	1.07	0.1063	0.0263	0.0197	0.2178
#4 Boiler	423795.8	4526686.0	1301.3	7.6	810.9	15.12	0.91	0.4397	0.0445	0.0334	0.3694

Table 6-4 Continued

Modeled PTE Emission Rates and Stack Parameters for Existing or Modified Holly Sources - Short Term

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Stack Exit Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO_X (g/s)	SO_2 (g/s)	PM_{10} (g/s)	CO (g/s)
#5 Boiler	423788.9	4526685.8	1301.3	15.2	810.9	16.72	1.22	0.1764	0.0876	0.0658	0.7264
#8 Boiler	423807.4	4526650.8	1302.0	15.2	810.9	22.15	1.60	0.2336	0.1159	0.0871	0.9619
#9 Boiler	423801.9	4526653.0	1302.0	15.2	810.9	12.38	1.60	0.2250	0.1118	0.0838	0.9266
#10 Boiler	423789.7	4526634.2	1302.0	15.2	810.9	12.38	1.60	0.2250	0.1118	0.0838	0.9266
North In-Tank Asphalt Heater	424141.2	4526736.4	1307.0	13.4	616.5	1.03	0.46	0.0098	0.0010	0.0008	0.0083
South In-Tank Asphalt Heater	424129.8	4526726.6	1307.0	13.4	616.5	1.03	0.46	0.0098	0.0010	0.0008	0.0083
North In-Tank Asphalt Heater	424102.6	4526818.5	1305.0	13.4	616.5	1.03	0.46	0.0098	0.0010	0.0008	0.0083
South In-Tank Asphalt Heater	424116.1	4526819.3	1305.0	13.4	616.5	1.03	0.46	0.0098	0.0010	0.0008	0.0083
Cooling Tower # 4	423796.7	4526582.7	1302.0	10.7	319.3	1.83	5.67	---	---	0.6294	---
Cooling Tower # 6	423779.3	4526580.9	1302.2	10.7	310.9	1.83	6.10	---	---	0.5700	---
Cooling Tower # 7	423746.0	4526589.1	1301.7	7.6	310.9	1.83	4.88	---	---	0.5374	---
Cooling Tower # 8	423764.9	4526587.8	1301.7	15.2	310.9	1.83	6.71	---	---	1.1458	---
Cooling Tower # 10	423880.6	4526843.2	1301.0	10.7	310.9	1.83	7.92	---	---	0.0027	---
Process Flare (south)	423707.0	4526793.5	1298.9	64.9	1273.0	20.00	0.78	0.1675	0.0030	---	0.9114
Process Flare (north)	423707.0	4526793.5	1298.9	64.9	1273.0	20.00	0.78	0.1675	0.0030	---	0.9115

Table 6-5

Modeled PTE NO_2– Annual Emission Rates and Stack Parameters for Proposed Holly Heavy Crude Processing Project Sources

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Stack Exit Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO_X (g/s)
20H3 Reactor Charge Heater	423909.2	4526400.9	1305.7	35.1	772.0	4.20	1.55	0.2129
24H1 Crude Furnace #3	423841.1	4526834.6	1300.3	36.6	772.0	7.49	1.65	0.3039
25H1 FCC #2 Feed Heater	423836.8	4526768.1	1301.0	35.5	772.0	6.06	1.58	0.2279
FCC #2 Scrubber	423801.2	4526732.1	1300.8	60.7	338.7	10.26	1.01	0.5727
26H1 Hot Oil Furnace	423802.9	4526783.7	1300.0	24.4	772.0	6.06	0.88	0.0709
27H1 Reactor Charge Furnace	423885.7	4526788.6	1301.0	39.6	772.0	10.01	1.83	0.2446
30H1 Hydrogen Reformer Feed Furnace	423851.5	4526891.3	1301.4	29.9	772.0	7.00	2.44	0.3042
30H2 Hydrogen Reformer Feed Furnace	423851.4	4526886.9	1301.3	29.9	772.0	7.00	2.44	0.3042
33H1 Vacuum Furnace Heater	423911.2	4526432.7	1305.2	39.6	772.0	13.14	1.83	0.3212
#11 Boiler	423780.3	4526634.1	1302.0	15.2	588.7	8.99	1.60	0.2250
SE In-Tank Asphalt Heater	424116.4	4526802.3	1305.2	13.4	616.5	1.03	0.46	0.0099
SW In-Tank Asphalt Heater	424102.4	4526801.9	1305.0	13.4	616.5	1.03	0.46	0.0099
North In-Tank Asphalt Heater	423763.5	4526544.5	1302.0	18.3	616.5	8.72	0.46	0.0099
South In-Tank Asphalt Heater	423751.2	4526533.7	1302.0	18.3	616.5	8.72	0.46	0.0099
North In-Tank Asphalt Heater	423761.9	4526519.5	1301.5	18.3	616.5	8.72	0.46	0.0099
South In-Tank Asphalt Heater	423750.3	4526506.9	1302.0	18.3	616.5	8.72	0.46	0.0099

Table 6-6

Modeled PTE NO_2– Annual Emission Rates and Stack Parameters for Existing or Modified Holly Sources

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Stack Exit Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO_X (g/s)
4H1 FCC Furnace	423849.4	4526682.2	1303.0	42.7	799.8	7.70	1.35	0.2021
KVG Compressor (West)	423909.7	4526680.9	1303.0	9.1	727.6	10.24	0.46	0.1790
KVG Compressor (East)	423917.0	4526681.0	1303.0	9.1	727.6	10.24	0.46	0.1790
FCC Scrubber	423858.3	4526654.3	1303.0	60.7	338.7	10.26	1.02	0.5727
6H1 Reformer Reheat Furnace	423927.8	4526591.5	1304.0	18.5	1088.7	13.86	1.37	0.6757
6H3 Reformer Reheater	423926.9	4526577.6	1304.0	38.1	672.0	8.49	1.14	0.4657
6H2 Reformer Reboiler	423914.1	4526562.8	1304.0	18.1	797.0	3.68	1.07	0.1482
SVG Compressor (East)	423846.6	4526590.7	1302.6	10.7	727.6	25.28	0.20	0.2020
SVG Compressor (West)	423839.5	4526591.1	1303.0	10.7	727.6	25.28	0.20	0.2020
7H3 H. F. Alkylation Reboiler	423798.7	4526547.2	1302.9	38.4	672.0	6.59	1.22	0.4114
7H1 Alky Regen Furnace	423802.3	4526569.9	1302.5	10.8	699.8	2.74	0.70	0.0543
8H1 Crude Furnace # 1	423913.8	4526505.6	1304.0	36.9	649.8	5.39	2.29	0.9979
9H1 DHDS Reactor Charge Heater	423919.6	4526529.6	1304.0	22.3	549.8	2.33	0.91	0.1000
9H2 DHDS Stripper Reboiler	423919.5	4526523.9	1304.0	13.3	738.7	5.58	0.49	0.0507
10H1 Asphalt Mix Heater	423826.1	4526508.7	1303.0	25.3	577.6	5.75	0.76	0.1630
10H2 Hot Oil Furnace	423931.3	4526444.2	1305.3	29.9	772.0	6.41	2.29	0.2446
11H1 SRGP Depentanizer Reboiler	423797.8	4526558.0	1302.5	24.4	810.9	7.55	1.07	0.2990
12H1 NHDS Reactor Charge Furnace	423919.7	4526441.1	1305.0	37.9	1088.7	12.72	1.37	0.4428
13H1 Isomerization Reactor Feed Furnace	423926.2	4526442.5	1305.1	17.4	533.2	5.65	0.52	0.0803
19H1 DHT Reactor Charge Heater	423898.8	4526434.1	1305.0	29.9	772.0	6.99	0.94	0.0917
20H1 Reactor Charge Heater	423903.7	4526402.4	1305.4	29.9	772.0	6.02	0.91	0.0755
20H2 Fractionator Charge Heater	423903.2	4526381.6	1305.8	29.9	772.0	6.63	1.55	0.2380
23H1 Reformate Splitter Reboiler Heater	423924.4	4526478.3	1304.6	29.9	772.0	6.24	1.07	0.1063
#4 Boiler	423795.8	4526686.0	1301.3	7.6	810.9	15.12	0.91	0.4397

Table 6-6 Continued

Modeled PTE NO_2 – Annual Emission Rates and Stack Parameters for Existing or Modified Holly Sources

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Stack Exit Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO_X (g/s)
#5 Boiler	423788.9	4526685.8	1301.3	15.2	810.9	16.72	1.22	0.1764
#8 Boiler	423807.4	4526650.8	1302.0	15.2	810.9	22.15	1.60	0.2336
#9 Boiler	423801.9	4526653.0	1302.0	15.2	810.9	12.38	1.60	0.2250
#10 Boiler	423789.7	4526634.2	1302.0	15.2	810.9	12.38	1.60	0.2250
North In-Tank Asphalt Heater	424141.2	4526736.4	1307.0	13.4	616.5	1.03	0.46	0.0098
South In-Tank Asphalt Heater	424129.8	4526726.6	1307.0	13.4	616.5	1.03	0.46	0.0098
North In-Tank Asphalt Heater	424102.6	4526818.5	1305.0	13.4	616.5	1.03	0.46	0.0098
South In-Tank Asphalt Heater	424116.1	4526819.3	1305.0	13.4	616.5	1.03	0.46	0.0098
Process Flare (south)	423707.0	4526793.5	1298.9	64.9	1273.0	20.00	0.78	0.1675
Process Flare (north)	423707.0	4526793.5	1298.9	64.9	1273.0	20.00	0.78	0.1675

The AERMOD model was run with the regulatory default option which includes the following:

- Stack tip downwash,
- Calms and missing meteorological data routine,
- Direction-specific building downwash,
- Actual receptor elevations,
- Sequential date checking, and
- Complex/intermediate terrain algorithms.

Other selected input variables that were used in AERMOD include:

- 24-hour averaging period for PM_{10},
- One-hour and annual averaging periods for NO_2,
- One-hour averaging for SO_2,
- 1- and 8- hour averaging periods for CO,
- elevated terrain,
- 1- or 24-hour averaging periods for HAPs (as necessary depending on type of HAP),
- Non-default Plume Volume Molar Ratio Method (PVMRM) for NO_2,
- Urban roughness length of 1.0 meter,
- Multiple urban areas for the full impact analysis, and
- concentrations.

6.9 Good Engineering Practice (GEP) Stack Height

The GEP stack height is defined under Section 123 of the CAA as "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes which may be created by the source itself, nearby structures or nearby terrain obstacles." GEP stack height was calculated with the formulas presented in 40 CFR 51.100 (ii). The EPA's refined formula height is defined as H +1.5 L, where L is length.

6.10 Downwash

The BPIP-Prime algorithm in AERMOD was utilized to address downwash effects. The height, width, length, and base elevation of the proposed structures that are in existence or will be constructed at the Holly refinery were utilized. BPIP determines, in each of the 36 wind directions (10 degree sectors) which buildings will produce the greatest downwash effects for a stack. Table 6-7 presents the building dimensions used in AERMOD.

Table 6-7

Building Dimensions used in AERMOD

Building Name	Building Code	E-W Dimension (meters)	N-S Dimension (meters)	Height (meters)
Sulfur Unit (lattice)	SULATT	24.69	19.31	12.00
Boiler House	BH	29.65	17.44	8.00
Heater 4-H-1	HTR4H1	3.03	14.66	15.00
Ammonia Stripping Unit (lattice)	ASULATT	6.90	19.78	20.00
TCC (lattice)	TCC	9.69	11.43	67.00
FCC (lattice)	FCC	10.36	22.77	40.00
Crude Tower	CRUTWR	4.80	5.88	41.00
Crude Unit (lattice)	CRUNIT	6.91	13.88	18.00
Reactor Charge Furnace (lower)	RCFLWR	4.64	4.00	12.00
Reactor Charge Furnace (upper)	RCFUPR	1.60	1.22	26.00
HDS Charge Heater (lower)	HDSLWR	1.43	1.22	7.00
HDS Charge Heater (upper)	HDSUPR	0.84	0.67	17.00
South Office	SOFFICE	33.19	27.09	4.00
North Office/CCR	NOFFICE	18.45	47.84	4.00
Horizontal Tank 122	TANK122	16.50	2.50	2.50
Horizontal Tank 123	TANK123	16.50	2.50	2.50
Horizontal Tank 133	TANK133	25.00	3.75	3.75
Horizontal Tank 134	TANK134	25.00	3.75	3.75
Horizontal Tank 136	TANK136	28.00	2.90	2.90
Horizontal Tank 147	TANK147	21.00	2.65	2.65
Horizontal Tank 148	TANK148	21.00	2.65	2.65
Horizontal Tank 149	TANK149	21.00	2.65	2.65
Horizontal Tank 150	TANK150	21.00	2.65	2.65
Horizontal Tank 151	TANK151	21.00	2.65	2.65
Horizontal Tank 152	TANK152	21.00	2.65	2.65
Horizontal Tank 153	TANK153	21.00	2.65	2.65
Horizontal Tank 324	TANK324	21.00	2.65	2.65
Horizontal Tank 141	TANK141	28.50	3.65	3.65
Horizontal Tank 171	TANK171	4.14	25.88	3.50
Horizontal Tank 172	TANK172	3.49	25.50	3.50
Horizontal Tank 173	TANK173	28.50	3.65	3.65
Horizontal Tank 174	TANK174	28.50	3.65	3.65

6.11 PVMRM

The non-default PVMRM option was utilized in the NO_2 dispersion modeling analysis. PVMRM accounts for NO_2/NO_x chemistry using an in-stack ratio of NO_2 to NO_x and ambient ozone values. In stack ratio used were based on source testing conducted by CCI Environmental Consultants on February 16, 2012. The results of the source testing are presented in Appendix G. Hourly ozone data obtained from the UDAQ Bountiful ambient air quality station for 2006-2009 was formatted for input into AERMOD.

6.12 Urban Roughness

The AERMOD model includes the option to specify if the source is located in an urban area which modifies the dispersion for low-level emission sources to produce more realistic urban dispersion. 40CFR 50 Appendix W provides two procedures to determine if rural or urban dispersion coefficients should be used for a source, land use classification and population density. The first procedure which is based on land use classification requires 50 percent of the area within a three kilometer radius be classified as land use types I1, I2, C1, R2, and R3. Figure 6.7 presents a depiction of 2006 National Land Cover Data (NLCD) data surrounding the Holly Facility. The second procedure requires a population density within the three kilometer radius to be greater than 750 people per square kilometer. Table 6-8 presents the 2010 population density for cities that are within a three-kilometer radius from the refinery. Figure 6.8 presents a population density analysis around Holly's Woods Cross Facility.

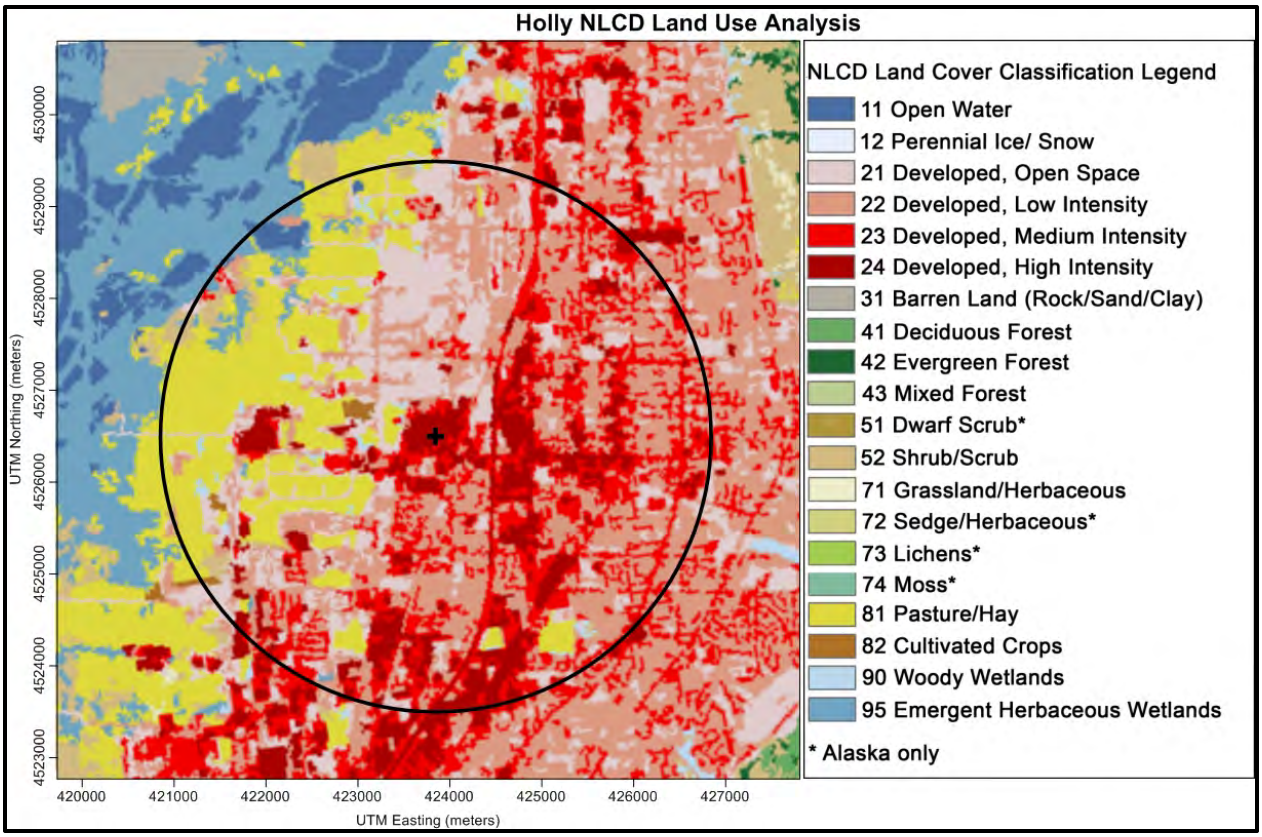

Figure 6.7 Land Use Surrounding Holly Refinery

Table 6-8

Surrounding City Population Densities

Area Name	Area Population	Area Population Density (People/km^2)
Bountiful	42,522	1,221
West Bountiful	5,265	625
Woods Cross	9,761	971
Salt Lake City	186,440	647
Centerville	15,335	990

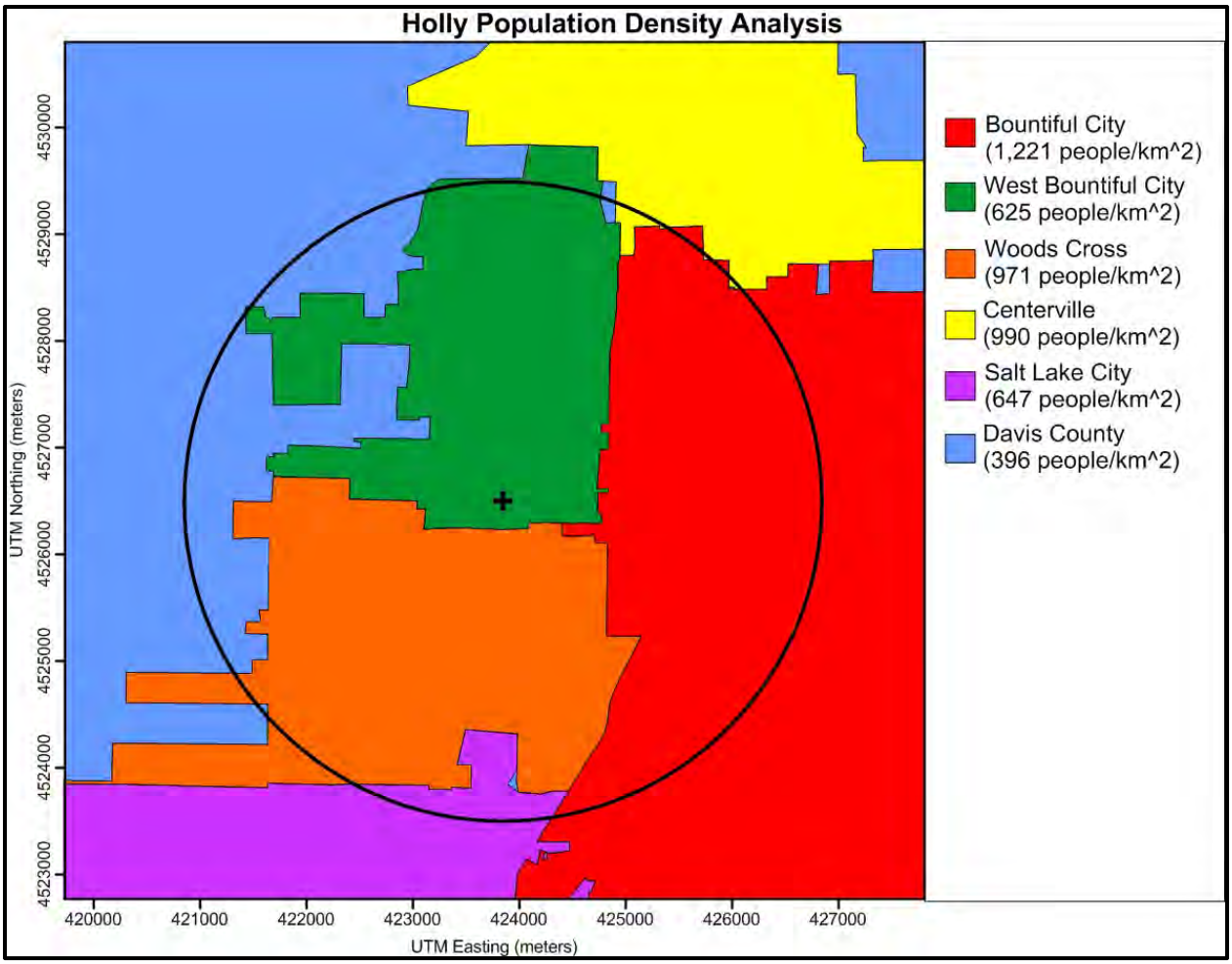

Figure 6.8 Cities/Population Densities Surrounding Holly

6.13 Near-Field Modeling Results

Although CO was the only projected pollutant with emissions above the modeling significance levels, per a request from the UDAQ, near-field modeling was performed for NO_2, CO, SO_2, and PM_{10}. The results of the near-field modeling from proposed new sources only from Holly's heavy crude processing project are presented in Table 6-9 and in Appendix H. AERMOD results for proposed and existing or modified sources at Holly are presented in Table 6-10 and Appendix H. Figures 6.9 through 6.14 present the modeled concentration isopleth plots for the entire Holly facility for NO_2, CO, SO_2, and PM_{10}.

Maximum modeled values are presented for one- and eight-hour CO, and annual NO_2 concentrations. High-second-high (HSH) modeled values are presented for 24-hour PM_{10}. Modeled values for one-hour NO_2 represent the 98th percentile based on a three-year average (2006-2008). Modeled values for one-hour SO_2 represent the 99th percentile based on a three-year average (2006-2008).

Table 6-9

Modeled Maximum and High-Second-High Near-Field Pollutant Concentrations for Proposed Holly Refining & Marketing Company Heavy Crude Processing Project

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Location of Model Predicted Concentration	
			UTM East (meters)	UTM North (meters)
NO_2	1-hour[1]	8.7	423887.1	4527160.1
	Annual	0.60	424198.4	4526780.0
SO_2	1-hour[2]	5.4	423840.6	4527010.2
CO	1-hour	70.6	424650.0	4527450.0
	8-hour	32.7	423776.4	4526311.5
PM_{10}	24-hour (high)	1.5	423768.5	4526277.5
	24-hour (HSH)	1.2	423776.4	4526311.5

HSH – High-Second-High
[1] - 98th percentile based on a three-year average (2006-2008)
[2] - 99th percentile based on a three-year average (2006-2008)

Table 6-10

Modeled Maximum and High-Second-High Near-Field Pollutant Concentrations for Proposed and Existing Holly Refining & Marketing Company Sources

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Location of Model Predicted Concentration	
			UTM East (meters)	UTM North (meters)
NO_2	1-hour[1]	88.3	423999.6	4526635.1
	Annual	5.4	423999.6	4526635.1
SO_2	1-hour[2]	23.5	424000.4	4526709.7
CO	1-hour	258.9	424000.4	4526709.7
	8-hour	86.9	423950.0	4526200.0
PM_{10}	24-hour (high)	80.6	423776.4	4526311.5
	24-hour (HSH)	55.7	424000.0	4526550.0

HSH – High-Second-High
[1] - 98th percentile based on a three-year average (2006-2008)
[2] - 99th percentile based on a three-year average (2006-2008)

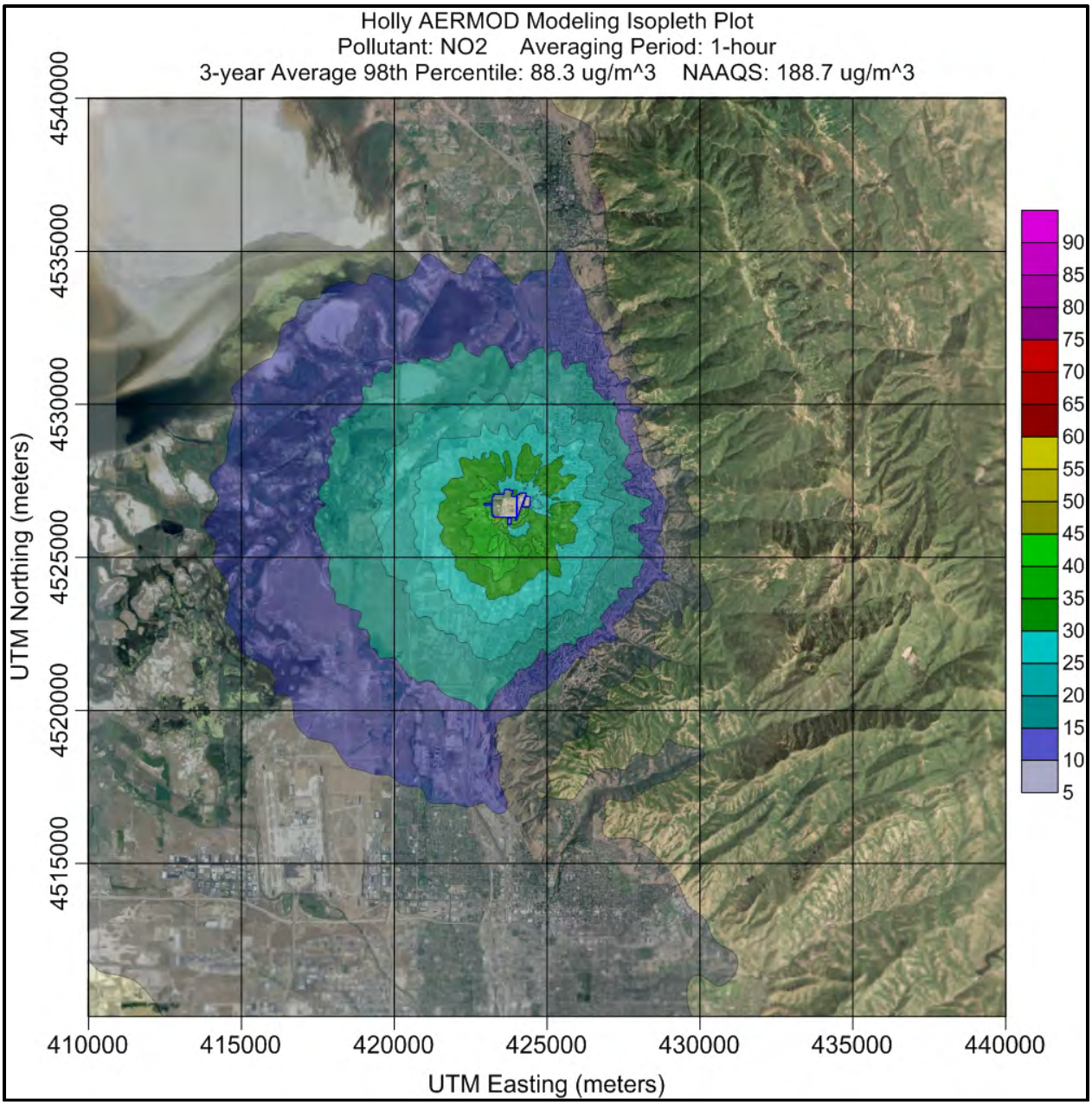

Figure 6.9 Modeled 98th Percentile One-hour NO_2 Concentration Isopleth Plot Based on Three-Year Average

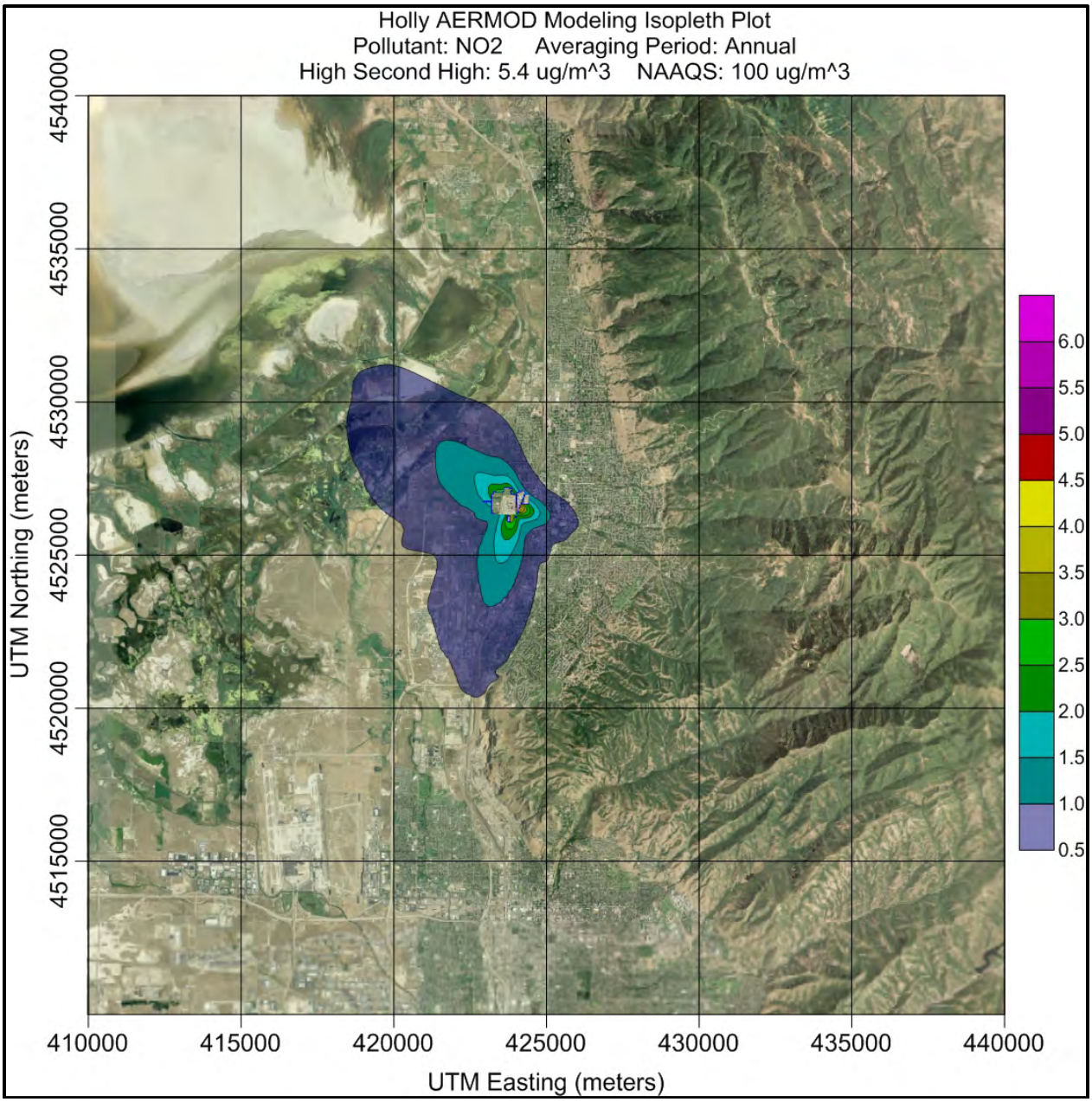

Figure 6.10 Modeled Maximum Annual NO_2 Concentration Isopleth Plot

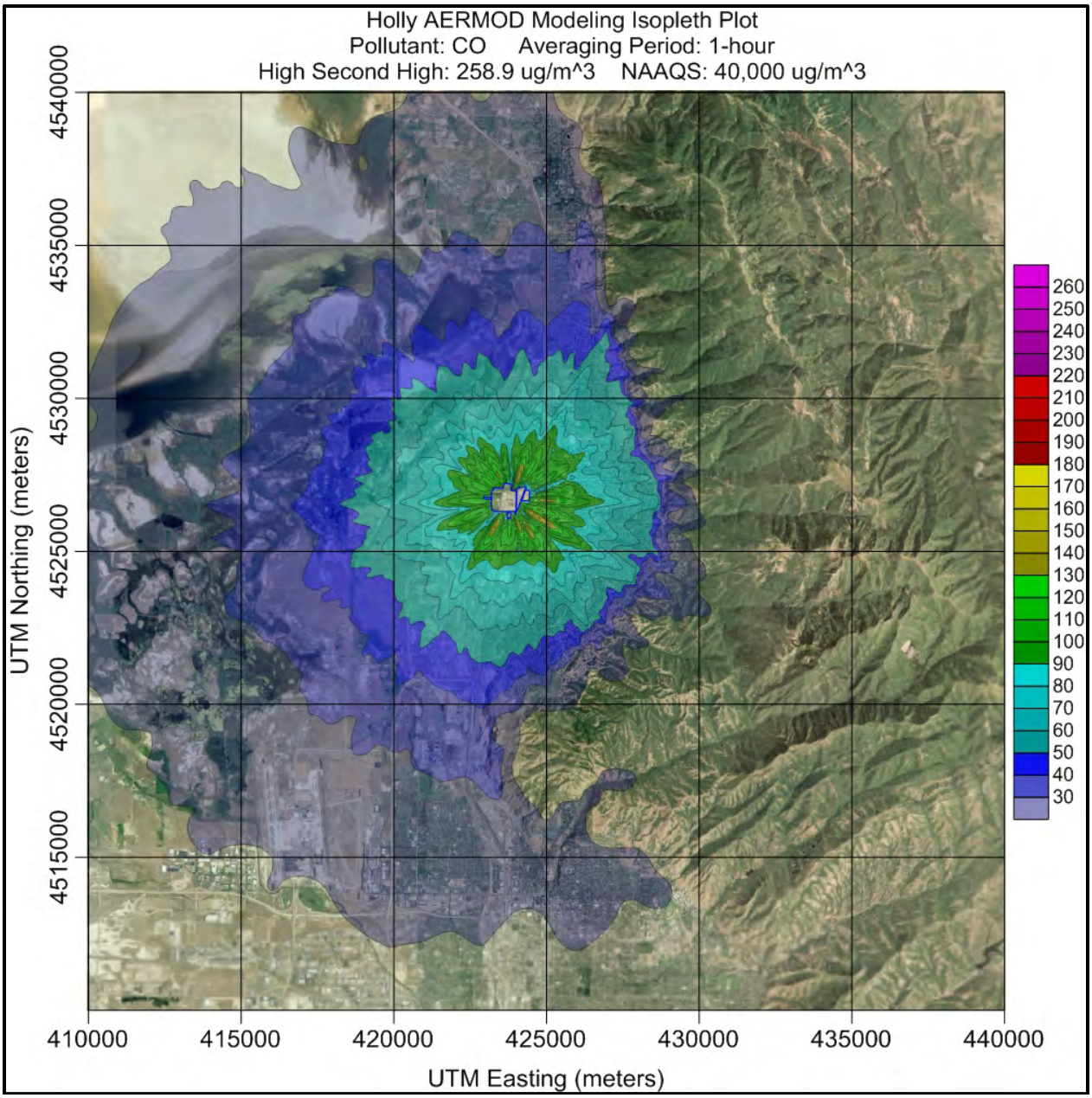

Figure 6.11 Modeled Maximum One-hour CO Concentration Isopleth Plot

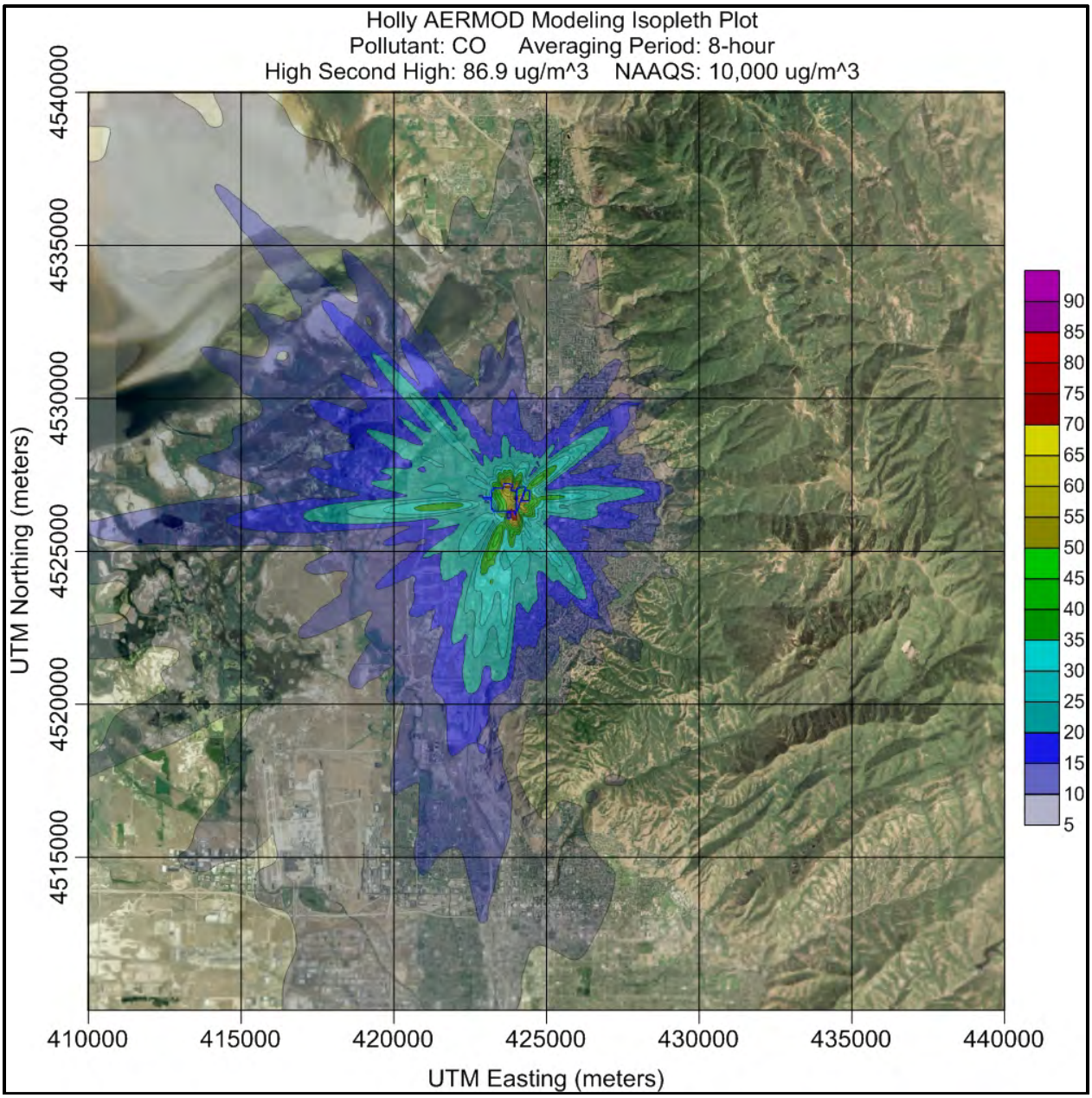

Figure 6.12 Modeled Maximum Eight-hour CO Concentration Isopleth Plot

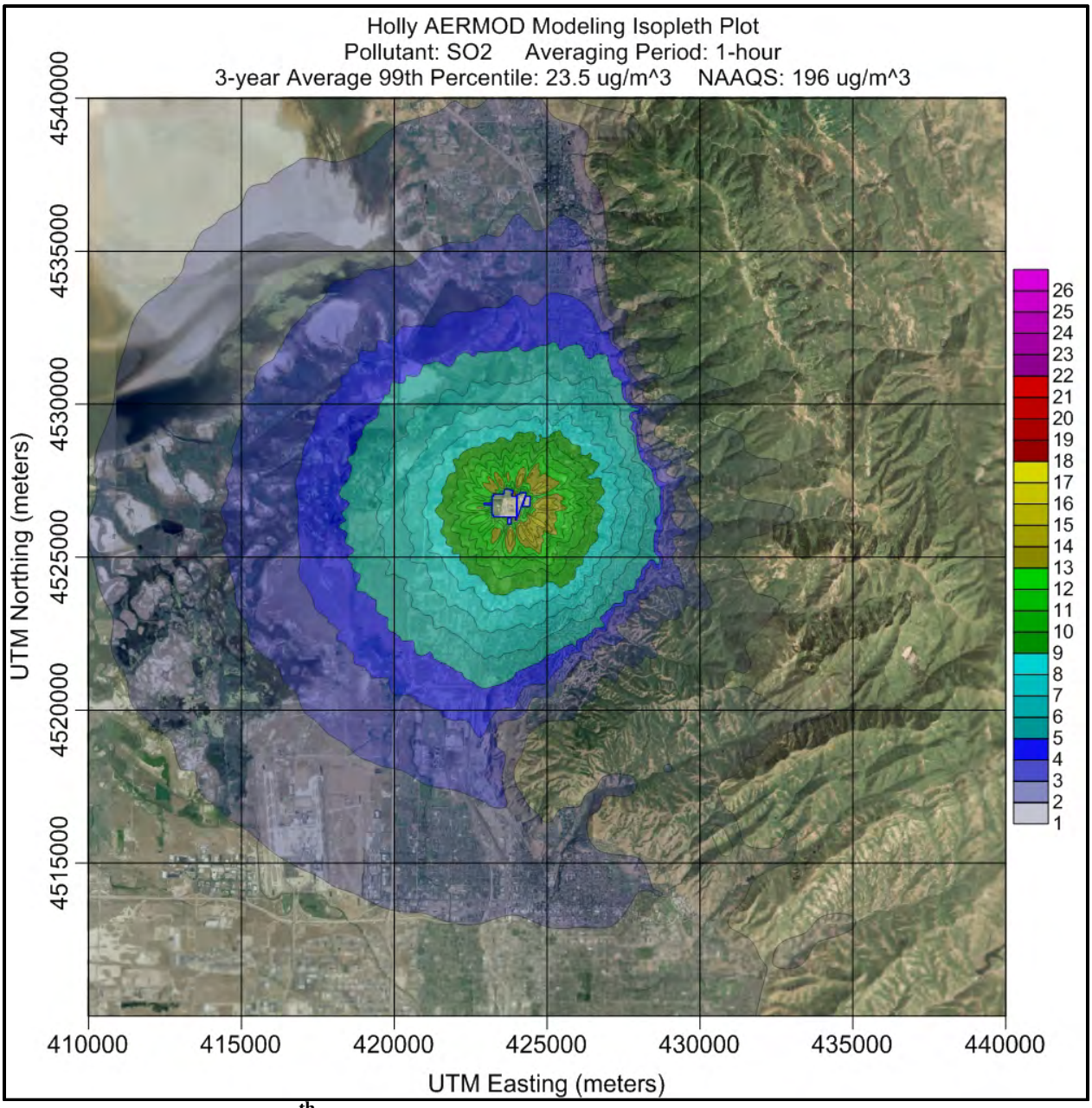

Figure 6.13 Modeled 99th Percentile One-hour SO_2 Concentration Isopleth Plot Based on Three-Year Average

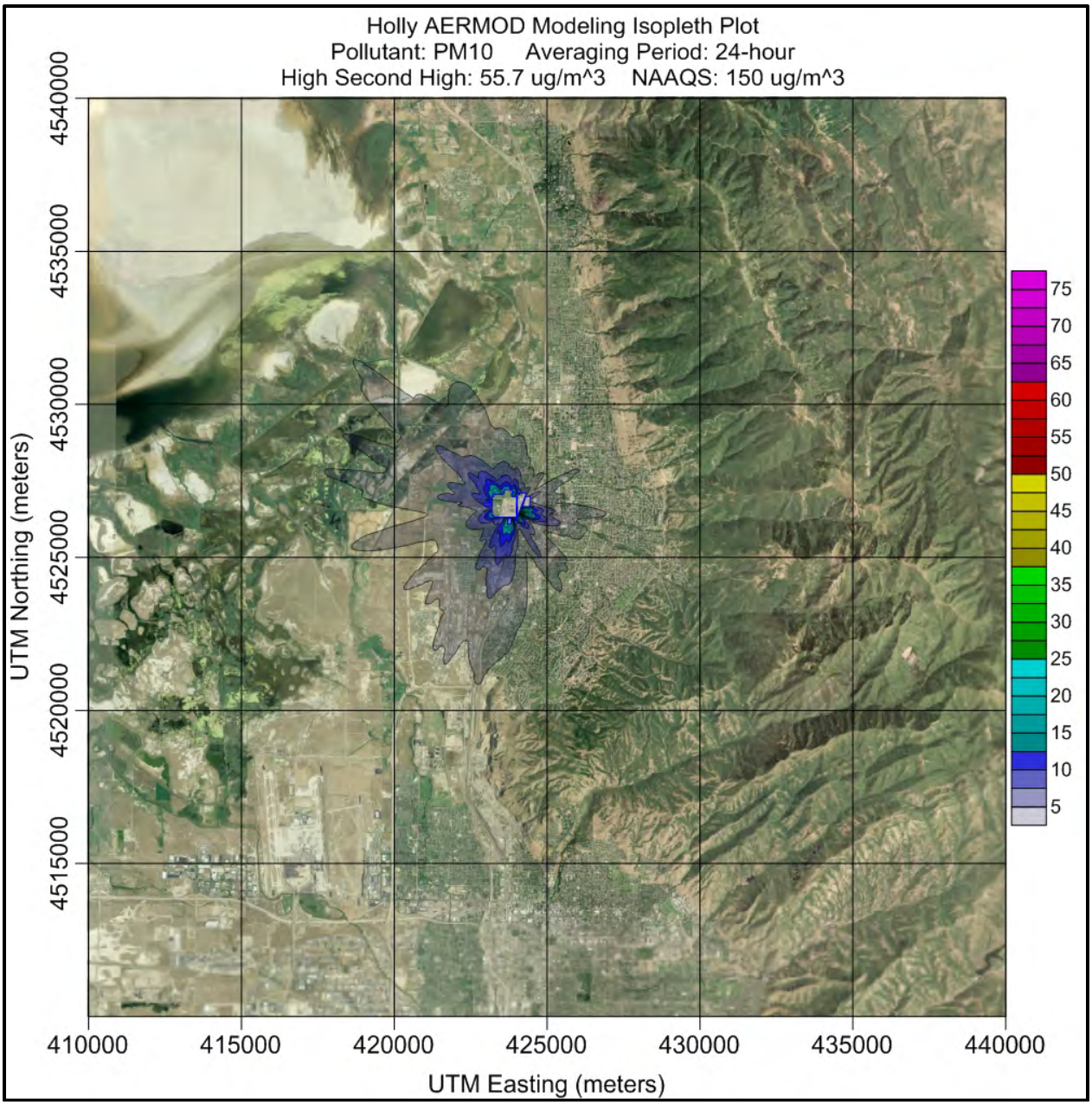

Figure 6.14 Modeled High-Second-High 24-hour PM_{10} Concentration Isopleth Plot

6.14 Significant Impact Levels

The EPA has adopted significant impact levels (SILs) for criteria pollutants. If the highest modeled concentrations for any pollutant and averaging period evaluated are less than the applicable SIL, a full impact or cumulative air quality analysis is not required for that pollutant and averaging period; however, these pollutants may still be subject to further review as part of the PSD additional impact analysis requirements. Table 6-11 presents the PSD Class II area SILs.

Table 6-11

PSD Class II Area Significant Air Quality Impact Levels

Pollutant	Averaging Period	Significant Impact Level ($\mu g/m^3$)
NO_2	1-hour	7.5
	annual	1
SO_2	1-hour	7.8
CO	1-hour	2000
	8-hour	500
PM_{10}	24-hour	5

6.15 Full Impact Analysis

A full impact analysis was performed to determine whether proposed Holly sources would cause a significant off-site impact. In addition to emissions from the proposed processing project, the full impact analysis considers emissions from existing sources as well as the growth associated with the new project. An impact area was established to determine the geographical area for which the required air quality analyses for the NAAQS and PSD increments are carried out. This area includes all locations where the significant increase in the potential emissions of a pollutant from the proposed Holly processing project will cause a significant ambient impact (i.e., equals or exceeds the applicable significant impact levels in Table 6-11). For those pollutants whose impacts were below the modeling significance levels, no further analyses were performed.

Table 6-12 compares modeled maximum concentrations with the significant impact levels. For Holly's heavy crude processing project sources, model predicted impacts of NO_2 were above the modeling significance levels; thus, a full impact analysis was performed to demonstrate compliance with the applicable standards. The impact area is a circular area with a radius extending from the source to the most distant point where AERMOD predicted a significant impact would occur. The maximum distance determined was 3.3 kilometers for one-hour NO_2. A distance of 50 kilometers was added to the maximum distance to define the scope of the full impact analysis.

Table 6-12

Comparison of Modeled Maximum Concentrations for

Holly's Proposed Heavy Crude Processing Project to Significant Impact Levels

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Percent of SIL	Radius of Impact
NO_2	1-hour	12.4	7.5	165%	3.3
	Annual	0.6	1	60%	NA
SO_2	1-hour	7.5	7.8	96%	NA
CO	1-hour	70.6	2,000	3.5%	NA
	8-hour	32.7	500	6.5%	NA
PM_{10}	24-hour	1.5	5	3.0%	NA

6.16 Near-by Source Inventory

UDAQ was contacted to obtain source and emissions information for sources of NO_x that fell within the radius of impact. The UDAQ identified several NO_x sources within the impact area and provided source and emissions information for these sources. A summary of the full impact sources modeled and distance from Holly's refinery are presented in Table 6-13.

Table 6-13

Full Impact Analysis Sources

Source Name	UTM East (meters)	UTM North (meters)	Distance from Holly (kilometers)
Bountiful Power	425416.2	4526557.3	1.6
Gadsby Power Plant	421445.2	4513453.8	13.4
Tesoro Refinery	423603.9	4516183.0	10.4
Chevron Refinery	422232.9	4519660.5	7.1
Big West Oil Refinery	422535.9	4521115.5	5.6
Silver Eagle Refinery	423257.9	4524414.5	2.3

The emissions and source information for PacifiCorp's Gadsby Plant, Chevron, Silver Eagle, Tesoro, and Big West Refineries and Bountiful Power were added to the Holly AERMOD model setup for proposed and existing sources and the model was rerun. Per the UDAQ, permit limits on daily NO_2 emissions were modeled. Stack parameters and emission rates were provided by UDAQ. All sources included in the full impact analysis were modeled as point sources. Full impact source parameters and emission rates are provided in Appendix I. The results of the full impact analysis are presented in Table 6-14 and in Appendix J.

Table 6-14

Full Impact Analysis AERMOD Results

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Location of Model Predicted Concentration	
			UTM East (meters)	UTM North (meters)
NO_2	1-hour[1]	167.8[2]	421500.0	4518000.0

[1] - 98th percentile based on a three-year average (2007-2009)
[2] - Includes background concentrations from UDAQ's Bountiful monitor

6.17 National Ambient Air Quality Standard Compliance

For NAAQS compliance, the background pollutant concentrations obtained from the UDAQ were added to the modeled maximum concentrations to evaluate the total impact. The modeled maximum and HSH pollutant concentrations, background concentrations, NAAQS, and percent of NAAQS for Holly heavy crude processing project sources and existing sources are presented in Table 6-15. The maximum, background concentrations, NAAQS, and percent of NAAQS for all sources modeled (Holly plus full impact sources) are presented in Table 6-16.

Table 6-15

NAAQS Compliance Demonstration for Holly's Proposed Heavy Crude Processing Project and Existing Holly Sources Only

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
NO_2	1-hour[1]	88.3[2]	89.7	178.0	188.7	94.3%
	Annual	5.4	35.5	40.9	100	40.9%
CO	1-hour	258.9	4,122	4,380.9	40,000	11.0%
	8-hour	86.9	2,484	2,570.9	10,000	25.7%
SO_2	1-hour[3]	24.2	26.2	50.4	196	25.7%
PM_{10}	24-hour (high)	80.6	56.3	136.9	150	91.3%
	24-hour (HSH)	55.7	56.3	112.0	150	74.7%

HSH – High-Second-High
[1] - 98th percentile based on a three-year average (2006-2008)
[2] – Without corresponding background concentrations from UDAQ's Bountiful monitor
[3] - 99th percentile based on a three-year average (2006-2008)

Table 6-16

NAAQS Compliance Demonstration for Full Impact Analysis Sources

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
NO_2	1-hour[1]	167.8	included	167.8	188.7	88.9%

[1] - 98th percentile based on a three-year average (2007-2009)

Full impact concentration isopleth plots for the entire modeling domain for the one-hour NO_2 are presented in Figure 6.15.

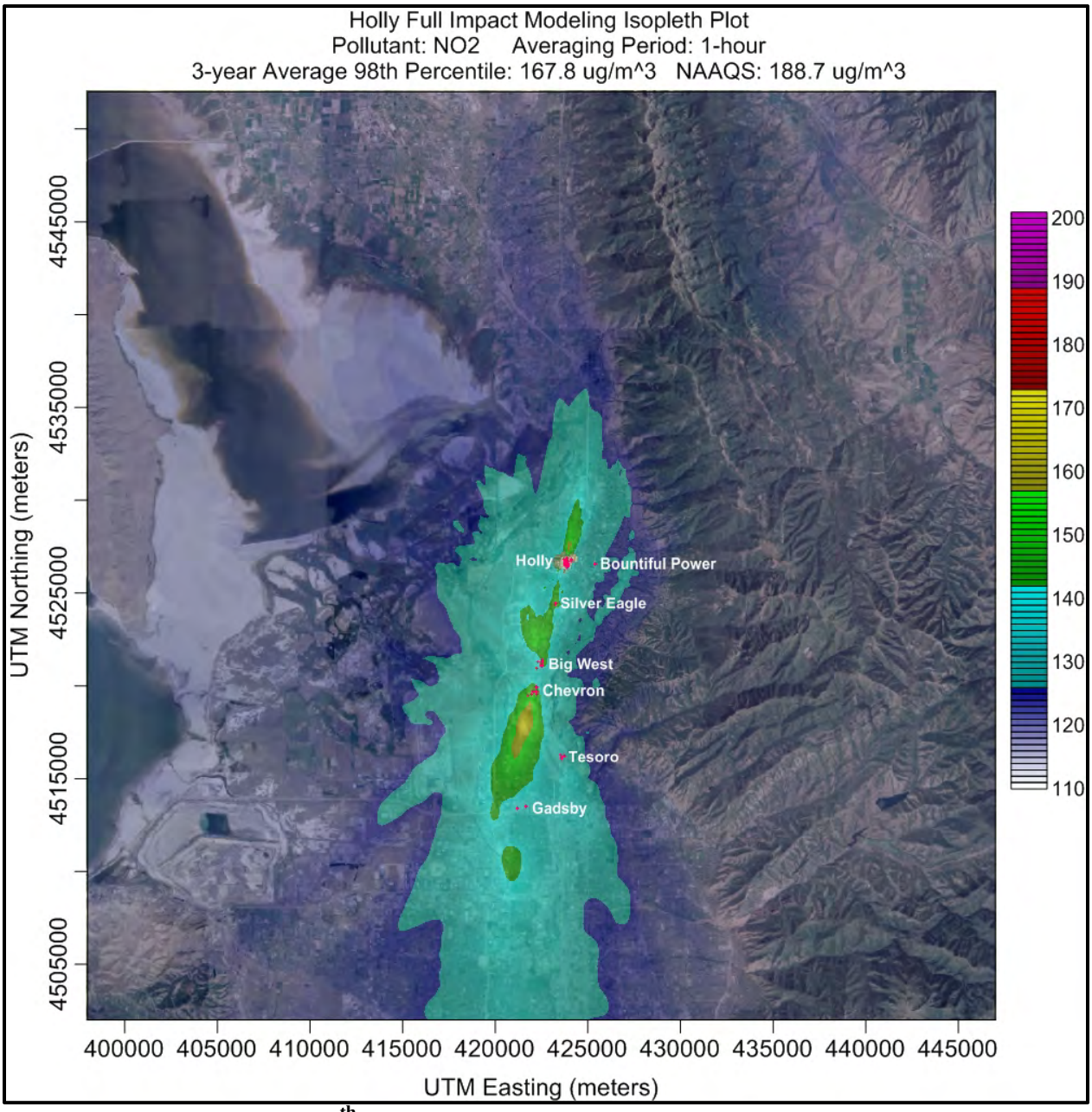

Figure 6.15 Modeled 98th Percentile One-Hour NO_2 Concentration Isopleth Plot – Full Impact Analysis - Entire Modeling Domain Based on Three-Year Average

6.18 PSD Class II Increment Compliance

For the PSD increment analysis, all NO_2 sources were assumed to consume PSD increment. The modeled maximum pollutant concentrations full impact sources for NO_2 were evaluated against the PSD Class II increments. The modeled pollutant concentrations, the PSD Class II increment, and percent of Class II increment consumed by full impact NO_2 sources are presented in Table 6-17.

Table 6-17

PSD Class II Increment Compliance for Full Impact Analysis Sources

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Percent of Class II Increment
NO_2	Annual[1]	9.3	25	37.2%

[1]Holly and full impact analysis sources

6.19 Hazardous Air Pollutant Air Quality Analyses

Hazardous air pollutant analyses were performed in accordance with Utah Administrative Code R307-410-5. To determine which HAPs required modeling, the UDAQ's 2009 ACGIH Threshold Limit Values (TLVs), Toxic Screening Levels (TSLs) and Emission Threshold Values (ETVs) Microsoft Excel spreadsheet was utilized. The spreadsheet TLVs were updated with data from the ACGIH's 2011 TLV and BEI's Threshold Limit Values for Chemical Substances and Physical Agents & Biological Exposure Indices Handbook.

Based on the spreadsheet results (presented in Appendix K), the emission rates of benzene, formaldehyde, beryllium, cadmium, chromium, and chlorine were above the ETV levels. Thus, dispersion modeling for these HAPs was conducted and the HAP model output is presented in Appendix L. All three HAPs were modeled as a vertically unrestricted release with a distance of greater than 20 meters to the property line.

Formaldehyde was considered to be acute while beryllium and chlorine were considered to be chronic and benzene, cadmium and chromium were considered carcinogenic. Per R307-410-5, the toxic screenings level is calculated by dividing safety factors to the TLV defined in ACGIH. The TLV is divided by 10 for averaging periods of 1-hour or less. For Chronic HAPs, the TLV is divided by 30 for a 24-hour averaging period and for carcinogenic HAPs, the TLV is divided by a safety factor of 90 for a 24-hour averaging period. The results of the HAPS modeling are presented in Table 6-18 and Appendix L.

Table 6-18

Modeled Maximum HAP Concentrations

HAP	Averaging Period	Model Predicted Conc. (ug/m3)	TLV ug/m3	Safety Factor	TSL (ug/m3)	Percent of NAAQS
Benzene	24-HR	0.6	1597.3	90	17.7	3.3%
Formaldehyde	1-HR	0.6	368.5	10	36.8	1.5%
Beryllium	24-HR	0.00E+00	0.1	30	1.67E-03	0.0%
Cadmium	24-HR	1.70E-04	2.0	90	2.22E-02	0.8%
Chromium	24-HR	2.20E-04	10.0	90	1.11E-01	0.2%
Chlorine	24-HR	1.7	1450.1	30	48.3	3.6%

6.20 Preconstruction Monitoring

The results of the SIL modeling were reviewed to determine if the ambient impacts from the proposed heavy crude processing project were below significant monitoring concentrations.

7.0 ADDITIONAL IMPACT ANALYSES

This section contains supplemental information regarding the potential impacts of the project; specifically, the potential for impacts to soils, vegetation, and growth.

7.1 Soils and Vegetation Analysis

The Holly Refinery is located in Davis County, Utah. The United States Department of Agriculture, Natural Resource conservation Service, Web Soil Survey tool was used to inventory the soil and vegetation types found in the area. Soils surrounding the refinery are mostly Draper and Chance loams, Logan silty clay loam, and Woods Cross silty clay loam. The most common vegetation in these soil types includes Kentucky bluegrass, clustered field and Nebraska sedge, and Arctic rush. The soil report and information on rangeland and forest vegetation classifications, productivity, and plant composition is included in Appendix M.

No sensitive aspects of the soil and vegetation in the area surrounding the facility have been identified. Carbon monoxide is generally not phytotoxic. Consequently, the evaluation of the secondary NAAQS, which was established to protect public welfare including the prevention of damage to vegetation, can be used to demonstrate that the increase in CO from the proposed project will not result in harmful effects. A conservative quantitative analysis was conducted by comparing the AERMOD-predicted ambient impacts of CO to the screening criteria for sensitive vegetation species as found in EPA's Screening Procedure for the Impacts of Air Pollution Sources of Plants, Soils, and Animals[19]. The results of the analysis are presented in Table 7-1. For CO, the listed one-week impact is conservatively assumed to be the same as the AERMOD-predicted 8-hour impact from the proposed new sources.

[19] U.S. Environmental Protection Agency, 1980: A Screening Procedure for the Impacts of Air Pollution Sources of Plants, Soils, and Animals. EPA-450/2-81/078.

Table 7-1

Vegetation Impact Analysis

Pollutant	Averaging Period	Modeled Impact[1] ($\mu g/m^3$)	Screening Concentration ($\mu g/m^3$)
CO	1-week	110.8	1,800,000

[1] Model predicted impact is maximum 8-hour concentration from new sources

Thus, as demonstrated in the analysis above, the maximum ground-level concentration associated is well below the EPA's screening concentration. Thus, it can be concluded that the proposed project will not have an adverse impact upon local soils and vegetation.

7.2 Growth Analysis

The work force for the proposed expansion project is expected to range from 50 to 100 jobs during various phases of the construction. It is expected that a regional construction force is already available to build the proposed expansion. Therefore, it is anticipated that no new housing, commercial or industrial construction is necessary to support Holly Refining & Marketing Company during the two-year construction schedule.

With the expansion, approximately 25 permanent positions will be added. It is assumed that individuals that already live in the region will perform these jobs. No new housing requirements are expected for any new personnel moving to the area. In addition, due to the small number of new individuals expected to move into the area to support the expansion project and the existence of commercial activity in the area, new commercial construction would not be necessary to support the permanent work force. Additionally, no significant level of industrial related support will be necessary for Holly's expansion project. Therefore, industrial growth is not expected. Based on the growth expectations discussed above, no new significant emissions from secondary growth during the construction and operation phases of Holly's expansion project are anticipated.

8.0 REFERENCES

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Appendix A
Baseline Emission Estimates

		PM10 Tons	PM2.5 Tons	SOx Tons	NOx Tons	VOC Tons	CO Tons	Lead Tons	Benzene Tons	Formalde. Tons	Hexane Tons	Toluene Tons	Arsenic Tons	Cadmium Tons	Chromium Tons	Cobalt Tons	Mercury Tons	Nickel Tons
2003	2004	57.16	36.25	446.72	66.43	14.56	49.66	0.00007	0.00029	0.01	0.25	0.00047	0.00003	0.00016	0.00020	0.00001	0.00004	0.03802
2004	2005	55.85	35.50	426.16	65.08	14.38	54.68	0.00013	-	-	-	-	-	-	-	-	-	-
2005	2006	57.73	36.77	442.36	68.95	14.11	69.37	0.00007	0.00042	0.01	0.36	0.00069	0.00004	0.00022	0.00028	0.00002	0.00005	0.03406
2006	2007	50.83	25.26	470.83	80.62	15.47	118.11	0.00007	0.00071	0.02	0.61	0.00115	0.00007	0.00038	0.00047	0.00003	0.00009	0.06799
2007	2008	41.64	25.54	461.99	84.10	12.79	137.13	0.00014	0.00065	0.02	0.55	0.00105	0.00006	0.00034	0.00043	0.00003	0.00008	0.05244
2008	2009	42.45	39.72	443.62	85.15	12.09	139.54	0.00007	0.00083	0.03	0.71	0.00135	0.00008	0.00044	0.00055	0.00004	0.00010	0.03867
2009	2010	42.96	40.23	329.43	96.65	15.56	162.27	-	0.00093	0.03	0.80	0.00151	0.00009	0.00049	0.00062	0.00004	0.00011	0.03476

SRU Incinerator - Unit 17
Holly Refining & Marketing

	PM10	PM2.5	SOx	NOx	VOC	CO	Lead	Benzene	Formalde.	Hexane	Toluene	Arsenic	Cadmium	Chromium	Cobalt	Mercury	Nickel
	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons
2001	0.07	0.07	139.45	0.88	0.05	0.74	0.00E+00	2.00E-05	6.80E-04	1.63E-02	3.00E-05	0.00E+00	1.00E-05	1.50E-05	0.00E+00	0.00E+00	2.00E-05
2002	0.06		147.73	0.78	0.04	0.65	0.00E+00	1.50E-05	5.90E-04	1.41E-02	2.50E-05	0.00E+00	1.00E-05	1.00E-05	0.00E+00	0.00E+00	1.50E-05
2003	0.07	0.07	159.08	0.86	0.05	0.72	0.00E+00	1.50E-05	5.90E-04	1.41E-02	2.50E-05	0.00E+00	1.00E-05	1.00E-05	0.00E+00	0.00E+00	1.50E-05
2004	0.06	0.06	149.37	0.85	0.05	0.71	4.24E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2005	0.06	0.06	149.37	0.85	0.05	0.71	4.24E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2006	0.06	0.06	170.78	0.74	0.04	0.62	0.00E+00	1.50E-05	6.10E-04	1.46E-02	3.00E-05	0.00E+00	1.00E-05	1.00E-05	0.00E+00	0.00E+00	1.50E-05
2007	0.06	0.06	170.78	0.80	0.04	0.68	4.02E-06	1.50E-05	6.10E-04	1.46E-02	3.00E-05	0.00E+00	1.00E-05	1.00E-05	0.00E+00	0.00E+00	1.50E-05
2008	0.07	0.07	125.39	0.90	0.05	0.75	4.02E-06	2.00E-05	6.70E-04	1.61E-02	3.00E-05	0.00E+00	1.00E-05	1.00E-05	0.00E+00	0.00E+00	2.00E-05
2009	0.07	0.07	119.62	0.89	0.05	0.75	0.00E+00	2.00E-05	6.70E-04	1.61E-02	3.00E-05	0.00E+00	1.00E-05	1.00E-05	0.00E+00	0.00E+00	2.00E-05
2010	0.07	0.07	182.94	0.90	0.05	0.76	0.00E+00	2.00E-05	6.65E-04	1.60E-02	3.00E-05	0.00E+00	1.00E-05	1.00E-05	0.00E+00	0.00E+00	2.00E-05
2011	0.07	0.07	122.45	0.90	0.05	0.76											
2003	0.0672	0.0672	154.2250	0.8541	0.0483	0.7162	0.0000	0.0000	0.0003	0.0071	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2004	0.0645	0.0645	149.3700	0.8481	0.0466	0.7124	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2005	0.0622	0.0622	160.0750	0.7941	0.0433	0.6662	0.0000	0.0000	0.0003	0.0073	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2006	0.0605	0.0605	170.7800	0.7719	0.0421	0.6476	0.0000	0.0000	0.0006	0.0146	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2007	0.0655	0.0655	148.0850	0.8519	0.0471	0.7126	0.0000	0.0000	0.0006	0.0153	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2008	0.0700	0.0700	122.5050	0.8950	0.0500	0.7500	0.0000	0.0000	0.0007	0.0161	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2009	0.0700	0.0700	151.2800	0.8950	0.0500	0.7550	0.0000	0.0000	0.0007	0.0160	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2010	0.0700	0.0700	152.6950	0.9000	0.0500	0.7600	0.0000	0.0000	0.0007	0.0160	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	0.0700	0.0700	170.7800	0.8950	0.0500	0.7550	0.0000	0.0000	0.0007	0.0161	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

South Flare - 66-1
Holly Refining & Marketing

	PM10 Tons	PM2.5 Tons	SOx Tons	NOx Tons	VOC Tons	CO Tons	Lead Tons	Benzene Tons	Formalde. Tons	Hexane Tons	Toluene Tons	Arsenic Tons	Cadmium Tons	Chromium Tons	Cobalt Tons	Mercury Tons	Nickel Tons
2001	0.04	0.04	0.05	0.36	0.03	1.94	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2002	0.01		0.00	0.13	0.01	0.70	0.00E+00	7.00E-05	2.59E-03	6.21E-02	1.15E-04	5.00E-06	4.00E-05	5.00E-05	5.00E-06	1.00E-05	7.00E-05
2003	0.11	0.11	23.68	2.09	2.34	11.37	0.00E+00	2.50E-05	9.75E-04	2.34E-02	4.50E-05	5.00E-06	1.50E-05	2.00E-05		5.00E-06	2.50E-05
2004	0.10	0.10	6.29	1.37	0.91	7.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2005	0.10	0.10	6.29	1.37	0.91	7.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2006	0.00	0.00	2.55	0.54	1.08	2.97	0.00E+00	1.35E-04	4.85E-03	1.16E-01	2.20E-04	1.50E-05	7.00E-05	9.00E-05	5.00E-06	1.50E-05	1.35E-04
2007	0.00	0.00	1.27	1.32	3.80	4.76	0.00E+00	0.00E+00	0.00E+00	5.00E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2008	0.00	0.00	4.44	2.32	4.78	12.62	0.00E+00	0.00E+00	0.00E+00	2.50E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2009	0.00	0.00	2.38	0.80	1.65	4.35	0.00E+00	0.00E+00	0.00E+00	5.00E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Assumptions:
South Flare rebuilt

2003	0.1035	0.1035	14.9859	1.7279	1.6251	9.2002	0.0000	0.0000	0.0005	0.0117	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2004	0.0971	0.0971	6.2918	1.3659	0.9102	7.0303	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2005	0.0485	0.0485	4.4209	0.9529	0.9951	5.0002	0.0000	0.0001	0.0024	0.0581	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2006	0.0000	0.0000	1.9100	0.9300	2.4400	3.8650	0.0000	0.0001	0.0024	0.0581	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2007	0.0000	0.0000	2.8550	1.8200	4.2900	8.6900	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2008	0.0000	0.0000	3.4100	1.5600	3.2150	8.4850	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2009	0.0000	0.0000	1.1900	0.4000	0.8250	2.1750	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	0.1035	0.1035	14.9859	1.8200	4.2900	9.2002	0.0000	0.0001	0.0024	0.0581	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001

FCCU-4H1
Holly Refining & Marketing

	PM10	PM2.5	SOx	NOx	VOC	CO	Lead	Benzene	Formalde.	Hexane	Toluene	Arsenic	Cadmium	Chromium	Cobalt	Mercury	Nickel
	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons
2001	1.09	1.09	1.48	7.15	0.79	12.01	7.50E-05	3.10E-04	1.11E-02	2.67E-01	5.05E-04	3.00E-05	1.65E-04	2.10E-04	1.00E-05	4.00E-05	3.10E-04
2002	1.00		0.26	6.55	0.72	11.01	0.00E+00	2.75E-04	9.90E-03	2.38E-01	4.50E-04	2.50E-05	1.45E-04	1.85E-04	1.00E-05	3.50E-05	2.75E-04
2003	0.98	0.98	0.59	6.42	0.71	10.78	0.00E+00	2.45E-04	8.81E-03	2.11E-01	4.00E-04	2.50E-05	1.30E-04	1.65E-04	1.00E-05	3.00E-05	2.45E-04
2004	1.08	1.08	1.58	7.12	0.78	11.96	7.12E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2005	1.08	1.08	1.58	4.56	0.78	11.96	7.12E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2006	0.94	0.94	0.2	6.16	0.68	10.35	0.00E+00	2.85E-04	1.01E-02	2.43E-01	4.60E-04	2.50E-05	1.50E-04	1.90E-04	1.00E-05	3.50E-05	2.85E-04
2007	1.00	1.00	0.21	6.57	0.72	11.04	6.57E-05	2.85E-04	1.02E-02	2.45E-01	4.65E-04	2.50E-05	1.50E-04	1.90E-04	1.00E-05	3.50E-05	2.85E-04
2008	0.90	0.90	0.25	5.93	0.65	9.96	6.57E-05	2.45E-04	8.83E-03	2.12E-01	4.00E-04	2.50E-05	1.30E-04	1.65E-04	1.00E-05	3.00E-05	2.45E-04
2009	0.89	0.89	0.37	5.87	0.65	9.86	0.00E+00	2.50E-04	8.85E-03	2.12E-01	4.00E-04	2.50E-05	1.30E-04	1.65E-04	1.00E-05	3.00E-05	2.50E-04
2010	1.11	1.11	0.39	7.32	0.80	12.29	0.00E+00	3.00E-04	1.08E-02	2.59E-01	4.90E-04	3.00E-05	1.60E-04	2.00E-04	1.00E-05	3.50E-05	3.00E-04
2011	0.90	0.90	0.21	5.91	0.65	9.93											

Assumptions:
Emissions will be routed to wet scrubber
CO Boiler Removed

2003	1.0312	1.0312	1.0854	6.7702	0.7466	11.3712	0.0000	0.0001	0.0044	0.1057	0.0002	0.0000	0.0001	0.0001	0.0000	0.0000	0.0001
2004	1.0823	1.0823	1.5807	5.8388	0.7832	11.9623	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2005	1.0112	1.0112	0.8904	5.3585	0.7316	11.1562	0.0000	0.0001	0.0051	0.1213	0.0002	0.0000	0.0001	0.0001	0.0000	0.0000	0.0001
2006	0.9696	0.9696	0.2029	6.3666	0.7015	10.6964	0.0000	0.0003	0.0102	0.2440	0.0005	0.0000	0.0002	0.0002	0.0000	0.0000	0.0003
2007	0.9496	0.9496	0.2279	6.2516	0.6865	10.5014	0.0001	0.0003	0.0095	0.2286	0.0004	0.0000	0.0001	0.0002	0.0000	0.0000	0.0003
2008	0.8950	0.8950	0.3100	5.9000	0.6500	9.9100	0.0000	0.0002	0.0088	0.2121	0.0004	0.0000	0.0001	0.0002	0.0000	0.0000	0.0002
2009	1.0000	1.0000	0.3800	6.5950	0.7250	11.0750	0.0000	0.0003	0.0098	0.2357	0.0004	0.0000	0.0001	0.0002	0.0000	0.0000	0.0003
2010	1.0050	1.0050	0.3000	6.6150	0.7250	11.1100	0.0000	0.0003	0.0108	0.2590	0.0005	0.0000	0.0002	0.0002	0.0000	0.0000	0.0003
	1.0823	1.0823	1.5807	6.7702	0.7832	11.9623	0.0001	0.0003	0.0102	0.2440	0.0005	0.0000	0.0002	0.0002	0.0000	0.0000	0.0003

Asphalt Furnace - 45H1
Holly Refining & Marketing

	PM10	PM2.5	SOx	NOx	VOC	CO	Lead	Benzene	Formalde.	Hexane	Toluene	Arsenic	Cadmium	Chromium	Cobalt	Mercury	Nickel
	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons
2001	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2003	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2004	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2005	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Assumptions:
This unit is being removed.

2003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2006	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2007	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2008	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2009	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

CO Boiler - 51-6
Holly Refining & Marketing

	PM10	PM2.5	SOx	NOx	VOC	CO	Lead	Benzene	Formalde.	Hexane	Toluene	Arsenic	Cadmium	Chromium	Cobalt	Mercury	Nickel
	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons
2001	113.99	0.92	422.55	76.18	0.66	10.15	6.50E-05	2.65E-04	9.40E-03	2.26E-01	4.25E-04	2.50E-05	1.40E-04	1.75E-04	1.00E-05	3.50E-05	1.90E-01
2002	56.27		279.50	54.51	0.65	9.92	0.00E+00	2.50E-04	8.92E-03	2.14E-01	4.05E-04	2.50E-05	1.30E-04	1.65E-04	1.00E-05	3.00E-05	9.42E-02
2003	57.12	35.64	283.73	55.33	0.78	11.90	0.00E+00	2.70E-04	9.72E-03	2.33E-01	4.40E-04	2.50E-05	1.45E-04	1.80E-04	1.00E-05	3.50E-05	7.57E-02
2004	54.10	33.75	269.11	52.41	0.64	9.85	5.86E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2005	54.10	33.75	268.72	52.41	0.64	9.85	5.86E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2006	57.41	35.82	285.22	55.61	0.65	9.95	0.00E+00	2.70E-04	9.73E-03	2.33E-01	4.40E-04	2.50E-05	1.45E-04	1.80E-04	1.00E-05	3.50E-05	6.76E-02
2007	38.46	8.93	310.66	55.57	0.74	11.23	6.69E-05	2.70E-04	9.73E-03	2.33E-01	4.40E-04	2.50E-05	1.45E-04	1.80E-04	1.00E-05	3.50E-05	6.76E-02
2008	38.50	35.83	310.98	55.63	0.67	10.19	6.69E-05	2.55E-04	9.04E-03	2.17E-01	4.10E-04	2.50E-05	1.35E-04	1.70E-04	1.00E-05	3.00E-05	3.66E-02
2009	40.09	37.30	323.80	57.92	0.83	12.73	0.00E+00	3.20E-04	1.14E-02	2.74E-01	5.20E-04	3.00E-05	1.70E-04	2.15E-04	1.50E-05	4.00E-05	3.97E-02
2010	38.48	35.81	29.35	72.08	0.82	25.24	0.00E+00	3.05E-04	1.09E-02	2.62E-01	4.95E-04	3.00E-05	1.60E-04	2.05E-04	1.00E-05	4.00E-05	2.86E-02
2011	38.23	35.57	28.44	58.05	0.72	33.79											

Assumptions:
CO Boiler will be removed

2003	55.6092	34.6974	276.4188	53.8683	0.7124	10.8737	0.0000	0.0001	0.0049	0.1166	0.0002	0.0000	0.0001	0.0001	0.0000	0.0000	0.0379
2004	54.0984	33.7548	268.9127	52.4066	0.6448	9.8473	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2005	55.7542	34.7874	276.9688	54.0083	0.6474	9.8987	0.0000	0.0001	0.0049	0.1167	0.0002	0.0000	0.0001	0.0001	0.0000	0.0000	0.0338
2006	47.9353	22.3730	297.9403	55.5894	0.6928	10.5924	0.0000	0.0003	0.0097	0.2334	0.0004	0.0000	0.0001	0.0002	0.0000	0.0000	0.0676
2007	38.4803	22.3780	310.8203	55.5994	0.7028	10.7124	0.0001	0.0003	0.0094	0.2251	0.0004	0.0000	0.0001	0.0002	0.0000	0.0000	0.0521
2008	39.2950	36.5650	317.3900	56.7750	0.7500	11.4600	0.0000	0.0003	0.0102	0.2456	0.0005	0.0000	0.0002	0.0002	0.0000	0.0000	0.0381
2009	39.2850	36.5550	176.5750	65.0000	0.8250	18.9850	0.0000	0.0003	0.0112	0.2683	0.0005	0.0000	0.0002	0.0002	0.0000	0.0000	0.0341
2010	38.3550	35.6900	28.8950	65.0650	0.7700	29.5150	0.0000	0.0003	0.0109	0.2622	0.0005	0.0000	0.0002	0.0002	0.0000	0.0000	0.0286
	55.7542	36.5650	317.3900	65.0000	0.8250	18.9850	0.0001	0.0003	0.0112	0.2683	0.0005	0.0000	0.0002	0.0002	0.0000	0.0000	0.0676

Cooling Towers ALL - 5 towers including #11
Holly Refining & Marketing

	PM10	PM2.5	SOx	NOx	VOC	CO	Lead	Benzene	Formalde.	Hexane	Toluene	Arsenic	Cadmium	Chromium	Cobalt	Mercury	Nickel
	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons	Tons
2001	0	0	0	0	45.44	0	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	43.35	0	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	42.07	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	45.84	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	45.84	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	43.49	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	43.49	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	44.81	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	46.14	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	47.59	0	0	0	0	0	0	0	0	0	0	0	0

Assumptions:
Implementation of monthly cooling tower hydrocarbon monitoring.

2003	0.0000	0.0000	0.0000	0.0000	43.9535	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2004	0.0000	0.0000	0.0000	0.0000	45.8370	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2005	0.0000	0.0000	0.0000	0.0000	44.6635	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2006	0.0000	0.0000	0.0000	0.0000	43.4900	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2007	0.0000	0.0000	0.0000	0.0000	44.1500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2008	0.0000	0.0000	0.0000	0.0000	45.4750	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2009	0.0000	0.0000	0.0000	0.0000	46.8650	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	0.0000	0.0000	0.0000	0.0000	46.8650	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000