State of Utah

GARY R. HERBERT
Governor

GREG BELL
Lieutenant Governor

Department of
Environmental Quality

Amanda Smith
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQE-IN101230041A-13

June 5, 2013

Mike Astin
Holly Refining & Marketing Company - Woods Cross LLC
1070 W 500 S
Woods Cross, UT 84087-1442

Dear Mr. Astin:

Re: Intent to Approve: Heavy Crude Processing Project
Project Number: N10123-0041A

The attached document is the Intent to Approve for the above-referenced project. The Intent to Approve is subject to public review. Any comments received shall be considered before an Approval Order is issued. The Division of Air Quality is authorized to charge a fee for reimbursement of the actual costs incurred in the issuance of an Approval Order. An invoice will follow upon issuance of the final Approval Order.

Future correspondence on this Intent to Approve should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. The project engineer for this action is Camron Harry, who may be reached at (801) 536-4232.

Sincerely,

Martin D. Gray, Manager
New Source Review Section

MDG:CAH:kw

cc: Mike Owens
Davis County Health Department

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

INTENT TO APPROVE: Heavy Crude Processing Project

Prepared by: Camron Harry, Engineer
Phone: (801) 536-4232
Email: caharry@utah.gov

INTENT TO APPROVE NUMBER

DAQE-IN101230041A-13

Date: June 5, 2013

Holly Refining & Marketing Company - Woods Cross LLC

Source Contact:
Eric Benson, Environmental Engineer
Phone: (801) 299-6623
Email: Eric.Benson@hollyfrontier.com

Martin D. Gray, Manager
New Source Review Section

ABSTRACT

Holly Refining & Marketing Company - Woods Cross LLC (Holly Refinery) is requesting a modification to their existing AO DAQE-AN0101230039-11 to accommodate processing black and yellow wax crudes. This modification includes increasing crude processing from 40,000 barrels per day to 60,000 barrels per day. Changes to the Holly Refinery include installation of new equipment and replacement and/or modifications to existing equipment as needed.

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 (Unit 8) through addition of a preflash tower;
2) Installation of second crude unit (Unit 24);
3) Installation of second fluid catalytic cracking unit (FCC Unit 25);
4) Installation of Poly Gasoline Unit (Unit 26);
5) Installation of Hydrocracker Unit (Unit 27);
6) Installation of a new cooling tower (#10) and expansion of an existing cooling tower (#11);
7) Installation of emergency generators;
8) Installation of several process heaters and furnaces; and
9) Installation of a steam boiler (Boiler #11).

Other existing facility process units will be modified and/or removed in this modification:

1) Installation of new or modification to existing tanks;
2) Installation of additional truck bays for crude unloading;
3) Changes to rail loading and unloading locations;
4) Removal of frozen earth propane storage; and
5) Removal of gas driven compressor engines.

The Holly Refinery is located in West Bountiful, Davis County. Davis County is nonattainment for $PM_{2.5}$ and is a maintenance area for Ozone. Holly Refinery is located four miles north of Salt Lake County and is defined as a contributing source for the Salt Lake County PM_{10} nonattainment area. The Holly Refinery is a major source of HAPs, a SIP source, and a PSD source. This modification is major for GHG and CO emissions. Title V of the Clean Air Act of 1990 applies to this source as a major source.

The projected emissions increase/decrease for this modification, in TPY, are as follows: PM_{10} + 8.31, $PM_{2.5}$ (subset of PM_{10}) + 6.82, NO_x - 21.53, SO_2 – 150.69, CO + 146.76, VOC – 17.42, total HAPs + 13.08, and CO_2e + 279,610.

Previous exclusions from the AO emission caps will be removed therefore the AO emission caps will be source wide caps. In addition, the AO emission caps will be reduced as follows, in tons per year: PM_{10} – 0.05, NO_x – 322.9, and SO_2 – 725.7.

The source wide potential to emit totals, in TPY, are as follows: PM_{10} = 147.8, $PM_{2.5}$ (a subset of PM_{10}) = 47.6, NO_x = 341.1, SO_2 = 110.3, CO = 967.3, VOC = 102.60, and CO_2e =1,003,300.

This project previously went out to public comment on December 4, 2012 with a hearing held on January 3, 2013. This project has been modified since then as follows:

1) The originally proposed 2008 EPA Consent Decree emission reductions have been removed from the PSD and Major NSR applicability netting analysis
2) Unit 26H1(poly gasoline unit heater) will now be an electric heater
3) Four (4) existing gas driven compressor engines (4K1A KVG Compressor West, 4K1B KVG Compressor East, 6K1 SVG Compressor East, and 6K2 Compressor West) will be replaced with four (4) electric compressor engines.
4) EPA published AP-42 PM emission factors have been replaced with EPA published PM National Emissions Inventory (NEI) emission factors. Verification stack testing requirements have been included.
5) Change of baseline actual emission 24-month periods for criteria pollutants
6) As a result of the changes stated above, the PSD, Major NSR, and offsetting applicability and netting analysis calculations have been adjusted. However, the project remains PSD for only CO and GHGs with no offset requriements triggered.
7) The permit caps for NO_x, SO_x, and PM_{10} have been reduced.
8) BACT determinations have remained the same.

The NOI for the above-referenced project has been evaluated and has been found to be consistent with the requirements of UAC R307. Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an AO by the Director of the Utah Division of Air Quality.

A 45-day public comment period will be held in accordance with UAC R307-401-7. A notification of the intent to approve will be published in the Salt Lake Tribune and Deseret News on June 10, 2013. During the public comment period the proposal and the evaluation of its impact on air quality will be available for the public to review and provide comment. A Public Hearing will be held on July 11, 2013 in accordance with UAC R307-401-7. The hearing will be held in the Board Room of the Multi Agency State Office Building, 195 North 1950 West, Salt Lake City, Utah, beginning at 6:00 pm and will be held for at least one hour. Any comments received during the public comment period and the hearing will be evaluated. The proposed conditions of the AO may be changed as a result of the comments received.

Name of Permittee:	**Permitted Location:**
Holly Refining & Marketing Company - Woods Cross LLC 1070 W 500 S Woods Cross, UT 84087-1442	Holly Refining & Marketing Company - Woods Cross LLC 393 South 800 West Woods Cross, UT 84087-1435

UTM coordinates: 424,000 m Easting, 4,526,227 m Northing, UTM Zone 12
SIC code: 2911 (Petroleum Refining)

Section I: GENERAL PROVISIONS

I.1 All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Director or Director's representative upon request, and the records shall include the two-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five (5) years. [R307-415-6a]

I.2 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]

I.3 The owner/operator shall comply with UAC R307-107. General Requirements: Breakdowns. [R307-107]

I.4 All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]

I.5 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]

I.6 Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]

I.7 The owner/operator shall comply with UAC R307-150 Series. Inventories, Testing and Monitoring. [R307-150]

Section II: SPECIAL PROVISIONS

II.A The approved installations shall consist of the following equipment:

II.A.1 **Holly Refinery**
Permitted Source

II.A.2 **Unit 4: Fluid Catalytic Cracking Unit (FCCU)**
8,880 bpd annual average capacity

II.A.3 **4H1: FCC Feed Heater**
68.4 MMBtu/hr process furnace, fired on plant gas, restricted to 39.9 MMBtu/hr, equipped with low NO_x burners (LNB)

II.A.4 **4K1A: KVG Compressor West**
Electrical motor compressor engine

II.A.5 **4K1B: KVG Compressor East**
Electrical motor compressor engine

II.A.6 **4V82 FCC Scrubber**
Wet gas scrubber to control Unit 4 FCCU

II.A.7 **4-97-0010**
Oxygen Injection Skid

II.A.8 **FCC 34" Flue Gas Bypass**
34" Stack

II.A.9 **Unit 6: Catalytic Reforming Unit (Reformer)**

II.A.10 **6H1**
Reformer charge and reheater furnace/waste heat boiler
54.7 MMBtu/hr process furnace, fired on plant gas

II.A.11 **6H2: Prefractionator Reboiler Heater**
12.0 MMBtu/hr process furnace, fired on plant gas

II.A.12 **6H3: Reformer Reheat Furnace**
37.7 MMBtu/hr process furnace, fired on plant gas

II.A.13 **6K1 SVG Compressor East**
Electrical motor compressor engine

II.A.14 **6K2: SVG Compressor West**
Electrical motor compressor engine

II.A.15 **Unit 7: Alkylation Unit**

II.A.16 **7H1: HF Alkylation Regeneration Furnace**
4.4 MMBtu/hr process furnace, fired on plant gas

II.A.17 **7H3: HF Alkylation Depropanizer Reboiler**
33.3 MMBtu/hr process furnace, fired on plant gas

II.A.18 **Unit 8: Crude Unit**
45,000 bpd annual average capacity

II.A.19 **8H1: Crude Furnace #1**
99.0 MMBtu/hr process furnace, fired on plant gas, equipped with next generation ultra-low NO_x burner (NGULNB)

II.A.20 **Unit 9: Distillate Hydrosulfurization (DHDS) Unit**

II.A.21 **9H1: DHDS Reactor Charge Heater**
8.1 MMBtu/hr process furnace, fired on plant gas

II.A.22 **9H2: DHDS Stripper Reboiler**
4.1 MMBtu/hr process furnace, fired on plant gas

II.A.23 **Unit 10: Solvent Deasphalting (SDA) Unit**

II.A.24 **10H1: Asphalt Mix Heater**
13.2 MMBtu/hr process furnace, fired on plant gas

II.A.25 **10H2: Hot Oil Furnace**
99 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and selective catalytic reduction (SCR) system

II.A.26 **Unit 11: Straight Run Gas Plant (SRGP)**

II.A.27 **11H1: SRGP Depentanizer Reboiler**
24.2 MMBtu/hr process furnace, fired on plant gas

II.A.28 **11K2: SRGP Electric Compressor**

II.A.29 **Unit 12:Naphtha Hydrodesulphurization (NHDS) Unit**

II.A.30 **12H1: NHDS Reactor Charge Furnace**
50.2 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB

II.A.31 **Unit 13: Isomerization Unit**

II.A.32 **13H1: Isomerization Reactor Feed Furnace**
6.5 MMBtu/hr process furnace, fired on plant gas

II.A.33 **Unit 16: Amine Treatment Unit**

II.A.34 **Unit 17: Sulfur Recovery (SRU)**

II.A.35 **SRU - Tailgas Incinerator**
For SRU under 20 LTPD

II.A.36 **Unit 18: Sour Water Stripping (SWS) Unit**

II.A.37 **Unit 19:Distillate Hydrodesulfurization Treatment**
(DHT)

II.A.38 **19H1: DHT Reactor Charge Heater**
18.1 MMBtu/hr Process Furnace, fired on plant gas, equipped with LNB

II.A.39 **Unit 20: Gas Oil Hydrocracking (GHC) Unit**

II.A.40 **20H1: Reactor Charge Heater**
14.9 MMBtu/hr process furnace, fired on plant gas, equipped with ultra-low NO_x Burners (ULNB)
Allows for expansion of Unit 19 (DHT)

II.A.41 **20H2: Fractionator Charge Heater**
47.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB

II.A.42 **20H3: Fractionator Charge Heater**
42.1 MMBtu/hr furnace, fired on plant gas, equipped with ULNB

II.A.43 **Unit 21: NaSH Sour Gas Treatment Unit**
Sized at 50 long tons of sulfur per day

II.A.44 **Unit 22:Sour Water Stripper/Ammonia Stripping Unit**

II.A.45 **Unit 23: Benzene Saturation Unit**

II.A.46 **23H1: Reformate Splitter Reboiler Heater**
21.0 MMBtu/hr heater, fired on plant gas, equipped with NGULNB

II.A.47 **Unit 24: Crude Unit**
15,000 bpd annual average capacity

II.A.48	**24H1: Crude Unit Furnace** 60.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
II.A.49	**Unit 25: FCCU** 8,500 bpd annual average capacity
II.A.50	**25H1: FCC Feed Heater** 45 MMBtu/hr process furnace, fired on plant gass, equipped with ULNB
II.A.51	**25FCC Scrubber** Wet gas scrubber to control FCCU Unit 25 and SRU Unit 17 Equipped with LoTOx control technology
II.A.52	**Unit 26: Poly Gasoline Unit**
II.A.53	**Unit 27: Hydrocracker/Hydroisom Unit**
II.A.54	**27H1: Reactor Charger Heater** 99.0 MMBtu/hr reactor charger heater, fired on plant gas, equipped with LNB and SCR
II.A.55	**Unit 28: Sour Water Stripping Unit** 100 gallons per minute capacity Under normal operations, effluent is sent to Unit 22 for ammonia removal
II.A.56	**Unit 30: Hydrogen plant**
II.A.57	**30H1 Hydrogen Reformer Feed Furnace** 123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
II.A.58	**30H2 Hydrogen Reformer Feed Furnace** 123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
II.A.59	**Unit 33: Vacuum Unit**
II.A.60	**33H1: Vacuum Furnace Heater** 130.0 MMBtu/hr heater, fired on plant gas, equipped with LNB and SCR
II.A.61	**Unit 45: Asphalt Storage**
II.A.62	**Unit 51: Steam Systems**
II.A.63	**Boiler #4** 35.6 MMBtu/hr boiler, fired on plant gas
II.A.64	**Boiler #5** 70.0 MMBtu/hr boiler, fired on plant gas, equipped with SCR
II.A.65	**Boiler #8** 92.7 MMBtu/hr boiler, fired on plant gas, equipped with LNB and SCR
II.A.66	**Boiler #9** 89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
II.A.67	**Boiler #10** 89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR

II.A.68 **Boiler #11**
89.3 MMBtu/hr steam boiler, fired on plant gas, equipped with LNB and SCR

II.A.69 **Unit 54: Cooling Towers**
All cooling towers implement the Modified El Paso Method utilizing a FID analyzer

II.A.70 **Cooling Tower #4**
Built pre 1975

II.A.71 **Cooling Tower #6**
Built pre 1975

II.A.72 **Cooling Tower #7**
Re-built 2006

II.A.73 **Cooling Tower #8**
Built pre 1975

II.A.74 **Cooling Tower #10**
8,500 gallons per minute capacity induced draft multi-cell flow, equipped with high efficiency drift eliminators (permitted 2013)

II.A.75 **Cooling Tower #11**
8,500 gallons per minute capacity induced draft multi-cell flow, equipped with high efficiency drift eliminators (permitted 2013)

II.A.76 **Unit 56: Wastewater Treatment**
Oil/Water Separator
Induced Air Floatation Unit
Moving Bed Bioreactors

II.A.77 **Unit 66: Flares**

II.A.78 **Unit 66-1: Process Flare South**
17,000 standard cubic feet per hour

II.A.79 **Unit 66-2: Process Flare North**

II.A.80 **Unit 68: Tank Farm**

II.A.81 **68H2: North In-tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 79, fired with natural gas

II.A.82 **68H3: South In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 79, fired with natural gas

II.A.83 **68H4: North West In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 59, fired on natural gas

II.A.84 **68H5: North East In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 59, fired on natural gas

II.A.85 **68H6: South East In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 59, fired on natural gas

II.A.86 **68H7: South West In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 59, fired on natural gas

II.A.87 **68H10: North In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 139, fired on natural gas

II.A.88 **68H11: South In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 139, fired on natural gas

II.A.89 **68H12: North In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 140, fired on natural gas

II.A.90 **68H13: South In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 140, fired on natural gas

II.A.91 **Tank 11: Petroleum Liquids (1932)**
9,868 bbl capacity storage tank with fixed roof

II.A.92 **Tank 12: Petroleum Liquids (1932)**
9,868 bbl capacity storage tank with internal floating roof, primary seal

II.A.93 **Tank 14: Petroleum Liquids (1932)**
2,539 bbl capacity storage tank with fixed roof

II.A.94 **Tank 15: Petroleum Liquids (1932)**
5,181 bbl capacity storage tank with fixed roof

II.A.95 **Tank 19: Petroleum Liquids (1933)**
7,463 bbl capacity storage tank with fixed roof

II.A.96 **Tank 20: Petroleum Liquids (1935)**
7,504 bbl capacity storage tank with fixed roof

II.A.97 **Tank 21: Petroleum Liquids (1935)**
354 bbl capacity storage horizontal storage tank

II.A.98 **Tank 23: Petroleum Liquids (2001)**
14,600 bbl capacity storage tank with fixed roof

II.A.99 **Tank 24: Petroleum Liquids (1936)**
15,016 bbl capacity storage tank with fixed roof

II.A.100 **Tank 28: Petroleum Liquids (1941)**
29,663 bbl capacity storage tank with fixed roof

II.A.101 **Tank 29: Petroleum Liquids (1938)**
336 bbl capacity storage tank with fixed roof

II.A.102 **Tank 31: Petroleum Liquids (1940)**
29,756 bbl capacity storage tank with fixed roof

II.A.103 **Tank 35: Petroleum Liquids (2001)**
105,000 bbl capacity storage tank with fixed roof

II.A.104 **Tank 37: Petroleum Liquids**
3,217 bbl capacity storage tank with fixed roof
(under re-construction)

II.A.105 **Tank 42A: Petroleum Liquids (1995)**
20 bbl capacity vertical storage tank

II.A.106 **Tank 47: Petroleum Liquids (1947)**
30,129 bbl capacity storage tank with fixed roof

II.A.107 **Tank 48: Petroleum Liquid (1948)**
29,782 bbl capacity storage tank with fixed roof

II.A.108 **Tank 50: Petroleum Liquids (1948)**
700 bbl capacity horizontal storage tank

II.A.109 **Tank 51: Petroleum Liquids (1948)**
580 bbl capacity horizontal storage tank

II.A.110 **Tank 52: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof

II.A.111 **Tank 53: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof

II.A.112 **Tank 54: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof

II.A.113 **Tank 55: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof

II.A.114 **Tank 56: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof

II.A.115 **Tank 57: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof

II.A.116 **Tank 58: Petroleum Liquids (1949)**
15,229 bbl capacity storage tank with fixed roof

II.A.117 **Tank 59: Petroleum Liquids (1948)**
30,019 bbl capacity storage tank with fixed roof
(converted 2013)

II.A.118 **Tank 60: Chemical (1948)**
1,008 bbl capacity storage tank with fixed roof

II.A.119 **Tank 61:Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof

II.A.120 **Tank 63: Petroleum Liquids (1949)**
30,135 bbl capacity storage tank with fixed roof

II.A.121 **Tank 64: Petroleum Liquids (1950)**
1,011 bbl capacity storage tank with fixed roof

II.A.122 **Tank 65: Petroleum Liquids (1950)**
1,011 bbl capacity storage tank with fixed roof

II.A.123 **Tank 70: Heavy Crude (1956)**
80,306 bbl capacity storage tank with fixed roof
(permitted for heavy crude 2013)

II.A.124 **Tank 71: Heavy Crude (1969)**
67,155 bbl capacity storage tank with internal floating roof, primary and secondary seals
(permitted for heavy crude 2013)

II.A.125 **Tank 72: Heavy Crude (1971)**
106,811 bbl liquids storage tank with internal floating roof, primary and secondary seals
(permitted for heavy crude 2013)

II.A.126 **Tank 73: Petroleum Liquids (1975)**
1,077 bbl storage tank with fixed roof

II.A.127 **Tank 74: Petroleum Liquids (1975)**
2,039 bbl storage tank with fixed roof

II.A.128 **Tank 75: Petroleum Liquids (1975)**
2,039 bbl storage tank with fixed roof

II.A.129 **Tank 76: Petroleum Liquids (1975)**
2,039 bbl storage tank with fixed roof

II.A.130 **Tank 77: Petroleum Liquids (1983)**
5,141 bbl storage tank with fixed roof

II.A.131 **Tank 78: Petroleum Liquids (1952)**
5,141 bbl storage tank with fixed roof

II.A.132 **Tank 79: Petroleum Liquids (2006)**
10,000 bbl capacity storage tank with fixed roof

II.A.133 **Tank 81: Chemical (2008)**
13,638 bbl capacity storage tank with fixed roof

II.A.134 **Tank 82: Chemical (2008)**
13,638 bbl capacity storage tank with fixed roof

II.A.135 **Tank 83: Chemical (2009)**
7,143 bbl capacity storage tank with fixed roof

II.A.136 **Tank 85: Petroleum Liquids**
19,600 bbl capacity storage tank with internal floating roof
(under construction, permitted in 2010)

II.A.137 **Tank 86: Petroleum Liquids**
109,660 bbl capacity storage tank with fixed cone roof
(under construction, permitted in 2010)

II.A.138 **Tank 87: Petroleum Liquids**
109,660 bbl capacity storage tank with fixed cone roof
(under construction, permitted in 2010)

II.A.139 **Tank 88: Petroleum Liquids**
26,730 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2010)

II.A.140 **Tank 89: Petroleum Liquids**
26,730 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.141 **Tank 90: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.142 **Tank 91: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.143 **Tank 92: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.144 **Tank 93: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.145 **Tank 94: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.146 **Tank 95: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.147 **Tank 96: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.148 **Tank 97: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.149 **Tank 98: Petroleum Liquids**
19,600 bbl capacity storage tank with internal floating roof
(under construction, permitted 2013)

II.A.150 **Tank 99: Petroleum Liquids**
66,000 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.151 **Tank 100: Petroleum Liquids (1952)**
53,372 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.152 **Tank 101: Petroleum Liquids (1952)**
53,564 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.153 **Tank 102: Petroleum Liquids (1952)**
52,990 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.154 **Tank 103: Petroleum Liquids (1952)**
24,686 bbl capacity storage tank with fixed roof

II.A.155 **Tank 104: Petroleum Liquids (1952)**
24,435 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.156 **Tank 105: Petroleum Liquids (1952)**
24,501 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.157 **Tank 106: Petroleum Liquids (1952)**
24,524 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.158 **Tank 107: Petroleum Liquids (1952)**
24,501 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.159 **Tank 108: Petroleum Liquids (1952)**
24,450 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.160 **Tank 109: Petroleum Liquids (1952)**
24,490 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.161 **Tank 113: Chemical (1953)**
168 bbl capacity storage tank with fixed roof

II.A.162 **Tank 114: Chemical (1953)**
65 bbl capacity storage tank with fixed roof

II.A.163 **Tank 116: Chemical (1954)**
140 bbl capacity storage tank with fixed roof

II.A.164 **Tank 117: Petroleum Liquids (1944)**
506 bbl capacity storage tank with no roof

II.A.165 **Tank 118: Petroleum Liquids (1944)**
657 bbl capacity storage tank with fixed roof

II.A.166 **Tank 121: Petroleum Liquids (1954)**
100,129 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.167 **Tank 122: Petroleum Liquids (1954)**
400 bbl capacity horizontal storage tank

II.A.168 **Tank 123: Petroleum Liquids (1954)**
400 bbl capacity horizontal storage tank

II.A.169 **Tank 124: Chemical (1950)**
550 bbl capacity horizontal storage tank

II.A.170 **Tank 125: Chemical (1950)**
550 bbl capacity horizontal storage tank

II.A.171 **Tank 126: Petroleum Liquids (1955)**
64,675 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.172 **Tank 127: Petroleum Liquids (1957)**
30,497 bbl capacity storage tank with fixed roof

II.A.173 **Tank 128: Petroleum Liquids (1958)**
10,100 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.174 **Tank 129: Petroleum Liquids (1958)**
55,074 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.175 **Tank 130: Chemical (1958)**
952 bbl capacity horizontal storage tank

II.A.176 **Tank 131: Petroleum Liquids (1958)**
65,159 bbl capacity storage tank with internal floating roof, primary and secondary seals

II.A.177 **Tank 132: Petroleum Liquids (1960)**
24,455 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.178 **Tank 133: Petroleum Liquids (1949)**
1,582 bbl capacity horizontal storage tank

II.A.179 **Tank 134: Petroleum Liquids (1949)**
1,582 bbl capacity horizontal storage tank

II.A.180 **Tank 135: Petroleum Liquids (1962)**
44,154 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.181 **Tank 136: Petroleum Liquids (1962)**
806 bbl capacity horizontal storage tank

II.A.182 **Tank 138: Petroleum Liquids (1963)**
44,247 bbl capacity storage tank with internal floating roof and primary seal

II.A.183 **Tank 139: Petroleum Liquids (1965)**
14,957 bbl capacity storage tank with fixed roof
(modified 2013)

II.A.184 **Tank 140: Petroleum Liquids (1965)**
14,857 bbl capacity storage tank with fixed roof
(modified 2013)

II.A.185 **Tank 141: Petroleum Liquids (1965)**
1,618 bbl capacity horizontal storage tank

II.A.186 **Tank 143: Petroleum Liquids (1968)**
4,008 bbl capacity storage pit with fixed roof

II.A.187 **Tank 145: Petroleum Liquids (1974)**
3,985 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.188 **Tank 146: Petroleum Liquids (1974)**
3,985 bbl capacity storage tank with external floating roof, primary and secondary seals

II.A.189 **Tank 147: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank

II.A.190 **Tank 148: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank

II.A.191 **Tank 149: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank

II.A.192 **Tank 150: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank

II.A.193 **Tank 151: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank

II.A.194 **Tank 152: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank

II.A.195 **Tank 153: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank

II.A.196 **Tank 158: Water**
64,315 bbl capacity wastewater storage tank with internal floating roof
(under construction, permitted 2013)

II.A.197 **Tank 159: Petroleum liquids (1987)**
4,999 bbl capacity spherical storage tank

II.A.198 **Tank 168: Water**
30,952 bbl capacity sour water feed storage tank with internal floating roof
(under construction, permitted 2013)

II.A.199 **Tank 170: Petroleum Liquids**
66,000 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

II.A.200 **Tank 171: Petroleum Liquids**
1,600 bbl capacity horizontal storage tank
(under construction, permitted 2013)

II.A.201 **Tank 172: Petroleum Liquids**
1,600 bbl capacity horizontal storage tank
(under construction, permitted 2013)

II.A.202 **Tank 173: Petroleum Liquids**
1,600 bbl capacity horizontal storage tank
(under construction, permitted 2013)

II.A.203 **Tank 174: Petroleum Liquids**
1,600 bbl capacity horizontal storage tank
(under construction, permitted 2013)

II.A.204 **Tank 301: Chemical (1968)**
176 bbl capacity storage tank with fixed roof

II.A.205 **Tank 300: Chemical (1968)**
176 bbl capacity storage tank with fixed roof

II.A.206 **Tank 302: Chemical (1968)**
176 bbl capacity storage tank with fixed roof

II.A.207 **Tank 303: Chemical (1968)**
238 bbl capacity storage tank with fixed roof

II.A.208 **Tank 304: Chemical (1968)**
368 bbl capacity storage tank with fixed roof

II.A.209 **Tank 305: Chemical (1975)**
368 bbl capacity storage tank with fixed roof

II.A.210 **Tank 306: Chemical (1975)**
514 bbl capacity storage tank with fixed roof

II.A.211 **Tank 307: Chemical (1975)**
514 bbl capacity storage tank with fixed roof

II.A.212 **Tank 308: Chemical (1975)**
157 bbl capacity storage tank with fixed roof

II.A.213 **Tank 310: Chemical (1975)**
514 bbl capacity storage tank with fixed roof

II.A.214 **Tank 312: Chemical (1975)**
14 bbl capacity vertical storage tank

II.A.215 **Tank 313: Chemical (1975)**
143 bbl capacity storage tank with fixed roof

II.A.216 **Tank 323: Petroleum Liquids (1992)**
14,686 bbl capacity storage tank with internal floating roof, primary seal

II.A.217 **Tank 324: Petroleum Liquids (1947)**
714 bbl capacity horizontal storage tank

II.A.218 **Tank 54-V4: Chemical (1972)**
76 bbl capacity horizontal storage tank

II.A.219 **Tank 54-V5: Chemical (1974)**
131 bbl capacity horizontal storage tank

II.A.220 **Tank 54-V7: Chemical (1990)**
72 bbl capacity storage tank with fixed roof

II.A.221 **East Tank Farm (ETF) Portable Diesel Generator**
135 kW diesel fired generator

II.A.222 **Unit 87: Loading/Unloading**
Sixteen (16) crude/gas oil/NGL truck unloading bays
One (1) NaHS truck loading spot
Two (2) NaHS/caustic rail car loading/unloading spots
Three (3) caustic truck unloading spot
Two (2) sulfur truck loading arms
One (1) fuel oil truck loading spot
One (1) fuel oil truck unloading spot
Four (4) fuel oil/asphalt rail car loading/unloading spots
Four (4) oil/diesel/caustic rail car loading/unloading and ethanol rail car unloading spots

II.A.223 **Unit 87: Loading/Unloading (continued)**
Four (4) NGL rail car loading/unloading spots
Five (5) NGL/Olefin rail car loading/unloading spots
One (1) asphalt truck loading spot
One (1) diesel truck unloading spot
One (1) light cycle oil truck unloading spot
Two (2) propane truck loading spot
One (1) kerosene truck loading spot
One (1) gasoline truck unloading spot
Fourteen (14) fuel oil or asphalt loading spots
Twenty-four (24) lube oil loading spots
Two (2) bio diesel rail unloading spots

II.A.224 **Ethanol Unloading**
Three (3) dedicated ethanol unloading areas which include:
One (1) 250 gpm truck unloading pump
One (1) 400 gpm LOD charge pump
One (1) 250 gpm LOD charge pump
Four (4) unloading arms

II.A.225 **Emergency Equipment (Diesel)**
1. Diesel powered water well No. 3 (224 hp)
2. Caterpillar diesel fire pump No. 1 (393 hp)
3. Caterpillar diesel fire pump No. 2 (393 hp)
4. Detroit diesel fire pump (180 hp)
5. Three (3) diesel powered plant air backup compressors (220 hp each)
6. Diesel powered standby generator, Boiler House (Cummins Model QSM11-G4, 470 hp)
7. Diesel powered standby generator, Central Control Room (380 hp)
8. Diesel powered standby generator (540 hp)

II.A.226 **Emergency Equipment (Natural Gas)**
Two (2) natural gas fired standby generators, Administration Bldg (142 kw each)

II.A.227 **PM_{10} Combustion Emissions Cap Sources**
PM_{10} Combustion Sources: includes Unit 66: Flares, 4H1: FCC Feed Heater, 10H1: Asphalt Mix Heater, Boiler #8, 68H2: North In-tank Asphalt Heater, Unit 30: Hydrogen plant, Unit 33: Vacuum Unit, 30H1 Hydrogen Reformer Feed Furnace, 23H1: Reformate Splitter Reboiler Heater, 68H7: South West In-Tank Asphalt Heater, Unit 6: Catalytic Reforming Unit (Reformer), Unit 8: Crude Unit, 6H2: Prefractionator Reboiler Heater, 9H1: DHDS Reactor Charge Heater, Unit 20: Gas Oil Hydrocracking (GHC) Unit, 68H10: North In-Tank Asphalt Heater, Unit 10: Solvent Deasphalting (SDA) Unit, Unit 12:Naphtha Hydrodesulphurization (NHDS) Unit, Unit 66-2: Process Flare North, 68H4: North West In-Tank Asphalt Heater, Unit 23: Benzene Saturation Unit, Unit 24: Crude Unit, 24H1: Crude Unit Furnace, 27H1: Reactor Charger Heater, 68H13: South In-Tank Asphalt Heater, Boiler #5, 19H1: DHT Reactor Charge Heater, Unit 19:Distillate Hydrodesulfurization Treatment , 20H2: Fractionator Charge Heater, 30H2 Hydrogen Reformer Feed Furnace, 25H1: FCC Feed Heater, 7H1: HF Alkylation Regeneration Furnace, 13H1: Isomerization Reactor Feed Furnace, Boiler #10, 33H1: Vacuum Furnace Heater, 68H12: North In-Tank Asphalt Heater, Emergency Equipment (Natural Gas), Unit 11: Straight Run Gas Plant (SRGP), 7H3: HF Alkylation Depropanizer Reboiler, 8H1: Crude Furnace #1, SRU - Tailgas Incinerator, FCC 34" Flue Gas Bypass, Emergency Equipment (Diesel), 20H1: Reactor Charge Heater, Boiler #9, Unit 25: FCCU, 68H11: South In-Tank Asphalt Heater, Unit 4: Fluid Catalytic Cracking Unit (FCCU), Unit 13: Isomerization Unit, 12H1: NHDS Reactor Charge Furnace, 9H2: DHDS Stripper Reboiler, 11H1: SRGP Depentanizer Reboiler, Boiler #4, 10H2: Hot Oil Furnace, Unit 17: Sulfur Recovery (SRU), Boiler #11, 25FCC Scrubber, Unit 9: Distillate Hydrosulfurization (DHDS) Unit, 6H1, 6H3:

Reformer Reheat Furnace, Unit 66-1: Process Flare South, 68H3: South In-Tank Asphalt Heater, 68H5: North East In-Tank Asphalt Heater, 20H3: Fractionator Charge Heater, Unit 27: Hydrocracker/Hydroisom Unit, 68H6: South East In-Tank Asphalt Heater

II.B Requirements and Limitations

II.B.1 **<u>Conditions on Permitted Source</u>**

II.B.1.a Stack testing to determine compliance shall be performed in accordance with the requirements of Section IX.H.1.a of the PM_{10} SIP. [R307-150]

II.B.1.b Holly Refinery shall provide a notification of any performance test date at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. It shall be held at least 30 days prior to the test between the owner/operator, the tester, and the Director. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and of the Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA).

A sample location shall be chosen as outlined in 40 CFR 60 Appendix A, Method 1. The volumetric flow rate shall be determined by 40 CFR 60 Appendix A, Method 2.

To determine mass emission rates, the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Director to give the results in the specified units of the emission limitation.

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three years. [R307-165]

II.B.1.c Visible emissions shall not exceed the following specifications:

All scrubbers: 15% opacity
All baghouses: 10% opacity
FCC Units/FCC Wet Gas Scrubbers: 20% opacity
8H1 Crude Furnace: 20% opacity
Flares: 20% opacity
All other combustion sources: 10% opacity
All fugitive emission points: 20% opacity

Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. [R307-401]

II.B.1.d The amine plant shall reduce the H_2S content of the refinery fuel gas to 60 ppm (on an annual average) or less. The Holly Refinery has installed and maintains a continuous monitoring system for monitoring the H_2S content of the refinery fuel gas and a continuous recorder to record the H_2S in the refinery fuel gas. The monitoring system shall comply with all applicable sections of R307-170-1, and 40 CFR 60, Appendix B, Specification 7. [R307-401]

II.B.1.e The throughput of the catalytic cracking Unit 4 shall not exceed 3,250,000 barrels per rolling 12-month period. Compliance with the annual throughput limit shall be measured with a throughput flow meter. [R307-401]

II.B.1.f Compliance with the annual limitations shall be determined on a rolling 12-month total except where specifically exempted or otherwise provided for. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. [R307-401]

II.B.1.g The Holly Refinery shall notify the Director in writing when the installation of the new equipment has been completed and is operational. The new equipment includes the following:

Four (4) electric motor compressor engines (replacing gas driven engines)
Preflash tower (Unit 8)
SRU (Unit 17) emissions routed to 25FCC Scrubber
Fractionator charge heater (20H3)
Crude Unit (Unit 24) & Crude Unit Furnace (24H1)
FCCU (Unit 25), FCC feed heater (25H1), & 25FCC Scrubber
Poly gasoline unit (Unit 26)
Hydrocracker/Hydroisom Unit (Unit 27) & Reactor charger heater (27H1)
Sour water stripping unit (Unit 28)
Vacuum furnace heater (33H1)
In-tank asphalt heaters (68H6, 68H7, 68H10, 68H11, 68H12, & 68H13)
Cooling Tower #10 & expansion of Cooling Tower #11
Boiler #11
LNB & SCR installed on Boiler #8, 10H2, 30H1, & 30H2
Biodiesel loading spots
One (1) 540 hp (diesel) Emergency Generator
Two (2) 142 kW (natural gas) Emergency Generators
Truck Bays
South Flare

To ensure proper credit when notifying the Director, send your correspondence to the Director, attn: Compliance Section.

If installation has not been completed within 18 months from the date of this AO, the Director shall be notified in writing on the status of the installation. At that time, the Director shall require documentation of the continuous installation of the operation and may revoke the AO. [R307-401-18]

II.B.2 **Conditions on the Fluid Catalytic Cracking Units (Unit 4 & 25)**

II.B.2.a CO emissions from the FCC Units shall not exceed 500 ppm by volume (dry basis) one-hour average at 0% oxygen. [40 CFR 60 Subpart J]

II.B.2.a.1 Holly Refinery shall install, calibrate, maintain, and operate a continuous monitoring system to measure the effluent FCC Units CO emissions. The monitoring system shall comply with all applicable sections of R307-170 and 40 CFR 60, Appendix B. [R307-170]

II.B.2.b NO_x emissions for the FCC Units shall not exceed the following concentrations:

40 ppmvd per 365-day rolling average; and
80 ppmvd per 7-day rolling average

SO_2 emissions for the FCC Units shall not exceed the following concentrations:

25 ppmvd per 365-day rolling average; and
50 ppmvd per 7-day rolling average

[R307-401, 40 CFR 60 Subpart Ja]

II.B.2.b.1 Emissions of NO_x and SO_2 from the FCC Units shall be determined through use of a CEM. The monitoring system shall comply with all applicable sections of R307-170-1, and 40 CFR 60, Appendix B, Specifications 2 (NO_x, SO_2) and 3 (O_2). [R307-401, R307-170]

II.B.2.c The emissions of PM_{10} from the FCC Unit 4 wet gas scrubber (4V82 FCC Scrubber) shall not exceed 0.50 lb/1000 lb coke burned.

The emissions of PM_{10} from the FCC Unit 25 wet gas scrubber (25FCC Scrubber) shall not exceed 0.30 lb/1000 lb coke burned.

Compliance shall be determined by a stack test to be performed every year. Holly Refinery shall conduct annual test no later than October 31st of each year. Upon demonstration through at least three (3) annual tests that the PM_{10} limits are not being exceeded, Holly Refinery may request approval to conduct less frequently than annually.

Emissions of PM_{10} shall be determined through use of 40 CFR 60, Appendix M, Method 201, 201a, 202, or other EPA-approved testing method, as acceptable to the Director.

The condensable particle emissions shall not be used for compliance demonstration, but shall be used for inventory purposes. [R307-401-8]

II.B.3 **Conditions on the SRU/Tail gas incinerator**

II.B.3.a Under normal operating conditions, emissions from the sour water stripper Unit 28 shall be routed to the sour water stripper/ammonia stripping Unit 22 prior to treatment in the SRU Unit 17. [R307-401-8]

II.B.3.b SRU off gas shall at all times be routed to the 4V82 FCC Scrubber or 25 FCC Scrubber (wet gas scrubbers) prior to being vented to the atmosphere. [R307-401-8]

II.B.3.c Copies of the SRU (Unit 17) Operating Instruction/Standard shall be made available to the Director upon request. [R307-401]

II.B.3.d Holly Refinery shall utilize monitors to measure volumetric flow rates from the wet gas scrubber stacks. The flow measurement shall be in accordance with the requirements of 40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75, Appendix A. [R307-401]

II.B.3.e The FCCU wet scrubbers (4V82 FCC Scrubber and 25FCC Scrubber) shall be equipped with a CEMS to measure SO_2 emissions. [40 CFR 60 Subpart Ja]

II.B.3.f If sulfur input to the SRU (Unit 17) exceeds 20 long tons per day, NSPS Subparts A and J shall apply. [40 CFR 60 Subpart J]

II.B.4 **Conditions on Cooling Towers**

II.B.4.a Holly Refinery shall perform monthly monitoring of Cooling towers 4, 6, 7, 8, 10, and 11 to identify leaks of total strippable VOC from heat exchange systems according to the following procedure. A leak is a total strippable VOC concentration (as methane) in the stripping gas of 6.2 ppmv or greater.

A monthly water sample will be collected and analyzed from each cooling tower return line 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, or a comparable method approved by the Director.

If cooling tower testing results in a VOC concentration of 6.2 ppmv or greater, each heat exchanger shall be tested to identify which heat exchanger system is contributing to the excess. Both inlet and outlet of each heat exchanger shall be tested, any test method maybe used.

If a leak is detected, it must be repaired to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak. Verification of the repair shall be done through additional testing.

Monthly records shall include; date of inspection, cooling tower/heat exchanger inspected, total strippable VOC concentration, repairs, and follow up testing. Records shall be kept for all periods when the refinery is in operation. [R307-401-8, 40 CFR 63 Subpart CC]

II.B.5 **Conditions on Emergency Equipment**

II.B.5.a Emergency engine usage shall not exceed 600 hours total of operation for testing and maintenance purposes per rolling 12-month period.

Compliance with the rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. Records of the hours of operation shall be kept for all periods when the plant is in operation. Records of the hours of operation shall be made available to the Director or the Director's representative upon request, and shall include a period of two years ending with the date of the request. The total hours of operation may be determined by an engine hour totalizer installed on each engine, but a separate record of non-emergency hours shall be kept on a weekly basis. Emissions from this equipment shall not be included under the SIP emissions cap. [R307-401-8, 40 CFR 63 Subpart ZZZZ]

II.B.5.b The ETF portable diesel generator shall not be operated more than 1,100 hours per rolling 12-month period without prior approval in accordance with R307-401. The total hours of operation shall be determined by an engine hour totalizer or by supervisor monitoring and maintaining of an operations log.

Compliance with the rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. Records of the hours of operation shall be kept for all periods when the plant is in operation. Records of the hours of operation shall be made available to the Director or the Director's representative upon request, and shall include a period of two years ending with the date of the request. The total hours of operation may be determined by an engine hour totalizer installed on each engine, but a separate record of non-emergency hours shall be kept on a weekly basis. Emissions from this equipment shall not be included under the SIP emissions cap. [R307-401]

II.B.5.c Holly Refinery shall use #1, #2 or a combination of #1 and #2 diesel as a fuel source for the diesel fuel fired emergency generators. The sulfur content of any fuel oil or diesel burned shall not exceed: 0.0015 percent by weight. Certification of fuels shall be either by Holly Refinery's own testing or test reports from the fuel marketer. [R307-401-8]

II.B.5.d Except for use in emergency and portable equipment, fuel oil shall not be burned in any existing combustion device at the refinery except during periods of natural gas curtailment.

Emergency generators shall be used for electricity-producing operation only during the periods when electric power from the public utilities is interrupted, or for testing and maintenance of the generators. Records documenting generator usage shall be kept in a log; and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each generator usage.

Torch oil may be burned in the FCCU (Units 4 and 25) regenerators to assist in starting, restarting, maintaining hot standby, or maintaining regenerator heat balance.

Small (<100 HP) portable fuel oil-powered equipment is exempt from the requirements of this AO and related emissions are not to be used for purposes of determining compliance. [R307-401-8]

II.B.6 **Conditions on SO_2 emissions sources**

II.B.6.a The emission of SO_2 into the atmosphere from all sources (excluding routine turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12-month period or 0.31tons per day (tpd).

The routine turnaround maintenance period (maximum of every 3 years for a maximum of a 15 day period) for the SRU (Unit 17) shall only be scheduled during the period of April 1 through October 31. The projected SRU turnaround period shall be submitted to the Director by April 1 of each year in which a turnaround is planned. Notice shall also be provided to the Director 30 days prior to the planned turnaround.

Emissions of SO_2 shall be limited as follows:

Emission Points	Emissions (tpd)	Total Emissions (tpy)
4V82 FCC	0.05	17.7
25FCC Scrubber	0.05	17.7
All other sources	0.21	74.9

Tons Per Day (TPD) = Daily 24-hour total. Daily means an interval of time between two consecutive midnights.

For all the above listed emission points a CEM shall be used to determine compliance as outlined in II.B.3.e.

Compliance with rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. The rolling 12-month total SO_2 emissions shall be used for inventory and compliance purposes. [R307-170]

II.B.6.b SO_2 emissions into the atmosphere shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel burned. SO_2 emission factors for the various fuels shall be as follows:

Natural gas - 0.60 lb SO_2/MMscf

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM which will measure the H_2S content of the fuel gas in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily H_2S content data from the CEM. Plant gas sulfur content shall not exceed 60 ppmv determined daily on a 365 successive calendar day rolling average basis. The emission factor shall be calculated as follows:

(lb SO_2/MMscf gas) = (24 hr avg. ppmv H_2S)/10^6 * (64 lb SO_2/lb mole) * (10^6 scf/MMscf)/(379 scf / lb mole)

Fuel oil - The emission factor to be used in conjunction with fuel oil combustion (during natural gas curtailments) shall be calculated based on the weight percent of sulfur, as determined by ASTM Method 0-4294-89 or approved equivalent, and the density of the fuel oil, as follows:

(lb of SO_2/kgal) = (density lb/gal) * (1000 gal/kgal) * (wt. %S)/100 * (64 g SO_2/32 g S)

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may be combusted only during periods of natural gas curtailment. The sulfur content of the fuel oil shall be tested if directed by the Director.

Fuel Consumption shall be measured as follows:

Natural gas and plant gas consumption shall be determined through the use of flow meters.

Fuel oil consumption shall be measured each day by means of leveling gauges on all tanks that supply oil to combustion sources.

The equations used to determine emissions shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs)/(2,000 lb/ton)

Total daily SO_2 emissions for the sources shall be calculated by adding daily results of the above SO_2 emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day; and records shall be kept which include the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt. %S, recorded for each day any fuel oil is burned), and the calculated emissions. The daily SO_2 emissions shall be used for compliance purposes. [R307-401]

II.B.7 **<u>Conditions on PM_{10} emissions sources</u>**

II.B.7.a PM_{10} emissions from all combustion sources shall not exceed 47.5 tons per rolling 12-month period or 0.13 tpd.

PM_{10} emissions from all other sources shall not exceed 100.3 tons per rolling 12-month period. [R307-401]

II.B.7.a.1 PM_{10} emissions into the atmosphere shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted in each unit.

4V82FCC Scrubber: 0.50 lb/1000 lb coke burned in the FCC Unit 4
25FCC Scrubber: 0.30 lb/1000 lb coke burned in the FCC Unit 25

Natural gas or Plant gas for all non-NSPS combustion equipment: 7.65 lb PM_{10}/MMscf

Natural gas or Plant gas for all NSPS combustion equipment: 0.52 lb PM_{10}/MMscf

PM_{10} emissions from cooling towers shall be determined based on the following equation:

PM = CR * TDS/10^6 * DR/100 * p * 60 * 8760/2000

PM = PM_{10} emissions in tpy
CR = Circulation Rate of water circulation rate of the cooling tower (gal/min)
TDS = Based on most current average of total dissolved solids (TDS) measurements collected from existing cooling tower water
P = density of water (lbs/gal)

DR = Drift Rate, drift loss of circulating water (%) = 0.0006 % (for Cooling Towers 4, 6, 7, & 8) and 0.0005 % (for Cooling Towers 10 & 11)

The PM_{10} emission factor for fuel oil combustion shall be determined based on the H_2S content of the fuel oil as follows:

PM_{10} (lb/kgal) = (10 * wt.%S) + 3

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gages on all tanks that supply fuel oil to combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural/Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)

Total 24-hour PM_{10} emissions for the sources shall be calculated by adding the daily results of the above PM_{10} emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt. %S), and the calculated emissions. The daily PM_{10} emissions shall be used for compliance. For the details of compliance demonstration, refer to Section IX.H.1.i(2) of the PM_{10} SIP.

Compliance with rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. The rolling 12-month total shall be used for compliance and inventory purposes. [R307-401]

II.B.7.a.2 The emissions of PM_{10} from the following NSPS Boilers and heaters shall not exceed 0.00051 lb/MMBtu. Holly Refinery shall conduct stack testing to verify the PM_{10} emissions on the following NSPS heaters and boilers: 10H2, 19H1, 20H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1, Boilers #8, #9, #10, and #11.

Compliance shall be determined by a stack test to be performed every year. Holly Refinery shall conduct annual test no later than October 31st of each year. Upon demonstration through at least three (3) annual tests that the PM_{10} limits are not being exceeded, Holly Refinery may request approval to conduct less frequently than annually.

Emissions of PM_{10} shall be determined through use of 40 CFR 60, Appendix M, Method 201, 201a, 202, or other EPA-approved testing method, as acceptable to the Director. The condensable particle emissions shall be used for compliance demonstration and for inventory purposes. [R307-401-8]

II.B.8 **Conditions on NO_x emissions sources**

II.B.8.a NO_x emissions into the atmosphere from all sources shall not exceed 347.1 tons per rolling 12-month period or 2.09 tpd. [R307-401]

II.B.8.b NO_x emissions shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted.

Natural gas/refinery fuel gas combustion boilers and furnaces, where "Natural gas/refinery fuel gas" shall represent any combustion of natural gas, refinery fuel gas, or combination of the two in the associated burner:

Natural gas/refinery fuel gas combustion using Low NO_x burners (LNB): 41 lbs/MMscf
Natural gas/refinery fuel gas combusted using Ultra-Low NO_x burners: 0.04 lbs/MMbtu
Natural gas/refinery fuel gas combusted using Next Generation Ultra Low NO_x burners: 0.10 lbs/MMbtu
Natural gas/refinery fuel gas combusted burners using selective catalytic reduction (SCR): 0.02 lbs/MMbtu
All other natural gas/refinery fuel gas combustion burners: 100 lb/MMscf
All fuel oil combustion: 120 lbs/Kgal
Boiler #5: 0.03 lbs/MMBtu
Boiler #8: 0.02 lbs/MMBtu
Boilers #9 & #10 (SCR): 0.02 lbs/MMBtu
Boiler #11 (LNB & SCR): 0.02 lbs/MMBtu

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMBTU) * Burner Heat Rating (BTU/hr) * 24 hours per day /(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)

Flares:

The NO_x emissions from flares shall be determined using the following equation:

NO_x = F * HHV * EF * 10^6 * 8760 / 2000

NO_x = Annual potential NO_x emissions from normal flaring (tpy)
F = Average non-upset flare throughput (scf/hr) based on most current monitored flare flow
HHV = Average higher heating value of flared gas (Btu/scf) based on most current monitored flare flow
EF = Emission factor for NO_x from industrial flares in lb/MMBtu

Total 24-hour NO_x emissions for sources shall be calculated by adding the results of the above NO_x equations for plant gas, fuel oil, and natural gas combustion. Results shall be tabulated for every day; and records shall be kept which include the meter readings (in the appropriate units), emission factors, and the calculated emissions. The daily NO_x emissions shall be used for compliance purposes. See Section IX.H.1.i(2) of the PM_{10} SIP for details of compliance determination.

Compliance with rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. The rolling 12-month total shall be used for compliance and inventory purposes. [R307-401]

II.B.8.c The emissions of NO_x from heaters 8H1 and 12H1 shall not exceed 0.10 lb/MMBtu on a three-hour average basis each. Compliance shall be determined by a stack test to be performed every three (3) years.

The emissions of NO_x from 10H2, 27H1, 30H1, 30H2, 33H1, and Boilers #8, #9, #10 and #11 shall not exceed 0.020 lb/MMBtu on a three-hour average basis each. Compliance shall be determined by a stack test to be performed every three (3) years

The emissions of NO_x from heaters 20H1, 24H1, and 25H1 shall not exceed 0.04 lb/MMBtu on a three-hour average basis each. Compliance shall be determined by a stack test to be performed every three (3) years.

The emissions of NO_x from Boiler #5 shall not exceed 0.03 lbs/MMBtu on a three-hour averages basis. Compliance shall be determined by a stack test to be performed every three (3) years.

The emission of NO_x from stab-in heaters 68H6, 68H7, 68H10, 68H11, 68H12, & 68H13 shall not exceed 0.098 lb/MMBtu on a three-hour average basis each. Compliance shall be determined by a stack test to be performed every three (3) years.

Emissions of NO_x shall be determined through use of 40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other EPA-approved testing method, as acceptable to the Director. [R307-401-8]

II.B.9 **<u>Conditions on CO Emission Sources</u>**

II.B.9.a The CO emissions from process heaters 24H1, 20H3, 25H1, 27H1, 68H6, 68H7, 68H10, 68H11, 68H12, 68H13, and 33H1 shall not exceed 0.08 lb/MMbtu on a one-hour average basis each.

The CO emissions from Boiler #11 shall not exceed 0.037 lb/MMBtu.

For process heaters 24H1, 20H3, 25H1, 27H1, and 33H1, Holly Refinery shall conduct stack testing to verify the CO emissions. This stack testing shall be conducted at least once every three (3) years from the date of this AO. Emissions of CO shall be determined through use of 40 CFR 60, Appendix A, Method 10 or other EPA-approved testing method, as acceptable to the Director. CO emissions shall be used for compliance and inventory purposes.

For process heaters 68H6, 68H7, 68H10, 68H11, 68H12, and 68H13, Holly Refinery shall conduct stack testing on a minimum of one (1) process heater to verify the CO emissions. This stack testing shall be conducted at least once every three (3) years from the date of this AO. Emissions of CO shall be determined through use of 40 CFR 60, Appendix A, Method 10 or other EPA-approved testing method, as acceptable to the Director. CO emissions shall be used for compliance and inventory purposes. [R307-401-8]

II.B.10 **Conditions on VOC Emission Sources**

II.B.10.a The VOC emissions from Boiler #11 shall not exceed 0.004 lb/MMBtu.

Holly Refinery shall conduct stack testing to verify the VOC emissions. This stack testing shall be conducted at least once every three (3) years from the date of this AO. Emissions of the VOC shall be determined through use of 40 CFR 60, Appendix A, Method 25, 25a, or other EPA-approved testing method, as acceptable to the Director. VOC emissions shall be used for compliance and inventory purposes. [R307-401-8]

II.B.10.b Within 180 days of commencing operation for storing heavy crude in each of Tanks 70, 71 and 72, Holly Refinery shall submit an analysis of the operating vapor pressure of these tanks to the Director for a determination on existing tank controls. Any existing tank controls shall not be removed until the Director finalizes this determination. [R307-401-8]

II.B.11 **Conditions on Green House Gases**

II.B.11.a Total plant wide emissions (excluding emissions covered under 40 CFR 98 Subpart MM - Suppliers of Petroleum Products) of GHG shall not exceed 1,003,300 short tons of CO_2e per rolling 12-month period. GHG emissions shall include combined emissions of CO_2, CH4 and N_2O. Compliance with the rolling 12-month period shall be determined as follows:

Holly Refinery shall multiply the actual rolling 12-month heat input for all fuel gas combustion units by the appropriate emissions factor and global warming potential listed below to calculate emissions of each GHG. The sum of all GHG emissions from all fuel gas combustion units shall be used to evaluate compliance with the CO_2e limit. Actual heat input values of natural gas shall be determined by natural gas purchasing records. Actual heat input values of plant gas shall be determined through refinery testing and multiplied by monthly flow rates.

GHG	Emission Factor	Global Warming Potential
CO_2	53.02 kg/MMBtu	1
CH4	0.001 kg/MMBtu	21
N2O	0.0001 kg/MMBtu	310

Compliance with each limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months.

Holly Refinery shall conduct stack testing to verify the CO_2 emissions from the fuel gas combustion equipment with heat input greater than or equal to 99.0 MMBtu/hr are no greater than the CO_2e emission factors listed above. This stack testing shall be conducted at least once every three (3) years from the date of this AO. CO_2 emissions shall be determined using the procedures outlined in 40 CFR 60 Appendix A, Method 3, 3A, or other EPA-approved test method, as acceptable to the Director.

Calculation, fuel purchase records, and stack test results verifying the CO_2e emission factors shall be recorded and maintained. [R307-401-8]

II.B.11.b Oxygen monitors and intake air flow monitors shall be installed on all heaters/burners greater than or equal to 99.0 MMBtu/hr. [R307-401-8]

II.B.11.c Air preheater package shall be installed on Unit 33H1. [R307-401-8]

II.B.11.d Flow meters and gas combustion monitors shall be installed on the South flare gas line to monitor flare combustion efficiency.

Flow meters shall be installed to monitor all fuel gas consumption at the Refinery. [R307-401-8]

II.B.11.e Holly Refinery shall install a vapor recovery system at the Unit 87 propane loading and unloading racks to control fugitive VOC emissions. [R307-401-8]

II.B.12 **Conditions on Wastewater Treatment**

II.B.12.a All applicable provisions of 40 CFR 60, NSPS Subpart QQQ, found at 40 CFR 60.690 to 60.699 (Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems) and 40 CFR 61, NESHAP Subpart FF, found at 40 CFR 61.340 to 61.359 (National Emission Standard for Benzene Waste Operations) apply to this installation. [40 CFR 60 Subpart QQQ, 40 CFR 61 Subpart FF]

II.B.12.b Emissions from any wastewater system control device installed to comply with 40 CFR 60 Subpart QQQ shall be monitored in accordance with 40 CFR 60.695. [40 CFR 60 Subpart QQQ]

Section III: APPLICABLE FEDERAL REQUIREMENTS

In addition to the requirements of this AO, all applicable provisions of the following federal programs have been found to apply to this installation. This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including UAC R307.

NSPS (Part 60), A: General Provisions
NSPS (Part 60), Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
NSPS (Part 60), J: Standards of Performance for Petroleum Refineries
NSPS (Part 60), Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
NSPS (Part 60), K: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978
NSPS (Part 60), 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
NSPS (Part 60), UU: Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture
NSPS (Part 60), GGG: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006
NSPS (Part 60), GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006
NSPS (Part 60), QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems
NSPS (Part 60), IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
NSPS (Part 60), JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
NESHAP (Part 61), A: General Provisions

NESHAP (Part 61), FF: National Emission Standard for Benzene Waste Operations
MACT (Part 63), A: General Provisions
MACT (Part 63), CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries
MACT (Part 63), UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units
MACT (Part 63), ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
MACT (Part 63), DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters
Title V (Part 70) major source

PERMIT HISTORY

The final AO will be based on the following documents:

Supersedes	DAQE-AN101230040 dated December 16, 2011
Incorporates	NOI dated May 23, 2012
Incorporates	Additional Information (Unit Designations) dated May 31, 2012
Incorporates	Additional Information (Equip Spec Sheets) dated June 18, 2012
Incorporates	Additional Information (NO_2 to NO_x stack ratio) dated June 28, 2012
Incorporates	Additional Information (from NOI Completeness Cklist) dated July 5, 2012
Incorporates	Additional Information (Updated NOI) dated July 12, 2012
Incorporates	Additional Information (In Stack Ratio info) dated July 19, 2012
Incorporates	Additional Information (Modeling Analysis Update) dated July 30, 2012
Incorporates	Additional Information (Updated Emissions) dated August 28, 2012
Incorporates	Additional Information (BACT) dated October 17, 2012
Incorporates	Additional Information (GHG & BACT) dated October 18, 2012
Incorporates	Additional Information (emergency generators) dated October 23, 2012
Incorporates	Additional Information (NEI EF and flare info) dated March 21, 2013
Incorporates	Additional Information (Netting Analysis) dated April 1, 2013
Incorporates	Additional Information (Calculations) dated April 10, 2013
Incorporates	Additional Information (Corrected Netting Analysis) dated April 22, 2013
Incorporates	Additional Information (Boiler #8 CD) dated April 30, 2013

ADMINISTRATIVE CODING

The following information is for UDAQ internal classification use only:

Davis County
CDS A
NSR, Nonattainment or Maintenance Area, Title V (Part 70) major source, PM_{10} SIP / Maint Plan, NESHAP (Part 61), Major HAP source, NSPS (Part 60), MACT (Part 63), PSD,

ACRONYMS

The following lists commonly used acronyms as they apply to this document:

40 CFR	Title 40 of the Code of Federal Regulations
AO	Approval Order
BACT	Best Available Control Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CDS	Classification Data System (used by EPA to classify sources by size/type)
CEM	Continuous emissions monitor
CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CMS	Continuous monitoring system
CO	Carbon monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent - 40 CFR Part 98, Subpart A, Table A-1
COM	Continuous opacity monitor
DAQ	Division of Air Quality (typically interchangeable with UDAQ)
DAQE	This is a document tracking code for internal UDAQ use
EPA	Environmental Protection Agency
FDCP	Fugitive Dust Control Plan
GHG	Greenhouse Gas(es) - 40 CFR 52.21 (b)(49)(i)
GWP	Global Warming Potential - 40 CFR Part 86.1818-12(a)
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
LB/HR	Pounds per hour
MACT	Maximum Achievable Control Technology
MMBTU	Million British Thermal Units
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Intent
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM_{10}	Particulate matter less than 10 microns in size
$PM_{2.5}$	Particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
R307	Rules Series 307
R307-401	Rules Series 307 - Section 401
SO_2	Sulfur dioxide
Title IV	Title IV of the Clean Air Act
Title V	Title V of the Clean Air Act
TPY	Tons per year
UAC	Utah Administrative Code
UDAQ	Utah Division of Air Quality (typically interchangeable with DAQ)
VOC	Volatile organic compounds