GLACIER

September 30, 2021

Permit Intake Clerk
Alaska Department of Environmental Conservation
Air Permit Program
555 Cordova Street
Anchorage, AK 99501

RE: **Cook Inlet Energy, LLC – Kustatan Production Facility**
Title V Air Quality Permit Renewal Application

Dear Permit Intake Clerk:

Cook Inlet Energy, LLC (CIE), a Glacier Oil and Gas Company, is respectfully submitting the enclosed Title V Air Quality Operating Permit (Title V Permit) application under 18 Alaska Administrative Code (AAC) 50.326(c) to renew the existing Title V Permit Number AQ0741TVP03, Revision 1 for Kustatan Production Facility. The attached renewal application contains Series Forms A, B, D and E, a copy of the most recent Annual Compliance Certification, and copies of the permits currently active, Title V Permit Number AQ0696TVP03, Revision 1 and AQ0741MSS03.

Note, in addition to the renewal, CIE is requesting Condition 14.3 be revised to remove the requirement to test both "raw" and "lean" gas and instead, require just one representative sample of the fuel combusted in the facility's emission units. Additionally, CIE requests that Permit No. AQ0741MSS03 be incorporated into the new permit.

CIE expects the Alaska Department of Environmental Conservation (ADEC) to charge an hourly permit administration fee for the processing the application under 18 AAC 50.326(c), per 18 AAC 50.400(j).

If you have any questions or would like any additional information, please contact Robert Tindall by phone at 907-433-3844 or by email at rtindall@glacieroil.com.

Sincerely,

9/30/21

David Pascal
Chief Operating Officer
Cook Inlet Energy, LLC-a Glacier Oil and Gas Company

cc: EPA Region 10, Office of Air Quality, M/S AOQ 107, 1200 Sixth Ave., Seattle, WA 98101
Encl.: Title V Air Quality Permit Application, hard copy and electronic copy

Kustatan Production Facility

Cook Inlet Energy, LLC
A Glacier Oil and Gas Company

Application to Renew Air Quality Control Operating Permit AQ0741TVP03, Revision 1

September 2021

Prepared by
Laster Environmental

FORM A1
Stationary Source (General Information)

GENERAL INFORMATION			
1. Permittee: Cook Inlet Energy, LLC			
Permittee Name: Cook Inlet Energy, LLC			
Mailing Address Line 1: 188 W. Northern Lights Blvd., Suite 510			
Mailing Address Line 2			
City: Anchorage		State: AK	Zip Code: 99503
2. Stationary Source Name: Kustatan Production Facility			
3. Stationary Source Physical Address: West Forelands, AK			
Physical Address Line 1: Cook Inlet, AK			
Physical Address Line 2 188 W Northern Lights Blvd, Suite 510			
City: Anchorage		State: AK	Zip Code: 99503
4. Location:Cook Inlet, AK	Latitude: 60° 43′ 28" North	Longitude: 151° 45′ 36" West	
5. Primary SIC Code: 211120	SIC Code Description: Crude Petroleum and Natural Gas		***Primary NAICS Code: 211120***
6. Current/Previous Title V Air Permit No.: AQ0741TVP03, Rev. 1		Expiration Date: 4/4/2022	
7. Does this application contain confidential data?	☐ Yes	☒ No	

8. APPLICATION IS BEING MADE FOR:		
☐ Initial Title V Permit for this Stationary Source	☐ Modify Title V Permit (currently permitted)	☒ Title V Permit Renewal

9. CONTACT INFORMATION (Attach additional sheets if needed)	
Owner:	***Operator:***
Name/Title: Cook Inlet Energy, LLC/Owner	Name/Title: Cook Inlet Energy, LLC/Owner
Mailing Address Line 1: 188 W. Northern Lights Blvd., Suite 510	Mailing Address Line 1: 188 W. Northern Lights Blvd., Suite 510
Mailing Address Line 2	Mailing Address Line 2
City: Anchorage State: AK Zip Code: 99503	City: Anchorage State: AK Zip Code: 99503
Permittee's Responsible Official:	***Designated Agent:***
Name/Title: David Pascal/Chief Operating Officer	Name/Title: Perkins Coie LLP-Elena Romerdahl, Partner
Mailing Address Line 1: 188 W. Northern Lights Blvd., Suite 510	Mailing Address Line 1: 1029 W. 3rd Ave., Suite 300
Mailing Address Line 2	Mailing Address Line 2
City: Anchorage State: AK Zip Code: 99503	City: Anchorage State: AK Zip Code: 99501
Stationary Source and Building Contact:	***Fee Contact:***
Name/Title: David Pascal/Chief Operating Officer	Name/Title: Robert Tindall/Compliance & Regulatory Manager
Mailing Address Line 1:188 W. Northern Lights Blvd., Suite 510	Mailing Address Line 1: 188 W. Northern Lights Blvd., Suite 510
Mailing Address Line 2	Mailing Address Line 2
City: Anchorage State: AK Zip Code: 99503	City: Anchorage State: AK Zip Code: 99503
Phone: (907) 433-3822 Email: dpascal@glacieroil.com	Phone: (907) 433-3814 Email: rtindall@glacieroil.com
Permit Contact:	***Person or Firm that Prepared Application:***
Name/Title: Robert Tindall/Compliance & Regulatory Manager	Name/Title: Dawn Laster/Owner of Laster Environmental
Mailing Address Line 1: 188 W. Northern Lights Blvd., Suite 510	Mailing Address Line 1: 22831 Green Garden Dr.
Mailing Address Line 2	Mailing Address Line 2
City: Anchorage State: AK Zip Code: 99503	City: Chugiak State: AK Zip Code: 99567
Phone: (907) 433-3814 Email: rtindall@glacieroil.com	Phone: (907) 301-5156 Email: dawn@lasterenviro.com

10. STATEMENT OF CERTIFICATION	
Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.	
Name of Responsible Official (typed): David Pascal	Title: Chief Operating Officer
X Signature (blue ink):	Date: 9/10/21

FORM A2
Stationary Source Description

Permit Number: AQ0741TVP04A

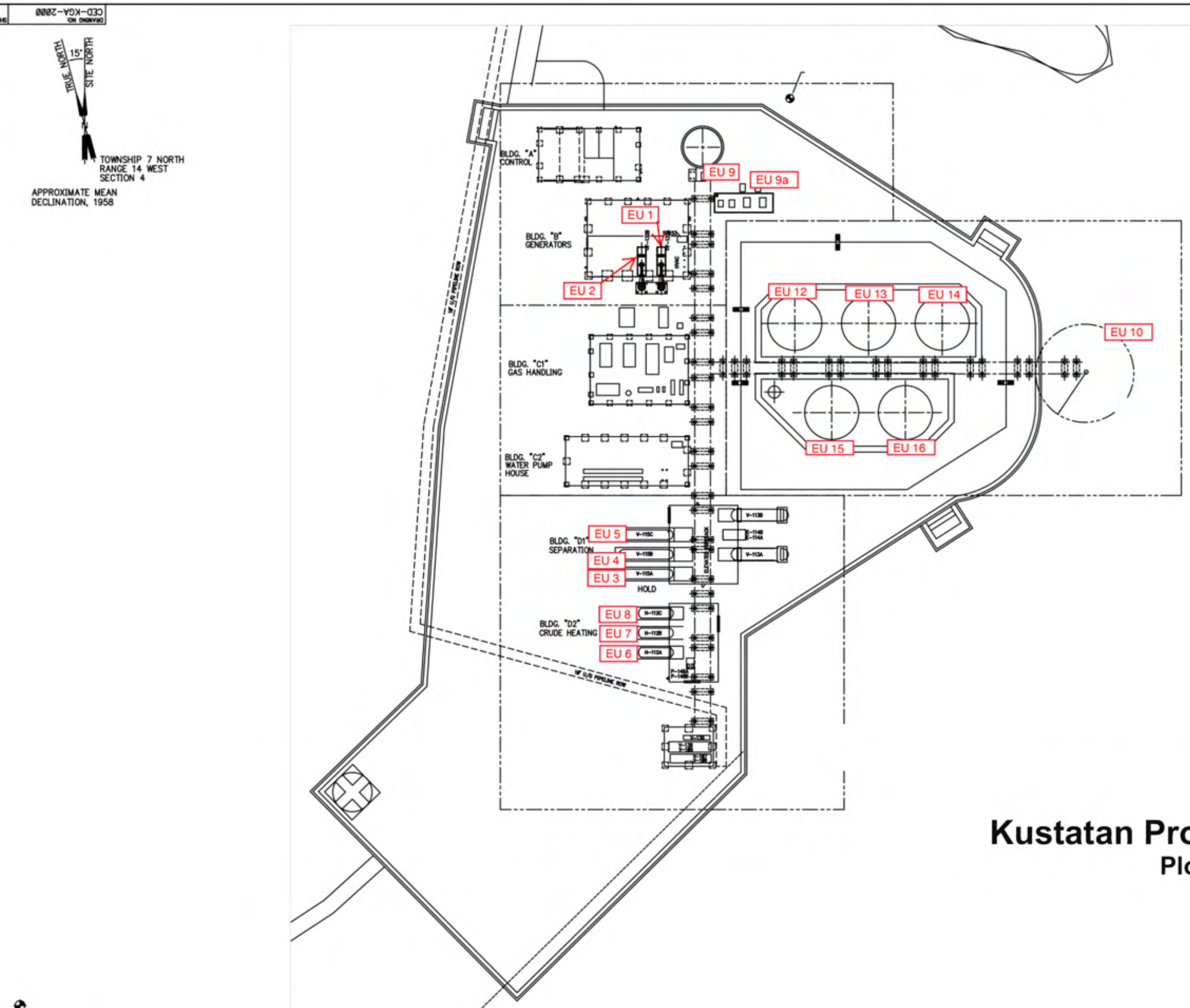
1.	Stationary Source Description (a thorough description of the stationary source, its processes, raw materials, operating scenarios, and other specific information that may be necessary to determine the applicability of Title V requirements.) The information may include property area or map, number of employees, maximum capacity, and other primary emission-generating activities co-located or on adjacent properties. The Kustatan Production Facility is part of the broader West Forelands Complex which also includes Osprey Platform and West McArthur River Production Facility, all owned and operated by Cook Inlet Energy, LLC, a Glacier Oil and Gas Company. Kustatan Production Facility is an onshore facility located on the west side of Cook Inlet, Alaska whose role is to separate the gas, water, and crude oil produced both on and offshore at Osprey Platform and West McArthur River Production Facility. The produced water is sent to the Osprey Platform for re-injection and most of the produced gas is used to power the facility's natural gas emission units, such as, the turbine generators used for electrical power and the heaters used in processing the crude oil. Any remaining gas and all the produced crude oil are transferred to the Cook Inlet pipeline system to be sold. Osprey Platform is permitted as a separate stationary source from Kustatan Production Facility for the purposes of air quality classifications. The Department disaggregated the two stationary sources of the West Forelands Facility in a letter dated May 8, 2009 from ADEC to Pacific Energy Resources, Ltd. (then-owner of the facility). ADEC issued Construction Permit No. AQ0741CP01 establishing this stationary source on May 2, 2002. The Kustatan Production Facility started operations in the 4th quarter of 2002. On June 6, 2003, Construction Permit No. AQ0741CP02, authorized an additional combustion turbine unit to the site. The Department issued Minor Permit No. AQ0741MSS01 to Forest Oil Corporation, on May 31, 2006; revisions in 2008 and 2010 addressed, among other things, changes in ownership for Pacific Energy and Cook Inlet Energy, respectively. Minor Permit AQ0741MSS02 was issued February 23, 2015. ADEC issued the initial Operating Permit No. AQ0741TVP01 on April 17, 2006 to Forest Oil Corporation and permit AQ0741TVP02 was issued to Cook Inlet Energy on June 14, 2012.	
2.	Nonattainment area [yes/no; if yes, specify]	No
3.	Does the CAM rule [40 CFR Part 64] apply to any of the emissions units? [if yes, review the guidance provided for CAM in the Form A2 instructions for this item]	No
4.	Does the accidental release prevention regulation [40 CFR Part 68] apply to the facility? [if yes, provide the appropriate regulatory applicability document in detail.]	No

5. Attach plot plan.

6. Attach regional map.

7. Attach USGS map.

Kustatan Production Facilty
Plot Plan



FORM: FO_DSIZE

REFERENCE DRAWINGS		
DRAWING NUMBER	SHEET	DESCRIPTION

REV	DATE	BY	CHK	DESCRIPTION	DISP CHGR	PROJ ENGR	CUST APP
1	10/10/17	YPB	YPB	REVISED TITLEBLOCK			
0	05/02	SW	SKW	ISSUED FOR CONSTRUCTION	MB	MD	PH
A	04/02	SW	SKW	ISSUED FOR REVIEW	MB	MD	

DESIGN: S. WOODHOUSE	DRAWN: S. WOODHOUSE
CHECKED: S. WOODHOUSE	APPROVAL: –
DATE: 4/22/02	SCALE: 1"=50'

Cook Inlet Energy

KUSTATAN PRODUCTION FACILITY
FOUNDATION LOCATION
KEY PLAN

PROJECT NO:	DRAWING NO:	SHEET:	REV:
AE1185	CED-KGA-2000	001 of 1	1

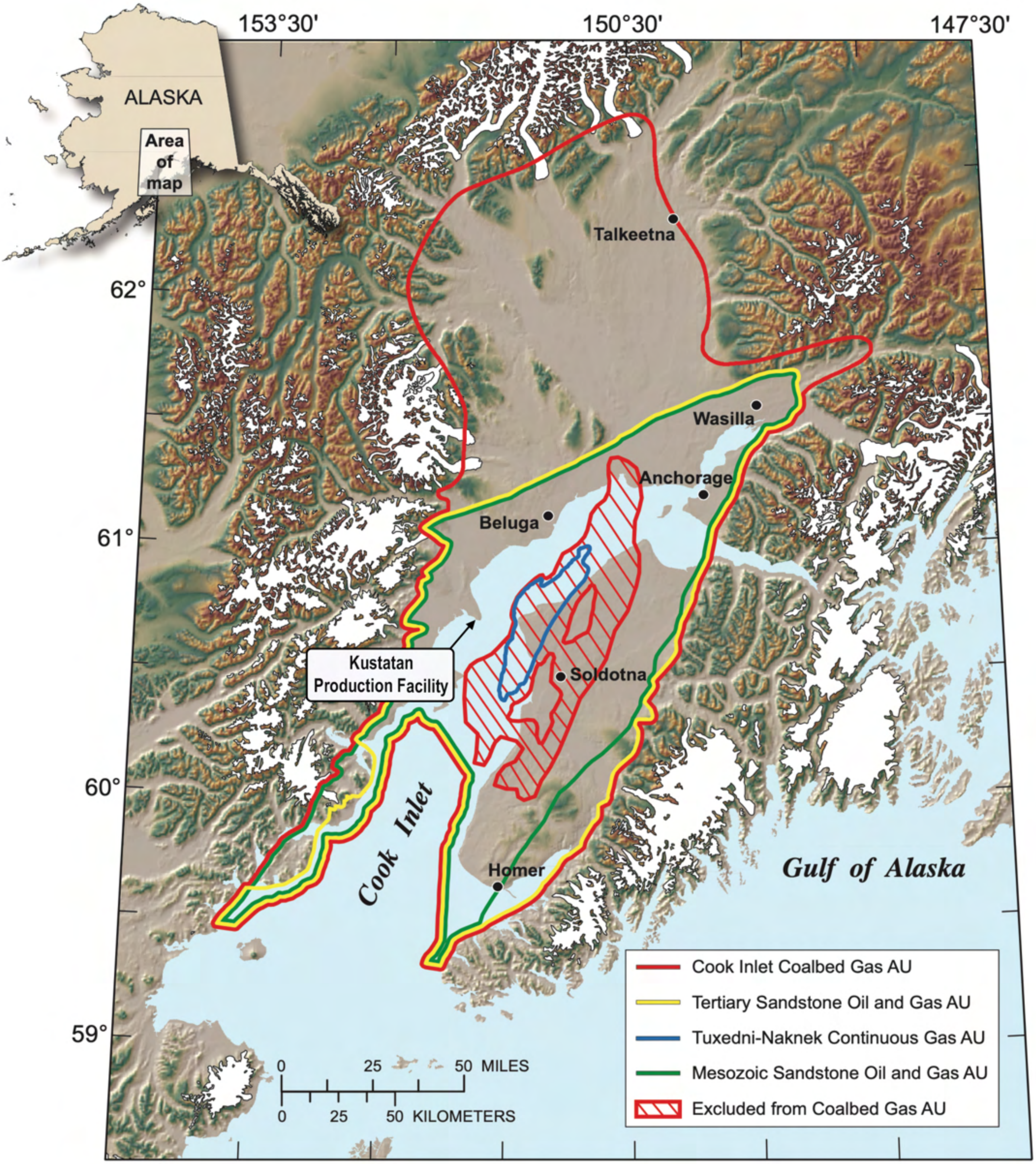
Kustatan Prosuction Facility
Regional Map

Kustatan Production Facility

USGS Map

Map Source the Assessment of Undiscovered Oil and Gas Resources of the Cook Inlet Region, South-Central Alaska Dated 2011

https://pubs.usgs.gov/fs/2011/3068/



FORM A3
Operating Scenario Description

Permit Number: AQ0741TVP04A

1.	Operating scenario ID	1
2.	Operating scenario description: The Kustatan Production Facility (KPF) is an oil and gas production facility located on the West Foreland of the western shore of Cook Inlet. KPF recieves multi-phase crude oil from production facilities at the (offshore) Osprey Platform and the (onshore) West McArthur River Unit. The facility process units heat and separates oil, water, and gas components prior to pipeline transport of Sales Oil (to market) and produced water (to disposal wells). All produced gas is used onsite to fuel processing equipment. The facility relies on stationary gas turbines to produce electricity that is distributed and used at KPF, Osprey, and other facilities in the West Forelands. These turbines burn fuel gas from the CIE DOT Gas Pipeline and KPF process units. Produced crude oil is pumped to Crude Heaters (H-112 A/B/C) to heat the oil prior to separation. Three-phase separation occurs in (unfired) primary separators and (gas-fired) Electrostatic Heater Treaters (V-115 A/B/C). The oil and produced waters are pumped to fixed roof storage tanks and produced gas is scrubbed and compressed for delivery to the process units. Crude oil storage tanks (T-133, T-134, T-135) accumulate processed oil prior to shipment by pipeline to the Hilcorp/Harvest custody transfer point. The Slop Oil tank (T-140) collects dropout/emulsion from the primary separator and crude oil storage tanks and subsequently refeeds this material into the process at a point upstream of the Heater Treaters. The Produced Water tank (T-142) accumulates process water prior to disposal well injection. All storage tanks are equipped with vapor recovery; the VRU gas is collected and combined with the other (separator/heater treater) produced gas streams and used in process units. Tank 146 functions as a utility tank and is used for temporary fluid accumulation of slop oil normally associated with blowdown and pigging of the process piping. The facility process flare provides safety flaring during operational upsets and emergencies.	
3.	List the emissions units involved in this operating scenario.	Turbines (EUs 1, 2, 2a), Heater Treaters (EUs 3, 4 , 5), Crude Heaters (EUs 6, 7, 8), Process Flare (EU 10), Storage Tanks (EUs 12, 13, 14, 15, 16)
4.	Operating schedule: hours/day	24
	days/week	7
	weeks/year	365
5.	Seasonal variation (%): December - February	25
	March – May	25
	June - August	25
	September - November	25

6. Attach process flow diagram

FORM A4
Title V Air Operating Permit Renewal Application Information

Permit Number: AQ0741TVP04A

1.	Permit Contact: Name	Robert Tindall
	Title	Compliance and Regulatory Manager
	Mailing Address Line 1	188 W. Northern Lights Blvd., Suite 510
	Mailing Address Line 2	Anchorage, AK 99503
	Phone Number	907-433-3814
	Email	rtindall@glacieroil.com
2.	Were there any changes to stationary source General Information (Form A1)? If yes, complete and submit a Form A1.	No
3.	Were there any changes to the stationary source description (Form A2)? If yes, complete and submit a Form A2.	No
4.	Were there any off-permit changes? Reference any notifications provided to the Department, and attach copies of the notifications.	No
	If yes, integrate changes into renewal permit? [if no, explain]	N/A
5.	Have any Alaska Title I permits been issued to the stationary source since the most recent Title V permit or revision issuance?	Yes
	If yes, integrate changes into renewal permit? [If yes, please list. If no, explain]	Cook Inlet Energy, LLC requests that the requirements of Permit No. AQ0741MSS03 be incorporated into Permit No. AQ0741TVP04. Note that Cook Inlet Energy, LLC is not requesting Permit No. AQ0741MSS04 to be incorporated. This permit was obtained strictly to allow the facility to operate portable generator engines as a source of electrical power while the facility was in a warm shutdown after the unprecedented events surrounding the COVID 19 pandemic. The generators are being used again to support both Kustatan Production Facility and Osprey Platform until production begins and the Solar Turbines (EUs 1 and 2) can be restarted. After EUs 1 and 2 are operating consistantly, Cook Inlet Energy, LLC intends to remove the generator engines from the facility and request that the Department to rescind the permit.
6.	Will there be any changes to the operating scenario(s)? [if yes, describe and attach Form A3]	No
7.	Will there be any new, modified, or reconstructed emission units or air pollution control equipment? [if yes, attach appropriate forms from Form Series B, C, D, and E]	No

8.	Are the current emissions units correctly identified and defined in the permit? [if no, attach appropriate forms from Form Series B, C, D, and E]	Yes
9.	Does the CAM rule [40 CFR Part 64] apply to any of the emissions units? [if yes, review the guidance provided for CAM in the Form A4 instructions for this item]	No
10.	Does the accidental release prevention regulation [40 CFR Part 68] apply to the facility? [if yes, provide the appropriate regulatory applicability document in detail.]	No
11.	Are there any other new applicable requirements? [if yes, list the new applicable requirements, emissions units, and attach the appropriate Series E Form]	No
12.	Are there any requested changes in the assessable potential to emit other than those identified in item 9 above? [if yes, answer the following]	No
	Are the changes a result of having better emissions information such as a new emission factor from a recent source test? [if yes, complete and attach any applicable emissions forms from Series D. Attach additional information as necessary to fully document.]	N/A
	Are the changes due to an increase in production? [if yes, complete and attach the applicable emissions form from Series D. Attach additional information as necessary to fully document.]	N/A
13.	Is the stationary source in compliance with all of the conditions of the current permit? If yes, attach a compliance certification. If no, attach a compliance schedule and/or actions taken for any out-of-compliance emission units.	Yes. Attached is the 2020 Annual Compliance Certification showing continuous compliance with all conditions. Note, two permit deviations were identified in 2021, corrective action was taken in both cases and the facility is currently in compliance with all permit requirements. The first deviation report was submitted on 9/2 for a late VE on EUs 9a, 17, and 18 causing deviations with Conditions 2.3b, 5.2, 79, 80 and AQ0741MSS04 Condition 4. The second report was submitted on 9/22 for oil changes not conducted in 2019 on EUs 9 and 9a causing deviations with Conditions 31.2a, 32.2a, 69.1(c)(i), 79, and 80.

14.	Are there any requested changes to testing and/or monitoring conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	Yes. Condition 14.3 requires that both the "raw" fuel gas and the "lean" fuel gas be analyzed, recorded, and reported in the Semiannual Facility Operating Reports. However, all of the produced gas, categorized as "raw" fuel gas in the permit, is sent to the Cook Inlet Energy, LLC Gas Pipeline to be mixed with sales gas before being piped back to the facility's fuel gas emission units. Therefore, Cook Inlet Energy, LLC is requesting that the requirement to test both "raw" and "lean" gas be removed and replaced with a requirement to just sample fuel representative of the fuel combusted in the facility's emission units.
15.	Are there any requested changes to monitoring conditions other than those being replaced by CAM? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	See #14 for requested changes to H2S monitoring
16.	Are there any requested changes to recordkeeping conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	See #14 for requested changes to H2S recordkeeping conditions
17.	Are there any requested changes to reporting conditions? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	See #14 for requested changes to H2S reporting conditions
18.	Are there any requested changes to the non-applicable requirements (i.e. permit shield)? [if yes, identify the emission unit, the requested change, and the reason in the appropriate Series B and/or D form. If the change applies stationary source-wide, complete the appropriate Series E form. Attach additional information as necessary to fully document.]	No
19.	Are there any other requested changes to any condition? [if yes, identify the condition, the requested change, and the reason. Attach additional information as necessary to fully document.]	See #14

FORM A4

Title V Air Operating Permit Renewal Application Information

Statement of Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

DAVID PASCAL

Name of Responsible Official

COO, GLACIER OIL & GAS

Title

9/30/21

Signature (blue ink)

Date

FORM B

Emission Unit Listing For This Application

Permit Number: AQ0741TVP03, Revision 1

EMISSION UNIT LISTING: New, Modified, Previously Unpermitted, Replaced, Deleted					
Emission Unit ID Number	**Emission Unit Name**	**Brief Emission Unit Description**	**Rating/Size**	**Construction Date**	**Notes**
Emission Units To Be ADDED By This Application (New, Previously Unpermitted, or Replacement)					
None					
Emission Units To Be MODIFIED By This Application					
None					
Emission Units To Be DELETED By This Application					
None					

SIGNIFICANT EMISSION UNIT LISTING: Title V permitted emission units that have not been modified					
Emission Unit ID Number	**Emission Unit Name**	**Brief Emission Unit Description**	**Rating/Size**	**Construction Date**	**Notes**
1	Taurus 60-T3701S	Turbine Generator #1	5,652 kW	2002	
2	Taurus 60-T3701S	Turbine Generator #2	5,652 kW	2002	
2a	Taurus 60-T3701S	Turbine Generator #3	5,652 kW	2003	
3	NATCO Electromax	Heater Treater #1	6.2 MMBtu/hr	2002	
4	NATCO Electromax	Heater Treater #2	6.2 MMBtu/hr	2002	
5	NATCO Electromax	Heater Treater #3	6.2 MMBtu/hr	2002	
6	NATCO Crude Heater	Crude Heater #1	8.0 MMBtu/hr	2002	
7	NATCO Crude Heater	Crude Heater #2	8.0 MMBtu/hr	2002	
8	NATCO Crude Heater	Crude Heater #3	8.0 MMBtu/hr	2002	
9	Cummins 6BTA	Fire Water Pump Engine	160.0 hp	2002	
9a	Caterpillar 3406C	Emergency Generator Engine	530.0 hp	2002	
10	Tornado Flare	Process Flare	0.8 MMBtu/hr	2002	

INSIGNIFICANT EMISSION UNIT LISTING: Insignificant Title V permitted emission units that have not been modified					
Emission Unit ID Number	**Emission Unit Name**	**Brief Emission Unit Description**	**Rating/Size**	**Construction Date**	**Notes**
12	Crude Tank T133	Crude Oil Storage Tank	10,000 bbls	2002	
13	Crude Tank T134	Crude Oil Storage Tank	10,000 bbls	2002	
14	Crude Tank T135	Crude Oil Storage Tank	10,000 bbls	2002	
15	Slop Oil Tank T141	Slop Oil Tank	10,000 bbls	2002	
16	Produced Water Tank T142	Produced Water Tank	10,000 bbls	2002	

B1 FORMS

Emission Unit Detail Form - External Combustion Equipment (Boilers and Heaters)

FORM B1

Emission Unit Detail Form - External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0741TVP03, Revision 1

1.	Emission Unit ID Number // Operating Scenario	3
2.	Date installation/construction commenced	December 20, 2001
3.	Date installed	2002
4.	Emission Unit serial number	7765-03
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer	NATCO Canada
7.	Description of emission unit, including type of boiler/heater and firing method: Heater Treater #1 (EU ID 3, V-115A) is a NATCO Canada Electromax Model VFH-CWW direct-fired process heater installed and commissioned in 2002. This unit burns raw fuel gas to heat and process crude oil (directly) for gas and liquids separation. The firing system for the unit is comprised of twin, parallel-fired 3.1 MMBtu/hr burners (Flameco Model SB34-24B) for a total rated capacity of 6.2 MMBtu/hr (combined, twin stacks).	
8.	Rated design capacity (heat input, MMBtu/hr)	6.2 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	Not Applicable
10.	Maximum steam pressure (psi)	Not Applicable
11.	Maximum steam temperature (°F)	Not Applicable

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	0.0072 MMscf/hr (Calculated rate based on a heat rate of 1073.8 Btu/scf the average from 2020 gas analyses and an assumed 80% efficiency)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Reasonable Inquiry / Record Review
AQ0741TVP03, Rev. 1, Conditions 1.1. and 6.1	18 AAC 50.040(j), 50.326(j), & 50.346© 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emission Standards	Burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Yes	Certify in the Annual Compliance Certificate.
AQ0741TVP03, Rev. 1, Condition 6	18 AAC 50.040(j), 50.055(b)(1) & 50.326(j) 40 C.F.R. 71.6(a)(1)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas averaged over three hours.	Yes	Burn only gas as fuel
AQ0741TVP03, Rev. 1, Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures.	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 63 Subpart DDDDD	This stationary source is not a major source of Hazardous Air Pollutants.
40 CFR 63 Subpart JJJJJJ	This stationary source is not an industrial, commercial, or institutional boiler as defined in 40 CFR 63.11237. By definition, this emission unit is a process heater, an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam.

[1]. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B1

Emission Unit Detail Form - External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0741TVP03, Revision 1

1.	Emission Unit ID Number // Operating Scenario	4
2.	Date installation/construction commenced	December 20, 2001
3.	Date installed	2002
4.	Emission Unit serial number	7766-03
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer	NATCO Canada
7.	Description of emission unit, including type of boiler/heater and firing method: Heater Treater #2 (EU ID 4, V-115B) is a NATCO Canada Electromax Model VFH-CWW direct-fired process heater installed and commissioned in 2002. This unit burns raw fuel gas to heat and process crude oil (directly) for gas and liquids separation. The firing system for the unit is comprised of twin, parallel-fired 3.1 MMBtu/hr burners (Flameco Model SB34-24B) for a total rated capacity of 6.2 MMBtu/hr (combined, twin stacks).	
8.	Rated design capacity (heat input, MMBtu/hr)	6.2 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	Not Applicable
10.	Maximum steam pressure (psi)	Not Applicable
11.	Maximum steam temperature (°F)	Not Applicable

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	0.0072 MMscf/hr (Calculated rate based on a heat rate of 1073.8 Btu/scf the average from 2020 gas analyses and an assumed 80% efficiency)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Perform visible emissions monitoring using Method 9 observations. Monitor, record, and report in accordance with Condition 2-4.
AQ0741TVP03, Rev. 1, Conditions 1 and 6	18 AAC 50.040(j), 50.326(j), & 50.346© 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emission Standards	Burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1, Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 63 Subpart DDDDD	This stationary source is not a major source of Hazardous Air Pollutants.
40 CFR 63 Subpart JJJJJJ	This stationary source is not an industrial, commercial, or institutional boiler as defined in 40 CFR 63.11237. By definition, this emission unit is a process heater, an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam.

[1]. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B1

Emission Unit Detail Form - External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0741TVP03, Revision 1

1.	Emission Unit ID Number // Operating Scenario	5
2.	Date installation/construction commenced	December 20, 2001
3.	Date installed	2002
4.	Emission Unit serial number	7767-03
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer	NATCO Canada
7.	Description of emission unit, including type of boiler/heater and firing method: Heater Treater #3 (EU ID 5, V-115C) is a NATCO Canada Electromax Model VFH-CWW direct-fired process heater installed and commissioned in 2002. This unit burns raw fuel gas to heat and process crude oil (directly) for gas and liquids separation. The firing system for the unit is comprised of twin, parallel-fired 3.1 MMBtu/hr burners (Flameco Model SB34-24B) for a total rated capacity of 6.2 MMBtu/hr (combined, twin stacks).	
8.	Rated design capacity (heat input, MMBtu/hr)	6.2 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	Not Applicable
10.	Maximum steam pressure (psi)	Not Applicable
11.	Maximum steam temperature (°F)	Not Applicable

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	0.0072 MMscf/hr (Calculated rate based on a heat rate of 1073.8 Btu/scf the average from 2020 gas analyses and an assumed 80% efficiency)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Perform visible emissions monitoring using Method 9 observations. Monitor, record, and report in accordance with Condition 2-4.
AQ0741TVP03, Rev. 1, Conditions 1 and 6	18 AAC 50.040(j), 50.326(j), & 50.346© 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emission Standards	Burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1, Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 63 Subpart DDDDD	This stationary source is not a major source of Hazardous Air Pollutants.
40 CFR 63 Subpart JJJJJJ	This stationary source is not an industrial, commercial, or institutional boiler as defined in 40 CFR 63.11237. By definition, this emission unit is a process heater, an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam.

1. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B1

Emission Unit Detail Form - External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0741TVP03, Revision 1

1.	Emission Unit ID Number // Operating Scenario	6
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Emission Unit serial number	7762-52
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer	NATCO Canada
7.	Description of emission unit, including type of boiler/heater and firing method: Crude Heater #1 (EU ID 6, H-112A) is a NATCO Canada indirect-fired boiler system installed and commissioned in 2002. The unit burns raw fuel gas to heat glycol heat transfer fluids (directly) and crude oil (indirectly) for processing. The firing system for the unit is comprised of twin parallel-fired 4.0 MMBtu/hr burners (Flameco Model SB38-24B) for a total rated capacity of 8.0 MMBtu/hr (combined, twin stacks).	
8.	Rated design capacity (heat input, MMBtu/hr)	8.0 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	Not Applicable
10.	Maximum steam pressure (psi)	Not Applicable
11.	Maximum steam temperature (°F)	Not Applicable

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	0.009 MMscf/hr (Calculated rate based on a heat rate of 1073.8 Btu/scf the average from 2020 gas analyses and an assumed 80% efficiency)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Perform visible emissions monitoring using Method 9 observations. Monitor, record, and report in accordance with Condition 2-4.
AQ0741TVP03, Rev. 1, Conditions 1 and 6	18 AAC 50.040(j), 50.326(j), & 50.346© 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emission Standards	Burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1, Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 63 Subpart DDDDD	This stationary source is not a major source of Hazardous Air Pollutants.
40 CFR 63 Subpart JJJJJJ	This stationary source is not an industrial, commercial, or institutional boiler as defined in 40 CFR 63.11237. By definition, this emission unit is a process heater, an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam.

1. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B1

Emission Unit Detail Form - External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0741TVP03, Revision 1

1.	Emission Unit ID Number // Operating Scenario	7
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Emission Unit serial number	7763-52
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer	NATCO Canada
7.	Description of emission unit, including type of boiler/heater and firing method: Crude Heater #2 (EU ID 7, H-112B) is a NATCO Canada indirect-fired boiler system installed and commissioned in 2002. The unit burns raw fuel gas to heat glycol heat transfer fluids (directly) and crude oil (indirectly) for processing. The firing system for the unit is comprised of twin parallel-fired 4.0 MMBtu/hr burners (Flameco Model SB38-24B) for a total rated capacity of 8.0 MMBtu/hr (combined, twin stacks).	
8.	Rated design capacity (heat input, MMBtu/hr)	8.0 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	Not Applicable
10.	Maximum steam pressure (psi)	Not Applicable
11.	Maximum steam temperature (°F)	Not Applicable

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	0.009 MMscf/hr (Calculated rate based on a heat rate of 1073.8 Btu/scf the average from 2020 gas analyses and an assumed 80% efficiency)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Perform visible emissions monitoring using Method 9 observations. Monitor, record, and report in accordance with Condition 2-4.
AQ0741TVP03, Rev. 1, Conditions 1 and 6	18 AAC 50.040(j), 50.326(j), & 50.346© 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emission Standards	Burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1, Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 63 Subpart DDDDD	This stationary source is not a major source of Hazardous Air Pollutants.
40 CFR 63 Subpart JJJJJJ	This stationary source is not an industrial, commercial, or institutional boiler as defined in 40 CFR 63.11237. By definition, this emission unit is a process heater, an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam.

1. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B1

Emission Unit Detail Form - External Combustion Equipment (Boilers and Heaters)

Permit Number: AQ0741TVP03, Revision 1

1.	Emission Unit ID Number // Operating Scenario	8
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Emission Unit serial number	7764-52
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer	NATCO Canada
7.	Description of emission unit, including type of boiler/heater and firing method: Crude Heater #3 (EU ID 8, H-112C) is a NATCO Canada indirect-fired boiler system installed and commissioned in 2002. The unit burns raw fuel gas to heat glycol heat transfer fluids (directly) and crude oil (indirectly) for processing. The firing system for the unit is comprised of twin parallel-fired 4.0 MMBtu/hr burners (Flameco Model SB38-24B) for a total rated capacity of 8.0 MMBtu/hr (combined, twin stacks).	
8.	Rated design capacity (heat input, MMBtu/hr)	8.0 MMBtu/hr
9.	Maximum steam production rate (lbs/hr)	Not Applicable
10.	Maximum steam pressure (psi)	Not Applicable
11.	Maximum steam temperature (°F)	Not Applicable

12. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	0.009 MMscf/hr (Calculated rate based on a heat rate of 1073.8 Btu/scf the average from 2020 gas analyses and an assumed 80% efficiency)

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Perform visible emissions monitoring using Method 9 observations. Monitor, record, and report in accordance with Condition 2-4.
AQ0741TVP03, Rev. 1, Conditions 1 and 6	18 AAC 50.040(j), 50.326(j), & 50.346© 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emission Standards	Burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1, Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions to exceed 500 ppm averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 63 Subpart DDDDD	This stationary source is not a major source of Hazardous Air Pollutants.
40 CFR 63 Subpart JJJJJJ	This stationary source is not an industrial, commercial, or institutional boiler as defined in 40 CFR 63.11237. By definition, this emission unit is a process heater, an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam.

1. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

B2 FORMS

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0741TVP03, Rev. 1

1.	Emission Unit ID Number // Operating Scenario	1
2.	Date installation/construction commenced[1]	2001
3.	Date installed	2002
4.	Emission Unit serial number	OHJ14-T2852
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer and model number	Solar Taurus 60-7301S
7.	Type of combustion device	Internal Combustion Engine
8.	Rated design capacity (horsepower rating for engines)	7174 hp
9.	Rated design capacity (horsepower input, MMBtu/hr rating	58.2 MMBtu/hr
10.	If used for power generation, electrical output (kW)	5200 kWe

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
-NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
-NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	77,986 scf/hr @ 1,072 Btu/scf per the results of the August 2019 Source Test Report Average High Load Test

12	Describe any specific modifications to the emission unit that must be addressed in the permit:
	None.

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Reasonable Inquiry / Record Review
AQ0741TVP03, Rev. 1 Conditions 1.1 and 6.1	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emission Standards	For EU IDs 1 through 8, burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1 Condition 6	18 AAC 50.040(j), 50.326(j) & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1 Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) and 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions, expressed as SO2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1 Condition 14.1	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Sulfur Compound Emissions	Limit sulfur compound emissions, expressed as SO2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 30.
AQ0741TVP03, Rev. 1 Condition 14.3	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Fuel Gas Sulfur Compounds Monitoring.	Analyze a representative sample of each fuel (raw fuel gas and lean fuel gas) monthly to determine the H2S content using either ASTM D4810-88 (Reapproved 1999), D4913-89 (Reapproved 1995), or a listed method approved in 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1). If total H2S content of the gas burned in the emission units exceeds 100 ppmv, then monitor weekly. If H2S content of the gas burned in the emission units exceeds 700 ppmv, then monitor the H2S content of the gas daily.	Yes	Analyze raw fuel gas and lean fuel gas monthly for H2S content of the gas. Increase analyses to weekly if content exceeds 100ppmv and to daily if content exceeds 700ppmv.
AQ0741TVP03, Rev. 1 Condition 14.4	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Fuel Gas Sulfur Compound Recordkeeping	The Permittee shall keep records of the H2S content analysis	Yes	Maintain records of fuel gas H2S analyses
AQ0741TVP03, Rev. 1 Condition 14.5	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Fuel Gas Sulfur Compound Reporting	Notify the Department at the end of the month for which the fuel gas H2S exceeds 100ppmv or 700ppmv. Report as excess emissions if the sulfur compound emissions exceed 500 parts per million (ppm) averaged over three hours.	Yes	Report to the Department if the H2S content exceeds 100ppmv or 700ppmv and report as an Excess Emission

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 17.1 and AQ0741MSS03 Condition 7	18 AAC 50.326(a) and 40 C.F.R. 71.2&71.6(a)(1) & (3)	Limits to Avoid Classification as PSD Major Source-Nitrogen Oxides (NO_X) Emission Limits	Limit NO_X emissions from EU IDs 1 and 2 by installing SoLoNO_X low NO_X combustion technology and limit combined NO_X emissions from EU IDs 1 and to no more than 64.5 tons per 12-month rolling period, expressed as NO_2.	Yes	Monitor, record, and report in accordance with Condition 17.2
AQ0741TVP03, Rev. 1 Condition 18.1a and AQ0741MSS03 Condition 8	18 AAC 50.326(a) 40 CFR 71.2 & 71.6(a)(1) & (3)	Limits to Avoid Classification as PSD Major Source-Carbon Monoxide (CO) Emission Limits	Limit the fuel gas burned to no more than 70MMscf in any 12-month rolling period.	Yes	Monitor, record, and report in accordance with Conditions 18.1b, 18.2, 18.3, and 18.4
AQ0741TVP03, Rev. 1 Condition 21	18 AAC 50.040(a)(1) 40 CFR 60.15(d)	NSPS Subpart A Notification	Replacement of components of an existing facility, for which the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, postmarked as soon as practicable, but no less than 60 days before commencement of replacement, and including information required by 40 CFR 60.15(d).	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 22	18 AAC 50.040(a)(1) 40 C.F.R. 60.7(b), Subpart A	NSPS Subpart A Startup, Shutdown, & Malfunction Requirements	Maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EU IDs 1 and 2, any malfunction of the associated air pollution control equipment, or any periods during which a continuous monitoring system (CMS) or monitoring device for EU IDs 1 and 2 is inoperative.	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 23	18 AAC 50.040(a)(1) 40 C.F.R. 60.7(c), Subpart A	NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report	Submit an EEMSP report and/or summary report form for EU IDs 1 and 2 to the Department and to EPA. Submit the report semiannually.	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 24	18 AAC 50.040(a)(1) 40 C.F.R. 60.7(c) & (d), Subpart A	NSPS Subpart A EEMSP Summary Report Form	Submit to the Department and to EPA one "summary report form" for each pollutant monitored for EU IDs 1 and 2.	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 25	18 AAC 50.040(a)(1) 40 C.F.R. 60.8(a), Subpart A	NSPS Subpart A Performance (Source) Tests	Conduct source tests according to Section 6 and as required in this condition on any affected facility at such times as may be required by the EPA, and shall provide the Department and EPA with a written report of the results of the source tests.	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 26	18 AAC 50.040(a)(1) 40 C.F.R. 60.11(d), Subpart A	NSPS Subpart A Good Air Pollution Control Practice	At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate EU IDs 1 and 2 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.	Yes	Reasonable Inquiry / Record Review

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 27	18 AAC 50.040(a)(1) 40 C.F.R. 60.11(g), Subpart A	NSPS Subpart A Credible Evidence	Nothing in 40 C.F.R. Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 1 and 2 would have been in compliance with applicable requirements of 40 C.F.R. Part 60 if the appropriate performance or compliance test or procedure had been performed.	N/A	Information condition only, no compliance task
AQ0741TVP03, Rev. 1 Condition 28	18 AAC 50.040(a)(1) 40 CFR 60.12	NSPS Subpart A Concealment of Emissions	Do not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of NSPS Subpart GG. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.	Yes	Reasonable Inquiry
AQ0741TVP03, Rev. 1 Condition 29	18 AAC 50.040(a), 18 AAC 50.040(j) & 50.326(j)(4), 18 AAC 50.220(a) - (c) 40 C.F.R. 60.332(a), (c),& (d), Subpart GG, 40 C.F.R. 71.6(a)(3)(ii) & (c)(6), 40 C.F.R. 60.8(b), Subpart A	NSPS Subpart GG NOx Standard	Do not allow the exhaust gas concentration of NOx from EU IDs 1and 2 to exceed 173.6 ppmvd at 15 percent O2 dry exhaust basis, International Standards Organization corrected.	Yes	Monitor, record, and report in accordance with Conditions 29.1, 29.2, and 29.3
AQ0741TVP03, Rev. 1 Condition 30, 30.1, and 30.2	18 AAC 50.040(a)(2)(V) 40 C.F.R. 60.333, Subpart GG	NSPS Subpart GG Sulfur Standard	Do not allow the exhaust gas concentration of SO2 from EU IDs 1 and 2 listed in Table A, to exceed 150 ppmvd corrected to 15 percent O2 or 0.8 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 30.3, 30.4, 30.5, and 30.6. Note: The Permittee chose to comply with the SO2 standard by not exceeding 0.8 percent by weight sulfur content of the fuel burned in the emission units. No monitoring is required for demonstrating compliance with the sulfur standard in accordance with Subpart GG regulation 60.334h(4)(ii)(A) effective July 8, 2004. The Permittee has completed sufficient monitoring under previous Title I permits to demonstrate that the fuel gas used meets the definition of pipeline natural gas and therefore does not need to sample the fuel for sulfur content.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 C.F.R. 60.332(a)(1) - Standard for nitrogen oxides	Emission unit is not an Electric Utility Stationary Gas Turbine as defined in 40 CFR 60 Subpart GG.
40 C.F.R. 60, Subpart GG §60.334(a), (b) & (d) and 60.335(b)(4)– Monitoring of Operations	Emission unit is not equipped with water injection to control emissions of NOx.
40 C.F.R. 60, Subpart GG §60.334(e) & (f)	Emission unit commenced construction prior to July 8, 2004.
40 C.F.R. 60, Subpart GG §60.334(g)	Emission unit is not subject to continuous monitoring requirements in 40 CFR 60.334(a), (d), or (f).
40 C.F.R. 60, Subpart GG §60.334(h)(1 & 2), (i), & (j)	The allowance for fuel bound nitrogen to calculate the NO_X emission limit under 40 CFR 60.332 has not been claimed and Kustatan Production Facility has completed sufficient monitoring under previous Title I permits to demonstrate that the fuel gas used meets the definition of pipeline natural gas.
40 C.F.R. 60, Subpart A §60.7(a)(1 & 3) – Notification and Recordkeeping (Initial Notification) and §60.8(a) – performance Test (Initial Performance Test Only)	Source tests were completed as required.
40 CFR 60.7(a)(6)	No opacity observations required.
40 C.F.R. 60, Subpart KKKK §60.4300 - Standards of Performance for New Stationary Sources	This requirement only applies to stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005.
40 C.F.R. 63, Subpart YYYY	The affected facility is not a major source of hazardous air pollutants (HAPs).

[1]. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0741TVP03, Rev. 1

1.	Emission Unit ID Number // Operating Scenario	2
2.	Date installation/construction commenced[1]	2001
3.	Date installed	2002
4.	Emission Unit serial number	OHI14-T1247
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer and model number	Solar Taurus 60-7301S
7.	Type of combustion device	Internal Combustion Engine
8.	Rated design capacity (horsepower rating for engines)	6,692 Hp
9.	Rated design capacity (horsepower input, MMBtu/hr rating	55.3 MMBtu/hr
10.	If used for power generation, electrical output (kW)	5200 kWe

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
-NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
-NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Natural Gas	80,694 scf/hr @ 1,072 Btu/scf per the results of the August 2019 Source Test Report Average High Load Test

12	Describe any specific modifications to the emission unit that must be addressed in the permit:
	None.

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Reasonable Inquiry / Record Review
AQ0741TVP03, Rev. 1 Conditions 1.1 and 6.1	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emission Standards	For EU IDs 1 through 8, burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1 Condition 6	18 AAC 50.040(j), 50.326(j) & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1 Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) and 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions, expressed as SO2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1 Condition 14.1	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Sulfur Compound Emissions	Limit sulfur compound emissions, expressed as SO2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 30.
AQ0741TVP03, Rev. 1 Condition 14.3	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Fuel Gas Sulfur Compounds Monitoring.	Analyze a representative sample of each fuel (raw fuel gas and lean fuel gas) monthly to determine the H2S content using either ASTM D4810-88 (Reapproved 1999), D4913-89 (Reapproved 1995), or a listed method approved in 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1). If total H2S content of the gas burned in the emission units exceeds 100 ppmv, then monitor weekly. If H2S content of the gas burned in the emission units exceeds 700 ppmv, then monitor the H2S content of the gas daily.	Yes	Analyze raw fuel gas and lean fuel gas monthly for H2S content of the gas. Increase analyses to weekly if content exceeds 100ppmv and to daily if content exceeds 700ppmv.
AQ0741TVP03, Rev. 1 Condition 14.4	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Fuel Gas Sulfur Compound Recordkeeping	The Permittee shall keep records of the H2S content analysis	Yes	Maintain records of fuel gas H2S analyses
AQ0741TVP03, Rev. 1 Condition 14.5	18 AAC 50.040(j), 50.326(j), & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Fuel Gas Sulfur Compound Reporting	Notify the Department at the end of the month for which the fuel gas H2S exceeds 100ppmv or 700ppmv. Report as excess emissions if the sulfur compound emissions exceed 500 parts per million (ppm) averaged over three hours.	Yes	Report to the Department if the H2S content exceeds 100ppmv or 700ppmv and report as an Excess Emission

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 17.1 and AQ0741MSS03 Condition 7	18 AAC 50.326(a) and 40 C.F.R. 71.2&71.6(a)(1) & (3)	Limits to Avoid Classification as PSD Major Source- Nitrogen Oxides (NO_X) Emission Limits	Limit NO_X emissions from EU IDs 1 and 2 by installing SoLoNO_X low NO_X combustion technology and limit combined NO_X emissions from EU IDs 1 and to no more than 64.5 tons per 12-month rolling period, expressed as NO_2.	Yes	Monitor, record, and report in accordance with Condition 17.2
AQ0741TVP03, Rev. 1 Condition 18.1a and AQ0741MSS03 Condition 8	18 AAC 50.326(a) 40 CFR 71.2 & 71.6(a)(1) & (3)	Limits to Avoid Classification as PSD Major Source-Carbon Monoxide (CO) Emission Limits	Limit the fuel gas burned to no more than 70MMscf in any 12-month rolling period.	Yes	Monitor, record, and report in accordance with Conditions 18.1b, 18.2, 18.3, and 18.4
AQ0741TVP03, Rev. 1 Condition 21	18 AAC 50.040(a)(1) 40 CFR 60.15(d)	NSPS Subpart A Notification	Replacement of components of an existing facility, for which the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, postmarked as soon as practicable, but no less than 60 days before commencement of replacement, and including information required by 40 CFR 60.15(d).	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 22	18 AAC 50.040(a)(1) 40 C.F.R. 60.7(b), Subpart A	NSPS Subpart A Startup, Shutdown, & Malfunction Requirements	Maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EU IDs 1 and 2, any malfunction of the associated air pollution control equipment, or any periods during which a continuous monitoring system (CMS) or monitoring device for EU IDs 1 and 2 is inoperative.	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 23	18 AAC 50.040(a)(1) 40 C.F.R. 60.7(c), Subpart A	NSPS Subpart A Excess Emissions and Monitoring Systems Performance Report	Submit an EEMSP report and/or summary report form for EU IDs 1 and 2 to the Department and to EPA. Submit the report semiannually.	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 24	18 AAC 50.040(a)(1) 40 C.F.R. 60.7(c) & (d), Subpart A	NSPS Subpart A EEMSP Summary Report Form	Submit to the Department and to EPA one "summary report form" for each pollutant monitored for EU IDs 1 and 2.	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 25	18 AAC 50.040(a)(1) 40 C.F.R. 60.8(a), Subpart A	NSPS Subpart A Performance (Source) Tests	Conduct source tests according to Section 6 and as required in this condition on any affected facility at such times as may be required by the EPA, and shall provide the Department and EPA with a written report of the results of the source tests.	Yes	Records Review
AQ0741TVP03, Rev. 1 Condition 26	18 AAC 50.040(a)(1) 40 C.F.R. 60.11(d), Subpart A	NSPS Subpart A Good Air Pollution Control Practice	At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate EU IDs 1 and 2 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.	Yes	Reasonable Inquiry / Record Review

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 27	18 AAC 50.040(a)(1) 40 C.F.R. 60.11(g), Subpart A	NSPS Subpart A Credible Evidence	Nothing in 40 C.F.R. Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 1 and 2 would have been in compliance with applicable requirements of 40 C.F.R. Part 60 if the appropriate performance or compliance test or procedure had been performed.	N/A	Information condition only, no compliance task
AQ0741TVP03, Rev. 1 Condition 28	18 AAC 50.040(a)(1) 40 CFR 60.12	NSPS Subpart A Concealment of Emissions	Do not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of NSPS Subpart GG. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.	Yes	Reasonable Inquiry
AQ0741TVP03, Rev. 1 Condition 29	18 AAC 50.040(a), 18 AAC 50.040(j) & 50.326(j)(4), 18 AAC 50.220(a) - (c) 40 C.F.R. 60.332(a), (c),& (d), Subpart GG, 40 C.F.R. 71.6(a)(3)(ii) & (c)(6), 40 C.F.R. 60.8(b), Subpart A	NSPS Subpart GG NOx Standard	Do not allow the exhaust gas concentration of NOx from EU IDs 1and 2 to exceed 173.6 ppmvd at 15 percent O2 dry exhaust basis, International Standards Organization corrected.	Yes	Monitor, record, and report in accordance with Conditions 29.1, 29.2, and 29.3
AQ0741TVP03, Rev. 1 Condition 30, 30.1, and 30.2	18 AAC 50.040(a)(2)(V) 40 C.F.R. 60.333, Subpart GG	NSPS Subpart GG Sulfur Standard	Do not allow the exhaust gas concentration of SO2 from EU IDs 1 and 2 listed in Table A, to exceed 150 ppmvd corrected to 15 percent O2 or 0.8 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 30.3, 30.4, 30.5, and 30.6. Note: The Permittee chose to comply with the SO2 standard by not exceeding 0.8 percent by weight sulfur content of the fuel burned in the emission units. No monitoring is required for demonstrating compliance with the sulfur standard in accordance with Subpart GG regulation 60.334h(4)(ii)(A) effective July 8, 2004. The Permittee has completed sufficient monitoring under previous Title I permits to demonstrate that the fuel gas used meets the definition of pipeline natural gas and therefore does not need to sample the fuel for sulfur content.

[1]. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 C.F.R. 60.332(a)(1) - Standard for nitrogen oxides	Emission unit is not an Electric Utility Stationary Gas Turbine as defined in 40 CFR 60 Subpart GG.
40 C.F.R. 60, Subpart GG §60.334(a), (b) & (d) and 60.335(b)(4)– Monitoring of Operations	Emission unit is not equipped with water injection to control emissions of NOx.
40 C.F.R. 60, Subpart GG §60.334(e) & (f)	Emission unit commenced construction prior to July 8, 2004.
40 C.F.R. 60, Subpart GG §60.334(g)	Emission unit is not subject to continuous monitoring requirements in 40 CFR 60.334(a), (d), or (f).
40 C.F.R. 60, Subpart GG §60.334(h)(1 & 2), (i), & (j)	The allowance for fuel bound nitrogen to calculate the NOX emission limit under 40 CFR 60.332 has not been claimed and Kustatan Production Facility has completed sufficient monitoring under previous Title I permits to demonstrate that the fuel gas used meets the definition of pipeline natural gas.
40 C.F.R. 60, Subpart A §60.7(a)(1 & 3) – Notification and Recordkeeping (Initial Notification) and §60.8(a) – performance Test (Initial Performance Test Only)	Source tests were completed as required.
40 CFR 60.7(a)(6)	No opacity observations required.
40 C.F.R. 60, Subpart KKKK §60.4300 - Standards of Performance for New Stationary Sources	This requirement only applies to stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005.
40 C.F.R. 63, Subpart YYYY	The affected facility is not a major source of hazardous air pollutants (HAPs).

[1]. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0741TVP03, Revision 1

1.	Emission Unit ID Number // Operating Scenario	9
2.	Date installation/construction commenced[1]	October 14, 2002
3.	Date installed	2002
4.	Emission Unit serial number	46263509
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer and model number	Cummins 6BTA 5.9 F4
7.	Type of combustion device	Internal Combustion Engine
8.	Rated design capacity (horsepower rating for engines)	160 hp
9.	Rated design capacity (horsepower input, MMBtu/hr rating for turbines)	Not Applicable
10.	If used for power generation, electrical output (kW)	Not Applicable

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
-NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
-NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel Fuel	8.2 gal/hr (Based on Unit Spec Sheet)

12	Describe any specific modifications to the emission unit that must be addressed in the permit:
	None.

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Reasonable Inquiry / Record Review
AQ0741TVP03, Rev. 1, Condition 1.2	18 AAC 50.040(j), 50.326(j), & 50.346(c) 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emissions	As long as the emissions unit does not operate for more than 500 hours in a calendar year, monitoring shall consist of an annual compliance certification under Condition 71 with the visible emissions standard. Otherwise, monitor, record and report in accordance with Conditions 2 - 4 for the remainder of the permit term.. Monitor and record the monthly and calendar year-to-date operating hours. Report the calendar year-to-date operating hours in the operating report under Condition 70 for the period covered by the report.	Yes	Monitor, record, and report in accordance with Conditions 2-4
AQ0741TVP03, Rev. 1 Condition 6	18 AAC 50.040(j), 50.326(j) & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Yes	Certification of compliance with the PM standard if the unit does not operate more than 500 hours in a calendar year, otherwise, monitor, record, and report in accordance with Conditions 7-9.
AQ0741TVP03, Rev. 1 Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) and 40 C.F.R. 71.6(a)(1)	Sulfur Compound Standard	Do not cause or allow sulfur compound emissions, expressed as SO2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1 Condition 11	18 AAC 50.040(j), 50.326(j), & 50.346(c) 40 C.F.R. 71.6(a)(3)	Fuel Oil Sulfur Limit	Limit the fuel sulfur content of the diesel fuel burned to no greater than 0.5 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 12 and 13.
AQ0741TVP03, Rev. 1 Condition 16	Minor Permit No. AQ0741MSS02, Condition 5, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2&71.6(a)(1) & (3)	Fuel Oil Sulfur Limit	Limit the fuel sulfur content of the diesel fuel burned to no greater than 0.5 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 12 and 13.
AQ0741TVP03, Rev. 1, Condition 31	18 AAC 50.040(c)(1) & 50.326(j)] 40 C.F.R. 71.6(a)(1)] 40 C.F.R. 63.1-63.15, Subpart A 40 C.F.R. 63.6665 & Table 8, NESHAP Subpart ZZZZ	NESHAP Subpart A General Provisions	Comply with the applicable requirements of 40 CFR 63 Subpart A in accordance with the provisions for applicability of Subpart A in NESHAP Subpart ZZZZ, Table 8.	Yes	Monitor, record, and report in accordance with Table 8 of Subpart ZZZZ.
AQ0741TVP03, Rev. 1, Condition 32	18 AAC 50.040(c)(23) Subpart ZZZZ 40 CFR 63.6603(a) & Table 2d-Item 4	NESHAP Subpart ZZZZ Management Practices	Comply with the applicable requirements in Table 2d to 40 C.F.R. 63, Subpart ZZZZ.	Yes	Conduct maintenance as described in Condition 32.1
AQ0741TVP03, Rev. 1, Condition 33.1	18 AAC 50.040(c)(23) 40 CFR 63.6605(b)	NESHAP Subpart ZZZZ Good Air Pollution Control Practices	At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.	Yes	Records Review/Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 33.2	40 C.F.R. 63.6625(e) 40 C.F.R. 63.6625(h) & Table 2d, Column 3	NESHAP Subpart ZZZZ Operation and Maintenance Requirements	Operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan. Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period need for appropriate and safe loading of the engine, not to exceed 30 minutes	Yes	Records Review/Reasonable Inquiry

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 33.3	18 AAC 50.040(c)(23) 40 CFR 63.6605(b)	NESHAP Subpart ZZZZ Hour Meter	Install a non-resettable hour meter if one is not already installed.	Yes	Records Review/Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 33.4	40 C.F.R. 63.6625(i)]	NESHAP Subpart ZZZZ Oil Analysis Program	An alternative option is provided in NESHAP Subpart ZZZZ to utilize an oil analysis program in order to extend the specified oil change requirement in Condition 32.	Yes	Alternative testing must be conducted as described
AQ0741TVP03, Rev. 1, Condition 34	18 AAC 50.040(c)(23) 40 CFR 63.6640(f)(1)-(4)	NESHAP Subpart ZZZZ Operating Hours for Emergency Engines	Operate the emergency stationary RICE according to the requirements in Conditions 34.1.a - 34.1.c. In order for the engine to be considered an emergency stationary RICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in Conditions 34.1.a - 34.1.c, is prohibited. If you do not operate the engine according to the requirements in Conditions 34.1.a - 34.1.c, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.	Yes	Limit non-emergency operating hours to no more than 100 hours per calendar year, of those hours, only 50 of those can be used for regular operation. The remaining 50 hours are for maintenance and testing only. No limitation on emergency operating hours.
AQ0741TVP03, Rev. 1, Condition 35	40 C.F.R. 63.6640(a), 40 C.F.R. 63.6640(e), & Table 6, Item 9, Subpart ZZZZ	NESHAP Subpart ZZZZ Monitoring Requirements	Operate and maintain the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or Develop and follow your own maintenance plan.	Yes	Monitor and maintain emission sources according to the Good Air Pollution Control Practices described in NESHAP Subpart ZZZZ. Record and report as required by Conditions 36 and 37

[1.] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 63.6600, 63.6601, 63.6602, 63.6610, 63.6611-Subpart ZZZZ	Facility is not a major source of HAPs
40 CFR 63.63.6603(b), 6604, 63.6625(c), (d), 63.6625(g), 63.6640, 63.6645(a), (b), (c), (d), (e), (f), 63.6655(c)-Subpart ZZZZ	According to 40 CFR 63.6604(d), the provisions of 40 C.F.R. 80.510 do not apply to owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) as described in 40 CFR 63.6603(b)(1).
40 CFR 63.6605(a), 63.6630, 63.6635, 63.6640, 63.6650, 63.6655(a), (d)-Subpart ZZZZ	The emission units are not subject to emission limitations or operating limitations.
40 CFR 63.6612, 63.6615, 63.6620, 63.6645-Subpart ZZZZ	Emergency stationary RICE are not subject to performance tests or other compliance demonstrations.
40 CFR 63.6625(a), (b), 63.6655(b)-Subpart ZZZZ	Not required to use a CEMS, CPMS, or a CMS.
40 CFR 63.6655-Subpart ZZZZ	40 CFR 63.6603(b)(1) excludes the unit from the emission and operating limitations, therefore, recordkeeping requirements are also not required per 40 CFR 63.6655(a)
40 CFR 60 Subpart IIII	Emission unit was constructed prior to the effective date of July 11, 2005.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B2

Emission Unit Detail Form - Internal Combustion Equipment (Engines and Turbines)

Permit Number: AQ0741TVP03, Revision 1

1.	Emission Unit ID Number // Operating Scenario	9a
2.	Date installation/construction commenced[1]	November 28, 2000
3.	Date installed	2002
4.	Emission Unit serial number	4JK00799
5.	Special control requirements? [if yes, describe]	No
6.	Manufacturer and model number	Caterpillar 3406CDITA
7.	Type of combustion device	Internal Combustion Engine
8.	Rated design capacity (horsepower rating for engines)	519 hp
9.	Rated design capacity (horsepower input, MMBtu/hr rating for turbines)	Not Applicable
10.	If used for power generation, electrical output (kW)	Not Applicable

1. See page 2 of the Form B instructions regarding installation/construction date and consult regulations under 40 C.F.R. 60 (NSPS) and 40 C.F.R. 63 (NESHAP) for applicability dates, e.g.,
-NSPS Subparts IIII and JJJJ, and NESHAP Subpart ZZZZ for engines, and
-NSPS Subparts GG and KKKK, and NESHAP Subpart YYYY for turbines.
Note that other regulations may apply in addition to the regulations cited.

11. Fuel usage: [for EACH fuel, enter]:

Fuel	Maximum hourly firing rate (specify units)
Diesel Fuel	26.1 gal/hr corrected nominal fuel rate according to Test Specs provided by NC Machinery

12	Describe any specific modifications to the emission unit that must be addressed in the permit:
	None.

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 1	18 AAC 50.040(j), 50.055(a)(1), & 50.326(j) 40 C.F.R. 71.6(a)(1)	Visible Emission Standards	Do not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Reasonable Inquiry / Record Review
AQ0741TVP03, Rev. 1, Condition 1.3	18 AAC 50.040(j), 50.326(j), & 50.346(c) 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emissions	As long as the emissions unit does not operate for more than 243 hours in a consecutive 12 months period, monitoring shall consist of an annual compliance certification under Condition 71 with the visible emissions standard. Otherwise, monitor, record and report in accordance with Conditions 2 - 4 for the remainder of the permit term.. Monitor and record the monthly and calendar year-to-date operating hours. Report the calendar year-to-date operating hours in the operating report under Condition 70 for the period covered by the report.	Yes	Monitor, record, and report in accordance with Conditions 2-4 and 17.3b
AQ0741TVP03, Rev. 1 Condition 6	18 AAC 50.040(j), 50.326(j) & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Yes	Certification of compliance with the PM standard if the unit does not operate more than 500 hours in a calendar year, otherwise, monitor, record, and report in accordance with Conditions 7-9.
AQ0741TVP03, Rev. 1 Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) and 40 C.F.R. 71.6(a)(1)	Sulfur Compound Standard	Do not cause or allow sulfur compound emissions, expressed as SO2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1 Condition 11	18 AAC 50.040(j), 50.326(j), & 50.346(c) 40 C.F.R. 71.6(a)(3)	Fuel Oil Sulfur Limit	Limit the fuel sulfur content of the diesel fuel burned to no greater than 0.5 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 12 and 13.
AQ0741TVP03, Rev. 1 Condition 16	Minor Permit No. AQ0741MSS02, Condition 5, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2&71.6(a)(1) & (3)	Fuel Oil Sulfur Limit	Limit the fuel sulfur content of the diesel fuel burned to no greater than 0.5 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 12 and 13.
AQ0741TVP03, Rev. 1 Condition 17.3	Minor Permit No. AQ0741MSS02, Condition 6, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2&71.6(a)(1) & (3)	Limits to Avoid Classification as PSD Major Source Nitrogen Oxides (NO_X) Emission Limits	Limit operations of EU 9a to no more than 500 hours per 12-month rolling period. Monitor and record the hours of operation of EU 9a for each calendar month. Report the cumulative total monthly and 12 month rolling hours of operation of EU 9a in the operating report required Condition 70.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 31	18 AAC 50.040(c)(1) & 50.326(j)] 40 C.F.R. 71.6(a)(1)] 40 C.F.R. 63.1-63.15, Subpart A 40 C.F.R. 63.6665 & Table 8, NESHAP Subpart ZZZZ	NESHAP Subpart A General Provisions	Comply with the applicable requirements of 40 CFR 63 Subpart A in accordance with the provisions for applicability of Subpart A in NESHAP Subpart ZZZZ, Table 8.	Yes	Monitor, record, and report in accordance with Table 8 of Subpart ZZZZ.
AQ0741TVP03, Rev. 1, Condition 32	18 AAC 50.040(c)(23) Subpart ZZZZ 40 CFR 63.6603(a) & Table 2d-Item 4	NESHAP Subpart ZZZZ Management Practices	Comply with the applicable requirements in Table 2d to 40 C.F.R. 63, Subpart ZZZZ.	Yes	Conduct maintenance as described in Condition 32.2
AQ0741TVP03, Rev. 1, Condition 33.1	18 AAC 50.040(c)(23) 40 CFR 63.6605(b)	NESHAP Subpart ZZZZ Good Air Pollution Control Practices	At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.	Yes	Records Review/Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 33.2	40 C.F.R. 63.6625(e) 40 C.F.R. 63.6625(h) & Table 2d, Column 3	NESHAP Subpart ZZZZ Operation and Maintenance Requirements	Operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan. Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period need for appropriate and safe loading of the engine, not to exceed 30 minutes	Yes	Records Review/Reasonable Inquiry

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citiation[1]	Parameter/Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1, Condition 33.3	18 AAC 50.040(c)(23) 40 CFR 63.6605(b)	NESHAP Subpart ZZZZ Hour Meter	Install a non-resettable hour meter if one is not already installed.	Yes	Records Review/Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 33.4	40 C.F.R. 63.6625(i)]	NESHAP Subpart ZZZZ Oil Analysis Program	An alternative option is provided in NESHAP Subpart ZZZZ to utilize an oil analysis program in order to extend the specified oil change requirement in Condition 32.	Yes	Alternative testing must be conducted as described
AQ0741TVP03, Rev. 1, Condition 34	18 AAC 50.040(c)(23) 40 CFR 63.6640(f)(1)-(4)	NESHAP Subpart ZZZZ Operating Hours for Emergency Engines	Operate the emergency stationary RICE according to the requirements in Conditions 34.1.a - 34.1.c. In order for the engine to be considered an emergency stationary RICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in Conditions 34.1.a - 34.1.c, is prohibited. If you do not operate the engine according to the requirements in Conditions 34.1.a - 34.1.c, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.	Yes	Limit non-emergency operating hours to no more than 100 hours per calendar year, of those hours, only 50 of those can be used for regular operation. The remaining 50 hours are for maintenance and testing only. No limitation on emergency operating hours.
AQ0741TVP03, Rev. 1, Condition 35	40 C.F.R. 63.6640(a), 40 C.F.R. 63.6640(e), & Table 6, Item 9, Subpart ZZZZ	NESHAP Subpart ZZZZ Monitoring Requirements	Operate and maintain the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or Develop and follow your own maintenance plan.	Yes	Monitor and maintain emission sources according to the Good Air Pollution Control Practices described in NESHAP Subpart ZZZZ. Record and report as required by Conditions 36 and 37

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

Non-applicable Requirements Specific to Emission Unit (attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 63.6600, 63.6601, 63.6602, 63.6610, 63.6611-Subpart ZZZZ	Facility is not a major source of HAPs
40 CFR 63.6603(a), 63.6604, 63.6625(c), (d), (f), (g), 63.6645(a), (b), (c), (d), (e), (f), 6655(c), (f)-Subpart ZZZZ	40 CFR 63.6603(b)(1) excludes all existing stationary non-emergency CI RICE with a rating of more than 300hp located at an area of Alaska not accessible by the Federal Aid Highway System from having to meet the numerical CO emission limits specified in Table 2d of the subpart and from any operating limitations.
40 CFR 63.6604, 63.6625, 63.6640-Subpart ZZZZ	According to 40 CFR 63.6604(d), the provisions of 40 C.F.R. 80.510 do not apply to owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) as described in 40 CFR 63.6603(b)(1).
40 CFR 63.6605(a), 63.6630, 63.6635, 63.6640, 63.6650, 63.6655(a), (d)-Subpart ZZZZ	40 CFR 63.6603(b)(1) excludes the unit from the emission and operating limitations, therefore, recordkeeping requirements are also not required per 40 CFR 63.6655(a)
40 CFR 63, Subpart ZZZZ §§63.6612, 63.6615, 63.6620, 63.6645 (g) & (h)	The emission unit is not subject to performance tests or other compliance demonstrations.
40 CFR 63.6625(a), (b), 63.6655(b)	Not required to use a CEMS, CPMS, or a CMS.
40 CFR 60 Subpart IIII	Emission unit was constructed prior to the effective date of July 11, 2005.

[1]. Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

B4 FORMS

Emission Unit Detail Form - Volatile Liquid Storage Tanks

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit Number: AQ0741TVP04A

1.	**Emission Unit ID Number // Operating Scenario**	12 (T-133 Crude Tank No. 1)
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Special control requirements? [if yes, describe]	The tanks are required by Permit No. AQ0741TVP03, Rev. 1 Condition 19 and Permit No. AQ0741MSS03 Condition 9 requires that each tank be equipped with a closed vent system and control device to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device is to be designed to reduce inlet VOC emissions by 95% or greater.
5.	Rated capacity (gallons)	42,000 gal
6.	Tank height (ft)	24
7.	Tank diameter (ft)	55 (outside diameter)
8.	Tank age (years)	19
9.	Submerged fill pipe?	Yes
10.	Type of tank (specify)	Fixed Roof
11.	Underground?	No
	If underground, specify type of tube and vapor return.	N/A
12.	Above ground vapor control information:	
	Pipe material	Steel
	Pipe size	10"
	Piping drainage (continuous drain downward or condensate collection tank – if condensate collection, attach a description)	Continuous drainage (1/8" per 10 foot)
	Isolation valve installed in piping?	Yes
13.	Pressure vacuum relief valves:	
	Vent pressure settings (psia)	14.69 (V) to 14.92(P)
	Months in which relief valves removed (specify)	Not removed
14.	Pressure conservation vent? [if yes, specify pressure setting – psia]	14.772 psia
15.	Fixed roof tanks:	
	Roof color	White
	Shell color	White
	Average vapor space height (ft)	12
	Shell condition (specify)	Good

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	12 (T-133 Crude Tank No. 1)
16.	Floating roof tanks:	
	Type of construction (specify)	Not Applicable
	Condition (specify)	Not Applicable
	Tank color	Not Applicable
	Deck type (specify)	Not Applicable
17.	External floating roof tanks, seal type (specify)	Not Applicable
18.	Internal floating roof tanks:	
	Seal type (specify)	Not Applicable
	Number of columns	Not Applicable
	Effective column diameter (ft)	Not Applicable
	Total deck seam length (ft)	Not Applicable
	Deck fitting types – access hatch	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types - Automatic gauge float well	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types – column well	
	Built up column – sliding cover, gasketed	Not Applicable
	Built up column – sliding cover, ungasketed	Not Applicable
	Pipe column – flexible fabric sleeve seal	Not Applicable
	Pipe column – – sliding cover, gasketed	Not Applicable
	Pipe column – – sliding cover, ungasketed	Not Applicable
	Deck fitting types – ladder well	
	sliding cover, gasketed	Not Applicable
	sliding cover, ungasketed	Not Applicable

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	12 (T-133 Crude Tank No. 1)
	Deck fitting types – smple well or pipe	
	Slotted pipe – sliding cover, gasketed	Not Applicable
	Slotted pipe – sliding cover, ungasketed	Not Applicable
	Sample well – slit fabric seal, 10% open area	Not Applicable
	Stub drain – 1-inch diameter	Not Applicable
	Deck fitting type – roof leg or hanger will	
	Adjustable	Not Applicable
	fixed	Not Applicable
	Deck fitting type – vacuum breaker	
	Weighted mechanical actuation, gasketed	Not Applicable
	Weighted mechanical actuation, ungasketed	Not Applicable
19.	Maximum liquid loading rate (gal/hr)	35,000
20.	Submerged fill at out-loading(describe)	Submerged from storage tank provided directly to pipeline
21.	**Material(s) stored**	
	Type of material	Crude oil
	Normal annual throughput (gal/yr)	21,840,000
	Normal turnovers per year	52 (based on weekly delivery)
	Density (lbs/gal)	5.83-8.58 lbs/gal Bulk
	Molecular weight	206
	Average storage temperature (°F)	36
	Vapor pressure (psi)	8.5-15 psia@ 100°F

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 19 & AQ0741MSS03 Condition 9	Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2 & 71.6(a)(1) & (3)	Volatile Organic Compounds (VOC) Emission Limits – Tank Closed Vent System	Equip the crude tanks, slop oil tank and produced water tank, with a closed vent system and control device designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures.	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60, Subpart Kb	The facility has chosen to comply with the alternative means of compliance in 40 CFR 65.42(b)(5)(i) as allowed in Subpart Kb (40 CFR 60.110b(e)(1)(i) and install a control device designed and operated to reduce inlet VOC emissions by 95% or greater.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit Number: AQ0741TVP04A

1.	**Emission Unit ID Number // Operating Scenario**	13 (T-134 Crude Tank No. 2)
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Special control requirements? [if yes, describe]	The tanks are required by Permit No. AQ0741TVP03, Rev. 1 Condition 19 and Permit No. AQ0741MSS03 Condition 9 requires that each tank be equipped with a closed vent system and control device to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device is to be designed to reduce inlet VOC emissions by 95% or greater.
5.	Rated capacity (gallons)	42,000 gal
6.	Tank height (ft)	24
7.	Tank diameter (ft)	55 (outside diameter)
8.	Tank age (years)	19
9.	Submerged fill pipe?	Yes
10.	Type of tank (specify)	Fixed Roof
11.	Underground?	No
	If underground, specify type of tube and vapor return.	N/A
12.	Above ground vapor control information:	
	Pipe material	Steel
	Pipe size	10"
	Piping drainage (continuous drain downward or condensate collection tank – if condensate collection, attach a description)	Continuous drainage (1/8" per 10 foot)
	Isolation valve installed in piping?	Yes
13.	Pressure vacuum relief valves:	
	Vent pressure settings (psia)	14.69 (V) to 14.92(P)
	Months in which relief valves removed (specify)	Not removed
14.	Pressure conservation vent? [if yes, specify pressure setting – psia]	14.772 psia
15.	Fixed roof tanks:	
	Roof color	White
	Shell color	White
	Average vapor space height (ft)	12
	Shell condition (specify)	Good

	Emission Unit ID Number	13 (T-134 Crude Tank No. 2)
16.	Floating roof tanks:	
	Type of construction (specify)	Not Applicable
	Condition (specify)	Not Applicable
	Tank color	Not Applicable
	Deck type (specify)	Not Applicable
17.	External floating roof tanks, seal type (specify)	Not Applicable
18.	Internal floating roof tanks:	
	Seal type (specify)	Not Applicable
	Number of columns	Not Applicable
	Effective column diameter (ft)	Not Applicable
	Total deck seam length (ft)	Not Applicable
	Deck fitting types – access hatch	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types - Automatic gauge float well	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types – column well	
	Built up column – sliding cover, gasketed	Not Applicable
	Built up column – sliding cover, ungasketed	Not Applicable
	Pipe column – flexible fabric sleeve seal	Not Applicable
	Pipe column – – sliding cover, gasketed	Not Applicable
	Pipe column – – sliding cover, ungasketed	Not Applicable
	Deck fitting types – ladder well	
	sliding cover, gasketed	Not Applicable
	sliding cover, ungasketed	Not Applicable

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	13 (T-134 Crude Tank No. 2)
	Deck fitting types – simple well or pipe	
	Slotted pipe – sliding cover, gasketed	Not Applicable
	Slotted pipe – sliding cover, ungasketed	Not Applicable
	Sample well – slit fabric seal, 10% open area	Not Applicable
	Stub drain – 1-inch diameter	Not Applicable
	Deck fitting type – roof leg or hanger will	
	Adjustable	Not Applicable
	fixed	Not Applicable
	Deck fitting type – vacuum breaker	
	Weighted mechanical actuation, gasketed	Not Applicable
	Weighted mechanical actuation, ungasketed	Not Applicable
19.	Maximum liquid loading rate (gal/hr)	35,000
20.	Submerged fill at out-loading(describe)	Submerged from storage tank provided directly to pipeline
21.	**Material(s) stored**	
	Type of material	Crude oil
	Normal annual throughput (gal/yr)	21,840,000
	Normal turnovers per year	52 (based on weekly delivery)
	Density (lbs/gal)	5.83-8.58 lbs/gal Bulk
	Molecular weight	206
	Average storage temperature (°F)	36
	Vapor pressure (psi)	8.5-15 psia@ 100°F

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 19 & AQ0741MSS03 Condition 9	Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2 & 71.6(a)(1) & (3)	Volatile Organic Compounds Emission Limits – Tank Closed Vent System	Equip the crude tanks, slop oil tank and produced water tank, with a closed vent system and control device designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures.	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60, Subpart Kb	The facility has chosen to comply with the alternative means of compliance in 40 CFR 65.42(b)(5)(i) as allowed in Subpart Kb (40 CFR 60.110b(e)(1)(i) and install a control device designed and operated to reduce inlet VOC emissions by 95% or greater.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit Number: AQ0741TVP04A

1.	**Emission Unit ID Number // Operating Scenario**	14 (T-135 Crude Tank No. 3)
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Special control requirements? [if yes, describe]	The tanks are required by Permit No. AQ0741TVP03, Rev. 1 Condition 19 and Permit No. AQ0741MSS03 Condition 9 requires that each tank be equipped with a closed vent system and control device to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device is to be designed to reduce inlet VOC emissions by 95% or greater.
5.	Rated capacity (gallons)	42,000 gal
6.	Tank height (ft)	24
7.	Tank diameter (ft)	55 (outside diameter)
8.	Tank age (years)	19
9.	Submerged fill pipe?	Yes
10.	Type of tank (specify)	Fixed Roof
11.	Underground?	No
	If underground, specify type of tube and vapor return.	N/A
12.	Above ground vapor control information:	
	Pipe material	Steel
	Pipe size	10"
	Piping drainage (continuous drain downward or condensate collection tank – if condensate collection, attach a description)	Continuous drainage (1/8" per 10 foot)
	Isolation valve installed in piping?	Yes
13.	Pressure vacuum relief valves:	
	Vent pressure settings (psia)	14.69 (V) to 14.92(P)
	Months in which relief valves removed (specify)	Not removed
14.	Pressure conservation vent? [if yes, specify pressure setting – psia]	14.772 psia
15.	Fixed roof tanks:	
	Roof color	White
	Shell color	White
	Average vapor space height (ft)	12
	Shell condition (specify)	Good

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	14 (T-135 Crude Tank No. 3)
16.	Floating roof tanks:	
	Type of construction (specify)	Not Applicable
	Condition (specify)	Not Applicable
	Tank color	Not Applicable
	Deck type (specify)	Not Applicable
17.	External floating roof tanks, seal type (specify)	Not Applicable
18.	Internal floating roof tanks:	
	Seal type (specify)	Not Applicable
	Number of columns	Not Applicable
	Effective column diameter (ft)	Not Applicable
	Total deck seam length (ft)	Not Applicable
	Deck fitting types – access hatch	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types - Automatic gauge float well	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types – column well	
	Built up column – sliding cover, gasketed	Not Applicable
	Built up column – sliding cover, ungasketed	Not Applicable
	Pipe column – flexible fabric sleeve seal	Not Applicable
	Pipe column – – sliding cover, gasketed	Not Applicable
	Pipe column – – sliding cover, ungasketed	Not Applicable
	Deck fitting types – ladder well	
	sliding cover, gasketed	Not Applicable
	sliding cover, ungasketed	Not Applicable

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	14 (T-135 Crude Tank No. 3)
	Deck fitting types – simple well or pipe	
	Slotted pipe – sliding cover, gasketed	Not Applicable
	Slotted pipe – sliding cover, ungasketed	Not Applicable
	Sample well – slit fabric seal, 10% open area	Not Applicable
	Stub drain – 1-inch diameter	Not Applicable
	Deck fitting type – roof leg or hanger will	
	Adjustable	Not Applicable
	fixed	Not Applicable
	Deck fitting type – vacuum breaker	
	Weighted mechanical actuation, gasketed	Not Applicable
	Weighted mechanical actuation, ungasketed	Not Applicable
19.	Maximum liquid loading rate (gal/hr)	35,000
20.	Submerged fill at out-loading(describe)	Submerged from storage tank provided directly to pipeline
21.	**Material(s) stored**	
	Type of material	Crude oil
	Normal annual throughput (gal/yr)	21,840,000
	Normal turnovers per year	52 (based on weekly delivery)
	Density (lbs/gal)	5.83-8.58 lbs/gal Bulk
	Molecular weight	206
	Average storage temperature (°F)	36
	Vapor pressure (psi)	8.5-15 psia@ 100°F

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 19 & AQ0741MSS03 Condition 9	Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2 & 71.6(a)(1) & (3)	Volatile Organic Compounds Emission Limits – Tank Closed Vent System	Equip the crude tanks, slop oil tank and produced water tank, with a closed vent system and control device designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3) & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures.	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60, Subpart Kb	The facility has chosen to comply with the alternative means of compliance in 40 CFR 65.42(b)(5)(i) as allowed in Subpart Kb (40 CFR 60.110b(e)(1)(i) and install a control device designed and operated to reduce inlet VOC emissions by 95% or greater.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit Number: AQ0741TVP04A

1.	**Emission Unit ID Number // Operating Scenario**	15 (T-140 Slop Oil Tank)
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Special control requirements? [if yes, describe]	The tanks are required by Permit No. AQ0741TVP03, Rev. 1 Condition 19 and Permit No. AQ0741MSS03 Condition 9 requires that each tank be equipped with a closed vent system and control device to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device is to be designed to reduce inlet VOC emissions by 95% or greater.
5.	Rated capacity (gallons)	42,000 gal
6.	Tank height (ft)	24
7.	Tank diameter (ft)	55 (outside diameter)
8.	Tank age (years)	19
9.	Submerged fill pipe?	Yes
10.	Type of tank (specify)	Fixed Roof
11.	Underground?	No
	If underground, specify type of tube and vapor return.	N/A
12.	Above ground vapor control information:	
	Pipe material	Steel
	Pipe size	10"
	Piping drainage (continuous drain downward or condensate collection tank – if condensate collection, attach a description)	Continuous drainage (1/8" per 10 foot)
	Isolation valve installed in piping?	Yes
13.	Pressure vacuum relief valves:	
	Vent pressure settings (psia)	14.69 (V) to 14.92(P)
	Months in which relief valves removed (specify)	Not removed
14.	Pressure conservation vent? [if yes, specify pressure setting – psia]	14.772 psia
15.	Fixed roof tanks:	
	Roof color	White
	Shell color	White
	Average vapor space height (ft)	12
	Shell condition (specify)	Good

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	15 (T-140 Slop Oil Tank)
16.	Floating roof tanks:	
	Type of construction (specify)	Not Applicable
	Condition (specify)	Not Applicable
	Tank color	Not Applicable
	Deck type (specify)	Not Applicable
17.	External floating roof tanks, seal type (specify)	Not Applicable
18.	Internal floating roof tanks:	
	Seal type (specify)	Not Applicable
	Number of columns	Not Applicable
	Effective column diameter (ft)	Not Applicable
	Total deck seam length (ft)	Not Applicable
	Deck fitting types – access hatch	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types - Automatic gauge float well	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types – column well	
	Built up column – sliding cover, gasketed	Not Applicable
	Built up column – sliding cover, ungasketed	Not Applicable
	Pipe column – flexible fabric sleeve seal	Not Applicable
	Pipe column – – sliding cover, gasketed	Not Applicable
	Pipe column – – sliding cover, ungasketed	Not Applicable
	Deck fitting types – ladder well	
	sliding cover, gasketed	Not Applicable
	sliding cover, ungasketed	Not Applicable

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	15 (T-140 Slop Oil Tank)
	Deck fitting types – simple well or pipe	
	Slotted pipe – sliding cover, gasketed	Not Applicable
	Slotted pipe – sliding cover, ungasketed	Not Applicable
	Sample well – slit fabric seal, 10% open area	Not Applicable
	Stub drain – 1-inch diameter	Not Applicable
	Deck fitting type – roof leg or hanger will	
	Adjustable	Not Applicable
	fixed	Not Applicable
	Deck fitting type – vacuum breaker	
	Weighted mechanical actuation, gasketed	Not Applicable
	Weighted mechanical actuation, ungasketed	Not Applicable
19.	Maximum liquid loading rate (gal/hr)	35,000
20.	Submerged fill at out-loading(describe)	Submerged from storage tank provided directly to pipeline
21.	**Material(s) stored**	
	Type of material	Crude oil
	Normal annual throughput (gal/yr)	21,840,000
	Normal turnovers per year	52 (based on weekly delivery)
	Density (lbs/gal)	5.83-8.58 lbs/gal Bulk
	Molecular weight	206
	Average storage temperature (°F)	36
	Vapor pressure (psi)	8.5-15 psia@ 100°F

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 19 & AQ0741MSS03 Condition 9	Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2 & 71.6(a)(1) & (3)	Volatile Organic Compounds Emission Limits – Tank Closed Vent System	Equip the crude tanks, slop oil tank and produced water tank, with a closed vent system and control device designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures.	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60, Subpart Kb	The facility has chosen to comply with the alternative means of compliance in 40 CFR 65.42(b)(5)(i) as allowed in Subpart Kb (40 CFR 60.110b(e)(1)(i) and install a control device designed and operated to reduce inlet VOC emissions by 95% or greater.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit Number: AQ0741TVP04A

1.	**Emission Unit ID Number // Operating Scenario**	16 (T-142 Slop Oil Tank)
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Special control requirements? [if yes, describe]	The tanks are required by Permit No. AQ0741TVP03, Rev. 1 Condition 19 and Permit No. AQ0741MSS03 Condition 9 requires that each tank be equipped with a closed vent system and control device to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device is to be designed to reduce inlet VOC emissions by 95% or greater.
5.	Rated capacity (gallons)	42,000 gal
6.	Tank height (ft)	24
7.	Tank diameter (ft)	55 (outside diameter)
8.	Tank age (years)	19
9.	Submerged fill pipe?	Yes
10.	Type of tank (specify)	Fixed Roof
11.	Underground?	No
	If underground, specify type of tube and vapor return.	N/A
12.	Above ground vapor control information:	
	Pipe material	Steel
	Pipe size	10"
	Piping drainage (continuous drain downward or condensate collection tank – if condensate collection, attach a description)	Continuous drainage (1/8" per 10 foot)
	Isolation valve installed in piping?	Yes
13.	Pressure vacuum relief valves:	
	Vent pressure settings (psia)	14.69 (V) to 14.92(P)
	Months in which relief valves removed (specify)	Not removed
14.	Pressure conservation vent? [if yes, specify pressure setting – psia]	14.772 psia
15.	Fixed roof tanks:	
	Roof color	White
	Shell color	White
	Average vapor space height (ft)	12
	Shell condition (specify)	Good

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	16 (T-142 Slop Oil Tank)
16.	Floating roof tanks:	
	Type of construction (specify)	Not Applicable
	Condition (specify)	Not Applicable
	Tank color	Not Applicable
	Deck type (specify)	Not Applicable
17.	External floating roof tanks, seal type (specify)	Not Applicable
18.	Internal floating roof tanks:	
	Seal type (specify)	Not Applicable
	Number of columns	Not Applicable
	Effective column diameter (ft)	Not Applicable
	Total deck seam length (ft)	Not Applicable
	Deck fitting types – access hatch	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types - Automatic gauge float well	
	bolted cover, gasketed	Not Applicable
	unbolted cover, gasketed	Not Applicable
	unbolted cover, ungasketed	Not Applicable
	Deck fitting types – column well	
	Built up column – sliding cover, gasketed	Not Applicable
	Built up column – sliding cover, ungasketed	Not Applicable
	Pipe column – flexible fabric sleeve seal	Not Applicable
	Pipe column – – sliding cover, gasketed	Not Applicable
	Pipe column – – sliding cover, ungasketed	Not Applicable
	Deck fitting types – ladder well	
	sliding cover, gasketed	Not Applicable
	sliding cover, ungasketed	Not Applicable

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

	Emission Unit ID Number	16 (T-142 Slop Oil Tank)
	Deck fitting types – simple well or pipe	
	Slotted pipe – sliding cover, gasketed	Not Applicable
	Slotted pipe – sliding cover, ungasketed	Not Applicable
	Sample well – slit fabric seal, 10% open area	Not Applicable
	Stub drain – 1-inch diameter	Not Applicable
	Deck fitting type – roof leg or hanger will	
	Adjustable	Not Applicable
	fixed	Not Applicable
	Deck fitting type – vacuum breaker	
	Weighted mechanical actuation, gasketed	Not Applicable
	Weighted mechanical actuation, ungasketed	Not Applicable
19.	Maximum liquid loading rate (gal/hr)	35,000
20.	Submerged fill at out-loading(describe)	Submerged from storage tank provided directly to pipeline
21.	**Material(s) stored**	
	Type of material	Water (Production Wastewater)
	Normal annual throughput (gal/yr)	21,840,000
	Normal turnovers per year	52 (assumed weekly to be most conservative)
	Density (lbs/gal)	5.83-8.58 lbs/gal Bulk. (assumed the same as crude oil to be most conservative)
	Molecular weight	206
	Average storage temperature (°F)	36
	Vapor pressure (psi)	8.5-15 psia@ 100°F

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03, Rev. 1 Condition 19 & AQ0741MSS03 Condition 9	Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2 & 71.6(a)(1) & (3)	Volatile Organic Compounds Emission Limits – Tank Closed Vent System	Equip the crude tanks, slop oil tank and produced water tank, with a closed vent system and control device designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures.	Yes	Records Review

1 Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B4

Emission Unit Detail Form - Volatile Liquid Storage Tanks

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60, Subpart Kb	The facility has chosen to comply with the alternative means of compliance in 40 CFR 65.42(b)(5)(i) as allowed in Subpart Kb (40 CFR 60.110b(e)(1)(i) and install a control device designed and operated to reduce inlet VOC emissions by 95% or greater.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

B5 FORMS

Emission Unit Detail Form - Miscellaneous Emission Units

FORM B5

Emission Unit Detail Form - Miscellaneous Emission Units

Permit Number: AQ0741TVP04A

1.	Emission Unit ID Number // Operating Scenario	10
2.	Date installation/construction commenced	2002
3.	Date installed	2002
4.	Emission Unit serial number	2-3061
5.	Special control requirements? [if yes, describe]	N/A
6.	Description of process: Process Flare (EU ID 10, H-150) is a Tornado Model TTI-SLT high-efficiency, air-assisted flare installed and commissioned in 2002. This unit burns raw fuel gas from process and system upsets. The flare tip has a 46.1 MMscf/day maximum design capacity.	
7.	Continuous or batch process? [if batch, maximum batches per hour]	N/A

8. Raw material usage: [for EACH raw material used, enter]:

Material	Maximum design capacity (lbs/batch or lbs/hr)
Fuel Gas	1.92 MMscf/hr

9. Production data: [for EACH product, enter]:

Product	Maximum design capacity (lbs/batch or lbs/hr)
N/A	N/A

10. Attach any additional information necessary to describe this process and its operating and usage parameters, both short-term and annual. Not Applicable

FORM B5

Emission Unit Detail Form - Miscellaneous Emission Units

Applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Demonstrate Compliance
AQ0741TVP03 Condition 1	18 AAC 50.040(j), 50.326(j), & 50.346(c) 40 C.F.R. 71.6(a)(3) & (c)(6)	Visible Emissions	The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Yes	Perform visible emissions monitoring using Method 9 observations. Monitor, record, and report in accordance with Condition 5.
AQ0741TVP03, Rev. 1 Condition 6	18 AAC 50.040(j), 50.326(j) & 50.346(c) and 40 C.F.R. 71.6(a)(3) & (c)(6)	Particulate Matter (PM) Emissions	Do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Yes	Certify in each facility operating report that only gas is burned as fuel during the reporting period.
AQ0741TVP03, Rev. 1 Condition 10	18 AAC 50.040(j), 50.055(c) & 50.326(j) and 40 C.F.R. 71.6(a)(1)	Sulfur Compound Emissions	Do not cause or allow sulfur compound emissions, expressed as SO2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 14.
AQ0741TVP03, Rev. 1 Condition 18	Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2 & 71.6(a)(1) & (3)	Carbon Monoxide Emissions Limits	Limit the fuel gas burned to no more than 70 million standard cubic feet (MMscf) in any 12-month rolling period.	Yes	Monitor, record, and report in accordance with Conditions 18.1a and 18.1b.
AQ0741TVP03, Rev. 1, Condition 48	18 AAC 50.326(j)(3), & 50.346(b)(5)	Good Air Pollution Control Practice	Perform regular maintenance considering the manufacturer's or operator's maintenance procedures, keep records of maintenance, and keep a copy of maintenance procedures.	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM B5

Emission Unit Detail Form - Miscellaneous Emission Units

Non-applicable Requirements Specific to Emission Unit (*attach additional sheets as needed. Form B Supplement - Emission Unit-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60.18	This flare is not control devices used to comply with applicable Subparts of 40 CFR 60 and 40 CFR 61.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

C5 FORM

Pollution Control Device Form - Other Pollution Control Devices

FORM C5

Pollution Control Device Form - Other Pollution Control Devices

Permit Number: AQ0741TVP04A

1.	Name	Vapor Recovery Unit
2.	Emission Unit ID Number	EU IDs 12, 13, 14, 15, and 16
3.	Date installed	2002
4.	Manufacturer	UMC Automation
5.	Model number	VR-12L
6.	Type of device (describe): The VRU is a closed vent vapor recovery system designed and operated to capture volatile organic compounds emitted from hydrocarbon liquids in storage tanks. The system draws vapors from the storage tanks via manifolded vents on Tanks T-133, T-134, T-135, T-140, T-142, and T146. The liquids in the storage tanks are covered by blanket (fuel) gas that constantly feeds produced gas from the facility at approximately 6 oz/sq in (gauge). The blanket gas flows into the storage tank vent manifold and provides gas to the tanks when needed. Gas flows through the tank equalization line, into storage tanks (as needed), and through to the VRU system. The blanket gas flows continuously to ensure maintenance of hydrocarbon vapors throughout the VRU system. The VRU compressor draws gas through the scrubber and ensures gas flow throught the system during normal operations. VRU operation is controlled by PLC and tank pressure pressure sensors. Normal VRU operations allow gas to flow through the scrubber and to a compressor that feeds the gas to KPF production equipment. The scrubber also collects condensate, which is returned to the separation processes. The VRU will shut down if manifold pressure drops below 0.5 oz/ sq in (gauge), but the operational cycle resumes when the pressure builds above that level.	
7.	Rated efficiency (%)	95%
8	Date of most recent source test on control device	Not Applicable
9	Emission factor (result) of most recent source test	Not Applicable
10.	Design inlet gas flow rate (acfm)	766.4-1084.6
11.	Describe control device operating limits	>0.5 oz/sq in (gauge) manifold pressure
12.	Control device subject to Compliance Assurance Monitoring (CAM) under 40 C.F.R. Part 64?	No

FORM C5

Pollution Control Device Form - Other Pollution Control Devices

Applicable Requirements Specific to Control Device (*attach additional sheets as needed. Form C Supplement – Control Device-Specific Applicable Requirements*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping and Reporting Methods Used to Determine Compliance
AQ0741TVP03, Rev. 1 Condition 19 & AQ0741MSS03 Condition 9	Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2 & 71.6(a)(1) & (3)	Volatile Organic Compounds Emission Limits – Tank Closed Vent System	Equip the crude tanks, slop oil tank and produced water tank, with a closed vent system and control device designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.	Yes	Records Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

FORM C5

Pollution Control Device Form - Other Pollution Control Devices

Non-applicable Requirements Specific to Control Device (*attach additional sheets as needed. Form C Supplement – Control Device-Specific Permit Shield Request*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 60, Subpart OOOO	Facility was not constructed in 2002, not between August 23, 2011 and September 18, 2015.

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

D1 and D2 FORMS

Potential to Emit Before Controls/Limits

FORMS D1 &D2

Emissions Summary

Table D1. Kustatan Production Facility - Potential To Emit (PTE) Summary
Potential Annual Emissions Before Controls/Limitations

Emissions Unit Type	Regulated Air Pollutant Emissions (tons per year) [1]								
	NO_X	CO	PM	PM_{10} [2]	$PM_{2.5}$ [2]	VOC	SO_2	HAP[3]	GHG[4,5]
Significant	736.1	2,864.4	249.7	245.9	248.2	1,266.5	1,107.4	#N/A	1,287,552
Insignificant	2.7	1.7	0.0	0.0	0.0	3.8	0.0	0.0	260.3
Total Emissions	**739**	**2,866**	**246**	**246**	**248**	**1,270**	**1,107**	**#N/A**	**1,287,812**

Notes:

1. Regulated air pollutant calculations based on permitted fuel rates, source test results, AP-42 emission factors, and mass balances as shown in accompanying spreadsheets.
2. PM emissions are assumed to be equal to the sum of $PM_{2.5}$ and PM_{10}. However, separate $PM_{2.5}$ and PM_{10} emission factors are not always available, therefore, the PM factor from AP-42 is used in their place causing the $PM_{2.5}$ and PM_{10} to be conservatively inflated.
3. See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).
4. GHG emissions are defined as CO2e emissions. CO2e is the summation of CO2, CH4, and N2O, applying the global warming potential for each pollutant.
5. Per 40 CFR 71.2, GHGs are subject to regulation beginning on July 1, 2011.

Table D1-A. Emission Unit Inventory
Potential Annual Emissions Before Controls/Limitations

ID	Emission Unit Name	Description	Fuel Type	Maximum Fuel Consumption	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation
Turbine Generators							
1	Solar Taurus 60-T7301S Turbine	Turbine Generator #1	Fuel Gas	0.078 MMscf/hr[1]	683 MMscf/yr	58.2 MMBtu/hr[2]	8,760 hr/yr
2	Solar Taurus 60-T7301S Turbine	Turbine Generator #2	Fuel Gas	0.081 MMscf/hr[1]	707 MMscf/yr	55.3 MMBtu/hr[2]	8,760 hr/yr
Heaters							
3	NATCO Natural Draft Burners	Heater Treater #1	Fuel Gas	0.007 MMscf/hr[3]	63 MMscf/yr	6.2 MMBtu/hr	8,760 hr/yr
4	NATCO Natural Draft Burners	Heater Treater #2	Fuel Gas	0.007 MMscf/hr[3]	63 MMscf/yr	6.2 MMBtu/hr	8,760 hr/yr
5	NATCO Natural Draft Burners	Heater Treater #3	Fuel Gas	0.007 MMscf/hr[3]	63 MMscf/yr	6.2 MMBtu/hr	8,760 hr/yr
6	NATCO Natural Draft Burners	Crude Heater #1	Fuel Gas	0.009 MMscf/hr[3]	79 MMscf/yr	8.0 MMBtu/hr	8,760 hr/yr
7	NATCO Natural Draft Burners	Crude Heater #2	Fuel Gas	0.009 MMscf/hr[3]	79 MMscf/yr	8.0 MMBtu/hr	8,760 hr/yr
8	NATCO Natural Draft Burners	Crude Heater #3	Fuel Gas	0.009 MMscf/hr[3]	79 MMscf/yr	8.0 MMBtu/hr	8,760 hr/yr
Diesel Engines							
9	Cummins 6BTA5.9	Fire Water Pump	Diesel	8.2 gal/hr	71832 gal/yr	160 hp	8,760 hr/yr
9a	Caterpillar 3406C	Backup Generator	Diesel	14.2 gal/hr	123954 gal/yr	519 hp	8,760 hr/yr
Flare							
10	Tornado TTI-SLT	Process Flare	Fuel Gas and Produced Gas	1.9 MMscf/hr	16819 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr
Storage Tanks							
12	Crude Tank No. 1	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
13	Crude Tank No. 2	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
14	Crude Tank No. 3	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
15	Slop Oil Tank	Slop Oil Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
16	Produced Water Tank	Produced Water Tank	Produced Water	N/A	N/A	10,000 bbls	8,760 hr/yr
Insignificant Emission Units							
N/A	Generator	Honda S-351 Generator	Gasoline	0.27 gal/hr[4]	2378 gal/yr	2 kW	8,760 hr/yr
N/A	Generator	Honda S-351 Generator	Gasoline	0.27 gal/hr[4]	2378 gal/yr	2 kW	8,760 hr/yr
N/A	Trash Pump	Wacker Neuson PDT 3A 3" Diaphragm	Gasoline	1.2 gal/hr	10512 gal/yr	4 hp	8,760 hr/yr
N/A	Trash Pump	Wacker Neuson PD 3A 3" Diaphragm	Gasoline	1.2 gal/hr	10512 gal/yr	4 hp	8,760 hr/yr
T-146	Utility Tank	Process Fluids Storage Tank	Miscellaneous Process Fluids	N/A	N/A	21,000 gal	8,760 hr/yr
DF-01	Diesel Day Tank	Diesel Storage Tank	Diesel	N/A	N/A	500 gal	8,760 hr/yr
N/A	Pig Cooker Tank	Crude Oil Storage Tank	Crude Oil, Produced Water, and Paraffin	N/A	N/A	104 gal	8,760 hr/yr
T-156	Fire Water Pump Diesel Day Tank	Diesel Storage Tank	Diesel	N/A	N/A	150 gal	8,760 hr/yr
N/A	Cat 3406 Diesel Tank	Diesel Storage Tank	Diesel	N/A	N/A	200 gal	8,760 hr/yr
T-214	Methanol Tank	Methanol Storage Tank	Methanol	N/A	N/A	10,000 gal	8,760 hr/yr
N/A	Boiler Diesel Fuel Tank	Diesel Storage Tank	Diesel	N/A	N/A	5,000 gal	8,760 hr/yr

Table Notes:
1. EU IDs 1 and 2 Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. EU IDs 3-8 Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
4. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.

Table D1-B. Potential NO_X Emissions
Potential Annual Emissions Before Controls/Limitations

ID	Emission Unit Name	Reference	Emission Factor	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential NO_X Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	4.7 lb/hr[1]	683.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	8,760 hr/yr	20.59 tpy
2	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	6.1 lb/hr[1]	706.9 MMscf/yr[2]	55.3 MMBtu/hr[3]	8,760 hr/yr	26.72 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	2.2 tpy
4	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	2.2 tpy
5	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	2.2 tpy
6	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	3.0 tpy
7	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	3.0 tpy
8	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	3.0 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	4.41 lb/MMBtu	71832 gal/yr	160 hp	8,760 hr/yr	21.7 tpy[5]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	4.41 lb/MMBtu	123954 gal/yr	519 hp	8,760 hr/yr	37.4 tpy[5]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP 42 Table 13.5-1	0.068 lb/MMBtu	16819 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr	614.1 tpy[6]
Storage Tanks							
12	Crude Tank No. 1	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential NO_X Emissions				**736.1 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	1.63 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.3 tpy[8]
N/A	Gasoline Generator	AP-42 Table 3.3-1	1.63 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.3 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	1.63 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	1.1 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	1.63 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	1.1 tpy[8]
T-146	Utility Tank	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential NO_X Emissions				**2.7 tpy**

Table Notes:

1. EU IDs 1 and 2 NO_X emission factors were obtained from the results of the August 2019 Source Test. The highest result while operating above 50% load was used to be most conservative and it was increased by 10% to account for changes in load and temperature.
2. EU IDs 1 and 2 Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. EU IDs 3-8 Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
5. Diesel engine emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
6. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
7. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
8. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D1-C. Potential CO Emissions
Potential Annual Emissions Before Controls/Limitations

ID	Emission Unit Name	Reference	Emission Factor	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential CO Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	0.5 lb/hr[1]	683.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	8,760 hr/yr	2.19 tpy
2	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	0.37 lb/hr[1]	706.9 MMscf/yr[2]	55.3 MMBtu/hr[3]	8,760 hr/yr	1.62 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
4	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
5	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
6	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.5 tpy
7	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.5 tpy
8	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.5 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	4.41 lb/MMBtu	71832 gal/yr	160 hp	8,760 hr/yr	21.7 tpy[5]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	4.41 lb/MMBtu	123954 gal/yr	519 hp	8,760 hr/yr	37.4 tpy[5]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.31 lb/MMBtu	16819 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr	2,799.4 tpy[6]
Storage Tanks							
12	Crude Tank No. 1	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential CO Emissions				**2,864.4 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.99 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.2 tpy[8]
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.99 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.2 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.99 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	0.7 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.99 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	0.7 tpy[8]
T-146	Utility Tank	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential CO Emissions				**1.7 tpy**

Table Notes:

1. EU IDs 1 and 2 CO emission factors were obtained from the results of the August 2019 Source Test. The highest result while operating above 50% load was used to be most conservative and it was increased by 10% to account for changes in load and temperature.
2. EU IDs 1 and 2 Maximum Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. EU IDs 3-8 Maximum Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
5. Diesel engine emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
6. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
7. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
8. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D1-D. Potential PM/PM10/PM2.5 Emissions
Potential Annual Emissions Before Controls/Limitations

ID	Emission Unit Name	Reference	PM_{Total} Emission Factor	PM_{10} Emission Factor	$PM_{2.5}$ Emission Factor	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential PM_{Total} Emissions	Potential PM_{10} Emissions	Potential $PM_{2.5}$ Emissions
Turbine Generators (Fuel Gas)											
1	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	6.9E-03 lb/MMBtu[1]	2E-03 lb/MMBtu[1]	4.9E-03 lb/MMBtu[1]	683.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	8,760 hr/yr	1.8 tpy	0.5 tpy	1.3 tpy
2	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	6.9E-03 lb/MMBtu[1]	2E-03 lb/MMBtu[1]	4.9E-03 lb/MMBtu[1]	706.9 MMscf/yr[2]	55.3 MMBtu/hr[3]	8,760 hr/yr	1.7 tpy	0.5 tpy	1.2 tpy
Heaters (Fuel Gas)											
3	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.00086 lb/MMscf	2.00022 lb/MMscf	6.00065 lb/MMscf	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
4	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.00086 lb/MMscf	2.00022 lb/MMscf	6.00065 lb/MMscf	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
5	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.00086 lb/MMscf	2.00022 lb/MMscf	6.00065 lb/MMscf	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
6	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.00086 lb/MMscf	2.00022 lb/MMscf	6.00065 lb/MMscf	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
7	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.00086 lb/MMscf	2.00022 lb/MMscf	6.00065 lb/MMscf	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
8	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.00086 lb/MMscf	2.00022 lb/MMscf	6.00065 lb/MMscf	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
Engines (Diesel)											
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	71832 gal/yr	160 hp	8,760 hr/yr	1.4 tpy	1.4 tpy	1.4 tpy
9a	Caterpillar 3406C	AP-42 Table 3.3-1	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	123954 gal/yr	519 hp	8,760 hr/yr	4.7 tpy	4.7 tpy	4.7 tpy
Flare (Produced Gas and Fuel Gas)											
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.0264 lb/MMBtu	0.0264 lb/MMBtu	0.0264 lb/MMBtu	16819 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr	238.4 tpy[5]	238.4 tpy[5]	238.4 tpy[5]
Storage Tanks											
12	Crude Tank No. 1	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
						Significant EUs Total Potential PM Emissions			**249.7 tpy**	**245.9 tpy**	**248.2 tpy**
Insignificant Emission Units											
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	2378 gal/yr[6]	2 kW	8,760 hr/yr	0.02 tpy[7]	0.02 tpy[7]	0.02 tpy[7]
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	2378 gal/yr[6]	2 kW	8,760 hr/yr	0.02 tpy[7]	0.02 tpy[7]	0.02 tpy[7]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	0.07 tpy[7]	0.07 tpy[7]	0.07 tpy[7]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	0.07 tpy[7]	0.07 tpy[7]	0.07 tpy[7]
T-146	Utility Tank	N/A	N/A	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
						Insignificant EUs Total Potential PM Emissions			**0.2 tpy**	**0.2 tpy**	**0.2 tpy**

Table Notes:

1. PM Emission Factors for EU IDs 1-8 are adjusted for the actual average heat rate from fuel gas testing in 2020 rather than the assumed rate of 1,020 Btu/scf noted in AP-42.
   Fuel Gas Heating Value = 1073.8 Btu/scf
2. EU IDs 1 and 2 Maximum Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. EU IDs 3-8 Maximum Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
7. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D1-E. Potential VOC Emissions
Potential Annual Emissions Before Controls/Limitations

ID	Emission Unit Name	Reference	Emission Factor	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential VOC Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu	683.2 MMscf/yr[1]	58.2 MMBtu/hr[2]	8,760 hr/yr	0.54 tpy
2	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu	706.9 MMscf/yr[1]	55.3 MMBtu/hr[2]	8,760 hr/yr	0.51 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	63.1 MMscf/yr[3]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
4	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	63.1 MMscf/yr[3]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
5	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	63.1 MMscf/yr[3]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
6	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	78.8 MMscf/yr[3]	8.0 MMBtu/hr	8,760 hr/yr	0.2 tpy
7	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	78.8 MMscf/yr[3]	8.0 MMBtu/hr	8,760 hr/yr	0.2 tpy
8	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	78.8 MMscf/yr[3]	8.0 MMBtu/hr	8,760 hr/yr	0.2 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	0.35 lb/MMBtu	71832 gal/yr	160 hp	8,760 hr/yr	0.01 tpy[4]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	0.35 lb/MMBtu	123954 gal/yr	519 hp	8,760 hr/yr	0.02 tpy[4]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.14 lb/MMBtu	16819 MMscf/yr	1.92 MMscf/day	8,760 hr/yr	1,264.2 tpy[5]
Storage Tanks							
12	Crude Tank No. 1	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	4.4 tpy
13	Crude Tank No. 2	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	4.4 tpy
14	Crude Tank No. 3	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	4.4 tpy
15	Slop Oil Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	3.3 tpy
16	Produced Water Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	2.2 tpy
			Significant EUs Total Potential VOC Emissions				**1,266.5 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	2.1 lb/MMBtu	2378 gal/yr[6]	2 kW	8,760 hr/yr	0.3 tpy[7]
N/A	Gasoline Generator	AP-42 Table 3.3-1	2.1 lb/MMBtu	2378 gal/yr[6]	2 kW	8,760 hr/yr	0.3 tpy[7]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	2.1 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	1.4 tpy[7]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	2.1 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	1.4 tpy[7]
T-146	Utility Tank	EPA TANKS 4.09	N/A	N/A	21,000 gal	8,760 hr/yr	0.3 tpy
DF-01	Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	500 gal	8,760 hr/yr	0.0 tpy
N/A	Pig Cooker Tank	EPA TANKS 4.09	N/A	N/A	104 gal	8,760 hr/yr	0.0 tpy
T-156	Fire Water Pump Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	150 gal	8,760 hr/yr	0.0 tpy
N/A	Cat 3406 Diesel Tank	EPA TANKS 4.09	N/A	N/A	200 gal	8,760 hr/yr	0.0 tpy
T-214	Methanol Tank	EPA TANKS 4.09	N/A	N/A	10,000 gal	8,760 hr/yr	0.0 tpy
N/A	Boiler Diesel Fuel Tank	EPA TANKS 4.09	N/A	N/A	5,000 gal	8,760 hr/yr	0.0 tpy
			Insignificant EUs Total Potential VOC Emissions				**3.8 tpy**

Table Notes:

1. EU IDs 1 and 2 Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. EU IDs 3-8 Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
4. Diesel engine emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
7. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D1-F. Potential SO_2 Emissions
Potential Annual Emissions Before Controls/Limitations

ID	Emission Unit Name	Reference	Emission Factor[1]	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential SO_2 Emissions[4,5]
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	Mass Balance	700 ppmv H_2S	683.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	8,760 hr/yr	40.34 tpy
2	Solar Taurus 60-T7301S Turbine	Mass Balance	700 ppmv H_2S	706.9 MMscf/yr[2]	55.3 MMBtu/hr[3]	8,760 hr/yr	41.75 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	63.1 MMscf/yr[6]	6.2 MMBtu/hr	8,760 hr/yr	3.72 tpy
4	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	63.1 MMscf/yr[6]	6.2 MMBtu/hr	8,760 hr/yr	3.72 tpy
5	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	63.1 MMscf/yr[6]	6.2 MMBtu/hr	8,760 hr/yr	3.72 tpy
6	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	78.8 MMscf/yr[6]	8.0 MMBtu/hr	8,760 hr/yr	4.66 tpy
7	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	78.8 MMscf/yr[6]	8.0 MMBtu/hr	8,760 hr/yr	4.66 tpy
8	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	78.8 MMscf/yr[6]	8.0 MMBtu/hr	8,760 hr/yr	4.66 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	Mass Balance	0.5 wt% S	71832 gal/yr	160 hp	8,760 hr/yr	2.53 tpy
9a	Caterpillar 3406C	Mass Balance	0.5 wt% S	123954 gal/yr	519 hp	8,760 hr/yr	4.37 tpy
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	Mass Balance	700 ppmv H_2S	16819 MMscf/yr	1.92 MMscf/day	8,760 hr/yr	993.3 tpy[7]
Storage Tanks							
12	Crude Tank No. 1	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential SO2 Emissions				**1,107.4 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	10 ppm	2378 gal/yr[8]	2 kW	8,760 hr/yr	0.00015 tpy[9]
N/A	Gasoline Generator	AP-42 Table 3.3-1	10 ppm	2378 gal/yr[8]	2 kW	8,760 hr/yr	0.00015 tpy[9]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	10 ppm	10512 gal/yr	4 hp	8,760 hr/yr	0.00067 tpy[9]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	10 ppm	10512 gal/yr	4 hp	8,760 hr/yr	0.00067 tpy[9]
T-146	Utility Tank	EPA TANKS 4.09	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	EPA TANKS 4.09	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	EPA TANKS 4.09	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	EPA TANKS 4.09	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	EPA TANKS 4.09	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential SO_2 Emissions				**0.0 tpy**

Table Notes:

1. The H_2S standard for fuel gas units is based on the limit set out in AQ0741TVP03, Rev. 1 Condition 14.2 of 700ppmv. The diesel sulfur limit is 0.5 wt% S per Condition 13.1. The gasoline sulfur limit is based on the standard annual average of 10 ppm as specified in 40 CFR 80.1603.
2. EU IDs 1 and 2 Maximum Annual Fuel Capacity based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. Mass balance of fuel gas is estimated based on the following assumptions:

1 lb mole of gas at standard temperature at 60º F and pressure 14.7 psia:	379.3	scf/lb-mole (Ideal gas conversion)
Conversions:	64	lb SO_2/lb-mole
	1	lb-mole H_2S/lb-mole SO_2

5. Mass balance of diesel fuel and gasoline emission units is estimated based on the following assumptions

Conversions:	64	lb SO_2/lb-mole
	32	lb S/64 lb SO_2
	7.05	lb/gal distillate fuel (AP-42 Appendix A, page A-7)
	0.76	SG of Marathon Unleaded gasoline (converted by 8.33 lb/gal water)

6. EU IDs 3-8 Maximum Annual Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
7. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.

   Fuel Gas Heating Value = 1073.8 Btu/scf
8. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
9. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.

   Gasoline Heating Value = 130,000 Btu/gallon

Table D1-G. Potential CO2-e Emissions

Potential Annual Emissions Before Controls/Limitations

ID	Emission Unit Description	Reference (40 CFR 98)	CO2 Emission Factor	Reference (40 CFR 98)	CH4 Emission Factor	Reference (40 CFR 98)	N_2O Emission Factor	Maximum Fuel Rate	Maximum Capacity	Maximum Operation	Potential CO2-e Emissions[8]
Turbine Generators (Fuel Gas)											
1	Solar Taurus 60-T7301S Turbine	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.078 MMscf/hr[1]	58.2 MMBtu/hr[2]	8,760 hr/yr	41,707.9 tpy
2	Solar Taurus 60-T7301S Turbine	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.081 MMscf/hr[1]	55.3 MMBtu/hr[2]	8,760 hr/yr	39,629.7 tpy
Heaters (Fuel Gas)											
3	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	8,760 hr/yr	3,547.5 tpy
4	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	8,760 hr/yr	3,547.5 tpy
5	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	8,760 hr/yr	3,547.5 tpy
6	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	8,760 hr/yr	4,577.4 tpy
7	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	8,760 hr/yr	4,577.4 tpy
8	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	8,760 hr/yr	4,577.4 tpy
Engines (Diesel)											
9	Cummins 6BTA5.9	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	8.2 gal/hr	160.0 hp	8,760 hr/yr	805.1 tpy[4]
9a	Caterpillar 3406C	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	14.2 gal/hr	519.0 hp	8,760 hr/yr	1,389.2 tpy[4]
Flare (Produced Gas and Fuel Gas)											
10	Tornado TTI-SLT	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.9 MMscf/hr	1.9 MMscf/hr[5]	8,760 hr/yr	1,179,645.4 tpy
Storage Tanks											
12	Crude Tank No. 1	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
13	Crude Tank No. 2	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
14	Crude Tank No. 3	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
15	Slop Oil Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
16	Produced Water Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
								Significant Total Potential CO2-e Emissions			**1,287,551.8 tpy**
Insignificant Emission Units											
N/A	Generator	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.3 gal/hr[6]	2.0 kW	8,760 hr/yr	24.0 tpy[7]
N/A	Generator	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.3 gal/hr[6]	2.0 kW	8,760 hr/yr	24.0 tpy[7]
N/A	Trash Pump	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.2 gal/hr	4.0 hp	8,760 hr/yr	106.2 tpy[7]
N/A	Trash Pump	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.2 gal/hr	3.5 hp	8,760 hr/yr	106.2 tpy[7]
T-146	Utility Tank	NA	NA	NA	NA	NA	NA	N/A	21,000.0 gal	8,760 hr/yr	0.0 tpy
DF-01	Diesel Day Tank	NA	NA	NA	NA	NA	NA	N/A	500.0 gal	8,760 hr/yr	0.0 tpy
N/A	Pig Cooker Tank	NA	NA	NA	NA	NA	NA	N/A	104.0 gal	8,760 hr/yr	0.0 tpy
T-156	Fire Water Pump Diesel Day Tank	NA	NA	NA	NA	NA	NA	N/A	150.0 gal	8,760 hr/yr	0.0 tpy
N/A	Cat 3406 Diesel Tank	NA	NA	NA	NA	NA	NA	N/A	200.0 gal	8,760 hr/yr	0.0 tpy
T-214	Methanol Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 gal	8,760 hr/yr	0.0 tpy
N/A	Boiler Diesel Fuel Tank	NA	NA	NA	NA	NA	NA	N/A	5,000.0 gal	8,760 hr/yr	0.0 tpy
								Insignificant EUs Total Potential CO2-e Emissions			**260.3 tpy**

Table Notes:

1. EU IDs 1 and 2 Maximum Fuel Consumption Rate based on the average results of the 2019 Source Test Report at high load.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. EU IDs 3-8 Maximum Fuel Consumption Rate calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
4. Diesel engine emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
7. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon
8. Global Warming Potentials listed in Table A-1 of 40 CFR 98 Subpart A were used to estimate the CO2e using the equation $CO_{2e} = CO_2 + 25*CH_4 + 298*N_2O$
   1 tonne (metric ton) = 907.18 kg
   GWP of CH_4 = 25
   GWP of N_2O = 298

Table D1-H. Potential Hazardous Air Pollutant (HAP) Emissions Summary Table
Potential Annual Emissions Before Controls/Limitations

Hazardous Air Pollutant	Stationary Gas Turbines	Natural Gas External Emission Units	Diesel Engines ≤ 600 hp	Flare	Total HAP Emissions
1,3-Butadiene	2.0E-07		8.1E-04		8.1E-04
3-Methylcholanthrene				1.51E-04	1.5E-04
1,3-Butadiene	2.0E-07		8.1E-04		8.1E-04
2-Methylnaphthalene		4.2E-06		2.02E-03	2.0E-03
3-Methylcholanthrene		3.1E-07			3.1E-07
7,12- Dimethylbenz(a)anthracene				1.35E-03	1.3E-03
Acenaphthene		3.1E-07	3.0E-05	1.51E-04	1.8E-04
Acenaphthylene		3.1E-07	1.1E-04	1.51E-04	2.6E-04
Acetaldehyde	1.9E-05		1.6E-02		1.6E-02
Acrolein	3.0E-06		1.9E-03		1.9E-03
Anthracene		4.2E-07	3.9E-05	2.02E-04	2.4E-04
Benz(a)anthracene		3.1E-07		1.51E-04	1.5E-04
Benzene	5.6E-06	3.6E-04	1.9E-02	1.77E-01	2.0E-01
Benzo(a)anthracene			3.5E-05		3.5E-05
Benzo(a)pyrene		2.1E-07	3.9E-06	1.01E-04	1.1E-04
Benzo(b)fluoranthene		3.1E-07	2.1E-06	1.51E-04	1.5E-04
Benzo(g,h,i)perylene		2.1E-07		1.01E-04	1.0E-04
Benzo(k)fluoranthene		3.1E-07	3.2E-06	1.51E-04	1.5E-04
Butane		3.6E-01		1.77E+02	1.8E+02
Chrysene		3.1E-07	7.3E-06	1.51E-04	1.6E-04
Dibenz(a,h)anthracene			1.2E-05		1.2E-05
Dichlorobenzene		2.1E-04		1.01E-01	1.0E-01
Ethane		5.4E-01		2.61E+02	2.6E+02
Ethylbenzene	1.5E-05				1.5E-05
Fluoranthene		5.2E-07	1.6E-04	2.52E-04	4.1E-04
Fluorene		4.9E-07	6.1E-04	2.35E-04	8.4E-04
Formaldehyde	3.3E-04	1.3E-02	2.5E-02	6.31E+00	6.3E+00
Hexane		3.1E-01		1.51E+02	1.5E+02
Indeno(1,2,3-cd)pyrene		3.1E-07	7.8E-06	1.51E-04	1.6E-04
Naphthalene	6.0E-07	1.1E-04	1.8E-03	5.13E-02	5.3E-02
PAH	1.0E-06				1.0E-06
Pentane		4.5E-01		2.19E+02	2.2E+02
Phenanathrene		#N/A			#N/A
Propane		2.8E-01		1.35E+02	1.3E+02
Propylene			5.4E-02		5.4E-02
Propylene Oxide	1.3E-05				1.3E-05
Pyrene		8.7E-07	1.0E-04	4.20E-04	5.2E-04
Pyrene		8.7E-07	1.0E-04	4.20E-04	5.2E-04
Toluene	6.0E-05	5.9E-04	8.5E-03	2.86E-01	3.0E-01
Xylenes	3.0E-05		5.9E-03		6.0E-03
Total HAPs - Maximum Individual HAP	**3.3E-04**	**#N/A**	**5.4E-02**	**260.7**	**#N/A**
Total HAPs Emissions	**4.8E-04**	**#N/A**	**0.135**	**948.8**	**#N/A**

Notes:

1. Detailed methodology and assumptions included with the individual emission unit category calculations in Tables D-9A(2) through D-9A(5).

Table D1-H(a). Potential Hazardous Air Pollutant (HAP) Emissions

Potential Annual Emissions Before Controls/Limitations

Stationary Gas Turbines

Maximum Total Heat Input: 994,260.0 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]		Estimated Emissions	
106-99-0	1,3-Butadiene	4.30E-07	lb/MMscf	2.0E-07	tpy
75-07-0	Acetaldehyde	4.00E-05	lb/MMscf	1.9E-05	tpy
107-02-8	Acrolein	6.40E-06	lb/MMscf	3.0E-06	tpy
100-41-4	Benzene	1.20E-05	lb/MMscf	5.6E-06	tpy
203-96-8	Ethylbenzene	3.20E-05	lb/MMscf	1.5E-05	tpy
50-00-0	Formaldehyde	7.10E-04	lb/MMscf	3.3E-04	tpy
91-20-3	Naphthalene	1.30E-06	lb/MMscf	6.0E-07	tpy
	PAH	2.20E-06	lb/MMscf	1.0E-06	tpy
75-56-9	Propylene Oxide	2.90E-05	lb/MMscf	1.3E-05	tpy
108-88-3	Toluene	1.30E-04	lb/MMscf	6.0E-05	tpy
1330-20-7	Xylenes	6.40E-05	lb/MMscf	3.0E-05	tpy
		Total Potential HAP Emissions:		**4.8E-04**	tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual	Maximum Capacity
1	Solar Taurus 60-T7301S Turbine	8760 hr	113.5 MMBtu/hr
2	Solar Taurus 60-T7301S Turbine	8760 hr	

Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
Maximum Capacity is from the manufacturer's Certified Test Report.

Fuel Gas Heating Value = 1073.8 Btu/scf

2. Emission Factors assumed from AP-42, Table 1.4-3 Emission Factors For Speciated Organic Compounds From Natural Gas

Table D1-H(b). Potential Hazardous Air Pollutant (HAP) Emissions

Potential Annual Emissions Before Controls/Limitations

Natural Gas External Combustion Units

Maximum Total Heat Input: 373,176.0 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]		Estimated Emissions	
91-57-6	2-Methylnaphthalene	2.40E-05	lb/MMscf	4.2E-06	tpy
56-49-5	3-Methylcholanthrene	1.80E-06	lb/MMscf	3.1E-07	tpy
	7,12-Dimethylbenz(a)anthracene	1.60E-05	lb/MMscf	2.8E-06	tpy
83-32-9	Acenaphthene	1.80E-06	lb/MMscf	3.1E-07	tpy
203-96-8	Acenaphthylene	1.80E-06	lb/MMscf	3.1E-07	tpy
120-12-7	Anthracene	2.40E-06	lb/MMscf	4.2E-07	tpy
56-55-3	Benz(a)anthracene	1.80E-06	lb/MMscf	3.1E-07	tpy
71-43-2	Benzene	2.10E-03	lb/MMscf	3.6E-04	tpy
50-32-8	Benzo(a)pyrene	1.20E-06	lb/MMscf	2.1E-07	tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06	lb/MMscf	3.1E-07	tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06	lb/MMscf	2.1E-07	tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06	lb/MMscf	3.1E-07	tpy
106-97-8	Butane	2.10E+00	lb/MMscf	3.6E-01	tpy
218-01-9	Chrysene	1.80E-06	lb/MMscf	3.1E-07	tpy
53-70-3	Dibenzo(a,h)anthracene	1.20E-06	lb/MMscf	2.1E-07	tpy
25321-22-6	Dichlorobenzene	1.20E-03	lb/MMscf	2.1E-04	tpy
74-84-0	Ethane	3.10E+00	lb/MMscf	5.4E-01	tpy
206-44-0	Fluoranthene	3.00E-06	lb/MMscf	5.2E-07	tpy
86-73-7	Fluorene	2.80E-06	lb/MMscf	4.9E-07	tpy
50-00-0	Formaldehyde	7.50E-02	lb/MMscf	1.3E-02	tpy
B110-54-3	Hexane	1.80E+00	lb/MMscf	3.1E-01	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.80E-06	lb/MMscf	3.1E-07	tpy
91-20-3	Naphthalene	6.10E-04	lb/MMscf	1.1E-04	tpy
109-66-0	Pentane	2.60E+00	lb/MMscf	4.5E-01	tpy
85-01-8	Phenanthrene	1.70E-05	lb/MMscf	3.0E-06	tpy
74-98-6	Propane	1.60E+00	lb/MMscf	2.8E-01	tpy
129-00-0	Pyrene	5.00E-06	lb/MMscf	8.7E-07	tpy
108-88-3	Toluene	3.40E-03	lb/MMscf	5.9E-04	tpy

Total Potential HAP Emissions: **2.0** tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual	Maximum Capacity
3	NATCO Natural Draft Burners	8760 hr	42.6 MMBtu/hr
4	NATCO Natural Draft Burners	8760 hr	
5	NATCO Natural Draft Burners	8760 hr	
6	NATCO Natural Draft Burners	8760 hr	
7	NATCO Natural Draft Burners	8760 hr	
8	NATCO Natural Draft Burners	8760 hr	

Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.

Fuel Gas Heating Value = 1073.8 Btu/scf

2. Emission Factors assumed from AP-42, Table 1.4-3 Emission Factors For Speciated Organic Compounds From Natural Gas

Table D1-H(c). Potential Hazardous Air Pollutant (HAP) Emissions

Potential Annual Emissions Before Controls/Limitations

Diesel Engines Up to or Equal to 600 Horsepower

Maximum Total Heat Input: 41,636.3 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]	Significant Units Estimated Emissions
	VOC HAP Emissions		**0.1 tpy**
106-99-0	1,3-Butadiene	3.91E-05 lb/MMBtu	8.1E-04 tpy
75-07-0	Acetaldehyde	7.67E-04 lb/MMBtu	1.6E-02 tpy
107-02-8	Acrolein	9.25E-05 lb/MMBtu	1.9E-03 tpy
71-43-2	Benzene	9.33E-04 lb/MMBtu	1.9E-02 tpy
50-00-0	Formaldehyde	1.18E-03 lb/MMBtu	2.5E-02 tpy
115-07-1	Propylene	2.58E-03 lb/MMBtu	5.4E-02 tpy
108-88-3	Toluene	4.09E-04 lb/MMBtu	8.5E-03 tpy
1330-20-7	Xylenes	2.85E-04 lb/MMBtu	5.9E-03 tpy
	Polycyclic Organic Matter (POM)		
	Polycyclic aromatic hydrocarbons (PAH)		**3.5E-03 tpy**
208-96-8	Acenaphthene	1.42E-06 lb/MMBtu	3.0E-05 tpy
83-32-9	Acenaphthylene	5.06E-06 lb/MMBtu	1.1E-04 tpy
120-12-7	Anthracene	1.87E-06 lb/MMBtu	3.9E-05 tpy
56-55-3	Benzo(a)anthracene	1.68E-06 lb/MMBtu	3.5E-05 tpy
50-32-8	Benzo(a)pyrene	1.88E-07 lb/MMBtu	3.9E-06 tpy
205-99-2	Benzo(b)fluoranthene	9.91E-08 lb/MMBtu	2.1E-06 tpy
191-24-2	Benzo(g,h,l)perylene	4.89E-07 lb/MMBtu	1.0E-05 tpy
207-08-9	Benzo(k)fluoranthene	1.55E-07 lb/MMBtu	3.2E-06 tpy
218-01-9	Chrysene	3.53E-07 lb/MMBtu	7.3E-06 tpy
53-70-3	Dibenz(a,h)anthracene	5.83E-07 lb/MMBtu	1.2E-05 tpy
206-44-0	Fluoranthene	7.61E-06 lb/MMBtu	1.6E-04 tpy
86-73-7	Fluorene	2.92E-05 lb/MMBtu	6.1E-04 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	3.75E-07 lb/MMBtu	7.8E-06 tpy
91-20-3	Naphthalene	8.48E-05 lb/MMBtu	1.8E-03 tpy
85-01-8	Phenanthrene	2.94E-05 lb/MMBtu	6.1E-04 tpy
129-00-0	Pyrene	4.78E-06 lb/MMBtu	1.0E-04 tpy
		Total Potential HAP Emissions:	**0.1** tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual Operating Hours	Maximum Capacity
9	Firewater Pump Engine	8760 hr	160 hp
9a	Backup Generator	8760 hr	519 hp

Average BSFC = 7,000 Btu/hp-hr

2. Emission Factors assumed from AP-42, Table 3.3-2, Speciated Organic Compound Emission Factors For Uncontrolled Diesel

Table D1-H(d). Potential Hazardous Air Pollutant (HAP) Emissions

Potential Annual Emissions Before Controls/Limitations

Flare

CAS No.	Chemical Name	Emission Factor[2]		Estimated Emissions	
	VOC HAP Emissions			**948.7**	**tpy**
71-43-2	Benzene	2.1E-03	lb/MMscf	0.2	tpy
106-97-8	Butane	2.1	lb/MMscf	176.6	tpy
74-84-0	Ethane	3.1	lb/MMscf	260.7	tpy
50-00-0	Formaldehyde	7.5E-02	lb/MMscf	6.3	tpy
110-54-3	Hexane	1.8	lb/MMscf	151.4	tpy
91-20-3	Naphthalene	6.1E-04	lb/MMscf	5.1E-02	tpy
109-66-0	Pentane	2.6	lb/MMscf	218.6	tpy
74-98-6	Propane	1.6	lb/MMscf	134.6	tpy
108-88-3	Toluene	3.4E-03	lb/MMscf	0.3	tpy
91-57-6	2-Methylnaphthalene	2.4E-05	lb/MMscf	2.0E-03	tpy
N/A	**Polycyclic Organic Matter (POM)**				
	Polycyclic aromatic hydrocarbons (PAH)			**0.11**	**tpy**
56-49-5	3-Methylcholanthrene	1.8E-06	lb/MMscf	1.5E-04	tpy
	7,12- Dimethylbenz(a)anthracene	1.6E-05	lb/MMscf	1.3E-03	tpy
83-32-9	Acenaphthene	1.8E-06	lb/MMscf	1.5E-04	tpy
203-96-8	Acenaphthylene	1.8E-06	lb/MMscf	1.5E-04	tpy
120-12-7	Anthracene	2.4E-06	lb/MMscf	2.0E-04	tpy
56-55-3	Benz(a)anthracene	1.8E-06	lb/MMscf	1.5E-04	tpy
50-32-8	Benzo(a)pyrene	1.2E-06	lb/MMscf	1.0E-04	tpy
205-99-2	Benzo(b)fluoranthene	1.8E-06	lb/MMscf	1.5E-04	tpy
191-24-2	Benzo(g,h,i)perylene	1.2E-06	lb/MMscf	1.0E-04	tpy
207-08-9	Benzo(k)fluoranthene	1.8E-06	lb/MMscf	1.5E-04	tpy
218-01-9	Chrysene	1.8E-06	lb/MMscf	1.5E-04	tpy
53-70-3	Dibenzo(a,h)anthracene	1.2E-06	lb/MMscf	1.0E-04	tpy
25321-22-6	Dichlorobenzene	1.2E-03	lb/MMscf	1.0E-01	tpy
206-44-0	Fluoranthene	3.0E-06	lb/MMscf	2.5E-04	tpy
86-73-7	Fluorene	2.8E-06	lb/MMscf	2.4E-04	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.8E-06	lb/MMscf	1.5E-04	tpy
85-01-8	Phenanathrene	1.7E-05	lb/MMscf	1.4E-03	tpy
129-00-0	Pyrene	5.0E-06	lb/MMscf	4.2E-04	tpy
		Total Potential HAP Emissions:		**948.8**	tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual		Maximum Capacity	
10	Tornado TTI-SLT	8760	hr	16,819.2	MMscf/yr
	Fuel Gas Htg. Value =	1050	Btu/scf		

2. Heating Value for fuel burned in EU ID 16 (Test Flare) was assumed to be the value for Natural Gas listed in AP-42 Appendix A-Typical Parameters of Various Fuels.

3. A representative fuel gas analysis was not available at the time this permit application was assembled. Therefore, the emission factors from AP-42 for Natural-Gas Fired External Combustion units.

D1 and D2 FORMS

Potential to Emit AFTER Controls/Limits

FORMS D1 &D2

Emissions Summary

Table D2. Kustatan Production Facility - Potential To Emit (PTE) Summary
Potential Annual Emissions After Controls/Limitations

Emissions Unit Type	Regulated Air Pollutant Emissions (tons per year) [1]								
	NO_X	CO	PM	PM_{10} [2]	$PM_{2.5}$ [2]	VOC	SO_2	HAP[3]	GHG[4,5]
Significant	86.1	153.1	6.5	2.8	5.1	7.5	111.8	950.9	1,285,483
Insignificant	2.7	1.7	0.0	0.0	0.0	3.8	0.0	0.0	260.3
Total Emissions	**89**	**155**	**6**	**3**	**5**	**11**	**112**	**951**	**1,285,743**

Notes:

1. Regulated air pollutant calculations based on permitted fuel rates, source test results, AP-42 emission factors, and mass balances as shown in accompanying spreadsheets.
2. PM emissions are assumed to be equal to the sum of $PM_{2.5}$ and $PM_{10.}$ However, separate $PM_{2.5}$ and PM_{10} emission factors are not always available, therefore, the PM factor from AP-42 is used in their place causing the $PM_{2.5}$ and PM_{10} to be conservatively inflated.
3. See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).
4. GHG emissions are defined as CO2e emissions. CO2e is the summation of CO2, CH4, and N2O, applying the global warming potential for each pollutant.
5. Per 40 CFR 71.2, GHGs are subject to regulation beginning on July 1, 2011.

Table D2-A. Emission Unit Inventory
Potential Annual Emissions After Controls/Limitations

ID	Emission Unit Name	Description	Fuel Type	Maximum Fuel Consumption	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation
Turbine Generators							
1	Solar Taurus 60-T7301S Turbine	Turbine Generator #1	Fuel Gas	0.078 MMscf/hr[1]	683 MMscf/yr	58.2 MMBtu/hr[2]	8,760 hr/yr
2	Solar Taurus 60-T7301S Turbine	Turbine Generator #2	Fuel Gas	0.081 MMscf/hr[1]	707 MMscf/yr	55.3 MMBtu/hr[2]	8,760 hr/yr
Heaters							
3	NATCO Natural Draft Burners	Heater Treater #1	Fuel Gas	0.007 MMscf/hr[3]	63 MMscf/yr	6.2 MMBtu/hr	8,760 hr/yr
4	NATCO Natural Draft Burners	Heater Treater #2	Fuel Gas	0.007 MMscf/hr[3]	63 MMscf/yr	6.2 MMBtu/hr	8,760 hr/yr
5	NATCO Natural Draft Burners	Heater Treater #3	Fuel Gas	0.007 MMscf/hr[3]	63 MMscf/yr	6.2 MMBtu/hr	8,760 hr/yr
6	NATCO Natural Draft Burners	Crude Heater #1	Fuel Gas	0.009 MMscf/hr[3]	79 MMscf/yr	8.0 MMBtu/hr	8,760 hr/yr
7	NATCO Natural Draft Burners	Crude Heater #2	Fuel Gas	0.009 MMscf/hr[3]	79 MMscf/yr	8.0 MMBtu/hr	8,760 hr/yr
8	NATCO Natural Draft Burners	Crude Heater #3	Fuel Gas	0.009 MMscf/hr[3]	79 MMscf/yr	8.0 MMBtu/hr	8,760 hr/yr
Diesel Engines							
9	Cummins 6BTA5.9	Fire Water Pump	Diesel	8.2 gal/hr	4100 gal/yr	160 hp	500 hr/yr[4]
9a	Caterpillar 3406C	Backup Generator	Diesel	14.2 gal/hr	7075 gal/yr	519 hp	500 hr/yr[5]
Flare							
10	Tornado TTI-SLT	Process Flare	Fuel Gas and Produced Gas	1.9 MMscf/hr	70 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr
Storage Tanks							
12	Crude Tank No. 1	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
13	Crude Tank No. 2	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
14	Crude Tank No. 3	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
15	Slop Oil Tank	Slop Oil Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
16	Produced Water Tank	Produced Water Tank	Produced Water	N/A	N/A	10,000 bbls	8,760 hr/yr
Insignificant Emission Units							
N/A	Generator	Honda S-351 Generator	Gasoline	0.27 gal/hr[4]	2378 gal/yr	2 kW	8,760 hr/yr
N/A	Generator	Honda S-351 Generator	Gasoline	0.27 gal/hr[4]	2378 gal/yr	2 kW	8,760 hr/yr
N/A	Trash Pump	Wacker Neuson PDT 3A 3" Diaphragm	Gasoline	1.2 gal/hr	10512 gal/yr	4 hp	8,760 hr/yr
N/A	Trash Pump	Wacker Neuson PD 3A 3" Diaphragm	Gasoline	1.2 gal/hr	10512 gal/yr	4 hp	8,760 hr/yr
T-146	Utility Tank	Process Fluids Storage Tank	Miscellaneous Process Fluids	N/A	N/A	21,000 gal	8,760 hr/yr
DF-01	Diesel Day Tank	Diesel Storage Tank	Diesel	N/A	N/A	500 gal	8,760 hr/yr
N/A	Pig Cooker Tank	Crude Oil Storage Tank	Crude Oil, Produced Water, and Paraffin	N/A	N/A	104 gal	8,760 hr/yr
T-156	Fire Water Pump Diesel Day Tank	Diesel Storage Tank	Diesel	N/A	N/A	150 gal	8,760 hr/yr
N/A	Cat 3406 Diesel Tank	Diesel Storage Tank	Diesel	N/A	N/A	200 gal	8,760 hr/yr
T-214	Methanol Tank	Methanol Storage Tank	Methanol	N/A	N/A	10,000 gal	8,760 hr/yr
N/A	Boiler Diesel Fuel Tank	Diesel Storage Tank	Diesel	N/A	N/A	5,000 gal	8,760 hr/yr

Table Notes:
1. EU IDs 1 and 2 Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. EU IDs 3-8 Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
4. Per NESHAP Subpart ZZZZ 40 CFR 63.6640(f)(2) and Condition 34.1b of Permit No. AQ0741TVP03, Rev. 1, non-emergency operating hours on the Firewater Pump (EU 9) are limited to 100 hours per calendar year. Potential emissions are based on 500 hours per 12-month rolling period as a conservative effort to account for any potential emergency hours.
5. Permit No. AQ0741TVP03, Rev. 1 Condition 17.3 limits operations of EU 9a to no more than 500 hours per 12-month rolling period.
6. Permit No. AQ0741TVP03, Rev. 1 Condition 18.1 limits the fuel gas burned in EU 10 to no more than 70 mmscf in any 12-month rolling period.
4. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.

Table D2-B. Potential NO_X Emissions
Potential Annual Emissions After Controls/Limitations

ID	Emission Unit Name	Reference	Emission Factor	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential NO_X Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	4.7 lb/hr[1]	683.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	8,760 hr/yr	64.5 tpy[4]
2	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	6.1 lb/hr[1]	706.9 MMscf/yr[2]	55.3 MMBtu/hr[3]	8,760 hr/yr	
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	2.2 tpy
4	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	2.2 tpy
5	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	2.2 tpy
6	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	3.0 tpy
7	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	3.0 tpy
8	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	3.0 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	4.41 lb/MMBtu	4100 gal/yr	160 hp	500 hr/yr	1.2 tpy[5]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	4.41 lb/MMBtu	7075 gal/yr	519 hp	500 hr/yr	2.1 tpy[5]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP 42 Table 13.5-1	0.068 lb/MMBtu	70 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr	2.6 tpy[6]
Storage Tanks							
12	Crude Tank No. 1	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential NO_X Emissions				**86.1 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	1.63 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.3 tpy[8]
N/A	Gasoline Generator	AP-42 Table 3.3-1	1.63 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.3 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	1.63 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	1.1 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	1.63 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	1.1 tpy[8]
T-146	Utility Tank	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential NO_X Emissions				**2.7 tpy**

Table Notes:

1. EU IDs 1 and 2 NO_X emission factors were obtained from the results of the August 2019 Source Test. The highest result while operating above 50% load was used to be most conservative and it was increased by 10% to account for changes in load and temperature.

2. EU IDs 1 and 2 Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.

3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.

4. Permit No. AQ0741TVP03, Rev. 1 Condition 17.1b and AQ0741MSS03 Condition 7.1b limits the total combined NO_X emissions from EUs 1 and 2 to 64.5 tons per 12-month rolling period.

4. EU IDs 3-8 Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.

5. Diesel engine emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon

6. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf

7. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.

8. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D2-C. Potential CO Emissions
Potential Annual Emissions After Controls/Limitations

ID	Emission Unit Name	Reference	Emission Factor	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential CO Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	0.5 lb/hr[1]	683.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	8,760 hr/yr	136.0 tpy[4]
2	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	0.4 lb/hr[1]	706.9 MMscf/yr[2]	55.3 MMBtu/hr[3]	8,760 hr/yr	
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
4	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
5	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
6	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.5 tpy
7	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.5 tpy
8	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.5 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	4.41 lb/MMBtu	4100 gal/yr	160 hp	500 hr/yr	1.2 tpy[5]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	4.41 lb/MMBtu	7075 gal/yr	519 hp	500 hr/yr	2.1 tpy[5]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.31 lb/MMBtu	70 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr	11.7 tpy[6]
Storage Tanks							
12	Crude Tank No. 1	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential CO Emissions				**153.1 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.99 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.2 tpy[8]
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.99 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.2 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.99 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	0.7 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.99 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	0.7 tpy[8]
T-146	Utility Tank	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential CO Emissions				**1.7 tpy**

Table Notes:

1. EU IDs 1 and 2 CO emission factors were obtained from the results of the August 2019 Source Test. The highest result while operating above 50% load was used to be most conservative and it was increased by 10% to account for changes in load and temperature.
2. EU IDs 1 and 2 Maximum Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. Permit No. AQ0741TVP03, Rev. 1 Condition 17.1b and AQ0741MSS03 Condition 8.1 limits the total combined CO emissions from EUs 1 and 2 to 136 tons per 12-month rolling period.
4. EU IDs 3-8 Maximum Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
5. Diesel engine emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
6. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
7. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
8. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D2-D. Potential PM/PM10/PM2.5 Emissions
Potential Annual Emissions After Controls/Limitations

ID	Emission Unit Name	Reference	PM_{Total} Emission Factor	PM_{10} Emission Factor	$PM_{2.5}$ Emission Factor	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential PM_{Total} Emissions	Potential PM_{10} Emissions	Potential $PM_{2.5}$ Emissions
Turbine Generators (Fuel Gas)											
1	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	6.9E-03 lb/MMBtu[1]	2E-03 lb/MMBtu[1]	4.9E-03 lb/MMBtu[1]	683.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	8,760 hr/yr	1.8 tpy	0.5 tpy	1.3 tpy
2	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	6.9E-03 lb/MMBtu[1]	2E-03 lb/MMBtu[1]	4.9E-03 lb/MMBtu[1]	706.9 MMscf/yr[2]	55.3 MMBtu/hr[3]	8,760 hr/yr	1.7 tpy	0.5 tpy	1.2 tpy
Heaters (Fuel Gas)											
3	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.0 lb/MMscf	2.0 lb/MMscf	6.0 lb/MMscf	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
4	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.0 lb/MMscf	2.0 lb/MMscf	6.0 lb/MMscf	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
5	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.0 lb/MMscf	2.0 lb/MMscf	6.0 lb/MMscf	63.1 MMscf/yr[4]	6.2 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
6	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.0 lb/MMscf	2.0 lb/MMscf	6.0 lb/MMscf	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
7	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.0 lb/MMscf	2.0 lb/MMscf	6.0 lb/MMscf	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
8	NATCO Natural Draft Burners	AP-42 Table 1.4-2	8.0 lb/MMscf	2.0 lb/MMscf	6.0 lb/MMscf	78.8 MMscf/yr[4]	8.0 MMBtu/hr	8,760 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
Engines (Diesel)											
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	4100 gal/yr	160 hp	500 hr/yr[4]	0.1 tpy	0.1 tpy	0.1 tpy
9a	Caterpillar 3406C	AP-42 Table 3.3-1	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	7075 gal/yr	519 hp	500 hr/yr[5]	0.3 tpy	0.3 tpy	0.3 tpy
Flare (Produced Gas and Fuel Gas)											
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.0264 lb/MMBtu	0.0264 lb/MMBtu	0.0264 lb/MMBtu	70 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr	1.0 tpy[5]	1.0 tpy[5]	1.0 tpy[5]
Storage Tanks											
12	Crude Tank No. 1	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
						Significant EUs Total Potential PM Emissions			**6.5 tpy**	**2.8 tpy**	**5.1 tpy**
Insignificant Emission Units											
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	2378 gal/yr[6]	2 kW	8,760 hr/yr	0.02 tpy[7]	0.02 tpy[7]	0.02 tpy[7]
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	2378 gal/yr[6]	2 kW	8,760 hr/yr	0.02 tpy[7]	0.02 tpy[7]	0.02 tpy[7]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	0.07 tpy[7]	0.07 tpy[7]	0.07 tpy[7]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	0.07 tpy[7]	0.07 tpy[7]	0.07 tpy[7]
T-146	Utility Tank	N/A	N/A	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
						Insignificant EUs Total Potential PM Emissions			**0.2 tpy**	**0.2 tpy**	**0.2 tpy**

Table Notes:

1. PM Emission Factors for EU IDs 1-8 are adjusted for the actual average heat rate from fuel gas testing in 2020 rather than the assumed rate of 1,020 Btu/scf noted in AP-42. Note separate PM_{10} and $PM_{2.5}$ emission factors are not always available, in those cases, the PM factor from AP-42 is used in their place.
   Fuel Gas Heating Value = 1073.8 Btu/scf
2. EU IDs 1 and 2 Maximum Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. EU IDs 3-8 Maximum Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
7. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D2-E. Potential VOC Emissions
Potential Annual Emissions After Controls/Limitations

ID	Emission Unit Name	Reference	Emission Factor	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential VOC Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu	683.2 MMscf/yr[1]	58.2 MMBtu/hr[2]	8,760 hr/yr	0.54 tpy
2	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu	706.9 MMscf/yr[1]	55.3 MMBtu/hr[2]	8,760 hr/yr	0.51 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	63.1 MMscf/yr[3]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
4	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	63.1 MMscf/yr[3]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
5	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	63.1 MMscf/yr[3]	6.2 MMBtu/hr	8,760 hr/yr	0.2 tpy
6	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	78.8 MMscf/yr[3]	8.0 MMBtu/hr	8,760 hr/yr	0.2 tpy
7	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	78.8 MMscf/yr[3]	8.0 MMBtu/hr	8,760 hr/yr	0.2 tpy
8	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	78.8 MMscf/yr[3]	8.0 MMBtu/hr	8,760 hr/yr	0.2 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	0.35 lb/MMBtu	4100 gal/yr	160 hp	500 hr/yr 4	0.00 tpy[4]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	0.35 lb/MMBtu	7075 gal/yr	519 hp	500 hr/yr 5	0.00 tpy[4]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.14 lb/MMBtu	70 MMscf/yr	1.92 MMscf/day	8,760 hr/yr	5.3 tpy[5]
Storage Tanks							
12	Crude Tank No. 1	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.2 tpy[6]
13	Crude Tank No. 2	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.2 tpy[6]
14	Crude Tank No. 3	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.2 tpy[6]
15	Slop Oil Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.2 tpy[6]
16	Produced Water Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.1 tpy[6]
			Significant EUs Total Potential VOC Emissions				**7.5 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	2.1 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.3 tpy[8]
N/A	Gasoline Generator	AP-42 Table 3.3-1	2.1 lb/MMBtu	2378 gal/yr[7]	2 kW	8,760 hr/yr	0.3 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	2.1 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	1.4 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	2.1 lb/MMBtu	10512 gal/yr	4 hp	8,760 hr/yr	1.4 tpy[8]
T-146	Utility Tank	EPA TANKS 4.09	N/A	N/A	21,000 gal	8,760 hr/yr	0.3 tpy
DF-01	Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	500 gal	8,760 hr/yr	0.0 tpy
N/A	Pig Cooker Tank	EPA TANKS 4.09	N/A	N/A	104 gal	8,760 hr/yr	0.0 tpy
T-156	Fire Water Pump Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	150 gal	8,760 hr/yr	0.0 tpy
N/A	Cat 3406 Diesel Tank	EPA TANKS 4.09	N/A	N/A	200 gal	8,760 hr/yr	0.0 tpy
T-214	Methanol Tank	EPA TANKS 4.09	N/A	N/A	10,000 gal	8,760 hr/yr	0.0 tpy
N/A	Boiler Diesel Fuel Tank	EPA TANKS 4.09	N/A	N/A	5,000 gal	8,760 hr/yr	0.0 tpy
			Insignificant EUs Total Potential VOC Emissions				**3.8 tpy**

Table Notes:

1. EU IDs 1 and 2 Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. EU IDs 3-8 Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
4. Diesel engine emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. EU IDs 12-16 are part of a closed vent system that reduces VOC emissions by 95%.
7. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
8. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D2-F. Potential SO_2 Emissions
Potential Annual Emissions After Controls/Limitations

ID	Emission Unit Name	Reference	Emission Factor[1]	Maximum Annual Fuel Consumption	Maximum Capacity	Maximum Operation	Potential SO_2 Emissions[4,5]
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	Mass Balance	700 ppmv H_2S	683.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	8,760 hr/yr	40.34 tpy
2	Solar Taurus 60-T7301S Turbine	Mass Balance	700 ppmv H_2S	706.9 MMscf/yr[2]	55.3 MMBtu/hr[3]	8,760 hr/yr	41.75 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	63.1 MMscf/yr[6]	6.2 MMBtu/hr	8,760 hr/yr	3.72 tpy
4	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	63.1 MMscf/yr[6]	6.2 MMBtu/hr	8,760 hr/yr	3.72 tpy
5	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	63.1 MMscf/yr[6]	6.2 MMBtu/hr	8,760 hr/yr	3.72 tpy
6	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	78.8 MMscf/yr[6]	8.0 MMBtu/hr	8,760 hr/yr	4.66 tpy
7	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	78.8 MMscf/yr[6]	8.0 MMBtu/hr	8,760 hr/yr	4.66 tpy
8	NATCO Natural Draft Burners	Mass Balance	700 ppmv H_2S	78.8 MMscf/yr[6]	8.0 MMBtu/hr	8,760 hr/yr	4.66 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	Mass Balance	0.5 wt% S	4100 gal/yr	160 hp	500 hr/yr 4	0.14 tpy
9a	Caterpillar 3406C	Mass Balance	0.5 wt% S	7075 gal/yr	519 hp	500 hr/yr 5	0.25 tpy
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	Mass Balance	700 ppmv H_2S	70 MMscf/yr	1.92 MMscf/day	8,760 hr/yr	4.1 tpy[7]
Storage Tanks							
12	Crude Tank No. 1	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential SO2 Emissions				**111.8 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	10 ppm	2378 gal/yr[8]	2 kW	8,760 hr/yr	0.00015 tpy[9]
N/A	Gasoline Generator	AP-42 Table 3.3-1	10 ppm	2378 gal/yr[8]	2 kW	8,760 hr/yr	0.00015 tpy[9]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	10 ppm	10512 gal/yr	4 hp	8,760 hr/yr	0.00067 tpy[9]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	10 ppm	10512 gal/yr	4 hp	8,760 hr/yr	0.00067 tpy[9]
T-146	Utility Tank	EPA TANKS 4.09	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	EPA TANKS 4.09	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	EPA TANKS 4.09	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	EPA TANKS 4.09	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	EPA TANKS 4.09	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential SO_2 Emissions				**0.0 tpy**

Table Notes:

1. The H_2S standard for fuel gas units is based on the limit set out in AQ0741TVP03, Rev. 1 Condition 14.2 of 700ppmv. The diesel sulfur limit is 0.5 wt% S per Condition 13.1. The gasoline sulfur limit is based on the standard annual average of 10 ppm as specified in 40 CFR 80.1603.
2. EU IDs 1 and 2 Maximum Annual Fuel Capacity based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. Mass balance of fuel gas is estimated based on the following assumptions:

1 lb mole of gas at standard temperature at 60º F and pressure 14.7 psia:	379.3	scf/lb-mole (Ideal gas conversion)
Conversions:	64	lb SO_2/lb-mole
	1	lb-mole H_2S/lb-mole SO_2

5. Mass balance of diesel fuel and gasoline emission units is estimated based on the following assumptions

Conversions:	64	lb SO_2/lb-mole
	32	lb S/64 lb SO_2
	7.05	lb/gal distillate fuel (AP-42 Appendix A, page A-7)
	0.76	SG of Marathon Unleaded gasoline (converted by 8.33 lb/gal water)

6. EU IDs 3-8 Maximum Annual Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
7. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
8. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
9. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D2-G. Potential CO2-e Emissions

Potential Annual Emissions After Controls/Limitations

ID	Emission Unit Description	Reference (40 CFR 98)	CO2 Emission Factor	Reference (40 CFR 98)	CH4 Emission Factor	Reference (40 CFR 98)	N_2O Emission Factor	Maximum Fuel Rate	Maximum Capacity	Maximum Operation	Potential CO2-e Emissions[8]
Turbine Generators (Fuel Gas)											
1	Solar Taurus 60-T7301S Turbine	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.078 MMscf/hr[1]	58.2 MMBtu/hr[2]	8,760 hr/yr	41,707.9 tpy
2	Solar Taurus 60-T7301S Turbine	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.081 MMscf/hr[1]	55.3 MMBtu/hr[2]	8,760 hr/yr	39,629.7 tpy
Heaters (Fuel Gas)											
3	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	8,760 hr/yr	3,547.5 tpy
4	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	8,760 hr/yr	3,547.5 tpy
5	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	8,760 hr/yr	3,547.5 tpy
6	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	8,760 hr/yr	4,577.4 tpy
7	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	8,760 hr/yr	4,577.4 tpy
8	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	8,760 hr/yr	4,577.4 tpy
Engines (Diesel)											
9	Cummins 6BTA5.9	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	8.2 gal/hr	160.0 hp	500 hr/yr	46.0 tpy[4]
9a	Caterpillar 3406C	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	14.2 gal/hr	519.0 hp	500 hr/yr	79.3 tpy[4]
Flare (Produced Gas and Fuel Gas)											
10	Tornado TTI-SLT	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.9 MMscf/hr	1.9 MMscf/hr[5]	8,760 hr/yr	1,179,645.4 tpy
Storage Tanks											
12	Crude Tank No. 1	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
13	Crude Tank No. 2	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
14	Crude Tank No. 3	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
15	Slop Oil Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
16	Produced Water Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
								Significant Total Potential CO2-e Emissions			**1,285,482.7 tpy**
Insignificant Emission Units											
N/A	Generator	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.3 gal/hr[6]	2.0 kW	8,760 hr/yr	24.0 tpy[7]
N/A	Generator	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.3 gal/hr[6]	2.0 kW	8,760 hr/yr	24.0 tpy[7]
N/A	Trash Pump	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.2 gal/hr	4.0 hp	8,760 hr/yr	106.2 tpy[7]
N/A	Trash Pump	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.2 gal/hr	3.5 hp	8,760 hr/yr	106.2 tpy[7]
T-146	Utility Tank	NA	NA	NA	NA	NA	NA	N/A	21,000.0 gal	8,760 hr/yr	0.0 tpy
DF-01	Diesel Day Tank	NA	NA	NA	NA	NA	NA	N/A	500.0 gal	8,760 hr/yr	0.0 tpy
N/A	Pig Cooker Tank	NA	NA	NA	NA	NA	NA	N/A	104.0 gal	8,760 hr/yr	0.0 tpy
T-156	Fire Water Pump Diesel Day Tank	NA	NA	NA	NA	NA	NA	N/A	150.0 gal	8,760 hr/yr	0.0 tpy
N/A	Cat 3406 Diesel Tank	NA	NA	NA	NA	NA	NA	N/A	200.0 gal	8,760 hr/yr	0.0 tpy
T-214	Methanol Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 gal	8,760 hr/yr	0.0 tpy
N/A	Boiler Diesel Fuel Tank	NA	NA	NA	NA	NA	NA	N/A	5,000.0 gal	8,760 hr/yr	0.0 tpy
								Insignificant EUs Total Potential CO2-e Emissions			**260.3 tpy**

Table Notes:

1. EU IDs 1 and 2 Maximum Fuel Consumption Rate based on the average results of the 2019 Source Test Report at high load.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. EU IDs 3-8 Maximum Fuel Consumption Rate calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
4. Diesel engine emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
7. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon
8. Global Warming Potentials listed in Table A-1 of 40 CFR 98 Subpart A were used to estimate the CO2e using the equation $CO_{2e} = CO_2 + 25 \cdot CH_4 + 298 \cdot N_2O$
   1 tonne (metric ton) = 907.18 kg
   GWP of CH_4 = 25
   GWP of N_2O = 298

Table D2-H. Potential Hazardous Air Pollutant (HAP) Emissions Summary Table
Potential Annual Emissions After Controls/Limitations

Hazardous Air Pollutant	Stationary Gas Turbines	Natural Gas External Emission Units	Diesel Engines ≤ 600 hp	Flare	Total HAP Emissions
1,3-Butadiene	2.0E-07		8.1E-04		8.1E-04
3-Methylcholanthrene				1.51E-04	1.5E-04
1,3-Butadiene	2.0E-07		8.1E-04		8.1E-04
2-Methylnaphthalene		4.2E-06		2.02E-03	2.0E-03
3-Methylcholanthrene		3.1E-07			3.1E-07
7,12- Dimethylbenz(a)anthracene				1.35E-03	1.3E-03
Acenaphthene		3.1E-07	3.0E-05	1.51E-04	1.8E-04
Acenaphthylene		3.1E-07	1.1E-04	1.51E-04	2.6E-04
Acetaldehyde	1.9E-05		1.6E-02		1.6E-02
Acrolein	3.0E-06		1.9E-03		1.9E-03
Anthracene		4.2E-07	3.9E-05	2.02E-04	2.4E-04
Benz(a)anthracene		3.1E-07		1.51E-04	1.5E-04
Benzene	5.6E-06	3.6E-04	1.9E-02	1.77E-01	2.0E-01
Benzo(a)anthracene			3.5E-05		3.5E-05
Benzo(a)pyrene		2.1E-07	3.9E-06	1.01E-04	1.1E-04
Benzo(b)fluoranthene		3.1E-07	2.1E-06	1.51E-04	1.5E-04
Benzo(g,h,i)perylene		2.1E-07		1.01E-04	1.0E-04
Benzo(k)fluoranthene		3.1E-07	3.2E-06	1.51E-04	1.5E-04
Butane		3.6E-01		1.77E+02	1.8E+02
Chrysene		3.1E-07	7.3E-06	1.51E-04	1.6E-04
Dibenz(a,h)anthracene			1.2E-05		1.2E-05
Dichlorobenzene		2.1E-04		1.01E-01	1.0E-01
Ethane		5.4E-01		2.61E+02	2.6E+02
Ethylbenzene	1.5E-05				1.5E-05
Fluoranthene		5.2E-07	1.6E-04	2.52E-04	4.1E-04
Fluorene		4.9E-07	6.1E-04	2.35E-04	8.4E-04
Formaldehyde	3.3E-04	1.3E-02	2.5E-02	6.31E+00	6.3E+00
Hexane		3.1E-01		1.51E+02	1.5E+02
Indeno(1,2,3-cd)pyrene		3.1E-07	7.8E-06	1.51E-04	1.6E-04
Naphthalene	6.0E-07	1.1E-04	1.8E-03	5.13E-02	5.3E-02
PAH	1.0E-06				1.0E-06
Pentane		4.5E-01		2.19E+02	2.2E+02
Phenanathrene		3.0E-06			3.0E-06
Propane		2.8E-01		1.35E+02	1.3E+02
Propylene			5.4E-02		5.4E-02
Propylene Oxide	1.3E-05				1.3E-05
Pyrene		8.7E-07	1.0E-04	4.20E-04	5.2E-04
Pyrene		8.7E-07	1.0E-04	4.20E-04	5.2E-04
Toluene	6.0E-05	5.9E-04	8.5E-03	2.86E-01	3.0E-01
Xylenes	3.0E-05		5.9E-03		6.0E-03
Total HAPs - Maximum Individual HAP	**3.3E-04**	**5.4E-01**	**5.4E-02**	**260.7**	**261.2**
Total HAPs Emissions	**4.8E-04**	**2.0**	**0.135**	**948.8**	**950.9**

Notes:

1. Detailed methodology and assumptions included with the individual emission unit category calculations in Tables D-9A(2) through D-9A(5).

Table D2-H(a). Potential Hazardous Air Pollutant (HAP) Emissions

Potential Annual Emissions After Controls/Limitations

Stationary Gas Turbines

Maximum Total Heat Input: 994,260.0 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]		Estimated Emissions	
106-99-0	1,3-Butadiene	4.30E-07	lb/MMscf	2.0E-07	tpy
75-07-0	Acetaldehyde	4.00E-05	lb/MMscf	1.9E-05	tpy
107-02-8	Acrolein	6.40E-06	lb/MMscf	3.0E-06	tpy
100-41-4	Benzene	1.20E-05	lb/MMscf	5.6E-06	tpy
203-96-8	Ethylbenzene	3.20E-05	lb/MMscf	1.5E-05	tpy
50-00-0	Formaldehyde	7.10E-04	lb/MMscf	3.3E-04	tpy
91-20-3	Naphthalene	1.30E-06	lb/MMscf	6.0E-07	tpy
	PAH	2.20E-06	lb/MMscf	1.0E-06	tpy
75-56-9	Propylene Oxide	2.90E-05	lb/MMscf	1.3E-05	tpy
108-88-3	Toluene	1.30E-04	lb/MMscf	6.0E-05	tpy
1330-20-7	Xylenes	6.40E-05	lb/MMscf	3.0E-05	tpy
		Total Potential HAP Emissions:		**4.8E-04**	tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual	Maximum Capacity
1	Solar Taurus 60-T7301S Turbine	8760 hr	113.5 MMBtu/hr
2	Solar Taurus 60-T7301S Turbine	8760 hr	

Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
Maximum Capacity is from the manufacturer's Certified Test Report.

Fuel Gas Heating Value = 1073.8 Btu/scf

2. Emission Factors assumed from AP-42, Table 1.4-3 Emission Factors For Speciated Organic Compounds From Natural Gas

Table D2-H(b). Potential Hazardous Air Pollutant (HAP) Emissions

Potential Annual Emissions After Controls/Limitations

Natural Gas External Combustion Units

Maximum Total Heat Input: 373,176.0 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]		Estimated Emissions	
91-57-6	2-Methylnaphthalene	2.40E-05	lb/MMscf	4.2E-06	tpy
56-49-5	3-Methylcholanthrene	1.80E-06	lb/MMscf	3.1E-07	tpy
	7,12-Dimethylbenz(a)anthracene	1.60E-05	lb/MMscf	2.8E-06	tpy
83-32-9	Acenaphthene	1.80E-06	lb/MMscf	3.1E-07	tpy
203-96-8	Acenaphthylene	1.80E-06	lb/MMscf	3.1E-07	tpy
120-12-7	Anthracene	2.40E-06	lb/MMscf	4.2E-07	tpy
56-55-3	Benz(a)anthracene	1.80E-06	lb/MMscf	3.1E-07	tpy
71-43-2	Benzene	2.10E-03	lb/MMscf	3.6E-04	tpy
50-32-8	Benzo(a)pyrene	1.20E-06	lb/MMscf	2.1E-07	tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06	lb/MMscf	3.1E-07	tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06	lb/MMscf	2.1E-07	tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06	lb/MMscf	3.1E-07	tpy
106-97-8	Butane	2.10E+00	lb/MMscf	3.6E-01	tpy
218-01-9	Chrysene	1.80E-06	lb/MMscf	3.1E-07	tpy
53-70-3	Dibenzo(a,h)anthracene	1.20E-06	lb/MMscf	2.1E-07	tpy
25321-22-6	Dichlorobenzene	1.20E-03	lb/MMscf	2.1E-04	tpy
74-84-0	Ethane	3.10E+00	lb/MMscf	5.4E-01	tpy
206-44-0	Fluoranthene	3.00E-06	lb/MMscf	5.2E-07	tpy
86-73-7	Fluorene	2.80E-06	lb/MMscf	4.9E-07	tpy
50-00-0	Formaldehyde	7.50E-02	lb/MMscf	1.3E-02	tpy
B110-54-3	Hexane	1.80E+00	lb/MMscf	3.1E-01	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.80E-06	lb/MMscf	3.1E-07	tpy
91-20-3	Naphthalene	6.10E-04	lb/MMscf	1.1E-04	tpy
109-66-0	Pentane	2.60E+00	lb/MMscf	4.5E-01	tpy
85-01-8	Phenanathrene	1.70E-05	lb/MMscf	3.0E-06	tpy
74-98-6	Propane	1.60E+00	lb/MMscf	2.8E-01	tpy
129-00-0	Pyrene	5.00E-06	lb/MMscf	8.7E-07	tpy
108-88-3	Toluene	3.40E-03	lb/MMscf	5.9E-04	tpy
		Total Potential HAP Emissions:		**2.0**	tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual	Maximum Capacity
3	NATCO Natural Draft Burners	8760 hr	
4	NATCO Natural Draft Burners	8760 hr	
5	NATCO Natural Draft Burners	8760 hr	42.6 MMBtu/hr
6	NATCO Natural Draft Burners	8760 hr	
7	NATCO Natural Draft Burners	8760 hr	
8	NATCO Natural Draft Burners	8760 hr	

Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.

Fuel Gas Heating Value = 1073.8 Btu/scf

2. Emission Factors assumed from AP-42, Table 1.4-3 Emission Factors For Speciated Organic Compounds From Natural Gas

Table D2-H(c). Potential Hazardous Air Pollutant (HAP) Emissions

Potential Annual Emissions After Controls/Limitations

Diesel Engines Up to or Equal to 600 Horsepower

Maximum Total Heat Input: 41,636.3 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]	Significant Units Estimated Emissions
	VOC HAP Emissions		**0.1 tpy**
106-99-0	1,3-Butadiene	3.91E-05 lb/MMBtu	8.1E-04 tpy
75-07-0	Acetaldehyde	7.67E-04 lb/MMBtu	1.6E-02 tpy
107-02-8	Acrolein	9.25E-05 lb/MMBtu	1.9E-03 tpy
71-43-2	Benzene	9.33E-04 lb/MMBtu	1.9E-02 tpy
50-00-0	Formaldehyde	1.18E-03 lb/MMBtu	2.5E-02 tpy
115-07-1	Propylene	2.58E-03 lb/MMBtu	5.4E-02 tpy
108-88-3	Toluene	4.09E-04 lb/MMBtu	8.5E-03 tpy
1330-20-7	Xylenes	2.85E-04 lb/MMBtu	5.9E-03 tpy
	Polycyclic Organic Matter (POM)		
	Polycyclic aromatic hydrocarbons (PAH)		**3.5E-03 tpy**
208-96-8	Acenaphthene	1.42E-06 lb/MMBtu	3.0E-05 tpy
83-32-9	Acenaphthylene	5.06E-06 lb/MMBtu	1.1E-04 tpy
120-12-7	Anthracene	1.87E-06 lb/MMBtu	3.9E-05 tpy
56-55-3	Benzo(a)anthracene	1.68E-06 lb/MMBtu	3.5E-05 tpy
50-32-8	Benzo(a)pyrene	1.88E-07 lb/MMBtu	3.9E-06 tpy
205-99-2	Benzo(b)fluoranthene	9.91E-08 lb/MMBtu	2.1E-06 tpy
191-24-2	Benzo(g,h,l)perylene	4.89E-07 lb/MMBtu	1.0E-05 tpy
207-08-9	Benzo(k)fluoranthene	1.55E-07 lb/MMBtu	3.2E-06 tpy
218-01-9	Chrysene	3.53E-07 lb/MMBtu	7.3E-06 tpy
53-70-3	Dibenz(a,h)anthracene	5.83E-07 lb/MMBtu	1.2E-05 tpy
206-44-0	Fluoranthene	7.61E-06 lb/MMBtu	1.6E-04 tpy
86-73-7	Fluorene	2.92E-05 lb/MMBtu	6.1E-04 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	3.75E-07 lb/MMBtu	7.8E-06 tpy
91-20-3	Naphthalene	8.48E-05 lb/MMBtu	1.8E-03 tpy
85-01-8	Phenanthrene	2.94E-05 lb/MMBtu	6.1E-04 tpy
129-00-0	Pyrene	4.78E-06 lb/MMBtu	1.0E-04 tpy
		Total Potential HAP Emissions:	**0.1** tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual Operating Hours	Maximum Capacity
9	Firewater Pump Engine	500 hr	160 hp
9a	Backup Generator	500 hr	519 hp

Average BSFC = 7,000 Btu/hp-hr

2. Emission Factors assumed from AP-42, Table 3.3-2, Speciated Organic Compound Emission Factors For Uncontrolled Diesel

Table D2-H(d). Potential Hazardous Air Pollutant (HAP) Emissions

Potential Annual Emissions After Controls/Limitations

Flare

CAS No.	Chemical Name	Emission Factor[2]	Estimated Emissions
	VOC HAP Emissions		**948.7 tpy**
71-43-2	Benzene	2.1E-03 lb/MMscf	0.2 tpy
106-97-8	Butane	2.1 lb/MMscf	176.6 tpy
74-84-0	Ethane	3.1 lb/MMscf	260.7 tpy
50-00-0	Formaldehyde	7.5E-02 lb/MMscf	6.3 tpy
110-54-3	Hexane	1.8 lb/MMscf	151.4 tpy
91-20-3	Naphthalene	6.1E-04 lb/MMscf	5.1E-02 tpy
109-66-0	Pentane	2.6 lb/MMscf	218.6 tpy
74-98-6	Propane	1.6 lb/MMscf	134.6 tpy
108-88-3	Toluene	3.4E-03 lb/MMscf	0.3 tpy
91-57-6	2-Methylnaphthalene	2.4E-05 lb/MMscf	2.0E-03 tpy
N/A	**Polycyclic Organic Matter (POM)**		
	Polycyclic aromatic hydrocarbons (PAH)		**0.11 tpy**
56-49-5	3-Methylcholanthrene	1.8E-06 lb/MMscf	1.5E-04 tpy
	7,12- Dimethylbenz(a)anthracene	1.6E-05 lb/MMscf	1.3E-03 tpy
83-32-9	Acenaphthene	1.8E-06 lb/MMscf	1.5E-04 tpy
203-96-8	Acenaphthylene	1.8E-06 lb/MMscf	1.5E-04 tpy
120-12-7	Anthracene	2.4E-06 lb/MMscf	2.0E-04 tpy
56-55-3	Benz(a)anthracene	1.8E-06 lb/MMscf	1.5E-04 tpy
50-32-8	Benzo(a)pyrene	1.2E-06 lb/MMscf	1.0E-04 tpy
205-99-2	Benzo(b)fluoranthene	1.8E-06 lb/MMscf	1.5E-04 tpy
191-24-2	Benzo(g,h,i)perylene	1.2E-06 lb/MMscf	1.0E-04 tpy
207-08-9	Benzo(k)fluoranthene	1.8E-06 lb/MMscf	1.5E-04 tpy
218-01-9	Chrysene	1.8E-06 lb/MMscf	1.5E-04 tpy
53-70-3	Dibenzo(a,h)anthracene	1.2E-06 lb/MMscf	1.0E-04 tpy
25321-22-6	Dichlorobenzene	1.2E-03 lb/MMscf	1.0E-01 tpy
206-44-0	Fluoranthene	3.0E-06 lb/MMscf	2.5E-04 tpy
86-73-7	Fluorene	2.8E-06 lb/MMscf	2.4E-04 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.8E-06 lb/MMscf	1.5E-04 tpy
85-01-8	Phenanathrene	1.7E-05 lb/MMscf	1.4E-03 tpy
129-00-0	Pyrene	5.0E-06 lb/MMscf	4.2E-04 tpy
		Total Potential HAP Emissions:	**948.8** tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual	Maximum Capacity
10	Tornado TTI-SLT	8760 hr	16,819.2 MMscf/yr
	Fuel Gas Htg. Value =	1050 Btu/scf	

2. Heating Value for fuel burned in EU ID 16 (Test Flare) was assumed to be the value for Natural Gas listed in AP-42 Appendix A-Typical Parameters of Various Fuels.

3. A representative fuel gas analysis was not available at the time this permit application was assembled. Therefore, the emission factors from AP-42 for Natural-Gas Fired External Combustion units.

D1 & D2 FORMS

Expected Actual Annual Emissions Based on 2019 Actual Operating Data

`

FORMS D1 & D2

Emissions Summary

Table D3. Kustatan Production Facility - Expected Actual Annual Emissions Based on 2019 Actual Operating Data[1]

Emissions Unit Type	Regulated Air Pollutant Emissions (tons per year) [1]								
	NO_X	CO	PM	PM_{10}[2]	$PM_{2.5}$[2]	VOC	SO_2	HAP[3]	GHG[4,5]
Significant	36.4	9.1	2.2	1.0	1.7	3.3	7.2	950.5	1,234,439
Insignificant	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	3.0
Total Emissions	**36**	**9**	**1**	**1**	**2**	**4**	**7**	**950**	**1,234,442**

Notes:

1. 2019 operating data was used to represent expected annual emissions rather than 2020 due to the unprecedented events surrounding the COVID pandemic. The facility was placed in a warm shutdown beginning in May 2020 and moved to a cold shutdown in October. Emission calculations were also based on permitted fuel rates, source test results, AP-42 emission factors, and mass balances as shown in accompanying spreadsheets.

2. PM emissions are assumed to be equal to the sum of $PM_{2.5}$ and PM_{10}. However, separate $PM_{2.5}$ and PM_{10} emission factors are not always available, therefore, the PM factor from AP-42 is used in their place causing the $PM_{2.5}$ and PM_{10} to be conservatively inflated.

3. See individual emissions unit category HAP emissions calculations for details on methodology and assumptions (electronic copy).
4. GHG emissions are defined as CO2e emissions. CO2e is the summation of CO2, CH4, and N2O, applying the global warming potential for each pollutant.
5. Per 40 CFR 71.2, GHGs are subject to regulation beginning on July 1, 2011.

Table D3-A. Emission Unit Inventory
Expected Actual Annual Emissions Based on 2019 Actual Operating Data

ID	Emission Unit Name	Description	Fuel Type	Maximum Fuel Consumption	2019 Fuel Consumption	Maximum Capacity	2019 Operation
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	Turbine Generator #1	Fuel Gas	0.078 MMscf/hr[1]	103.2 MMscf/yr	58.2 MMBtu/hr	1,724 hr/yr
2	Solar Taurus 60-T7301S Turbine	Turbine Generator #2	Fuel Gas	0.081 MMscf/hr[1]	447.6 MMscf/yr	55.3 MMBtu/hr	7,036 hr/yr
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	Heater Treater #1	Fuel Gas	0.007 MMscf/hr[3]	1.3 MMscf/yr	6.2 MMBtu/hr	6,849 hr/yr
4	NATCO Natural Draft Burners	Heater Treater #2	Fuel Gas	0.007 MMscf/hr[3]	1.1 MMscf/yr	6.2 MMBtu/hr	7,866 hr/yr
5	NATCO Natural Draft Burners	Heater Treater #3	Fuel Gas	0.007 MMscf/hr[3]	0.0 MMscf/yr	6.2 MMBtu/hr	0 hr/yr
6	NATCO Natural Draft Burners	Crude Heater #1	Fuel Gas	0.009 MMscf/hr[3]	6.0 MMscf/yr	8.0 MMBtu/hr	8,576 hr/yr
7	NATCO Natural Draft Burners	Crude Heater #2	Fuel Gas	0.009 MMscf/hr[3]	0.0 MMscf/yr	8.0 MMBtu/hr	0 hr/yr
8	NATCO Natural Draft Burners	Crude Heater #3	Fuel Gas	0.009 MMscf/hr[3]	11.7 MMscf/yr	8.0 MMBtu/hr	8,251 hr/yr
Engines (Diesel)							
9	Cummins 6BTA5.9	Fire Water Pump	Diesel	8.2 gal/hr	25 gal/yr	160 hp	3 hr/yr
9a	Caterpillar 3406C	Backup Generator	Diesel	14.2 gal/hr	460 gal/yr	519 hp	17 hr/yr
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	Process Flare	Fuel Gas and Produced Gas	1.9 MMscf/hr	36 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr
Storage Tanks							
12	Crude Tank No. 1	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
13	Crude Tank No. 2	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
14	Crude Tank No. 3	Crude Storage Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
15	Slop Oil Tank	Slop Oil Tank	Crude Oil	N/A	N/A	10,000 bbls	8,760 hr/yr
16	Produced Water Tank	Produced Water Tank	Produced Water	N/A	N/A	10,000 bbls	8,760 hr/yr
Insignificant Emission Units							
N/A	Generator	Honda S-351 Generator	Gasoline	0.27 gal/hr	27 gal/yr	2 kW	100 hr/yr
N/A	Generator	Honda S-351 Generator	Gasoline	0.27 gal/hr	27 gal/yr	2 kW	100 hr/yr
N/A	Trash Pump	Wacker Neuson PDT 3A 3" Diaphragm	Gasoline	1.2 gal/hr	120 gal/yr	4 hp	100 hr/yr
N/A	Trash Pump	Wacker Neuson PD 3A 3" Diaphragm	Gasoline	1.2 gal/hr	120 gal/yr	4 hp	100 hr/yr
T-146	Utility Tank	Process Fluids Storage Tank	Miscellaneous Process Fluids	N/A	N/A	21,000 gal	8,760 hr/yr
DF-01	Diesel Day Tank	Diesel Storage Tank	Diesel	N/A	N/A	500 gal	8,760 hr/yr
N/A	Pig Cooker Tank	Crude Oil Storage Tank	Crude Oil, Produced Water, and Paraffin	N/A	N/A	104 gal	8,760 hr/yr
T-156	Fire Water Pump Diesel Day Tank	Diesel Storage Tank	Diesel	N/A	N/A	150 gal	8,760 hr/yr
N/A	Cat 3406 Diesel Tank	Diesel Storage Tank	Diesel	N/A	N/A	200 gal	8,760 hr/yr
T-214	Methanol Tank	Methanol Storage Tank	Methanol	N/A	N/A	10,000 gal	8,760 hr/yr
N/A	Boiler Diesel Fuel Tank	Diesel Storage Tank	Diesel	N/A	N/A	5,000 gal	8,760 hr/yr

Table Notes:

1. Potential Annual Emissions based on 2019 actual operating hours and fuel consumption. Note, Glacier Oil and Gas made the decision to start shutting in wells and putting the Cook Inlet facilities into a warm shutdown on May 4, 2002, due to the unprecedented events surrounding the COVID-19 pandemic. The facility was then put in a cold shutdown on October 27, 2020. Therefore, the 2019 operational data best represents normal operations at Kustatan Production Facility under normal conditions.

2. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.

Table D3-B. NO_X Emissions
Expected Actual Annual Emissions Based on 2019 Actual Operating Data

ID	Emission Unit Name	Reference	Emission Factor	2019 Fuel Consumption	Maximum Capacity	2019 Operation	2019 NO_X Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	4.7 lb/hr[1]	103.2 MMscf/yr	58.2 MMBtu/hr[2]	1,724 hr/yr	4.05 tpy
2	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	6.1 lb/hr[1]	447.6 MMscf/yr	55.3 MMBtu/hr[2]	7,036 hr/yr	21.46 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	1.3 MMscf/yr	6.2 MMBtu/hr	6,849 hr/yr	1.7 tpy
4	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	1.1 MMscf/yr	6.2 MMBtu/hr	7,866 hr/yr	2.0 tpy
5	NATCO Natural Draft Burners	May 2003 Source Test	0.51 lb/hr	0.0 MMscf/yr	6.2 MMBtu/hr	0 hr/yr	0.0 tpy
6	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	6.0 MMscf/yr	8.0 MMBtu/hr	8,576 hr/yr	2.9 tpy
7	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	0.0 MMscf/yr	8.0 MMBtu/hr	0 hr/yr	0.0 tpy
8	NATCO Natural Draft Burners	May 2003 Source Test	0.68 lb/hr	11.7 MMscf/yr	8.0 MMBtu/hr	8,251 hr/yr	2.8 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	4.41 lb/MMBtu	25 gal/yr	160 hp	3 hr/yr	0.0 tpy[3]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	4.41 lb/MMBtu	460 gal/yr	519 hp	17 hr/yr	0.1 tpy[3]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP 42 Table 13.5-1	0.068 lb/MMBtu	36 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr	1.3 tpy[4]
Storage Tanks							
12	Crude Tank No. 1	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential NO_X Emissions				**36.4 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	1.63 lb/MMBtu	27 gal/yr	2 kW	100 hr/yr	0.0 tpy[5,6]
N/A	Gasoline Generator	AP-42 Table 3.3-1	1.63 lb/MMBtu	27 gal/yr	2 kW	100 hr/yr	0.0 tpy[5,6]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	1.63 lb/MMBtu	120 gal/yr	4 hp	100 hr/yr	0.0 tpy[6]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	1.63 lb/MMBtu	120 gal/yr	4 hp	100 hr/yr	0.0 tpy[6]
T-146	Utility Tank	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential NO_X Emissions				**0.0 tpy**

Table Notes:

1. EU IDs 1 and 2 NO_X emission factors were obtained from the results of the August 2019 Source Test. The highest result while operating above 50% load was used to be most conservative and it was increased by 10% to account for changes in load and temperature.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. Diesel Engines emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
4. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
5. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
6. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D3-C. CO Emissions
Expected Actual Annual Emissions Based on 2019 Actual Operating Data

ID	Emission Unit Name	Reference	Emission Factor	2019 Fuel Consumption	Maximum Capacity	2019 Operation	2019 CO Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	0.5 lb/hr[1]	103.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	1,724 hr/yr	0.43 tpy
2	Solar Taurus 60-T7301S Turbine	August 2019 Source Test	0.37 lb/hr[1]	447.6 MMscf/yr[2]	55.3 MMBtu/hr[3]	7,036 hr/yr	1.30 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	1.3 MMscf/yr[4]	6.2 MMBtu/hr	6,849 hr/yr	0.2 tpy
4	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	1.1 MMscf/yr[4]	6.2 MMBtu/hr	7,866 hr/yr	0.2 tpy
5	NATCO Natural Draft Burners	May 2003 Source Test	0.05 lb/hr	0.0 MMscf/yr[4]	6.2 MMBtu/hr	0 hr/yr	0.0 tpy
6	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	6.0 MMscf/yr[4]	8.0 MMBtu/hr	8,576 hr/yr	0.5 tpy
7	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	0.0 MMscf/yr[4]	8.0 MMBtu/hr	0 hr/yr	0.0 tpy
8	NATCO Natural Draft Burners	May 2003 Source Test	0.11 lb/hr	11.7 MMscf/yr[4]	8.0 MMBtu/hr	8,251 hr/yr	0.5 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	4.41 lb/MMBtu	25 gal/yr	160 hp	3 hr/yr	0.0 tpy[5]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	4.41 lb/MMBtu	460 gal/yr	519 hp	17 hr/yr	0.1 tpy[5]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.31 lb/MMBtu	36 MMscf/yr	1.92 MMscf/hr	8,576 hr/yr	6.0 tpy[6]
Storage Tanks							
12	Crude Tank No. 1	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential CO Emissions				**9.1 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.99 lb/MMBtu	27 gal/yr[7]	2 kW	100 hr/yr	0.0 tpy[8]
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.99 lb/MMBtu	27 gal/yr[7]	2 kW	100 hr/yr	0.0 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.99 lb/MMBtu	120 gal/yr	4 hp	100 hr/yr	0.0 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.99 lb/MMBtu	120 gal/yr	4 hp	100 hr/yr	0.0 tpy[8]
T-146	Utility Tank	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential CO Emissions				**0.0 tpy**

Table Notes:

1. EU IDs 1 and 2 CO emission factors were obtained from the results of the August 2019 Source Test. The highest result while operating above 50% load was used to be most conservative and it was increased by 10% to account for changes in load and temperature.
2. EU IDs 1 and 2 Maximum Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. EU IDs 3-8 Maximum Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
5. Diesel Engines emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
6. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
7. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
8. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D3-D. PM/PM10/PM2.5 Emissions
Expected Actual Annual Emissions Based on 2019 Actual Operating Data

ID	Emission Unit Name	Reference	PM_{Total} Emission Factor	PM_{10} Emission Factor	$PM_{2.5}$ Emission Factor	2019 Fuel Consumption	Maximum Capacity	2019 Operation	2019 PM_{Total} Emissions	2019 PM_{10} Emissions	2019 $PM_{2.5}$ Emissions
Turbine Generators (Fuel Gas)											
1	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	6.9E-03 lb/MMBtu[1]	2E-03 lb/MMBtu[1]	4.9E-03 lb/MMBtu[1]	103.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	1,724 hr/yr	0.3 tpy	0.1 tpy	0.2 tpy
2	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	6.9E-03 lb/MMBtu[1]	2E-03 lb/MMBtu[1]	4.9E-03 lb/MMBtu[1]	447.6 MMscf/yr[2]	55.3 MMBtu/hr[3]	7,036 hr/yr	1.4 tpy	0.4 tpy	1.0 tpy
Heaters (Fuel Gas)											
3	NATCO Natural Draft Burners	AP-42 Table 1.4-2	0 lb/MMscf	0 lb/MMscf	0 lb/MMscf	1.3 MMscf/yr[4]	6.2 MMBtu/hr	6,849 hr/yr	0.0 tpy	0.0 tpy	0.0 tpy
4	NATCO Natural Draft Burners	AP-42 Table 1.4-2	0 lb/MMscf	0 lb/MMscf	0 lb/MMscf	1.1 MMscf/yr[4]	6.2 MMBtu/hr	7,866 hr/yr	0.0 tpy	0.0 tpy	0.0 tpy
5	NATCO Natural Draft Burners	AP-42 Table 1.4-2	0 lb/MMscf	0 lb/MMscf	0 lb/MMscf	0.0 MMscf/yr[4]	6.2 MMBtu/hr	0 hr/yr	0.0 tpy	0.0 tpy	0.0 tpy
6	NATCO Natural Draft Burners	AP-42 Table 1.4-2	0 lb/MMscf	0 lb/MMscf	0 lb/MMscf	6.0 MMscf/yr[4]	8.0 MMBtu/hr	8,576 hr/yr	0.0 tpy	0.0 tpy	0.0 tpy
7	NATCO Natural Draft Burners	AP-42 Table 1.4-2	0 lb/MMscf	0 lb/MMscf	0 lb/MMscf	0.0 MMscf/yr[4]	8.0 MMBtu/hr	0 hr/yr	0.0 tpy	0.0 tpy	0.0 tpy
8	NATCO Natural Draft Burners	AP-42 Table 1.4-2	0 lb/MMscf	0 lb/MMscf	0 lb/MMscf	11.7 MMscf/yr[4]	8.0 MMBtu/hr	8,251 hr/yr	0.0 tpy	0.0 tpy	0.0 tpy
Engines (Diesel)											
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	25 gal/yr	160 hp	3 hr/yr	0.0 tpy	0.0 tpy	0.0 tpy
9a	Caterpillar 3406C	AP-42 Table 3.3-1	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	2.05E-03 lb/hp-hr	460 gal/yr	519 hp	17 hr/yr	0.0 tpy	0.0 tpy	0.0 tpy
Flare (Produced Gas and Fuel Gas)											
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.0264 lb/MMBtu	0.0264 lb/MMBtu	0.0264 lb/MMBtu	36 MMscf/yr	1.92 MMscf/hr	8,760 hr/yr	0.5 tpy[5]	0.5 tpy[5]	0.5 tpy[5]
Storage Tanks											
12	Crude Tank No. 1	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
13	Crude Tank No. 2	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
14	Crude Tank No. 3	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
15	Slop Oil Tank	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
16	Produced Water Tank	N/A	N/A	N/A	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
					Significant EUs Total Potential PM Emissions				**2.2 tpy**	**1.0 tpy**	**1.7 tpy**
Insignificant Emission Units											
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	27 gal/yr[6]	2 kW	100 hr/yr	0.00 tpy[7]	0.00 tpy[7]	0.00 tpy[7]
N/A	Gasoline Generator	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	27 gal/yr[6]	2 kW	100 hr/yr	0.00 tpy[7]	0.00 tpy[7]	0.00 tpy[7]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	120 gal/yr	4 hp	100 hr/yr	0.00 tpy[7]	0.00 tpy[7]	0.00 tpy[7]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	0.1 lb/MMBtu	0.1 lb/MMBtu	0.1 lb/MMBtu	120 gal/yr	4 hp	100 hr/yr	0.00 tpy[7]	0.00 tpy[7]	0.00 tpy[7]
T-146	Utility Tank	N/A	N/A	N/A	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
DF-01	Diesel Day Tank	N/A	N/A	N/A	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Pig Cooker Tank	N/A	N/A	N/A	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	N/A	N/A	N/A	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Cat 3406 Diesel Tank	N/A	N/A	N/A	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
T-214	Methanol Tank	N/A	N/A	N/A	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
N/A	Boiler Diesel Fuel Tank	N/A	N/A	N/A	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy	N/A tpy	N/A tpy
					Insignificant EUs Total Potential PM Emissions				**0.0 tpy**	**0.0 tpy**	**0.0 tpy**

Table Notes:

1. PM Emission Factors for EU IDs 1-8 are adjusted for the actual average heat rate from fuel gas testing in 2020 rather than the assumed rate of 1,020 Btu/scf noted in AP-42.
   Fuel Gas Heating Value = 1073.8 Btu/scf
2. EU IDs 1 and 2 Maximum Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. EU IDs 3-8 Maximum Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
7. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon

Table D3-E. VOC Emissions
Expected Actual Annual Emissions Based on 2019 Actual Operating Data

ID	Emission Unit Name	Reference	Emission Factor	2019 Fuel Consumption	Maximum Capacity	2019 Operation	2019 VOC Emissions
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu	103.2 MMscf/yr	58.2 MMBtu/hr[2]	1,724 hr/yr	0.11 tpy
2	Solar Taurus 60-T7301S Turbine	AP-42 Table 3.1-2a	2.1E-03 lb/MMBtu	447.6 MMscf/yr	55.3 MMBtu/hr[2]	7,036 hr/yr	0.41 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	1.3 MMscf/yr	6.2 MMBtu/hr	6,849 hr/yr	0.0 tpy
4	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	1.1 MMscf/yr	6.2 MMBtu/hr	7,866 hr/yr	0.0 tpy
5	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	0.0 MMscf/yr	6.2 MMBtu/hr	0 hr/yr	0.0 tpy
6	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	6.0 MMscf/yr	8.0 MMBtu/hr	8,576 hr/yr	0.0 tpy
7	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	0.0 MMscf/yr	8.0 MMBtu/hr	0 hr/yr	0.0 tpy
8	NATCO Natural Draft Burners	AP-42 Table 1.4-2	5.5 lb/MMscf	11.7 MMscf/yr	8.0 MMBtu/hr	8,251 hr/yr	0.0 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	AP-42 Table 3.3-1	0.35 lb/MMBtu	24.8 gal/yr	160 hp	3 hr/yr	0.00 tpy[4]
9a	Caterpillar 3406C	AP-42 Table 3.3-1	0.35 lb/MMBtu	460.1 gal/yr	519 hp	17 hr/yr	0.01 tpy[4]
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	AP-42 Table 13.5-1	0.14 lb/MMBtu	35.9 MMscf/yr	1.92 MMscf/day	8,760 hr/yr	2.7 tpy[5]
Storage Tanks							
12	Crude Tank No. 1	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.222 tpy[6]
13	Crude Tank No. 2	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.222 tpy[6]
14	Crude Tank No. 3	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.222 tpy[6]
15	Slop Oil Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.166 tpy[6]
16	Produced Water Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	0.111 tpy[6]
			Significant EUs Total Potential VOC Emissions				**3.3 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	2.1 lb/MMBtu	27 gal/yr[7]	2 kW	100 hr/yr	0.0 tpy[8]
N/A	Gasoline Generator	AP-42 Table 3.3-1	2.1 lb/MMBtu	27 gal/yr[7]	2 kW	100 hr/yr	0.0 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	2.1 lb/MMBtu	120 gal/yr	4 hp	100 hr/yr	0.0 tpy[8]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	2.1 lb/MMBtu	120 gal/yr	4 hp	100 hr/yr	0.0 tpy[8]
T-146	Utility Tank	EPA TANKS 4.09	N/A	N/A	21,000 gal	8,760 hr/yr	0.3 tpy
DF-01	Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	500 gal	8,760 hr/yr	0.0 tpy
N/A	Pig Cooker Tank	EPA TANKS 4.09	N/A	N/A	104 gal	8,760 hr/yr	0.0 tpy
T-156	Fire Water Pump Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	150 gal	8,760 hr/yr	0.0 tpy
N/A	Cat 3406 Diesel Tank	EPA TANKS 4.09	N/A	N/A	200 gal	8,760 hr/yr	0.0 tpy
T-214	Methanol Tank	EPA TANKS 4.09	N/A	N/A	10,000 gal	8,760 hr/yr	0.0 tpy
N/A	Boiler Diesel Fuel Tank	EPA TANKS 4.09	N/A	N/A	5,000 gal	8,760 hr/yr	0.0 tpy
			Insignificant EUs Total Potential VOC Emissions				**0.3 tpy**

Table Notes:

1. Potential Annual Emissions based on 2019 actual operating hours and fuel consumption. Note, Glacier Oil and Gas made the decision to start shutting in wells and putting the Cook Inlet facilities into a warm shutdown on May 4, 2002, due to the unprecedented events surrounding the COVID-19 pandemic. The facility was then put in a cold shutdown on October 27, 2020. Therefore, the 2019 operational data best represents normal operations at Kustatan Production Facility.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. EU IDs 3-8 Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
4. Diesel Engines emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. EU IDs 12-16 are part of a closed vent system that reduces VOC emissions by 95%.
7. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
8. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon
   Average BSFC = 7,000 Btu/hp-hr
   Engine Efficiency = 75%

Table D3-F. SO_2 Emissions
Expected Actual Annual Emissions Based on 2019 Actual Operating Data

ID	Emission Unit Name	Reference	Emission Factor[1]	2019 Fuel Consumption	Maximum Capacity	2019 Operation	2019 SO_2 Emissions[4,5]
Turbine Generators (Fuel Gas)							
1	Solar Taurus 60-T7301S Turbine	Mass Balance	140 ppmv H_2S	103.2 MMscf/yr[2]	58.2 MMBtu/hr[3]	1,724 hr/yr	1.22 tpy
2	Solar Taurus 60-T7301S Turbine	Mass Balance	140 ppmv H_2S	447.6 MMscf/yr[2]	55.3 MMBtu/hr[3]	7,036 hr/yr	5.29 tpy
Heaters (Fuel Gas)							
3	NATCO Natural Draft Burners	Mass Balance	140 ppmv H_2S	1.3 MMscf/yr[6]	6.2 MMBtu/hr	6,849 hr/yr	0.02 tpy
4	NATCO Natural Draft Burners	Mass Balance	140 ppmv H_2S	1.1 MMscf/yr[6]	6.2 MMBtu/hr	7,866 hr/yr	0.01 tpy
5	NATCO Natural Draft Burners	Mass Balance	140 ppmv H_2S	0.0 MMscf/yr[6]	6.2 MMBtu/hr	0 hr/yr	0.00 tpy
6	NATCO Natural Draft Burners	Mass Balance	140 ppmv H_2S	6.0 MMscf/yr[6]	8.0 MMBtu/hr	8,576 hr/yr	0.07 tpy
7	NATCO Natural Draft Burners	Mass Balance	140 ppmv H_2S	0.0 MMscf/yr[6]	8.0 MMBtu/hr	0 hr/yr	0.00 tpy
8	NATCO Natural Draft Burners	Mass Balance	140 ppmv H_2S	11.7 MMscf/yr[6]	8.0 MMBtu/hr	8,251 hr/yr	0.14 tpy
Engines (Diesel)							
9	Cummins 6BTA5.9	Mass Balance	0.015 wt% S	25 gal/yr	160 hp	3 hr/yr	0.00 tpy
9a	Caterpillar 3406C	Mass Balance	0.015 wt% S	460 gal/yr	519 hp	17 hr/yr	0.00 tpy
Flare (Produced Gas and Fuel Gas)							
10	Tornado TTI-SLT	Mass Balance	140 ppmv H_2S	36 MMscf/yr	1.92 MMscf/day	8,576 hr/yr	0.4 tpy[7]
Storage Tanks							
12	Crude Tank No. 1	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
13	Crude Tank No. 2	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
14	Crude Tank No. 3	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
15	Slop Oil Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
16	Produced Water Tank	EPA TANKS 4.09	N/A	N/A	10,000 bbls	8,760 hr/yr	N/A tpy
			Significant EUs Total Potential SO2 Emissions				**7.2 tpy**
Insignificant Emission Units							
N/A	Gasoline Generator	AP-42 Table 3.3-1	10 ppm	27 gal/yr[8]	2 kW	100 hr/yr	1.7E-06 tpy[9]
N/A	Gasoline Generator	AP-42 Table 3.3-1	10 ppm	27 gal/yr[8]	2 kW	100 hr/yr	1.7E-06 tpy[9]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	10 ppm	120 gal/yr	4 hp	100 hr/yr	7.6E-06 tpy[9]
N/A	Gasoline Trash Pump	AP-42 Table 3.3-1	10 ppm	120 gal/yr	4 hp	100 hr/yr	7.6E-06 tpy[9]
T-146	Utility Tank	EPA TANKS 4.09	N/A	N/A	21,000 gal	8,760 hr/yr	N/A tpy
DF-01	Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	500 gal	8,760 hr/yr	N/A tpy
N/A	Pig Cooker Tank	EPA TANKS 4.09	N/A	N/A	104 gal	8,760 hr/yr	N/A tpy
T-156	Fire Water Pump Diesel Day Tank	EPA TANKS 4.09	N/A	N/A	150 gal	8,760 hr/yr	N/A tpy
N/A	Cat 3406 Diesel Tank	EPA TANKS 4.09	N/A	N/A	200 gal	8,760 hr/yr	N/A tpy
T-214	Methanol Tank	EPA TANKS 4.09	N/A	N/A	10,000 gal	8,760 hr/yr	N/A tpy
N/A	Boiler Diesel Fuel Tank	EPA TANKS 4.09	N/A	N/A	5,000 gal	8,760 hr/yr	N/A tpy
			Insignificant EUs Total Potential SO_2 Emissions				**0.0 tpy**

Table Notes:

1. The highest H2S sample result of fuel gas combusted at the facility in 2019 was 140 ppm. The diesel deliveries received at the facility in 2019 never exceeded the ULSD standard of 15ppm S. The gasoline sulfur limit is based on the standard annual average of 10 ppm as specified in 40 CFR 80.1603.
2. EU IDs 1 and 2 Maximum Annual Fuel Capacity based on the average results of the 2019 Source Test Report at high load.
3. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
4. Mass balance of fuel gas is estimated based on the following assumptions:

1 lb mole of gas at standard temperature at 60º F and pressure 14.7 psia:	379.3	scf/lb-mole (Ideal gas conversion)
Conversions:	64	lb SO_2/lb-mole
	1	lb-mole H_2S/lb-mole SO_2

5. Mass balance of diesel fuel and gasoline emission units is estimated based on the following assumptions

Conversions:	64	lb SO_2/lb-mole
	32	lb S/64 lb SO_2
	7.05	lb/gal distillate fuel (AP-42 Appendix A, page A-7)
	0.76	SG of Marathon Unleaded gasoline (converted by 8.33 lb/gal water)

6. EU IDs 3-8 Maximum Annual Fuel Capacity calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
7. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.

   Fuel Gas Heating Value = 1073.8 Btu/scf

8. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
9. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.

   Gasoline Heating Value = 130,000 Btu/gallon

Table D3-G. CO2-e Emissions
Expected Actual Annual Emissions Based on 2019 Actual Operating Data

ID	Emission Unit Description	Reference (40 CFR 98)	CO2 Emission Factor	Reference (40 CFR 98)	CH4 Emission Factor	Reference (40 CFR 98)	N_2O Emission Factor	2019 Fuel Rate	Maximum Capacity	2019 Operation	2019 CO2-e Emissions[8]
Turbine Generators (Fuel Gas)											
1	Solar Taurus 60-T7301S Turbine	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.078 MMscf/hr[1]	58.2 MMBtu/hr[2]	1,724 hr/yr	8,209.2 tpy
2	Solar Taurus 60-T7301S Turbine	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.081 MMscf/hr[1]	55.3 MMBtu/hr[2]	7,036 hr/yr	31,830.0 tpy
Heaters (Fuel Gas)											
3	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	6,849 hr/yr	2,773.4 tpy
4	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	7,866 hr/yr	3,185.4 tpy
5	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.007 MMscf/hr[3]	6.2 MMBtu/hr	0 hr/yr	0.0 tpy
6	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	8,576 hr/yr	4,481.2 tpy
7	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	0 hr/yr	0.0 tpy
8	NATCO Natural Draft Burners	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Fuel Gas	0.003 kg/MMBtu	Table C-2 Fuel Gas	6.0E-04 kg/MMBtu	0.009 MMscf/hr[3]	8.0 MMBtu/hr	8,251 hr/yr	4,311.1 tpy
Engines (Diesel)											
9	Cummins 6BTA5.9	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	8.2 gal/hr	160.0 hp	3 hr/yr	0.3 tpy[4]
9a	Caterpillar 3406C	Table C-1 to Part C: Distillate Fuel Oil No. 2	73.96 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	14.2 gal/hr	519.0 hp	17 hr/yr	2.7 tpy[4]
Flare (Produced Gas and Fuel Gas)											
10	Tornado TTI-SLT	Table C-1 to Part C: Fuel Gas	59.00 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.9 MMscf/hr	1.9 MMscf/hr[5]	8,760 hr/yr	1,179,645.4 tpy
Storage Tanks											
12	Crude Tank No. 1	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
13	Crude Tank No. 2	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
14	Crude Tank No. 3	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
15	Slop Oil Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
16	Produced Water Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 bbls	8,760 hr/yr	0.0 tpy
								Significant Total Potential CO2-e Emissions			**1,234,438.7 tpy**
Insignificant Emission Units											
N/A	Generator	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.3 gal/hr[6]	2.0 kW	100 hr/yr	0.3 tpy[7]
N/A	Generator	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	0.3 gal/hr[6]	2.0 kW	100 hr/yr	0.3 tpy[7]
N/A	Trash Pump	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.2 gal/hr	4.0 hp	100 hr/yr	1.2 tpy[7]
N/A	Trash Pump	Table C-1 to Part C: Motor Gasoline	70.22 kg/MMBtu	Table C-2 Petroleum Products	0.003 kg/MMBtu	Table C-2 Petroleum Products	6.0E-04 kg/MMBtu	1.2 gal/hr	3.5 hp	100 hr/yr	1.2 tpy[7]
T-146	Utility Tank	NA	NA	NA	NA	NA	NA	N/A	21,000.0 gal	8,760 hr/yr	0.0 tpy
DF-01	Diesel Day Tank	NA	NA	NA	NA	NA	NA	N/A	500.0 gal	8,760 hr/yr	0.0 tpy
N/A	Pig Cooker Tank	NA	NA	NA	NA	NA	NA	N/A	104.0 gal	8,760 hr/yr	0.0 tpy
T-156	Fire Water Pump Diesel Day Tank	NA	NA	NA	NA	NA	NA	N/A	150.0 gal	8,760 hr/yr	0.0 tpy
N/A	Cat 3406 Diesel Tank	NA	NA	NA	NA	NA	NA	N/A	200.0 gal	8,760 hr/yr	0.0 tpy
T-214	Methanol Tank	NA	NA	NA	NA	NA	NA	N/A	10,000.0 gal	8,760 hr/yr	0.0 tpy
N/A	Boiler Diesel Fuel Tank	NA	NA	NA	NA	NA	NA	N/A	5,000.0 gal	8,760 hr/yr	0.0 tpy
								Insignificant EUs Total Potential CO2-e Emissions			**3.0 tpy**

Table Notes:

1. EU IDs 1 and 2 Maximum Fuel Consumption Rate based on the average results of the 2019 Source Test Report at high load.
2. EU IDs 1 and 2 Maximum Capacity is from the manufacturer's Certified Test Report.
3. EU IDs 3-8 Maximum Fuel Consumption Rate calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.
4. Diesel Engines emissions estimated based on the following assumptions:
   Diesel Heating Value = 137,000 Btu/gallon
5. Heating Value for fuel burned in EU ID 10 (Flare) was assumed to be the average heat rate from fuel gas testing in 2020.
   Fuel Gas Heating Value = 1073.8 Btu/scf
6. Honda Generators were reported to be 2000W Model S-351, assumed the same specs as Honda EU2000i generator with a GX100 engine.
7. Emissions are estimated using an assumed heating value of gasoline per AP-42 Appendix A.
   Gasoline Heating Value = 130,000 Btu/gallon
8. Global Warming Potentials listed in Table A-1 of 40 CFR 98 Subpart A were used to estimate the CO2e using the equation $CO_{2e} = CO_2 + 25*CH_4 + 298*N_2O$
   1 tonne (metric ton) = 907.18 kg
   GWP of CH_4 = 25
   GWP of N_2O = 298

Table D3-H. Hazardous Air Pollutant (HAP) Emissions Summary Table
Expected Actual Annual Emissions Based on 2019 Actual Operating Data

Hazardous Air Pollutant	Stationary Gas Turbines	Natural Gas External Emission Units	Diesel Engines ≤ 600 hp	Flare	Total HAP Emissions
1,3-Butadiene	3.9E-08		8.1E-04		8.1E-04
3-Methylcholanthrene				1.51E-04	1.5E-04
1,3-Butadiene	3.9E-08		8.1E-04		8.1E-04
2-Methylnaphthalene		3.3E-06		2.02E-03	2.0E-03
3-Methylcholanthrene		2.4E-07			2.4E-07
7,12- Dimethylbenz(a)anthracene				1.35E-03	1.3E-03
Acenaphthene		2.4E-07	3.0E-05	1.51E-04	1.8E-04
Acenaphthylene		2.4E-07	1.1E-04	1.51E-04	2.6E-04
Acetaldehyde	3.6E-06		1.6E-02		1.6E-02
Acrolein	5.8E-07		1.9E-03		1.9E-03
Anthracene		3.3E-07	3.9E-05	2.02E-04	2.4E-04
Benz(a)anthracene		2.4E-07		1.51E-04	1.5E-04
Benzene	1.1E-06	2.9E-04	1.9E-02	1.77E-01	2.0E-01
Benzo(a)anthracene			3.5E-05		3.5E-05
Benzo(a)pyrene		1.6E-07	3.9E-06	1.01E-04	1.0E-04
Benzo(b)fluoranthene		2.4E-07	2.1E-06	1.51E-04	1.5E-04
Benzo(g,h,i)perylene		1.6E-07		1.01E-04	1.0E-04
Benzo(k)fluoranthene		2.4E-07	3.2E-06	1.51E-04	1.5E-04
Butane		2.9E-01		1.77E+02	1.8E+02
Chrysene		2.4E-07	7.3E-06	1.51E-04	1.6E-04
Dibenz(a,h)anthracene			1.2E-05		1.2E-05
Dichlorobenzene		1.6E-04		1.01E-01	1.0E-01
Ethane		4.2E-01		2.61E+02	2.6E+02
Ethylbenzene	2.9E-06				2.9E-06
Fluoranthene		4.1E-07	1.6E-04	2.52E-04	4.1E-04
Fluorene		3.8E-07	6.1E-04	2.35E-04	8.4E-04
Formaldehyde	6.5E-05	1.0E-02	2.5E-02	6.31E+00	6.3E+00
Hexane		2.4E-01		1.51E+02	1.5E+02
Indeno(1,2,3-cd)pyrene		2.4E-07	7.8E-06	1.51E-04	1.6E-04
Naphthalene	1.2E-07	8.3E-05	1.8E-03	5.13E-02	5.3E-02
PAH	2.0E-07				2.0E-07
Pentane		3.5E-01		2.19E+02	2.2E+02
Phenanathrene		2.3E-06			2.3E-06
Propane		2.2E-01		1.35E+02	1.3E+02
Propylene			5.4E-02		5.4E-02
Propylene Oxide	2.6E-06				2.6E-06
Pyrene		6.8E-07	1.0E-04	4.20E-04	5.2E-04
Pyrene		6.8E-07	1.0E-04	4.20E-04	5.2E-04
Toluene	1.2E-05	4.6E-04	8.5E-03	2.86E-01	2.9E-01
Xylenes	5.8E-06		5.9E-03		5.9E-03
Total HAPs - Maximum Individual HAP	**6.5E-05**	**4.2E-01**	**5.4E-02**	**260.7**	**261.1**
Total HAPs Emissions	**9.4E-05**	**1.5**	**0.135**	**948.8**	**950.5**

Notes:

1. Detailed methodology and assumptions included with the individual emission unit category calculations in Tables D-9A(2) through D-9A(5).

Table D3-H(a). Hazardous Air Pollutant (HAP) Emissions

Expected Actual Annual Emissions Based on 2019 Actual Operating Data

Stationary Gas Turbines

Maximum Total Heat Input: 195,696.7 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]		Estimated Emissions	
106-99-0	1,3-Butadiene	4.30E-07	lb/MMscf	3.9E-08	tpy
75-07-0	Acetaldehyde	4.00E-05	lb/MMscf	3.6E-06	tpy
107-02-8	Acrolein	6.40E-06	lb/MMscf	5.8E-07	tpy
100-41-4	Benzene	1.20E-05	lb/MMscf	1.1E-06	tpy
203-96-8	Ethylbenzene	3.20E-05	lb/MMscf	2.9E-06	tpy
50-00-0	Formaldehyde	7.10E-04	lb/MMscf	6.5E-05	tpy
91-20-3	Naphthalene	1.30E-06	lb/MMscf	1.2E-07	tpy
	PAH	2.20E-06	lb/MMscf	2.0E-07	tpy
75-56-9	Propylene Oxide	2.90E-05	lb/MMscf	2.6E-06	tpy
108-88-3	Toluene	1.30E-04	lb/MMscf	1.2E-05	tpy
1330-20-7	Xylenes	6.40E-05	lb/MMscf	5.8E-06	tpy
		Total 2019 HAP Emissions:		**9.4E-05**	tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual	Maximum Capacity
1	Solar Taurus 60-T7301S Turbine	1724 hr	113.5 MMBtu/hr
2	Solar Taurus 60-T7301S Turbine	7036 hr	

Maximum Annual Fuel Consumption based on the average results of the 2019 Source Test Report at high load.
Maximum Capacity is from the manufacturer's Certified Test Report.

Fuel Gas Heating Value = 1073.8 Btu/scf

2. Emission Factors assumed from AP-42, Table 1.4-3 Emission Factors For Speciated Organic Compounds From Natural Gas

Table D1-H(b). Hazardous Air Pollutant (HAP) Emissions

Expected Actual Annual Emissions Based on 2019 Actual Operating Data

Natural Gas External Combustion Units

Maximum Total Heat Input: 291,746.1 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]		Estimated Emissions	
91-57-6	2-Methylnaphthalene	2.40E-05	lb/MMscf	3.3E-06	tpy
56-49-5	3-Methylcholanthrene	1.80E-06	lb/MMscf	2.4E-07	tpy
	7,12-Dimethylbenz(a)anthracene	1.60E-05	lb/MMscf	2.2E-06	tpy
83-32-9	Acenaphthene	1.80E-06	lb/MMscf	2.4E-07	tpy
203-96-8	Acenaphthylene	1.80E-06	lb/MMscf	2.4E-07	tpy
120-12-7	Anthracene	2.40E-06	lb/MMscf	3.3E-07	tpy
56-55-3	Benz(a)anthracene	1.80E-06	lb/MMscf	2.4E-07	tpy
71-43-2	Benzene	2.10E-03	lb/MMscf	2.9E-04	tpy
50-32-8	Benzo(a)pyrene	1.20E-06	lb/MMscf	1.6E-07	tpy
205-99-2	Benzo(b)fluoranthene	1.80E-06	lb/MMscf	2.4E-07	tpy
191-24-2	Benzo(g,h,i)perylene	1.20E-06	lb/MMscf	1.6E-07	tpy
207-08-9	Benzo(k)fluoranthene	1.80E-06	lb/MMscf	2.4E-07	tpy
106-97-8	Butane	2.10E+00	lb/MMscf	2.9E-01	tpy
218-01-9	Chrysene	1.80E-06	lb/MMscf	2.4E-07	tpy
53-70-3	Dibenzo(a,h)anthracene	1.20E-06	lb/MMscf	1.6E-07	tpy
25321-22-6	Dichlorobenzene	1.20E-03	lb/MMscf	1.6E-04	tpy
74-84-0	Ethane	3.10E+00	lb/MMscf	4.2E-01	tpy
206-44-0	Fluoranthene	3.00E-06	lb/MMscf	4.1E-07	tpy
86-73-7	Fluorene	2.80E-06	lb/MMscf	3.8E-07	tpy
50-00-0	Formaldehyde	7.50E-02	lb/MMscf	1.0E-02	tpy
B110-54-3	Hexane	1.80E+00	lb/MMscf	2.4E-01	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.80E-06	lb/MMscf	2.4E-07	tpy
91-20-3	Naphthalene	6.10E-04	lb/MMscf	8.3E-05	tpy
109-66-0	Pentane	2.60E+00	lb/MMscf	3.5E-01	tpy
85-01-8	Phenanathrene	1.70E-05	lb/MMscf	2.3E-06	tpy
74-98-6	Propane	1.60E+00	lb/MMscf	2.2E-01	tpy
129-00-0	Pyrene	5.00E-06	lb/MMscf	6.8E-07	tpy
108-88-3	Toluene	3.40E-03	lb/MMscf	4.6E-04	tpy
		Total 2019 HAP Emissions:		**1.5**	tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual		Maximum Capacity	
3	NATCO Natural Draft Burners	6849	hr		
4	NATCO Natural Draft Burners	7866	hr		
5	NATCO Natural Draft Burners	0	hr	42.6	MMBtu/hr
6	NATCO Natural Draft Burners	8576	hr		
7	NATCO Natural Draft Burners	0	hr		
8	NATCO Natural Draft Burners	8251	hr		

Maximum Annual Fuel Consumption calculated based on the average heat rate from fuel gas testing in 2020 of 1073.8 Btu/scf, an assumed 80% efficiency, and the rated design capacity of the unit.

Fuel Gas Heating Value = 1073.8 Btu/scf

2. Emission Factors assumed from AP-42, Table 1.4-3 Emission Factors For Speciated Organic Compounds From Natural Gas

Table D1-H(c). Hazardous Air Pollutant (HAP) Emissions

Expected Actual Annual Emissions Based on 2019 Actual Operating Data

Diesel Engines Up to or Equal to 600 Horsepower

Maximum Total Heat Input: 41,636.3 MMBtu/yr[1]

CAS No.	Chemical Name	Emission Factor[2]	Significant Units Estimated Emissions
	VOC HAP Emissions		**0.1 tpy**
106-99-0	1,3-Butadiene	3.91E-05 lb/MMBtu	8.1E-04 tpy
75-07-0	Acetaldehyde	7.67E-04 lb/MMBtu	1.6E-02 tpy
107-02-8	Acrolein	9.25E-05 lb/MMBtu	1.9E-03 tpy
71-43-2	Benzene	9.33E-04 lb/MMBtu	1.9E-02 tpy
50-00-0	Formaldehyde	1.18E-03 lb/MMBtu	2.5E-02 tpy
115-07-1	Propylene	2.58E-03 lb/MMBtu	5.4E-02 tpy
108-88-3	Toluene	4.09E-04 lb/MMBtu	8.5E-03 tpy
1330-20-7	Xylenes	2.85E-04 lb/MMBtu	5.9E-03 tpy
	Polycyclic Organic Matter (POM)		
	Polycyclic aromatic hydrocarbons (PAH)		**3.5E-03 tpy**
208-96-8	Acenaphthene	1.42E-06 lb/MMBtu	3.0E-05 tpy
83-32-9	Acenaphthylene	5.06E-06 lb/MMBtu	1.1E-04 tpy
120-12-7	Anthracene	1.87E-06 lb/MMBtu	3.9E-05 tpy
56-55-3	Benzo(a)anthracene	1.68E-06 lb/MMBtu	3.5E-05 tpy
50-32-8	Benzo(a)pyrene	1.88E-07 lb/MMBtu	3.9E-06 tpy
205-99-2	Benzo(b)fluoranthene	9.91E-08 lb/MMBtu	2.1E-06 tpy
191-24-2	Benzo(g,h,l)perylene	4.89E-07 lb/MMBtu	1.0E-05 tpy
207-08-9	Benzo(k)fluoranthene	1.55E-07 lb/MMBtu	3.2E-06 tpy
218-01-9	Chrysene	3.53E-07 lb/MMBtu	7.3E-06 tpy
53-70-3	Dibenz(a,h)anthracene	5.83E-07 lb/MMBtu	1.2E-05 tpy
206-44-0	Fluoranthene	7.61E-06 lb/MMBtu	1.6E-04 tpy
86-73-7	Fluorene	2.92E-05 lb/MMBtu	6.1E-04 tpy
193-39-5	Indeno(1,2,3-cd)pyrene	3.75E-07 lb/MMBtu	7.8E-06 tpy
91-20-3	Naphthalene	8.48E-05 lb/MMBtu	1.8E-03 tpy
85-01-8	Phenanthrene	2.94E-05 lb/MMBtu	6.1E-04 tpy
129-00-0	Pyrene	4.78E-06 lb/MMBtu	1.0E-04 tpy
		Total 2019 HAP Emissions:	**0.1** tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual Operating Hours	Maximum Capacity
9	Firewater Pump Engine	3 hr	160 hp
9a	Backup Generator	17 hr	519 hp

Average BSFC = 7,000 Btu/hp-hr

2. Emission Factors assumed from AP-42, Table 3.3-2, Speciated Organic Compound Emission Factors For Uncontrolled Diesel

Table D1-H(d). Hazardous Air Pollutant (HAP) Emissions

Expected Actual Annual Emissions Based on 2019 Actual Operating Data

Flare

CAS No.	Chemical Name	Emission Factor[2]		Estimated Emissions	
	VOC HAP Emissions			**948.7**	**tpy**
71-43-2	Benzene	2.1E-03	lb/MMscf	0.2	tpy
106-97-8	Butane	2.1	lb/MMscf	176.6	tpy
74-84-0	Ethane	3.1	lb/MMscf	260.7	tpy
50-00-0	Formaldehyde	7.5E-02	lb/MMscf	6.3	tpy
110-54-3	Hexane	1.8	lb/MMscf	151.4	tpy
91-20-3	Naphthalene	6.1E-04	lb/MMscf	5.1E-02	tpy
109-66-0	Pentane	2.6	lb/MMscf	218.6	tpy
74-98-6	Propane	1.6	lb/MMscf	134.6	tpy
108-88-3	Toluene	3.4E-03	lb/MMscf	0.3	tpy
91-57-6	2-Methylnaphthalene	2.4E-05	lb/MMscf	2.0E-03	tpy
N/A	**Polycyclic Organic Matter (POM)**				
	Polycyclic aromatic hydrocarbons (PAH)			**0.11**	**tpy**
56-49-5	3-Methylcholanthrene	1.8E-06	lb/MMscf	1.5E-04	tpy
	7,12- Dimethylbenz(a)anthracene	1.6E-05	lb/MMscf	1.3E-03	tpy
83-32-9	Acenaphthene	1.8E-06	lb/MMscf	1.5E-04	tpy
203-96-8	Acenaphthylene	1.8E-06	lb/MMscf	1.5E-04	tpy
120-12-7	Anthracene	2.4E-06	lb/MMscf	2.0E-04	tpy
56-55-3	Benz(a)anthracene	1.8E-06	lb/MMscf	1.5E-04	tpy
50-32-8	Benzo(a)pyrene	1.2E-06	lb/MMscf	1.0E-04	tpy
205-99-2	Benzo(b)fluoranthene	1.8E-06	lb/MMscf	1.5E-04	tpy
191-24-2	Benzo(g,h,i)perylene	1.2E-06	lb/MMscf	1.0E-04	tpy
207-08-9	Benzo(k)fluoranthene	1.8E-06	lb/MMscf	1.5E-04	tpy
218-01-9	Chrysene	1.8E-06	lb/MMscf	1.5E-04	tpy
53-70-3	Dibenzo(a,h)anthracene	1.2E-06	lb/MMscf	1.0E-04	tpy
25321-22-6	Dichlorobenzene	1.2E-03	lb/MMscf	1.0E-01	tpy
206-44-0	Fluoranthene	3.0E-06	lb/MMscf	2.5E-04	tpy
86-73-7	Fluorene	2.8E-06	lb/MMscf	2.4E-04	tpy
193-39-5	Indeno(1,2,3-cd)pyrene	1.8E-06	lb/MMscf	1.5E-04	tpy
85-01-8	Phenanathrene	1.7E-05	lb/MMscf	1.4E-03	tpy
129-00-0	Pyrene	5.0E-06	lb/MMscf	4.2E-04	tpy
		Total 2019 HAP Emissions:		**948.8**	tpy

Table Notes:

1. Total fuel based on estimated operating hours and assumptions below:

ID	Emission Unit Name	Estimated Annual		Maximum Capacity	
10	Tornado TTI-SLT	8760	hr	16,819.2	MMscf/yr
	Fuel Gas Htg. Value =	1050	Btu/scf		

2. Heating Value for fuel burned in EU ID 16 (Test Flare) was assumed to be the value for Natural Gas listed in AP-42 Appendix A-Typical Parameters of Various Fuels.

3. A representative fuel gas analysis was not available at the time this permit application was assembled. Therefore, the emission factors from AP-42 for Natural-Gas Fired External Combustion units.

E1 FORMS

Stationary Source-Wide Applicable Requirements

FORM E1
Stationary Source-Wide Applicable Requirements

Permit Number: AQ0741TVP04A

Stationary Source-Wide Applicable Requirements (*attach additional sheets as needed*):

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping, and Reporting Used to Determine Compliance
AQ0741TVP03, Rev. 1, Condition 15 AQ0741MSS03 Condition 5	Minor Permit No. AQ0741MSS02, Condition 4, 2/23/2015 18 AAC 50.326(a) 40 CFR 71.2 & 71.6(a)(1) & (3)	Preconstruction Permit Requirement	Ambient air quality standards compliance for the stationary source operation is demonstrated at the posted boundary specified in Cook Inlet Energy's Access Control Plan set out in Section 11. Establish and maintain ambient air boundaries as described in Section 11.	Yes	Reasonable Inquiry/Records Review
AQ0741TVP03, Rev. 1, Condition 16 AQ0741MSS03 Condition 6	Minor Permit No. AQ0741MSS02, Condition 5, 2/23/2015 18 AAC 50.326(a) 40 C.F.R. 71.2&71.6(a)(1) & (3)	SO_2 Requirements	Limit the fuel sulfur content of the diesel fuel burned at the Kustatan Production Facility to no greater than 0.5 percent by weight.	Yes	Monitor, record, and report in accordance with Conditions 12 and 13. (In accordance with Conditions 6.1 and 6.2 of the Minor Permit)
AQ0741TVP03, Rev. 1, Condition 20.1	18 AAC 50.055(a)	Visible Emissions	For insignificant emission units not listed in the permit do not cause or allow visible emissions to reduce visibility by more than 20 percent averaged over any six consecutive minutes.	Yes	Monitor, record, and report in accordance with Condition 20.4.
AQ0741TVP03, Rev. 1, Condition 20.2	18 AAC 50.055(b)(1)	Particulate Matter Standard	For insignificant emission units not listed in the permit do not cause or allow particulate matter to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Yes	Monitor, record, and report in accordance with Condition 20.4.
AQ0741TVP03, Rev. 1, Condition 21	18 AAC 50.035 & 50.040(a)(1) 40 C.F.R. 60.7(a) & 60.15(d), Subpart A	NSPS Subpart A	The Permittee shall furnish the Department and EPA written notification or, if acceptable to both the EPA and the Permittee, electronic notification, as follows: the date construction or reconstruction actual date of initial startup, physical or operational change to an existing facility, or replacement of any facility.	Yes	Records Review, notifications as required by 21.1-21.4

FORM E1
Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping, and Reporting Used to Determine Compliance
AQ0741TVP03, Rev. 1, Condition 38	18 AAC 50.040(b)(1) & (2)(F), & 50.326(j) 40 CFR 61, Subparts A & M, and Appendix A	Asbestos NESHAP	Comply with the requirements set forth in 40 C.F.R. 61.145, 61.150, and 61.152 of Subpart M, and the applicable sections set forth in 40 C.F.R. 61, Subpart A and Appendix A.	Yes	Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 39.1	18 AAC 50.040(d) & 50.326(j) 40 CFR 82, Subpart F	Protection of Stratospheric Ozone Subpart F	Comply with the standards for recycling and emissions reduction of refrigerants set forth in 40 C.F.R. 82, Subpart F.	Yes	Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 39.2	18 AAC 50.040(d) & 50.326(j) 40 CFR 82.174(b) through (d), Subpart F	Protection of Stratospheric Ozone Subpart G	Comply with the applicable prohibitions set out in 40 C.F.R. 82.174 (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).	Yes	Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 39.3	18 AAC 50.040(d) & 50.326(j) 40 CFR 82.270(b) through (f), Subpart H	Protection of Stratospheric Ozone Subpart H	The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.270 (Protection of Stratospheric Ozone Subpart H – Halon Emissions Reduction).	Yes	Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 40	18 AAC 50.040 (c)(1) & (j), & 50.326(j) 40CFR71.6(a)(3)(ii) 40 C.F.R. 63.1(b), 63.5(b)(4), 63.6(c)(1), & 63.10(b)(3)	NESHAP Applicability Determinations.	Determine rule applicability and designation of affected sources under NESHAPs for Source Categories (40 C.F.R. 63) in accordance with the procedures described in 40 C.F.R. 63.1(b) and 63.10(b)(3). If a source becomes affected by an applicable subpart of 40 C.F.R. 63, the Permittee shall comply with such standard by the compliance date established by the Administrator in the applicable subpart, in accordance with 40 C.F.R. 63.6(c).	Yes	Reasonable Inquiry/Records Review

FORM E1
Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping, and Reporting Used to Determine Compliance
AQ0741TVP03, Rev. 1, Condition 40.1	18 AAC 50.040(c)(1), 50.040(j), & 50.326(j) 40 C.F.R. 71.6(a)(3)(ii) 40 C.F.R. 63.1(b), 63.5(b)(4), 63.6(c)(1), & 63.10(b)(3)	NESHAP Applicability Determination	After the effective date of any relevant standard promulgated by the Administrator under 40 C.F.R. 63, an owner or operator who constructs a new affected source that is not major-emitting or reconstructs an affected source that is not major-emitting that is subject to such standard, or reconstructs a source such that the source becomes an affected source subject to the standard, must notify the Administrator and the Department of the intended construction or reconstruction. The notification must be submitted in accordance with the procedures in §63.9(b).	Yes	Notification to the Department as described in 40 CFR 63.9(b)
AQ0741TVP03, Rev. 1, Condition 41.1	18 AAC 50.326(j)(4) & 50.040(j) 40 CFR 60.13, 63.10(d) & (f)(1), and 71.6(c)(6)	NSPS and NESHAP Reports	Attach to the operating report required by Condition 75 for the period covered by the report, a copy of any NSPS and NESHAPs reports submitted to the U.S. Environmental Protection Agency (EPA) Region 10 unless a copy has already been provided to the Department at the time of submittal to EPA.	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 41.2	18 AAC 50.326(j)(4) & 50.040(j) 40 CFR 60.13, 63.10(d) & (f) and 71.6(c)(6)	NSPS and NESHAP Waivers	Upon request by the Department, provide a written copy of any EPA-granted alternative monitoring requirement, custom monitoring schedule or waiver of the Federal emission standards, recordkeeping, monitoring, performance testing, or reporting requirements. The Permittee shall keep a copy of each U.S. EPA issued monitoring waiver or custom monitoring schedule with the permit.	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 42 AQ0741MSS03 Condition12	18 AAC 50.326(j)(3), 50.345(a) & (e)	Standard Terms and Conditions	Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.	Not Applicable	Not Applicable
AQ0741TVP03, Rev. 1, Condition 43 AQ0741MSS03 Condition 13	18 AAC 50.326(j)(3) 50.345(a) & (f)	Standard Terms and Conditions	The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and re-issuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.	Not Applicable	Not Applicable
AQ0741TVP03, Rev. 1, Condition 44 AQ0741MSS03 Condition 14	18 AAC 50.326(j)(3) 50.345(a) & (g)	Standard Terms and Conditions	The permit does not convey any property rights of any sort, nor any exclusive privilege.	Not Applicable	Not Applicable

FORM E1
Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping, and Reporting Used to Determine Compliance
AQ0741TVP03, Rev. 1, Condition 45	18 AAC 50.326(j)(1), 50.400, & 50.403 AS 37.10.052(b) & AS 46.14.240	Administration Fees	The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-403.	Yes	Record review
AQ0741TVP03, Rev. 1, Condition 46	18 AAC 50.040(j)(3), 50.035, 50.326(j)(1), 50.346(b)(1), 50.410, & 50.420 40 CFR 71.5(c)(3)(ii)	Assessable Emissions	The Permittee shall pay to the Department an annual emission fee based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities 10 tons per year or greater.	Yes	Record review
AQ0741TVP03, Rev. 1, Condition 47	18 AAC 50.040(j)(3), 50.326(j)(1), 50.346(b)(1), 50.410, & 50.420 40 CFR 71.5(c)(3)(ii)	Assessable Emissions Estimate	Calculate assessable emissions and submit them to the Department by March 31 or plan to pay fees based on the potential emissions.	Yes	Record review
AQ0741TVP03, Rev. 1, Condition 49	18 AAC 50.045(a)	Dilution	The Permittee shall not dilute emissions with air to comply with this permit. Monitoring shall consist of an annual certification that the Permittee does not dilute emissions to comply with this permit.	Yes	Record review
AQ741TVP03, Rev. 1, Condition 50	18 AAC 50.045(d), 50.040(e), 50.326(j)(3), 50.346(c), & 50.055(g)	Fugitive Dust Prevention	Take reasonable precautions to prevent fugitive dust.	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 51	18 AAC 50.055(g)	Stack Injection	The Permittee shall not release materials other than process emissions, products of combustion or materials introduced to control pollutant emissions from a stack.	Yes	Reasonable Inquiry
AQ0741TVP03, Rev. 1, Condition 52	18 AAC 50.110, 50.040(e), 50.326(j)(3) & 50.346(a) 40 CFR 71.6(a)(3)	Air Pollution Prohibited	No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which interferes with the enjoyment of life or property	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 53	18 AAC 50.235(a), 50.326(j)(4), & 50.040(j)(4)] 40 CFR 71.6(c)(6)	Technology-Based Emission Standard	During an unavoidable emergency, malfunction, or non-routine repair, the Permittee shall take reasonable steps to minimize emissions.	Yes	Reasonable Inquiry/Record Review

FORM E1
Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping, and Reporting Used to Determine Compliance
AQ0741TVP03, Rev. 1, Condition 54	18 AAC 50.065, 50.040(j), & 50.326(j) 40 CFR 71.6(a)(3)	Open Burning	The Permittee conducts open burning and shall comply with the requirements of 18 AAC 50.065.	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 55 through 64	18 AAC 50.220(a) & 50.345(a) & (k)	Source Testing	General source testing and monitoring requirements	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 65	18 AAC 50.040(a)(1) & 50.326(j) 40 C.F.R 60.7(f), Subpart A, 40 CFR 71.6(a)(3)(ii)(B)	Recordkeeping	Keep all applicable records for at least five years.	Yes	Record Review
AQ0741TVP03, Rev. 1, Condition 66	18 AAC 50.345(a) & (j), 50.205, & 50.326(j) 40 C.F.R. 71.6(a)(3)(iii)(A)	Certification	Certify all reports, compliance certifications or other documents.	Yes	Record Review
AQ0741TVP03, Rev. 1, Condition 67	18 AAC 50.326(j) 40 CFR 71.6(a)(3)(iii)(A)	Submittals	Submit two copies of reports, compliance certifications and other submittals required by the permit to the Department.	Yes	Record Review
AQ0741TVP03, Rev. 1, Condition 68	18 AAC 50.326(j) 40 CFR 71.6(a)(3)(iii)(A)	Information Requests	Furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke and reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the Federal Administrator.	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 69	18 AAC 50.235(a)(2), 50.240(c), 50.326(j)(3), & 50.346(b)(2) & (3)	Excess Emissions and Permit Deviations Reports	Report all emissions or operations that exceed or deviate from the permit.	Yes	Reasonable Inquiry/Records Review
AQ0741TVP03, Rev. 1, Condition 70	18 AAC 50.346(b)(6) & 50.326(j) 40 CFR 71.6(a)(3)(iii)(A)	Operating Reports	Compile and submit to the Department operating reports.	Yes	Records Review

FORM E1
Stationary Source-Wide Applicable Requirements

Permit and Condition Number	Applicable Requirement Citation[1]	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Monitoring, Recordkeeping, and Reporting Used to Determine Compliance
AQ0741TVP03, Rev. 1, Condition 71	18 AAC 50.205, 50.345(a) & (j), & 50.326(j) 40 CFR 71.6(c)(5)	Annual Compliance Certification	Compile and submit to the Department an annual compliance certification report.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 72	18 AAC 50.346(b)(8) & 50.200 40 C.F.R. 51.15, 51.30(a)(1) & (b)(1), & 40 CFR 51, Appendix A to Subpart A	Emission Inventory Reporting	The Permittee shall conduct Emission Inventory Reporting every three years.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 73	18 AAC 50.040(j)(7), 50.326(a) & 50.346(b)(7) 40 CFR 71.10(d)(1)	Permit Applications and Submittals	The Permittee shall submit permit modifications and renewals to the Department and U.S. EPA.	Yes	Records Review
AQ0741TVP03, Rev. 1, Condition 74	18 AAC 50.040(j)(4) & 50.326(j) 40 CFR 71.6(a)(8)	Emissions Trading	No permit revisions shall be required for changes that are provided for in the permit.	Not Applicable	Not Applicable
AQ0741TVP03, Rev. 1, Condition 75	18 AAC 50.040(j)(4) & 50.326(j) 40 CFR 71.6(a)(12)	Off Permit Changes	The Permittee shall make changes that are not address or prohibited by this permit.	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 76	18 AAC 50.040(j)(4) & 50.326(j) 18 AAC 50.040(j)(4) & 50.326(j)	Operational Flexibility	The Permittee may make changes if the changes are not modifications under Title I and do not exceed the allowable emissions.	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 77	18 AAC 50.040(j)(3), 50.326(c) & (j)(2) 40 C.F.R. 71.5(a)(1)(iii) & 71.7(b) & (c)(1)(ii)	Permit Renewal	The Permittee shall submit an application between six and 18 months before the permit expires.	Yes	Reasonable Inquiry/Record Review
AQ0741TVP03, Rev. 1, Condition 78-83 AQ0741MSS03 Conditions 10 & 11	18 AAC 50.040, 50.326(j) & 50.345	General Compliance Requirements	The Permittee shall comply with each permit term and condition and allow the Department access to the facility.	Yes	Reasonable Inquiry/Record Review

[1] Citations must be specific. Include sub-paragraph level detail [e.g. 18 AAC 50.055(a)(1), or 40 C.F.R. 60.332(a)(2).]

E3 Form

Condition Change Request

FORM E3

Title V Condition Change Request

Permit Number: AQ0741TVP04A

Title V Permit Information (attach additional sheets as needed):

Current Title V Operating Permit Condition Number	Type of Change (Revise or Remove)	Reason for Change	Requested Alaska Title V Operating Condition
AQ0741TVP03 Rev. 1 Condition 14.3	Revise	Condition 14.3 requires that both the "raw" fuel gas and the "lean" fuel gas be analyzed, recorded, and reported in the Semiannual Facility Operating Reports. However, all of the produced gas, categorized as "raw" fuel gas in the permit, is sent to the Cook Inlet Energy, LLC Gas Pipeline to be mixed with sales gas before being piped back to the facility's fuel gas emission units. Therefore, Cook Inlet Energy, LLC is requesting that the requirement to test both "raw" and "lean" gas be removed and replaced with a requirement to just sample fuel representative of the fuel combusted in the facility's emission units.	Fuel Gas Sulfur Compounds Monitoring. For EU IDs 1, 2, 2a, 3 through 8, and 10, the Permittee shall analyze a representative sample of each fuel (raw fuel gas and lean fuel gas) monthly to determine the H2S content using either ASTM D4810-88 (Reapproved 1999), D4913-89 (Reapproved 1995), or a listed method approved in 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).

E4 FORM
Permit Shield Requests

FORM E4

Permit Shield Request

Permit Number: AQ0741TVP04A

Non-applicable requirements (*attach additional sheets as needed*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
18 AAC 50.055, Industrial processes and fuel burning equipment	Nonroad (mobile) internal combustion engines are not included in the definition of fuel-burning equipment under 18 AAC 50.990.
40 CFR 60 Subparts B, C, Cb, Cc, Cd, Ce, Cf, D, E, Ea, Ea, Eb, Ec, F, G, Ga, H, I, K, Ka, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, BBa, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, VVa, WW, XX, AAA, BBB, DDD, FFF, HHH, III, JJJ, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, WWW, XXX, BBBB, DDDD, FFFF, JJJJ, KKKK, LLLL, MMMM, QQQQ, TTTT, and UUUU	No affected emission units exist within the stationary source or not an affected stationary source, operation, or industry, including, no incinerator onsite.
40 CFR 60 Subparts J, Ja, GGG, GGGa, QQQ	Stationary source does not meet the definition for a petroleum refinery.
40 C.F.R. 60, NSPS- All portions of Subpart Kb except 60.116b(b)	Volatile Organic Liquid (VOL) tanks store organic liquids with vapor pressures less than 3.5 kilopascals.
40 CFR 60 Subpart KKK	Stationary source is not an onshore natural gas processing plant as defined in Subpart KKK.
40 CFR 60 Subpart LLL	Stationary source does not operate natural gas sweetening units.
40 CFR 60 Subparts AAAA, CCCC, and EEEE	Incinerators have not commenced construction, modification, or reconstruction after August 30, 1999.
40 CFR 60 Subparts OOOO and OOOOa	Stationary source is not located onshore.

FORM E4

Permit Shield Request

Permit Number: AQ0741TVP04A

Non-applicable requirements (*attach additional sheets as needed*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 CFR 61 Subpart B, C, D, E, F, H, I, K, L, N, O, P, Q, R, T, and W	No affected emission units exist within the stationary source or not an affected stationary source, operation, or industry.
40 CFR 61 Subpart J	Stationary source does not contain any equipment in benzene service (≥10% by weight).
40 CFR 61 Subpart V	Stationary source does not operate equipment in volatile hazardous air pollutant (VHAP) service, as defined under 40 CFR 61.241 (≥10 percent VHAP by weight).
40 CFR 61 Subpart Y	Stationary source does not operate storage vessels in benzene service.
40 CFR 61 Subpart BB	Stationary source does not conduct benzene transfer operations.
40 CFR 61 Subpart FF	Stationary source does not conduct benzene water operations.
40 C.F.R. 61, NESHAPs – All subparts of Subpart M except 61.145, 61.150, and 61.152	Stationary source does not engage in activities regulated by other sections of Subpart M.
40 CFR 62	Stationary souce does not operate any affected emission units and is not an affected source, operation, or industry.
40 CFR 63 Subparts, F, G, H, I, J, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, II, JJ, KK, LL, MM, NN, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, YYYY, AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS, TTTTT, UUUUU, WWWWW, YYYYY, ZZZZZ, BBBBBB, CCCCCC, DDDDDD, EEEEEE, FFFFFF, GGGGGG, HHHHHH, LLLLLL, MMMMMM, NNNNNN, OOOOOO, PPPPPP, QQQQQQ, RRRRRR, SSSSSS, TTTTTT, VVVVVV, WWWWWW, XXXXXX, YYYYYY, ZZZZZZ, AAAAAAA, BBBBBBB, CCCCCCC, DDDDDDD, EEEEEEE, HHHHHHH	Stationary souce does not operate any affected emission units and is not an affected source, operation, or industry.

FORM E4
Permit Shield Request

Permit Number: AQ0741TVP04A

Non-applicable requirements (*attach additional sheets as needed*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
40 C.F.R. 63, NESHAPs – Subparts HH	The stationary source exclusively processes, stores, or transfers black oil (63.760(e)(1)).
40 C.F.R. 68	Stationary source does not have more than the threshold quantity of a regulated substance in process.
40 C.F.R. 82, Subpart A	Stationary source does not produce, transform, destroy, import or export Class I or Group I or II substances or products.
40 C.F.R. 82.30, Subpart B	Stationary source and its employees do not perform service on motor vehicle air conditioners, for consideration or otherwise.
40 C.F.R. 82.60, Subpart C	Stationary source is not a manufacturer or distributor of Class I and II products or substances.
40 C.F.R. 82.80, Subpart D	Subpart applies only to Federal Departments, agencies, and instrumentalities.
40 C.F.R. 82.100, Subpart E	Stationary source is not a manufacturer or distributor of Class I and II products or substances.
40 C.F.R. 82.158 Subpart F	Stationary source does not manufacture or import recovery and recycling equipment.
40 C.F.R. 82.160	Stationary source does not contain commercial, industrial, or comfort air conditioning appliances containing ozonedepleting substances used as refrigerant.
40 C.F.R. 82.164	Stationary source does not sell reclaimed refrigerant.
40 C.F.R. 82, Subpart F, Appendix C	Stationary source is not a third party entity that certifies recovery equipment.
40 C.F.R. 82 Subpart F, Appendix D	Stationary source does not have a technician certification program.
40 C.F.R. 82.174(a), Subpart G	Stationary source does not manufacture substitute chemicals or products for ozone-depleting compounds.
40 C.F.R. 82.270(a), Subpart H	Stationary source does not manufacture halon.
18 AAC 50.050(b)	No incinerators are located at the facility.
18 AAC 50.055	The standards do not apply to the non-road engines. The non-road engines are not “industrial processes” or “fuel burning equipment” as defined in 18 AAC 50.990(39) or (49).
18 AAC 50.055(a)(2)	The emission units were not described in cited regulations or in operation before November 1982.
18 AAC 50.055(a)(3)-(9)	Stationary source has no emission units as described in cited regulations.
18 AAC 50.055(b)(2)-(6)	Stationary source has no emission units as described in cited regulations.
18 AAC 50.055(d)-(f)	The stationary source does not contain sources subject to these sulfur standards.
18 AAC 50.060, 50.070, 50.085, 50.090	Stationary source does not belong to the affected sources regulated by these standards.

FORM E4

Permit Shield Request

Permit Number: AQ0741TVP04A

Non-applicable requirements (*attach additional sheets as needed*):

Non-Applicable Requirements[1]	Reason for non-applicability and citation/basis
18 AAC 50.075, 50.076, 50.077	Stationary source has no emission units as described incited regulations.
40 CFR 82 Subpart B	Stationary source and its employees do not perform service on motor vehicle air conditioners, for consideration or otherwise.
40 CFR 82 Subpart F	Stationary source does not contain commercial, industrial, or comfort air conditioning appliances containing ozone depleting substances used as refrigerant.

2020 Annual Compliance Certification

AQ0741TVP03, Revision 1, AQ0741MSS03, and AQ0741MSS04

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
AQ0741MSS03 Condition 1	The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.	Records Review and Interview with Responsible Personnel	Continuous	None
Section 3. State Requirements				
Visible Emissions Standards				
1 AQ0741MSS02 Condition 9 AQ0741MSS04 Condition 5	**Industrial Process and Fuel-Burning Equipment Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes. **AQ0741MSS04 adds EUs 17 and 18 to this condition.**	Records Review and Interview with Responsible Personnel	Continuous	None
1.1	For EU IDs 1 through 8, burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Interview with Responsible Personnel	Continuous	None
1.2	For EU ID 9, as long as the emissions unit does not operate for more than 500 hours in a calendar year, monitoring shall consist of an annual compliance certification under Condition 71 with the visible emissions standard. Otherwise, monitor, record and report in accordance with Conditions 2 - 4 for the remainder of the permit term. a. Monitor and record the monthly and calendar year-to-date operating hours. b. Report the calendar year-to-date operating hours in the operating report under Condition 70 for the period covered by the report.	Records Review and Interview with Responsible Personnel	Continuous	None
1.3	For EU ID 9a, as long as the emissions unit does not operate for more than 243 hours in a consecutive 12 months period, monitoring shall consist of an annual compliance certification under Condition 71 with the visible emissions standard. Otherwise, monitor, record and report in accordance with Conditions 2 - 4 for the remainder of the permit term. a. Report the consecutive 12 months operating hours for each month, as described in Condition 17.3.b.	Records Review and Interview with Responsible Personnel	Continuous	None
1.4	For EU ID 10, monitor, record and report in accordance with Condition 5.	Records Review	Continuous	None

Annual Compliance Certification Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04 Kustatan Production Facility January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
Visible Emissions Monitoring, Recordkeeping and Reporting *Liquid Fuel-Fired Emission Units (EU IDs 9 and 9a)*				
2	**Visible Emissions Monitoring.** When required by any of Conditions 1.2 or 1.3, or in the event of replacement of any of EU IDs 9 and 9a during the permit term, the Permittee shall observe the exhaust of the emissions unit for visible emissions using either the Method 9 Plan under Condition 2.3 or the Smoke/No-Smoke Plan under Condition 2.4.	Records Review	Continuous	None
2.1	The Permittee may change visible emissions monitoring plan for an emissions unit at any time unless prohibited from doing so by Condition 2.5.			
2.2	The Permittee may for each unit elect to continue the visible emissions monitoring schedule in effect from the previous permit at the time a renewed permit is issued, if applicable.			
2.3	**Method 9 Plan.** For all 18-minute observations in this plan, observe exhaust, following 40 C.F.R. 60, Appendix A-4, Method 9, adopted by reference in 18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.			
2.3 a.)	**First Method 9 Observation.** Except as provided in Condition 2.2 or Condition 2.5.c(ii), for EU IDs 9 and 9a, observe exhaust for 18 minutes within six months after the issue date of this permit. For any emissions unit, observe exhaust for 18 minutes within 14 calendar days after changing from the Smoke/No-Smoke Plan of Condition 2.4. (i) For any emissions unit replaced during the term of this permit, observe exhaust for 18 minutes within 30 days of startup. (ii) For each existing emissions unit that exceeds the applicable operational threshold in Conditions 1.2 or 1.3, observe the exhaust for 18 minutes of operations within 30 days after the calendar month during which that threshold has been exceeded, or within 30 days of the unit's next scheduled operations, whichever is later.			
2.3 b.)	**Monthly Method 9 Observations.** After the first Method 9 observation, perform 18-minute observations at least once in each calendar month that an emissions unit operates.			
2.3 c.)	**Semiannual Method 9 Observations.** After observing emissions for three consecutive operating months under Condition 2.3.b, unless a six-minute average is greater than 15 percent and one or more observations are greater than 20 percent, perform 18-minute observations: (i) within six months after the preceding observation, or (ii) for an emissions unit with intermittent operations, within 30 days of startup following six months after the preceding observation.			
2.3 d.)	**Annual Method 9 Observations.** After at least two semiannual 18-minute observations, unless a six-minute average is greater than 15 percent and one or more individual observations are greater than 20 percent, perform 18- minute observations: (i) within 12 months after the preceding observation; or (ii) for an emissions unit with intermittent operations, within 30 days of startup following twelve months after the preceding observation			
2.3 e.)	**Increased Method 9 Frequency.** If a six-minute average opacity is observed during the most recent set of observations to be greater than 15 percent and one or more observations are greater than 20 percent, then increase or maintain the 18-minute observation frequency for that emissions unit to at least monthly intervals as described in Condition 2.3.b, until the criteria in Condition 2.3.c for semiannual monitoring are met.			
2.4	**Smoke/No Smoke Plan.** Observe the exhaust for the presence or absence of visible emissions, excluding condensed water vapor. a. **Initial Monitoring Frequency.** Observe the exhaust during each calendar day that an emission unit operates. b. **Reduced Monitoring Frequency.** After the emission unit has been observed on 30 consecutive operating days, if the emission unit operated without visible smoke in the exhaust for those 30 days, then observe emissions at least once in every calendar month that an emission unit operates. c. **Smoke Observed.** If smoke is observed, either begin the Method 9 Plan of Condition 2.1 or perform the corrective action required under Condition 2.3	Records Review	Continuous	None

Annual Compliance Certification
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04
Kustatan Production Facility
January 1-December 31, 2020

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
2.5	**Corrective Actions Based on Smoke/No Smoke Observations.** If visible emissions are present in the exhaust during an observation performed under the Smoke/No Smoke Plan of Condition 2.4, then the Permittee shall either follow the Method 9 Plan of Condition 2.3 or a. initiate actions to eliminate smoke from the emissions unit within 24 hours of the observation; b. keep a written record of the starting date, the completion date, and a description of the actions taken to reduce smoke; and c. after completing the actions required under Condition 2.5.a, (i) make smoke/no smoke observations in accordance with Condition 2.4 (A) at least once per day for the next seven operating days and until the initial 30 day observation period is completed; and (B) continue as described in Condition 2.4.b; or (ii) if the actions taken under Condition 2.5.a do not eliminate the smoke, or if subsequent smoke is observed under the schedule of Condition 2.5.c(i)(A), then observe the exhaust using the Method 9 Plan unless the Department gives written approval to resume observations under the Smoke/No Smoke Plan; after observing smoke and making observations under the Method 9 Plan, the Permittee may at any time take corrective action that eliminates smoke and restart the Smoke/No Smoke Plan under Condition 2.4.a.	Records Review	Continuous	None
3	**Visible Emissions Recordkeeping.** When required by any of Conditions 1.2 or 1.3, or in the event of replacement of any of EU IDs 9 and 9a during the permit term, the Permittee shall keep records as follows:	Records Review	Continuous	None
3.1	If using the Method 9 Plan of Condition 2.3, a. the observer shall record (i) the name of the stationary source, emissions unit and location, emissions unit type, observer's name and affiliation, and the date on the Visible Emissions Observation Form in Section 11; (ii) the time, estimated distance to the emissions location, sun location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), plume background, and operating mode (load or fuel consumption rate or best estimate if unknown) on the sheet at the time opacity observations are initiated and completed; (iii) the presence or absence of an attached or detached plume and the approximate distance from the emissions outlet to the point in the plume at which the observations are made; (iv) opacity observations to the nearest five percent at 15-second intervals on the Visible Emission Observation Form in Section 11, and (v) the minimum number of observations required by the permit; each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period. b. To determine the six-minute average opacity, divide the observations recorded on the record sheet into sets of 24 consecutive observations; sets need not be consecutive in time and in no case shall two sets overlap; for each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24; record the average opacity on the sheet.			
3.2	If using the Smoke/No Smoke Plan of Condition 2.4, record the following information in a written log for each observation and submit copies of the recorded information upon request of the Department: a. the date and time of the observation; b. from Table A, the ID of the emissions unit observed; c. whether visible emissions are present or absent in the exhaust; d. a description of the background to the exhaust during the observation; e. if the emissions unit starts operation on the day of the observation, the startup time of the emissions unit; f. name and title of the person making the observation; and g. operating rate (load or fuel consumption rate).			
4	**Visible Emissions Reporting.** When required by any of Conditions 1.2 or 1.3, or in the event of replacement of any of EU IDs 9 or 9a during the permit term, the Permittee shall report visible emissions as follows:	Records Review	Continuous	None
4.1	Include in each operating report required under Condition 70: a. which visible emissions plan of Condition 2 was used for each emissions unit; if more than one plan was used, give the time periods covered by each plan; b. for each emissions unit under the Method 9 Plan, (i) copies of the observation results (i.e. opacity observations) for each emissions unit that used the Method 9 Plan, except for the observations the Permittee has already supplied to the department; and (ii) a summary to include: (A) number of days observations were made; (B) highest six-minute and 18-consecutive-minute averages observed; and (C) dates when one or more observed six-minute averages were greater than 20 percent; c. for each emissions unit under the Smoke/No Smoke Plan, the number of days that smoke/no smoke observations were made and which days, if any, that smoke was observed; and d. a summary of any monitoring or recordkeeping required under Conditions 2 and 3			
4.2	Report under Condition 69: a. the results of Method 9 observations that exceed an average of 20 percent opacity for any six-minute period; and b. if any monitoring under Condition 2 was not performed when required, report within three days of the date the monitoring was required.			

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
Flares (EU ID 10)				
5	**Visible Emissions MR&R.** The Permittee shall observe one daylight flare event[1] within 12 months of the preceding flare event observation. If no event exceeds 1 hour within that 12-month period, then the Permittee shall observe the next daylight flare event. [1] For purposes of this permit, a "*flare event*" is flaring of gas for greater than one hour as a result of scheduled release operations, i.e. maintenance or well testing activities. It does not include non-scheduled release operations, i.e. process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations.	Records Review	Continuous	None
5.1	Monitor visible emissions during flare events using Method 9 for 18 minutes.			
5.2	Record the following information for observed events: a. the flare EU ID number; b. results of the Method-9 observations; c. reason(s) for flaring; d. date, beginning and ending time of event; and e. volume of gas flared.			
5.3	Monitoring of a flare event may be postponed for safety or weather reasons, or because a qualified observer is not available. If monitoring of a flare event is postponed for any of the reasons described in this condition, the Permittee shall include in the next operating report required by Condition 70 an explanation of the reason the event was not monitored.			
5.4	Attach copies of the records required by Condition 5.2 with the operating report required by Condition 70 for the period covered by that report.			
5.5	Report under Condition 69 whenever the opacity standard in Condition 1 is exceeded.			
Particulate Matter Emissions Standards				
6 AQ0741MSS02 Condition 10	**Industrial Process and Fuel-Burning Equipment Particulate Matter.** The Permittee shall not cause or allow particulate matter emitted from EU EU IDs 1 through 10 listed in Table A to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Records Review and Interview with Responsible Personnel	Continuous	None
6.1	For EU IDs 1 through 8, burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions units fired only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.	Interview with Responsible Personnel	Continuous	None
6.2	For EU ID 9, as long as the emissions unit does not operate for more than 500 hours in a calendar year, monitoring shall consist of an annual compliance certification under Condition 71 with the particulate matter emissions standard. Otherwise, monitor, record and report in accordance with Conditions 7 - 9 for the remainder of the permit term for that emissions unit. a. Comply with Conditions 1.2.a and 1.2.b	Records Review	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
6.3	For EU 9a, as long as the emissions unit does not operate for more than 243 hours in a consecutive 12 months period, monitoring shall consist of an annual compliance certification under Condition 71 with the particulate matter emissions standard. Otherwise, monitor, record and report in accordance with Conditions 7 - 9 for the remainder of the permit term for that emissions unit. a. Comply with Condition 1.3.a.	Records Review	Continuous	None
6.4	For EU ID 10, the Permittee must annually certify compliance under Condition 71 with the particulate matter standard.	Records Review	Continuous	None
PM Monitoring, Recordkeeping and Reporting *Liquid Fuel-Fired Engines (EU IDs 9 and 9a)*				
7	**Particulate Matter Monitoring.** The Permittee shall conduct source tests on diesel engines, EU IDs 9 and 9a, to determine the concentration of particulate matter in the exhaust of each emissions unit as follows:	Records Review	Continuous	None
7.1	Except as exempted in Condition 7.4, within six months of exceeding the criteria of Conditions 7.2.a or 7.2.b, either a. conduct a particulate matter source test according to requirements set out in Section 6; or b. make repairs so that emissions no longer exceed the criteria of Condition 7.2; to show that emissions are below those criteria, observe visible emissions as described in Condition 2.3 under load conditions comparable to those when the criteria were exceeded.			
7.2	Conduct the particulate matter source test or make repairs according to Condition 7.1 if a. 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity greater than 20 percent; or b. for an emissions unit with an exhaust stack diameter that is less than 18 inches, 18 consecutive minutes of Method 9 observations result in an 18- minute average opacity that is greater than 15 percent and not more than 20 percent, unless the Department has waived this requirement in writing.			
7.3	During each one-hour particulate matter source test run, observe the exhaust for 60 minutes in accordance with Method 9 and calculate the average opacity that was measured during each one-hour test run. Submit a copy of these observations with the source test report.			
7.4	The automatic particulate matter source test requirements in Conditions 7.1 and 7.2 are waived for an emissions unit if a particulate matter source test on that unit has shown compliance with the particulate matter standard during this permit term.			
8	**Particulate Matter Recordkeeping.** The Permittee shall keep records of the results of any particulate matter testing and visible emissions observations conducted under Condition 7.	Records Review and Interview with Responsible Personnel	Continuous	None
9	**Particulate Matter Reporting for Diesel Engines.** The Permittee shall report as follows:	Records Review and Interview with Responsible Personnel	Continuous	None
9.1	Report under Condition 69 a. within 30 days of the end of the month in which the source testing occur, if the results of any particulate matter source test conducted under Condition 7.1.a exceeds the particulate matter emissions limit; or b. within the next 24 hours of the date compliance with Condition 7.1 was required, if the Permittee did not comply with either Condition 7.1.a or 7.1.b when required;			
9.2	Report observations in excess of the threshold of Condition 7.2.b within 30 days of the end of the month in which the observations occur;			
9.3	In each operating report under Condition 70, include: a. the dates, EU ID(s), and results when an observed 18-minute average was greater than an applicable threshold in Condition 7.2; b. a summary of the results of any particulate matter testing under Condition 7; and c. copies of any visible emissions observation results (opacity observations) greater than the thresholds of Condition 7.2, if they were not already submitted.			
Sulfur Compound Emission Standards Requirements				
10 AQ0741MSS02 Condition 11	**Sulfur Compound Emissions.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.	Records Review	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
Sulfur Compound MR&R				
11	**Sulfur Content of Fuel Oil.** The Permittee shall comply with Condition 16. *Condition 16-SO2 Requirements. Limit the fuel sulfur content of the diesel fuel burned at the Kustatan Production Facility to no greater than 0.5 percent by weight.*	Records Review	Continuous	None
12	**Fuel Oil Sulfur Compounds Monitoring and Recordkeeping.** The Permitte shall monitor and record as follows:	Records Review	Continuous	None
12.1 AQ0741MSS02 Condition 5.1.1 AQ0741MSS03 Condition 6.1a	If the fuel grade requires a sulfur content less than 0.5 percent by weight, keep receipts that specify fuel grade and amount; or			
12.2 AQ0741MSS02 Condition 5.1.2 AQ0741MSS03 Condition 6.1b	If the fuel grade does not require a sulfur content less than 0.5 percent by weight, keep receipts that specify fuel grade and amount and a. test the fuel for sulfur content of each shipment; or b. obtain test results showing the sulfur content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent.			
12.3 AQ0741MSS02 Condition 5.1.3 AQ0741MSS03 Condition 6.1c	Fuel testing under Condition 12.2.a must follow an appropriate method listed in 18 AAC 50.035 or another method approved in writing by the Department.			
13	**Fuel Oil Sulfur Compounds Reporting.** The Permittee shall report as follows:	Records Review	Continuous	None
13.1	If sulfur content of the fuel burned in EU IDs 9 or 9a exceeds 0.5 percent by weight, the Permittee shall report under Condition 70.			
13.2 AQ0741MSS02 Condition 5.2 AQ0741MSS03 Condition 6.2	The Permittee shall include in the operating report required by Condition 70 a. a list of the fuel grades received at the stationary source during the reporting period; b. for any grade with a maximum fuel sulfur greater than 0.5 percent sulfur, the fuel sulfur of each shipment; and			
Fuel Gas (EU IDs 1 through 8 and 10)				
14	The Permittee will comply with the limit in Condition 10 as follows:	Records Review	Continuous	None
14.1	**Hydrogen sulfide (H2S) Content of Gas Burned in EU IDs 1, 2, and 2a.** For EU IDs 1, 2, and 2a, the Permittee shall comply with Condition 30.	Records Review	Continuous	None
14.2	**H2S Content of Gas Burned in EU IDs 3 – 8 and 10.** For EU IDs 3 through 8 and 10, the H2S content of the gas burned in the emission units shall not exceed 700 parts per million by volume (ppmv)[3]. [3] Permittee assumed 700 ppmv H2S in estimating SO2 emissions from EU IDs 3-8 and 10.	Records Review	Continuous	None
14.3	**Fuel Gas Sulfur Compounds Monitoring.** For EU IDs 1, 2, 2a, 3 through 8, and 10, the Permittee shall analyze a representative sample of each fuel (raw fuel gas and lean fuel gas) monthly to determine the H2S content using either ASTM D4810-88 (Reapproved 1999), D4913-89 (Reapproved 1995), or a listed method approved in 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1). a. If total H2S content of the gas burned in the emission units exceeds 100 ppmv, then monitor weekly. If H2S content of the gas burned in the emission units exceeds 700 ppmv, then monitor the H2S content of the gas daily.	Records Review and Interview with Responsible Personnel	Continuous	None
14.4	**Fuel Gas Sulfur Compound Recordkeeping.** The Permittee shall keep records of the H2S content analysis required under Condition 14.3.	Records Review	Continuous	None
14.5	**Fuel Gas Sulfur Compound Reporting.** The Permittee shall report as follows: a. Notify the Department at the end of the month for which the fuel gas H2S content initially exceeds the Condition 14.3 monthly monitoring threshold of 100 ppmv. b. Notify the Department at the end of the month for which the fuel gas H2S content initially exceeds the Condition 14.3.a weekly monitoring threshold of 700 ppmv. c. Report as excess emissions, in accordance with Condition 69, whenever the fuel combusted causes sulfur compound emissions to exceed the standard of Condition 10. d. Include copies of the records required by Condition 14.4 with the operating report required by Condition 70 for the period covered by the report.	Records Review and Interview with Responsible Personnel	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
Ambient Air Quality Standards				
15 AQ0741MSS02 Condition 4 AQ0741MSS03 Condition 5	Ambient air quality standards compliance for the stationary source operation is demonstrated at the posted boundary specified in Kustatan Production Facility's Access Control Plan set out in Section 14. Establish and maintain ambient air boundaries as described in Section 14.	Interview with Responsible Personnel	Continuous	None
16 AQ0741MSS02 Condition 5 & 5.1 AQ0741MSS03 Condition 6.1	**SO2 Requirements.** Limit the fuel sulfur content of the diesel fuel burned at the Kustatan Production Facility to no greater than 0.5 percent by weight.	Records Review and Interview with Responsible Personnel	Continuous	None
16.1	Monitor and record as described in Condition 12.	Records Review	Continuous	None
16.2	Report as described in Condition 13.	Records Review and Interview with Responsible Personnel	Continuous	None
Limits to Avoid Classification as PSD Major Source.				
17	**Oxides of Nitrogen (NOX) Emission Limits**	**No Compliance Task Required by this Condition.**		
17.1 AQ0741MSS02 Condition 6.1 AQ0741MSS03 Condition 7.1	Limit NOx emissions from EU IDs 1, 2, and 2a as follows: a. Install "SoLoNOx" low NOx combustion technology on EU IDs 1, 2, and 2a; b. Limit combined NOx emissions from EUs 1, 2 and 2a to no greater than 64.5 tons per 12-month rolling period, expressed as NO2.	Records Review	Continuous	None
17.2 AQ0741MSS02 Condition 6.2 AQ0741MSS03 Condition 7.2 & 7.3	**Monitoring, Recording, and Reporting NOx Emissions for EU IDs 1, 2, and 2a.** a. Calculate and record the NOx emissions, expressed as NO2 for each monthly period and 12 month rolling period using hours of operation and the following emission factors5: (i) 3.9 pounds per hour (lb/hr) for EU 1 (ii) 4.1 lb/hr for EU 2; and (iii) 6.6 lb/hr for EU 2a; and b. Verify NOx emission factors from the source testing required by Condition 29.1.a. Use exhaust properties determined by 40 CFR 60 Appendix A, Method 19, for each load tested. Use higher heating value throughout the analysis. c. In the first operating report due after the Department approval of the source test results, calculate and report the NOx emissions using the worst case emission factor for each of the emission units based on the latest source test results for each these emission units. Alternatively, upon Department written approval, the Permittee may recalculate emissions using the new emission factors beginning effective with the month in which the source test was conducted. d. Report the cumulative total monthly and 12-month rolling NOx emissions, expressed as NO2, from EUs 1, 2 and 2a in the operating report required by Condition 70.	Records Review	Continuous	None
17.3 AQ0741MSS02 Condition 6.4, 6.5, 6.6 AQ0741MSS03 Condition 7.4, 7.5, 7.6	Limit operations of EU 9a to no more than 500 hours per 12-month rolling period. a. Monitor and record the hours of operation of EU 9a for each calendar month. b. Report the cumulative total monthly and 12 month rolling hours of operation of EU 9a in the operating report required Condition 70.	Records Review	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
18 AQ0741MSS02 Condition 7 AQ0741MSS03 Condition 8	**Carbon Monoxide (CO) Emission Limits**	Records Review	Continuous	None
18.1 AQ0741MSS02 Condition 7.2, 7.5, & 7.6.2 AQ0741MSS03 Condition 8.2, 8.5, and 8.6	For EU ID 10, limit the fuel gas burned to no more than 70 million standard cubic feet (MMscf) in any 12-month rolling period. a. Monitor the fuel gas burned in EU ID 10 for each calendar month. Use flow meters and totalizers accurate to ±10%. Calculate and record the 12-month rolling fuel gas burned for each month of the reporting period, by the end of the following month. b. Report in the operating report required by Condition 70 the 12-month rolling fuel gas burned recorded in 18.1.a for each month of the reporting period.			
18.2 AQ0741MSS02 Condition 7.1 AQ0741MSS03 Condition 8.1	For EUs 1, 2 and 2a, limit combined total CO emissions to less than 136 tons per 12-month rolling period.	Records Review	Continuous	None
18.3 AQ0741MSS02 Condition 7.3 AQ0741MSS03 Condition 8.3	Operate EUs 1, 2 and 2a at all times, except at startup, shutdown, **malfunction,** and performance and emission tests at no less than the lower of either 50% load or the minimum load for which the most recent CO emission source tests were conducted.	Records Review	Continuous	None
18.4 AQ0741MSS02 Condition 7.4, 7.6, & 7.6.1 AQ0741MSS03 Condition 8.4	**Monitoring, Recording and Reporting for EU IDs 1, 2, and 2a:** a. Verify CO emission factors from applicable measurements from the source testing required by Condition 29.1.a. Use exhaust properties determined by 40 CFR 60 Appendix A, Method 19, for each load tested. Use higher heating value throughout the analysis. b. If the combined emission factors for EUs 1, 2 and 2a for worst case operation exceed 31 lb/hr[6], calculate and record the CO emissions for each month and 12 month rolling period for the period preceding submission of the source test results. Use hours of operation and the worst case emission factor for each unit in the calculations. c. For each of EUs 1, 2 and 2a, monitor the date, time, duration and reason for all operations less than the load listed in Condition 18.3. d. Report in the operating report required by Condition 70 the cumulative 12- month rolling CO emission from EUs 1, 2, and 2a recorded in Condition 18.4.b for each month of the reporting period. The Permittee is exempt from reporting CO emissions prior to submission of source test results. [6] Combined emission factor of 31 lb/hr for units 1, 2 and 2a is equivalent to 136 tpy of unlimited operations.	Records Review	Continuous	None
19 AQ0741MSS02 Condition 8 & 8.1 AQ0741MSS03 Condition 9 & 9.1	**Volatile Organic Compounds (VOC) Emission Limits – Tank Closed Vent System.** Equip the crude tanks, slop oil tank and produced water tank, EU IDs 12 through 16, with a closed vent system and control device meeting the following specifications:	Records Review	Continuous	None
19.1 AQ0741MSS02 Condition 8.1.1 AQ0741MSS03 Condition 9.1a	The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions;			
19.2 AQ0741MSS02 Condition 8.1.2 AQ0741MSS03 Condition 9.1b	The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater			

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
Insignificant Emissions Units				
20	For emissions units at the stationary source that are insignificant as defined in 18 AAC 50.326(e)-(i) that are not listed in this permit, the following apply:	Records Review	Continuous	None
20.1	**Visible Emissions Standard:** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from an industrial process, fuel-burning equipment, or an incinerator to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.			
20.2	**Particulate Matter Standard:** The Permittee shall not cause or allow particulate matter emitted from an industrial process or fuel-burning equipment to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.			
20.3	**Sulfur Standard:** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO2, from an industrial process or fuel-burning equipment, to exceed 500 ppm averaged over three hours.			
20.4	**General MR&R for Insignificant Emissions Units:** a. The Permittee shall submit the compliance certifications of Condition 71 based on reasonable inquiry; b. The Permittee shall comply with the requirements of Condition 52; c. The Permittee shall report in the operating report required by Condition 70 if an emissions unit has historically been classified as insignificant because of actual emissions less than the thresholds of 18 AAC 50.326(e) and current actual emissions become greater than any of those thresholds; and d. No other monitoring, recordkeeping or reporting is required.	Records Review	Continuous	None
Section 4 Federal Regulations Emission Units Subject to Federal NSPS, Subpart A				
40 C.F.R. Part 60 New Source Performance Standards (NSPS)Subpart A – General Provisions				
21	**NSPS Subpart A Notification.** For any affected facility[7] or existing facility[8] regulated under NSPS requirements in 40 C.F.R. 60, the Permittee shall furnish the Department and EPA written notification or, if acceptable to both the EPA and the Permittee, electronic notification, as follows: [7] Affected facility means, with reference to a stationary source, any apparatus to which a standard applies, as defined in 40 C.F.R. 60.2. [8] Existing facility means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type, as defined in 40 C.F.R. 60.2.	Records Review	Continuous	None
21.1	A notification of the date construction (or reconstruction as defined under 40 C.F.R. 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of massproduced facilities which are purchased in completed form.	Records Review	Continuous	None
21.2	A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.	Records Review	Continuous	None
21.3	A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 C.F.R. 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include: a. information describing the precise nature of the change, b. present and proposed emission control systems, c. productive capacity of the facility before and after the change, and	Records Review	Continuous	None
21.4	Any proposed replacement of an existing facility, for which the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, postmarked as soon as practicable, but no less than 60 days before commencement of replacement, and including the following information: a. the name and address of owner or operator, b. the location of the existing facility, c. a brief description of the existing facility and the components that are to be replaced, d. a description of the existing and proposed air pollution control equipment, e. an estimate of the fixed capital cost of the replacements, and of constructing a comparable entirely new facility, f. the estimated life of the existing facility after the replacements, and g. a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements .	Records Review	Continuous	None

Annual Compliance Certification
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04
Kustatan Production Facility
January 1-December 31, 2020

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
22	**NSPS Subpart A Startup, Shutdown, & Malfunction Requirements.** The Permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EU IDs 1, 2, and 2a, any malfunction of the associated air pollution control equipment, or any periods during which a continuous monitoring system (CMS) or monitoring device for EU IDs 1, 2, or 2a is inoperative.	Records Review	Continuous	None
23	**NSPS Subpart A Excess Emissions and Monitoring Systems Performance (EEMSP) Report.** The Permittee shall submit an EEMSP[9, 10] report and / or summary report form for EU IDs 1, 2, and 2a[11] to the Department and to EPA. Submit the report semiannually. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: [9] The Federal EEMSP report is not the same as the State excess emission report required by Condition 69. [10] Periods of excess emissions and monitor downtime for units subject to the NSPS Subpart GG SO2 limit (EU IDs 1 & 2) are defined in 40 C.F.R. 60.334(j)(2). [11] Condition 24 describes the summary report form requirements. See Conditions 24.1 and 24.2 for information on when the EEMSP report of Condition 23 is required to be submitted along with the summary report form of Condition 24.	Records Review	Continuous	None
23.1	The magnitude of excess emissions computed in accordance with 40 C.F.R. 60.13(h)(3), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period. [40 C.F.R. 60.7(c)(1), Subpart A]			
23.2	Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of EU IDs 1, 2, and 2a the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.			
23.3	The date and time identifying each period during which a CMS was inoperative except for zero and span checks and the nature of any repairs or adjustments.			
23.4	When no excess emissions have occurred or the CMS have not been inoperative, repaired, or adjusted, such information shall be stated in the report.			
24	**NSPS Subpart A Summary Report Form.** The Permittee shall submit to the Department and to the EPA one "summary report form" in the format shown in Figure 1 of 40 C.F.R. 60.7 (see Attachment A of the Statement of Basis) for each pollutant monitored for EU IDs 1, 2, and 2a.	Records Review	Continuous	None
24.1	If the total duration of excess emissions for the reporting period is less than one percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than five percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in Condition 23 need not be submitted unless requested by the Administrator, or			
24.2	If the total duration of excess emissions for the reporting period is one percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is five percent or greater of the total time for the reporting period, the summary report form and the excess emissions report described in Condition 23 shall both be submitted.			
25	**NSPS Subpart A Performance (Source) Tests.** The Permittee shall shall conduct source tests according to Section 6 and as required in this condition on any affected facility at such times as may be required by the EPA, and shall provide the Department and EPA with a written report of the results of the source tests.	Records Review	Continuous	None
26	**NSPS Subpart A Good Air Pollution Control Practice.** At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate EU IDs 1, 2, and 2a including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. The Administrator will determine whether acceptable operating and maintenance procedures are being used based on information available, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance records, and inspections of EU IDs 1, 2, and 2a.	Records Review and Interview with Responsible Personnel	Continuous	None
27	**NSPS Subpart A Credible Evidence.** For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of the standards set forth in Conditions 29 or 30, nothing in 40 C.F.R. Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 1, 2, and 2a would have been in compliance with applicable requirements of 40 C.F.R. Part 60 if the appropriate performance or compliance test or procedure had been performed.	Records Review and Interview with Responsible Personnel	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
28	**NSPS Subpart A Concealment of Emissions.** The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of a standard set forth in Conditions 29 and 30. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.	Records Review and Interview with Responsible Personnel	Continuous	None
NSPS, Subpart GG Requirements				
29	**NSPS Subpart GG NO_X Standard.** The Permittee shall not allow the exhaust gas concentration of NOX from EU IDs 1, 2, and 2a to exceed 173.6 ppmvd at 15 percent O_2, ISO corrected.	Records Review	Continuous	None
29.1	**Monitoring.** The Permittee shall comply with the following:	Records Review	Continuous	None
29.1 a)	**Periodic Testing.** For each turbine subject to Condition 29 that operates for 400 hours or more in any consecutive 12-month period during the life of this permit, the Permittee shall satisfy either Condition 29.1.a(i) or 29.1.a(ii). (i) For existing turbines whose latest emissions source testing was certified as operating at less than or equal to 90 percent of the limit shown in Condition 29, the Permittee shall conduct a NOx and O2 source test under 40 C.F.R. 60, Appendix A, Method 20, or Method 7E and either Method 3 or 3A, within the first applicable criteria below in the noted timeframe no later than April 4, 2022, except as set out in Conditions 29.1.a(i)(C) and 29.1.a(ii): (A) Within 5 years of the latest performance test, or (B) Within 1 year of the the effective date of this permit if the last source test occurred greater than five years prior to the effective date of this permit and the 400-hour threshold was triggered within 6 months of the permit's effective date, or (C) Within 1 year after exceeding 400 hours of operation in a 12- month period if the last source test occurred greater than 4 years prior to the exceedance. (ii) For existing turbines whose latest emissions source testing was certified as operating at greater than 90 percent of the limit shown in Condition 29, the Permittee shall conduct a NOx and O2 source test under 40 C.F.R. 60, Appendix A, Method 20, or Method 7E and either Method 3 or 3A, annually until two consecutive tests show performance results certified at less than or equal to 90 percent of the limit of Condition 29.			
29.1 b)	**Substituting Test Data.** The Permittee may use a Method 20, or Method 7E and either Method 3 or 3A, , test under Condition 29.1.a performed on only one of a group of turbines to satisfy the requirements of those conditions for the other turbines in the group if (i) the Permittee demonstrates that test results are less than or equal to 90 percent of the emission limit of Condition 29, and are projected under Condition 29.1.c to be less than or equal to 90 percent of the limit at maximum load; (ii) for any source test conducted after the effective date of this permit, the Permittee identifies in a source test plan under Condition 61 (A) the turbine to be tested; (B) the other turbines in the group that are to be represented by the test; and (C) why the turbine to be tested is representative, including that each turbine in the group (1) is located at a stationary source operated and maintained by the Permittee; (2) is tested under close to identical ambient conditions; (3) is the same make and model and has identical injectors and combustor; (4) uses the same fuel type from the same supply origin. (iii) The Permittee may not use substitute test results to represent emissions from a turbine or group of turbines if that turbine or group of turbines is operating at greater than 90 percent of the emission limit of Condition 29.	Records Review	Continuous	None
29.1 c)	**Load.** The Permittee shall comply with the following:	Records Review	Continuous	None
29.1 c) (i)	(i) Conduct all tests under Condition 29.1 in accordance with 40 C.F.R. 60.335(b)(2), except as otherwise approved in writing by the Department, or by EPA if the circumstances at the time of the EPA approval are still valid. For the highest load condition, if it is not possible to operate the turbine during the test at maximum load, the Permittee will test the turbine when operating at the highest load achievable by the turbine under the ambient and stationary source operating conditions in effect at the time of the test.			

Annual Compliance Certification Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04 Kustatan Production Facility January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
29.1 c) (ii)	Demonstrate in the source test plan for any test performed after the effective date of this permit whether the test is scheduled when maximum NOx emissions are expected.	Records Review	Continuous	None
29.1 c) (iii)	If the highest operating rate tested is less than the maximum load of the tested turbine or another turbine represented by the test data, (A) for each such turbine the Permittee shall provide to the Department as an attachment to the source test report (1) additional test information from the manufacturer or from previous testing of units in the group of turbines; if using previous testing of the group of turbines, the information must include all available test data for the turbines in the group, and (2) a demonstration based on the additional test information that projects the test results from Condition 29.1 to predict the highest load at which emissions will comply with the limit in Condition 29; (B) the Permittee shall not operate any turbine represented by the test data at loads for which the Permittee's demonstration predicts that emissions will exceed the limit of Condition 29; (C) the Permittee shall comply with a written finding prepared by the Department that (1) the information is inadequate for the Department to reasonably conclude that compliance is assured at any load greater than the test load, and that the Permittee must not exceed the test load, (2) the highest load at which the information is adequate for the Department to reasonably conclude that compliance assured is less than maximum load, and the Permittee must not exceed the highest load at which compliance is predicted, or (3) the Permittee must retest during a period of greater expected demand on the turbine, and (D) the Permittee may revise a load limit by submitting results of a more recent approved source test done at a higher load, and, if necessary, the accompanying information and demonstration described in Condition 29.1.c(iii)(A); the new limit is subject to any new Department finding under Condition 29.1.c(iii)(C) and	Records Review and Interview with Responsible Personnel	Continuous	None
29.1 c) (iv)	In order to perform an emission test required by Conditions 29.1.a and 29.1.b, the Permittee may operate a turbine at a higher load than that prescribed by Condition 29.1.c(iii).	Records Review	Continuous	None
29.1 c) (v)	For the purposes of Conditions 29.1 through 29.3, maximum load means the hourly average load that is the smallest of (A) 100 percent of manufacturer's design capacity of the gas turbine at ISO standard day conditions; (B) the highest load allowed by an enforceable condition that applies to the turbine; or (C) the highest load possible considering permanent physical restraints on the turbine or the equipment which it powers.	N/A	Continuous	None
29.2	**Recordkeeping.** The Permittee shall keep records as follows: a. The Permittee shall comply with the following for each turbine for which a demonstration under Condition 29.1.c(iii) does not show compliance with the limit of Condition 29 at maximum load. (i) The Permittee shall keep records of (A) load; or (B) as approved by the Department, surrogate measurements for load and the method for calculating load from those measurements. (ii) Records in Condition 29.2.a shall be hourly or otherwise as approved by the Department. (iii) Within one month after submitting a demonstration under Condition 29.1.c(iii)(A)(2) that predicts that the highest load at which emissions will comply is less than maximum load, or within one month of a Department finding under Condition 29.1.c(iii)(C), whichever is earlier, the Permittee shall propose to the Department how they will measure load or load surrogates, and shall propose and comply with a schedule for installing any necessary equipment and beginning monitoring. The Permittee shall comply with any subsequent Department direction on the load monitoring methods, equipment, or schedule. b. For any turbine subject to Condition 29, that will operate less than 400 hours in any 12 consecutive months, the Permittee shall keep monthly records of the hours of operation.	Records Review	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
29.3	**Reporting.** The Permittee shall keep report as follows a. In each operating report under Condition 70 the Permittee shall list for each turbine tested or represented by testing at less than maximum load and for which the Permittee must limit load under Condition 29.1.c(iii) (i) the load limit; (ii) the turbine identification; and (iii) the highest load recorded under Condition 29.2.a during the period covered by the operating report. b. In each operating report under Condition 70 for each turbine for which Condition 29.1 has not been satisfied because the turbine normally operates less than 400 hours in any 12 consecutive months, the Permittee shall identify (i) the turbine; (ii) the highest number of operating hours for any 12 consecutive months ending during the period covered by the report; and (iii) any turbine that operated for 400 or more hours. c. The Permittee shall report under Condition 69 if (i) a test result exceeds the emission standard; (ii) Method 20, or Method 7E and either Method 3 or 3A, testing is required under Condition 29.1.a(i) or 29.1.a(ii) but not performed, or (iii) the turbine was operated at a load exceeding that allowed by Conditions 29.1.c(iii)(B) and 29.1.c(iii)(C); exceeding a load limit is deemed a single violation rather than a multiple violation of both monitoring and the underlying emission limit.	Records Review and Interview with Responsible Personnel	Continuous	None
30	**NSPS Subpart GG Sulfur Standard.** The Permittee shall comply with either the SO2 standard in Condition 30.1, or the fuel sulfur content standard in Condition 30.2 below:	Records Review	Continuous	None
30.1	Do not allow the exhaust gas concentration of SO2 from EU IDs 1, 2, and 2a, listed in Table A, to exceed 150 ppmvd corrected to 15 percent O2, or			
30.2	Do not allow the sulfur content for the fuel burned in EU IDs 1, 2, and 2a to exceed 0.8 percent by weight.			
30.3	**Monitoring.** The Permittee shall monitor compliance with the standards listed in this condition, as follows:	N/A	Continuous	None
30.3 a.)	Monitor the total sulfur content of the fuel being fired in the turbine, except as provided in Condition 30.3.b. The sulfur content of the fuel must be determined using total sulfur methods described in 40 C.F.R. 60.335(b)(10) and Condition 30.4. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4,000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86, which measure the major sulfur compounds may be used.			
30.3 b.)	The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 C.F.R. 60.331(u), regardless of whether an existing custom schedule approved by the Administrator requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration[12]: (i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or (ii) Representative fuel sampling data, which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in 40 C.F.R. 75, Appendix D, Section 2.3.1.4 or 2.3.2.4 is required. [12] Periodic fuel sulfur monitoring under Condition 30.3.a and reporting under Conditions 23, 24, and 30.6 do not apply to Subpart GG turbines that have demonstrated that natural gas fuel meets the definition of 40 C.F.R. 60.331(u) as set out by Condition 30.3.b. Per 40 C.F.R. 60.334(i)(3)(i), a custom sulfur monitoring schedule under 60.334(i)(3)(ii)(A) is acceptable without prior Administrative approval.	Records Review	Continuous	None
30.3 c.)	For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.			

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
30.3 d.)	The frequency of determining the sulfur content of the fuel shall be as follows: (i) Gaseous fuel. For owners and operators that elect not to demonstrate sulfur content using options in Condition 30.3.b, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day. (ii) Custom schedules. Notwithstanding the requirements of Condition 30.3.d(i), operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 C.F.R. 60.334(i)(3)(i) and (i)(3)(ii), custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in Condition 30. The two custom sulfur monitoring schedules set forth in 40 C.F.R. 60.334(i)(3)(i)(A) through (D) and 60.334(i)(3)(ii) are acceptable without prior Administrative approval.	Records Review and Interview with Responsible Personnel	Continuous	None
30.4	**Test Methods and Procedures.** If the owner or operator is required under Conditions 30.3.a or 30.3.d(ii) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using Condition 30.4.a: a. For gaseous fuels, ASTM D1072-80, 90; D3246-81, 92, 96; D4468-85; or D6667-01. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator. b. The fuel analyses required under Condition 30.4 may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or	Records Review and Interview with Responsible Personnel	Continuous	None
30.5	**Recordkeeping.** Keep records as required by Condition 30.3 and 30.4, and in accordance with Condition 65.	Records Review	Continuous	None
30.6	**Reporting.** For each affected unit that periodically determines the fuel sulfur content under Condition 30.3.a, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with 40 C.F.R. 60.7(c) as summarized in Condition 23 except where otherwise approved by a custom fuel monitoring schedule. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction as described by 40 C.F.R. 60.334(j)(2).	Records Review and Interview with Responsible Personnel	Continuous	None
40 C.F.R. 63 NESHAPSubpart A – General Provisions				
31	**National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart A.** For stationary compression ignition internal combustion engines (CI ICE) EU IDs 9 and 9a, you must comply with the applicable requirements of 40 C.F.R. 63 Subpart A in accordance with the provisions for applicability of Subpart A in NESHAP Subpart ZZZZ, Table 8.	Records Review	Continuous	None
32	**Management Practices for RICEs at an Area Source of HAPs.** For EU IDs 9 and 9a, you must comply with the applicable requirements in Table 2d to 40 C.F.R. 63, Subpart ZZZZ.	Records Review	Continuous	None

Annual Compliance Certification

Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04

Kustatan Production Facility

January 1-December 31, 2020

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
NESHAP Subpart ZZZZ General Monitoring, Operation, and Maintenance Requirements				
32.1	**Management Practices for Stationary Emergency[13] CI RICE:** For EU ID 9, you must comply with the following management practices: a. Change oil and filter every 500 hours of operation or annually, whichever comes first; b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. [13] If EU ID 9 is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required under Condition 32.1, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the Permittee may delay the management practice until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated.	Records Review and Interview with Responsible Personnel	Continuous	None
32.2	**Management Practices for Non-Emergency Stationary CI RICEs > 500 hp at Area Sources not Accessible by the Federal Aid Highway System:** For EU ID 9a, you must comply with te following management practices: a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first; b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Records Review	Continuous	None
33	**General Requirements:** For EU IDs 9 and 9a, you must comply with the following:	N/A	Continuous	None
33.1	**Good Air Pollution Control Practices.** At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.			
33.2	**Operation and Maintenance Requirements.** a. You must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. b. You must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period need for appropriate and safe loading of the engine, not to exceed 30 minutes	Records Review	Continuous	None
33.3	**Hour Meter.** For emergency engine EU ID 9, you must install a non-resettable hour meter if one is not already installed.	Records Review	Continuous	None
33.4	**Oil Analysis Program for CI Engines.** You have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Condition 32. The oil analysis must be performed at the same frequency specified for changing the oil in Condition 32. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. [40 C.F.R. 63.6625(i)]	Records Review	Continuous	None
34	**Operating Hour Limits for Emergency Engine, EU ID 9.**	Records Review and Interview with Responsible Personnel	Continuous	None
34.1	**Operating Hour Limits for Emergency Engine.** You must operate the emergency stationary RICE according to the requirements in Conditions 34.1.a - 34.1.c. In order for the engine to be considered an emergency stationary RICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in Conditions 34.1.a - 34.1.c, is prohibited. If you do not operate the engine according to the requirements in Conditions 34.1.a - 34.1.c, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.			
34.1 a.)	There is no time limit on the use of emergency stationary RICE in emergency situations.	Interview with Responsible Personnel	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
34.1 b.)	You may operate the emission units for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of these units is limited to 100 hours per calendar year. The Permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. [40 C.F.R. 63.6640(f)(2)]	Records Review	Continuous	None
34.1 c.)	You may operate the emission units up to 50 hours per calendar year in nonemergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing under Condition 34.1.b. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.	Records Review	Continuous	None
NESHAP Subpart ZZZZ Monitoring				
35	**Continuous Compliance:** For EU IDs 9 and 9a, you must comply with the following:	Records Review and Interview with Responsible Personnel	Continuous	None
35.1	You must demonstrate continuous compliance with requirements in Condition 32 according to methods specified in Conditions 35.1.a and 35.1.b. a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or b. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. c. You must also report each instance in which you did not meet the requirements in Table 8 to NESHAP Subpart ZZZZ that apply to you.			
NESHAP Subpart ZZZZ Reporting				
36	**Recordkeeping.** For EU IDs 9 and 9a, you must comply with the following:	Records Review	Continuous	None
36.1	Keep record of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and aftertreatment control device (if any) according to your own maintenance plan.			
36.2	For EU ID 9, keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. Document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.	Records Review	Continuous	None
36.3	Keep records in a form suitable and readily available for expeditious review according to 40 C.F.R. 63.10(b)(1). a. Keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or record. b. Keep records readily accessible in hard copy or electronic form for at least five years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. c. All the records may be maintained offsite.	Records Review	Continuous	None
37	**Reporting.** For EU IDs 9 and 9a, you must include in the operating report required by Condition 70, a report of deviations as defined in 40 C.F.R. 63.6675 for each instance in which an applicable requirement in 40 C.F.R. 63, Subpart A as specified in Table 8 to Subpart ZZZZ was not met.	Records Review	Continuous	None
40 C.F.R. Part 61 NESHAP Subpart A – General Provisions & Subpart M – Asbestos				
38	The Permittee shall comply with the requirements set forth in 40 C.F.R. 61.145, 61.150, and 61.152 of Subpart M, and the applicable sections set forth in 40 C.F.R. 61, Subpart A and Appendix A.	Records Review	Continuous	None

Annual Compliance Certification
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04
Kustatan Production Facility
January 1-December 31, 2020

Condition Number	Condition Text	Method Used to Determine Compliance Status	Compliance Status	Permit Deviations Identified During Calendar Year
40 C.F.R. Part 82 Protection of Stratospheric Ozone				
39	**40 C.F.R. Part 82 Protection of Stratospheric Ozone**	N/A	Continuous	None
39.1	**Subpart F – Recycling and Emissions Reduction.** The Permittee shall comply with the standards for recycling and emissions reduction of refrigerants set forth in 40 C.F.R. 82, Subpart F.			
39.2	**Subpart G – Significant New Alternatives.** The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.174 (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).			
39.3	**Subpart H – Halons Emissions Reduction.** The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.270 (Protection of Stratospheric Ozone Subpart H – Halon Emissions Reduction).			
General NSPS and NESHAP Requirements				
40	**NESHAP Applicability Determinations.** The Permittee shall determine rule applicability and designation of affected sources under NESHAPs for Source Categories (40 C.F.R. 63) in accordance with the procedures described in 40 C.F.R. 63.1(b) and 63.10(b)(3). If a source becomes affected by an applicable subpart of 40 C.F.R. 63, the Permittee shall comply with such standard by the compliance date established by the Administrator in the applicable subpart, in accordance with 40 C.F.R. 63.6(c).	Records Review	Continuous	None
40.1	After the effective date of any relevant standard promulgated by the Administrator under this part, an owner or operator who constructs a new affected source that is not major-emitting or reconstructs an affected source that is not major-emitting that is subject to such standard, or reconstructs a source such that the source becomes an affected source subject to the standard, must notify the Administrator and the Department of the intended construction or reconstruction. The notification must be submitted in accordance with the procedures in 40 C.F.R. 63.9(b).	Records Review and Interview with Responsible Personnel		
41	**NSPS and NESHAP Reports.** The Permittee shall:	Records Review	Continuous	None
41.1	**Reports:** Except for federal reports and notices submitted through EPA's CDX/CEDRI online reporting system, attach to the operating report required by Condition 70 for the period covered by the report, a copy of any NSPS and NESHAPs reports submitted to the U.S. Environmental Protection Agency (EPA) Region 10. For reports submitted through CDX/CEDRI, state in the operating report the date and a brief description of each of the online reports submitted during the reporting period; and			
41.2	**Waivers**: Upon request by the Department, provide a written copy of any EPA-granted alternative monitoring requirement, custom monitoring schedule or waiver of the federal emission standards, recordkeeping, monitoring, performance testing, or reporting requirements. The Permittee shall keep a copy of each U.S. EPA-issued monitoring waiver or custom monitoring schedule with the permit.	Interview with Responsible Personnel		
Section 5 General Conditions Standard Terms and Conditions				
42 AQ0741MSS02 Condition 14 AQ0741MSS03 Condition 12 AQ0741MSS04 Condition 13	Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.	**No Compliance Task Required by this Condition.**		
43 AQ0741MSS02 Condition 15 AQ0741MSS03 Condition 13 AQ0741MSS04 Condition 14	The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and re-issuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.	**No Compliance Task Required by this Condition.**		
44 AQ0741MSS02 Condition 16 AQ0741MSS03 Condition 14 AQ0741MSS04 Condition 15	The permit does not convey any property rights of any sort, nor any exclusive privilege.	**No Compliance Task Required by this Condition.**		
45 AQ0741MSS03 Condition 2 AQ0741MSS04 Condition 2	**Administration Fees.** The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-403.	Records Review	Continuous	None
46 AQ0741MSS02 Condition 2 AQ0741MSS03 Condition 3 AQ0741MSS04 Condition 3	**Assessable Emissions.** The Permittee shall pay to the Department annual emission fees based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities 10 tons per year or greater. The quantity for which fees will be assessed is the lesser of			
46.1 AQ0741MSS02 Condition 2.1 AQ0741MSS03 Condition 3.1 AQ0741MSS04 Condition 3.1	the stationary source's assessable potential to emit of 309 TPY; or **Note AQ0741MSS03 Condition 3.1 raises the PTE to 375 TPY**			

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
46.2 AQ0741MSS02 Condition 2.2 AQ0741MSS03 Condition 3.2 AQ0741MSS04 Condition 3.2	the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12-month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods: a. an enforceable test method described in 18 AAC 50.220; b. material balance calculations; c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or d. other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.	Records Review	Continuous	None
47 AQ0741MSS02 Condition 3 AQ0741MSS03 Condition 4 AQ0741MSS04 Condition 4	**Assessable Emission Estimates.** Emission fees will be assessed as follows:	Records Review	Continuous	None
47.1 AQ0741MSS02 Condition 3.1 AQ0741MSS03 Condition 4.1 AQ0741MSS04 Condition 4.1	no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Ste 303, PO Box 111800, Juneau, AK 99811-1800; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or			
AQ0741MSS04 Condition 4.2	The Permittee shall include with the assessable emissions report all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates.			
47.2 AQ0741MSS02 Condition 3.2 AQ0741MSS03 Condition 4.2 AQ0741MSS04 Condition 4.3	if no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set out in Condition 46.1.			
48	**Good Air Pollution Control Practice.** The Permittee shall do the following for EU IDs 3 through 8, 10 and 12 through 16.	Records Review and Interview with Responsible Personnel	Continuous	None
48.1	perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;			
48.2	keep records of any maintenance that would have a significant effect on emissions; the records may be kept in electronic format;			
48.3	keep a copy of either the manufacturer's or the operator's maintenance procedures			
49	**Dilution.** The Permittee shall not dilute emissions with air to comply with this permit. Monitoring shall consist of an annual certification that the Permittee does not dilute emissions to comply with this permit.	Records Review and Interview with Responsible Personnel	Continuous	None
50	**Reasonable Precautions to Prevent Fugitive Dust.** A person who causes or permits bulk materials to be handled, transported, or stored, or who engages in an industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air.	Records Review	Continuous	None
50.1	The Permittee shall keep records of: a. complaints received by the Permittee and complaints received by the Department and conveyed to the Permittee; and b. any additional precautions that are taken (i) to address complaints described in Condition 50.1.a or to address the results of Department inspections that found potential problems; and (ii) to prevent future dust problems.	Records Review	Continuous	None
50.2	The Permittee shall report according to Condition 52.	Records Review	Continuous	None
51	**Stack Injection.** The Permittee shall not release materials other than process emissions, products of combustion, or materials introduced to control pollutant emissions from a stack at a stationary source constructed or modified after November 1, 1982, except as authorized by a minor or construction permit, Title V permit, or air quality control permit issued before October 1, 2004.	Records Review	Continuous	None
52	**Air Pollution Prohibited.** No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property.	Records Review	Continuous	None
52.1	**Monitoring, Recordkeeping, and Reporting for Condition 52:**	Records Review and Interview with Responsible Personnel	Continuous	None
52.1 a.)	If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions according to Condition 69.			
52.1 b.)	As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 52.			

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
52.1 c.)	The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if (i) after an investigation because of a complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 52; or (ii) the Department notifies the Permittee that it has found a violation of Condition 52.	Records Review and Interview with Responsible Personnel	Continuous	None
52.1 d.)	The Permittee shall keep records of (i) the date, time, and nature of all emissions complaints received; (ii) the name of the person or persons that complained, if known; (iii) a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 52; and (iv) any corrective actions taken or planned for complaints attributable to emissions from the stationary source.	Records Review	Continuous	None
52.1 e.)	With each stationary source operating report under Condition 70, the Permittee shall include a brief summary report which must include (i) the number of complaints received; (ii) the number of times the Permittee or the Department found corrective action necessary; (iii) the number of times action was taken on a complaint within 24 hours; and (iv) the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.	Records Review	Continuous	None
52.1 f.)	The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.	Records Review and Interview with Responsible Personnel	Continuous	None
53	**Technology-Based Emission Standard.** If an unavoidable emergency, malfunction (as defined in 18 AAC 50.235(d)), or non-routine repair (as defined in 18 AAC 50.990(64), causes emissions in excess of a technology-based emission standard[14] listed in Conditions 29, 30 and 39 (refrigerants), the Permittee shall [14] As defined in 18 AAC 50.990(106), the term "technology-based emission standard" means a best available control technology (BACT) standard; a lowest achievable emission rate (LAER) standard; a maximum achievable control technology (MACT) standard established under 40 C.F.R. 63, Subpart B, adopted by reference in 18 AAC 50.040(c); a standard adopted by reference in 18 AAC 50.040(a) or (c); and any other similar standard for which the stringency of the standard is based on determinations of what is technologically feasible, considering relevant factors.	Records Review and Interview with Responsible Personnel	Continuous	None
53.1	take all reasonable steps to minimize levels of emissions that exceed the standard, and			
53.2	report in accordance with Condition 69; the report must include information on the steps taken to mitigate emissions and corrective measures taken or to be taken.			
Open Burning Requirements				
54	**Open Burning.** If the Permittee conducts open burning at this stationary source, the Permittee shall comply with the requirements of 18 AAC 50.065. The Permittee shall	Records Review	Continuous	None
54.1	keep written records to demonstrate that the Permittee complies with the limitations in this condition and the requirements of 18 AAC 50.065. Upon request by the Department, submit copies of the records; and	Records Review and Interview with Responsible Personnel	Continuous	None
54.2	include this condition in the annual certification required under Condition 71.	Records Review	Continuous	None

Annual Compliance Certification Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04 Kustatan Production Facility January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
Section 6. General Source Testing and Monitoring Requirements				
55	**Requested Source Tests.** In addition to any source testing explicitly required by the permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.	Interview with Responsible Personnel	Continuous	None
56	**Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing	Records Review	Continuous	None
56.1	at a point or points that characterize the actual discharge into the ambient air; and	Records Review	Continuous	None
56.2	at the maximum rated burning or operating capacity of the emission unit or another rate determined by the Department to characterize the actual discharge into the ambient air.	Records Review	Continuous	None
57	**Reference Test Methods.** The Permittee shall use the following as reference test methods when conducting source testing for compliance with this permit:	Records Review and Interview with Responsible Personnel	Continuous	None
57.1	Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60.			
57.2	Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(b) must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 61.			
57.3	Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) must be conducted in accordance with the source test methods and procedures specified in 40 C.F.R. 63.			
57.4	Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in Reference Method 9. The Permittee may use the form in Section 11 to record data.			
57.5	Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals, and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.			
57.6	Source testing for emissions of PM2.5 and PM10 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.			
57.7	Source testing for emissions of any pollutant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.			
58	**Excess Air Requirements.** To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68°F and an absolute pressure of 760 millimeters of mercury).	Records Review	Continuous	None
59	**Test Exemption.** The Permittee is not required to comply with Conditions 61, 62 and 63 when the exhaust is observed for visible emissions by Method 9 Plan (Condition 2.3) or Smoke/No Smoke Plan (Condition 2.4).	Records Review	Continuous	None
60	**Test Deadline Extension.** The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department’s appropriate division director or designee.	Records Review	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
61	**Test Plans.** Except as provided in Condition 59, before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 55 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.	Records Review and Interview with Responsible Personnel	Continuous	None
62	**Test Notification.** Except as provided in Condition 59, at least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and the time the source test will begin.	Records Review	Continuous	None
63	**Test Reports.** Except as provided in Condition 59, within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the Source Test Report Outline, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 66. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.	Records Review and Interview with Responsible Personnel	Continuous	None
64	**Particulate Matter Calculations.** In source testing for compliance with the particulate matter standards in Conditions 6 and 20.2, the three-hour average is determined using the average of three one-hour test runs. The source test must account for those emissions caused by routine maintenance activities by ensuring that at least one test run includes the emissions caused by the routine maintenance activity and is conducted under conditions that lead to representative emissions from that activity. The emissions must be quantified using the following equation: Where: **E** = the total particulate matter emissions of the emissions unit in grains per dry standard cubic foot (gr/dscf) $\mathbf{E_M}$ = the particulate matter emissions in gr/dscf measured during the test that included the routine maintenance activity $\mathbf{E_{NM}}$ = the arithmetic average of particulate matter emissions in gr/dscf measured by the test runs that did not include the routine maintenance activity **A** = the period of routine maintenance activity occurring during the test run that included routine maintenance activity, expressed to the nearest hundredth of an hour **B** = the total period of the test run, less A **R** = the maximum period of emissions unit operation per 24 hours, expressed to the nearest hundredth of an hour **S** = the maximum period of routine maintenance activity per 24 hours, expressed to the nearest hundredth of an hour	Records Review	Continuous	None
Section 7. General Recordkeeping and Reporting Requirements				
Recordkeeping Requirements				
65	**Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:	Records Review	Continuous	None
65.1	Copies of all reports and certifications submitted pursuant to this section of the permit; and	Records Review	Continuous	None
65.2	Records of all monitoring required by this permit, and information about the monitoring including: a. the date, place, and time of sampling or measurements; b. the date(s) analyses were performed; c. the company or entity that performed the analyses; d. the analytical techniques or methods used; e. the results of such analyses; and, f. the operating conditions as existing at the time of sampling or measurement.	Records Review	Continuous	None
Reporting Requirements				
66 AQ0741MSS04 Condition 9	**Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: *"Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete."* Excess emission reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.	Records Review	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
66.1 AQ0741MSS04 Condition 9.1	The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if a. a certifying authority registered under AS 09.80.020 verifies that the electronic signature is authentic; and b. the person providing the electronic signature has made an agreement, with the certifying authority described in Condition 66.1.a, that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.	Records Review and Interview with Responsible Personnel	Continuous	None
67 AQ0741MSS04 Condition 10	**Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall submit reports, compliance certifications, and/or other submittals required by this permit, certified in accordance with Condition 66, to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The Permittee shall submit the documents either by hard copy or electronically.	Records Review and Interview with Responsible Personnel	Continuous	None
67.1	Provide electronic submittals, either by: a. E-mail under a cover letter using dec.aq.airreports@alaska.gov ; or b. using the Department's Air Online Services at http://dec.alaska.gov/applications/air/airtoolsweb/	Records Review	Continuous	None
AQ0741MSS04 Condition 10.1	Upon approval by the Department, the Permittee can submit reports by alternative methods, certified in accordance with Condition 9, and submitted by email under a cover letter using dec.aq.airreports@alaska.gov; or by letter, or form if the Permittee does not have the technical ability to submit the records using the Department's website.			
68	**Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke and reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the Federal Administrator.	Records Review and Interview with Responsible Personnel	Continuous	None
69	**Excess Emissions and Permit Deviation Reports**	Records Review	Continuous	None
69.1	Except as provided in Condition 52, the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows: a. in accordance with 18 AAC 50.240(c), as soon as possible after the event commences or is discovered, report (i) emissions that present a potential threat to human health or safety; and (ii) excess emissions that the Permittee believes to be unavoidable; b. in accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology-based emission standard; c. report all other excess emissions and permit deviations (i) within 30 days after the end of the month during which the excess emissions or deviation occurred, except as provided in Condition 69.1.c(iii); or (ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under Condition 69.1.c(i); and (iii) for failure to monitor, as required in Conditions 4.2.b and 9.1.b and other applicable conditions of this permit.			
69.2	When reporting either excess emissions or permit deviations, the Permittee shall report using either the Department's online form, which can be found at http://dec.alaska.gov/applications/air/airtoolsweb, http://dec.alaska.gov/air/ap/docs/eeform.pdf , or if the Permittee prefers, the form contained in Section 14 of this permit. The Permittee must provide all information called for by the form that is used.			
69.3	If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up an excess emissions report.			
70	**Operating Reports.** During the life of this permit, the Permittee shall submit to the Department an original and one copy of an operating report by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year. [15] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.	Records Review	Continuous	None
70.1	The operating report must include all information required to be in operating reports by other conditions of this permit for the period covered by the report.			

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
70.2	When excess emissions or permit deviations that occurred during the reporting period are not reported with the operating report under Condition 70.1, the Permittee shall identify a. the date of the deviation; b. the equipment involved; c. the permit condition affected; d. a description of the excess emissions or permit deviation; and e. any corrective action or preventive measures taken and the date(s) of such actions; or	Records Review	Continuous	None
70.3	When excess emissions or permit deviations have already been reported under Condition 69 the Permittee shall cite the date or dates of those reports.	Records Review	Continuous	None
70.4	The operating report must include for the period covered by the report a listing of emissions monitored under Conditions 2.3.e, 2.4.c, and 29.1.a which trigger additional testing or monitoring, whether or not the emissions monitored exceed an emission standard. The Permittee shall include in the report a. the date of the emissions; b. the equipment involved; c. the permit condition affected; and d. the monitoring result which triggered the additional monitoring.	Records Review	Continuous	None
70.5	**Transition from expired to renewed permit.** For the first period of this renewed operating permit, also provide the previous permit's operating report elements covering that partial period immediately preceding the effective date of this renewed permit.	Records Review	Continuous	None
71	**Annual Compliance Certification.** Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 67.	Records Review	Continuous	None
71.1	Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows: a. identify each term or condition set forth in Section 3 through Section 9, that is the basis of the certification; b. briefly describe each method used to determine the compliance status; c. state whether compliance is intermittent or continuous; and d. identify each deviation and take it into account in the compliance certification.			
71.2	**Transition from expired to renewed permit.** For the first period of this renewed operating permit, also provide the previous permit's annual compliance certification report elements covering that partial period immediately preceding the effective date of this renewed permit.			
71.3	In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, Mail Stop: OCE-101, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101.			
72	**Emission Inventory Reporting.** The Permittee shall submit to the Department reports of actual emissions, by emissions unit, of CO, Ammonia (NH3), NOx, PM10, PM2.5, SO2, VOCs and Lead (and lead compounds) using the form in Section 15 of this permit, as follows:	Records Review	Continuous	None
72.1	Each year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds: a. 250 TPY of NH3, PM10, PM2.5 or VOCs; or b. 2,500 TPY of CO, NOx or SO2.	Records Review and Interview with Responsible Personnel	Continuous	None
72.2	Every third year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds: a. 5 tons per year of lead (and lead compounds), or b. 1,000 TPY of CO; or c. 100 TPY of SO2, NH3, PM10, PM2.5, NOx or VOCs.	Records Review and Interview with Responsible Personnel	Continuous	None
72.3	For reporting under Condition 72.2, the Permittee shall report in 2018 for calendar year 2017, 2021 for calendar year 2020, 2024 for calendar year 2023, etc., in accordance with the Environmental Protection Agency set schedule.	Records Review	Continuous	None
72.4	Include in the report required by this condition, the required data elements contained within the form in Section 15 or those contained in Table 2A of Appendix A to Subpart A of 40 C.F.R. 51 for each stack associated with an emissions unit.	Records Review	Continuous	None

Annual Compliance Certification Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04 Kustatan Production Facility January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
Section 8. Permit Changes and Renewal				
73	**Permit Applications and Submittals.** The Permittee shall comply with the following requirements for submitting application information to the US Environmental Protection Agency (EPA):	Records Review	Continuous	None
73.1	The Permittee shall provide a copy of each application for modification or renewal of this permit, including any compliance plan, or application addenda, at the time the application or addendum is submitted to the Department;			
73.2	The information shall be submitted to the Part 70 Operating Permit Program, US EPA Region 10, AWT-150, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101.			
73.3	To the extent practicable, the Permittee shall provide to EPA applications in portable document format (pdf); MS Word format (.doc); or other computerreadable format compatible with EPA's national database management system; and			
73.4	The Permittee shall maintain records as necessary to demonstrate compliance with this condition.			
74	**Emissions Trading.** No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in the permit.	Records Review and Interview with Responsible Personnel	Continuous	None
75	**Off Permit Changes.** The Permittee may make changes that are not addressed or prohibited by this permit other than those subject to the requirements of 40 C.F.R. Part 72 through 78 or those that are modifications under any provision of Title I of the Act to be	Records Review and Interview with Responsible Personnel	Continuous	None
75.1	Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition;			
75.2	Provide contemporaneous written notice to EPA and the Department of each such change, except for changes that qualify as insignificant under 18 AAC 50.326(d) – (i). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change;			
75.3	The change shall not qualify for the shield under 40 C.F.R. 71.6(f);	Records Review and Interview with Responsible Personnel	Continuous	None
75.4	The Permittee shall keep a record describing changes made at the stationary source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.	Records Review and Interview with Responsible Personnel	Continuous	None
76	**Operational Flexibility.** The Permittee may make CAA Section 502(b)(10)[16] changes within the permitted stationary source without requiring a permit revision if the changes are not modifications under any provision of Title I of the Act and the changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emissions or in terms of total emissions): [16] As defined in 40 C.F.R. 71.2, CAA Section 502(b)(10) changes are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.	Records Review	Continuous	None
76.1	The Permittee shall provide EPA and the Department with a written notification no less than seven days in advance of the proposed change.			
76.2	For each such change, the notification required by Condition 76.1 shall include a brief description of the change within the permitted stationary source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.			
76.3	The permit shield described in 40 C.F.R. 71.6(f) shall not apply to any change made pursuant to Condition 76.	Records Review	Continuous	None
77	**Permit Renewal.** To renew this permit, the Permittee shall submit to the Department[17] an application under 18 AAC 50.326 no sooner than **October 4, 2020** and no later than **October 4, 2021**. The renewal application shall be complete before the permit expiration date listed on the cover page of this permit. Permit expiration terminates the stationary source's right to operate unless a timely and complete renewal application has been submitted consistent with 40 C.F.R. 71.7(b) and 71.5(a)(1)(iii). [17] Submit permit applications to the Department's Anchorage office. The current address is: Air Permit Intake Clerk, ADEC, 555 Cordova Street, Anchorage, AK 99501.	Records Review	Continuous	None

Annual Compliance Certification Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04 Kustatan Production Facility January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
Section 9. Compliance Requirements				
General Compliance Requirements				
78	Compliance with permit terms and conditions is considered to be compliance with those requirements that are:	Records Review	Continuous	None
78.1	included and specifically identified in the permit; or			
78.2	determined in writing in the permit to be inapplicable.			
79 AQ0741MSS02 Condition 12 AQ0741MSS03 Condition 10 AQ0741MSS04 Condition 11	The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for	Records Review	Continuous	None
79.1 AQ0741MSS02 Condition 12.1 AQ0741MSS03 Condition 10.1 AQ0741MSS04 Condition 11.1	an enforcement action;	Records Review	Continuous	None
79.2 AQ0741MSS02 Condition 12.2 AQ0741MSS03 Condition 10.2 AQ0741MSS04 Condition 11.2	permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280; or	Records Review	Continuous	None
79.3	denial of an operating permit renewal application.	Records Review	Continuous	None
80	For applicable requirements with which the stationary source is in compliance, the Permittee shall continue to comply with such requirements.	Records Review	Continuous	None
81 AQ0741MSS02 Condition 13 AQ0741MSS03 Condition 11 AQ0741MSS04 Condition 12	It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.	Records Review and Interview with Responsible Personnel	Continuous	None
82 AQ0741MSS02 Condition 17 AQ0741MSS04 Condition 16	The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to	Interview with Responsible Personnel	Continuous	None
82.1 AQ0741MSS02 Condition 17.1 AQ0741MSS04 Condition 16.1	enter upon the premises where a source subject to the permit is located or where records required by the permit are kept;			
82.2 AQ0741MSS02 Condition 17.2 AQ0741MSS04 Condition 16.2	have access to and copy any records required by the permit;			
82.3 AQ0741MSS02 Condition 17.3 AQ0741MSS04 Condition 16.3	inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and			
82.4 AQ0741MSS02 Condition 17.4 AQ0741MSS04 Condition 16.4	sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.			
Compliance Schedule				
83	For applicable requirements that will become effective during the permit term, the Permittee shall meet such requirements on a timely basis.	Records Review and Interview with Responsible Personnel	Continuous	None
New Permit-AQ0741MSS04				
AQ0741MSS04 Condition 1	The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 5	Visible Emissions for Industrial Process and Fuel-Burning Equipment. The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EUs 17 and 18 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 5.1	For EUs 17 and 18 perform an initial Method 9 observation within 60-days of initial startup of each EU. a. Record the date of initial startup of EUs 17 and 18. b. Report the results of the Method 9 observations required by Condition 5.1 in the first operating report due after the observations were performed, required by the operating report described in the applicable operating permit issued to the stationary source under AS 46.14 and 18 AAC 50.	Records Review and Interview with Responsible Personnel	Continuous	None

Annual Compliance Certification				
Permit No. AQ0741TVP03 Rev. 1, AQ0741MSS03, and AQ0741MSS04				
Kustatan Production Facility				
January 1-December 31, 2020				
Condition Number	**Condition Text**	**Method Used to Determine Compliance Status**	**Compliance Status**	**Permit Deviations Identified During Calendar Year**
AQ0741MSS04 Condition 5.2	For EUs 17 and 18, monitor, record, and report as described in the operating permit issued for the source under AS 46.14 and 18 AAC 50.	Records Review	Continuous	None
AQ0741MSS04 Condition 6	Particulate Matter for Industrial Process and Fuel-Burning Equipment. The Permittee shall not cause or allow particulate matter emitted from EUs 17 and 18 to exceed 0.05 grains per dry standard cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 6.1	Monitor, record, and report PM emissions as described in the operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50.	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 7	Sulfur Compound Emissions. The Permittee shall not cause or allow sulfur compound emissions, expressed as SO2, from EUs 17 and 18, to exceed 500 parts per million (ppm) averaged over three hours.	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 7.1	Monitor, record, and report sulfur compounds emissions as described in the operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50.	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 8	NOx Emission Limit for Minor Permitting Classification Avoidance	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 8.1	For EUs 17 and 18, limit combined total NOx emissions to less than 74.4 tons per 12-month rolling period.			
AQ0741MSS04 Condition 8.1a	The Permittee shall remove both of EUs 1 and 2 from service prior to either of EUs 17 and 18 becoming fully operational. Report in the next operating report required by the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50: (i) the dates EUs 1 and 2 were removed from service; (ii) the installation dates of EUs 17 and 18; and (iii) the dates EUs 17 and 18 became fully operational.	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 8.1b	The Permittee shall remove both of EUs 17 and 18 from service prior to either of EUs 1 and 2 becoming fully operational after restart3. Report in the next	Records Review and Interview with Responsible Personnel	Continuous	None
AQ0741MSS04 Condition 8.1c(i)-(iii)	Limit the combined hours of operation for EUs 17 and 18 to 8,970 hours per 12-month rolling period. (i) Install, operate, and maintain non-resettable hour meters on each EU listed in Condition 8.1c; (ii) Record the hour meter reading for each EU listed in 8.1c on the last day of each month; (iii) By the 15th of each month, calculate and record: (A) the number of hours each EU listed in Condition 8.1c operated during the previous month, if the meter is not operational assume continuous operation for that period; (B) the total number of hours each EU listed in Condition 8.1c operated during the previous 12-month rolling period; and (C) the combined total number of hours the EUs listed in Condition 8.1c opreated during the previous 12-month rolling period.	Records Review	Continuous	None
AQ0741MSS04 Condition 8.1c(iv)	Report in each operating report requried by the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 the following information for each month of the reporting period: (A) the hour meter reading obtained under Condition 8.1c(ii) for each EU listed in 8.1c; and (B) the values determined under Conditions 8.1c(iii)(B) for each EU listed in condition 8.1c.	Records Review	Continuous	None
AQ0741MSS04 Condition 8.1c(v)	Report as excess emissions and permit deviation as described in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50, whenever the limit in Condition 8.1c is exceeded, or if Conditions 8.1c(i) through 8.1c(iv) are not met.	Records Review	Continuous	None

Effective Permits for Renewal

AQ0741TVP03

AQ0741TVP03, Revision 1

AQ0741MSS03

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY OPERATING PERMIT

Permit No. AQ0741TVP03

Issue Date: Final Permit - April 4, 2017
Expiration Date: April 4, 2022

The Alaska Department of Environmental Conservation, under the authority of AS 46.14 and 18 AAC 50, issues an operating permit to **Cook Inlet Energy**, for the operation of the **Kustatan Production Facility**.

This permit satisfies the obligation of the owner and operator to obtain an operating permit as set out in AS 46.14.130(b).

As set out in AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this operating permit.

Citations listed herein are contained within 18 AAC 50 dated December 29, 2016, Register 220. All Federal regulation citations are from those sections adopted by reference in this version of regulation in 18 AAC 50.040 unless otherwise specified.

Upon effective date of this permit, Operating Permit No. AQ0741TVP02 and its revisions expire.

This Operating Permit becomes effective May 4, 2017.

James R. Plosay for

John F. Kuterbach, Manager
Air Permits Program

Table of Contents

Abbreviations and Acronyms

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AS	Alaska Statutes
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
bbls	U. S. Petroleum Barrels
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data Reporting Interface
C.F.R.	Code of Federal Regulations
CAA	Clean Air Act
The Act	Clean Air Act
CI	Compression Ignition
CIE	Cook Inlet Energy, LLC
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
Department	Alaska Department of Environmental Conservation
dscf	Dry Standard Cubic Foot
EPA	US Environmental Protection Agency
EU ID	Emissions Unit Identification Number
gr/dscf	Grains per Dry Standard Cubic Foot
H_2S	Hydrogen Sulfide
HAPs	Hazardous Air Pollutants
hp	Horsepower
ICE	Internal Combustion Engine
kW	Kilowatt
lb/hr	Pounds per hour
LAER	Lowest Achievable Emission Rate
MACT	Maximum Achievable Control Technology
MMBtu	Million British thermal units
MMBtu/hr	Million British Thermal Units per hour
MMscf	Million Standard Cubic Feet
MMscf/hr	Million Standard Cubic Feet per hour
MR&R	Monitoring, Recordkeeping, and Reporting
MW	Megawatts
NAICS	North American Industrial Classification System
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NOx	Nitrogen Oxides
NSPS	New Source Performance Standards
O_2	Oxygen
PM	Pariculate Matter
$PM_{2.5}$	Particulate Matter less than or equal to a nominal 2.5 microns in diameter
PM_{10}	Particulate Matter less than or equal to a nominal 10 microns in diameter
ppm	Parts per Million
ppmv	Parts per Million by volume
ppmvd	Parts per Million by volume on a dry basis
PS	Performance Specification
PSD	prevention of significant deterioration
PTE	potential to emit
RICE	Reciprocating Internal Combustion Engine
RM	Reference Method
SIC.	Standard Industrial Classification
SIP	State Implementation Plan
SPC	Standard Permit Condition or Standard Operating Permit Condition
SO_2	sulfur dioxide
The Act	Clean Air Act
TPY	tons per year
VOC	volatile organic compound
VOL	volatile organic liquid
vol%	volume percent
wt%	weight percent
$wt\%S_{fuel}$	weight percent of sulfur in fuel

Section 1. Stationary Source Information

Identification

Permittee:		**Cook Inlet Energy**, LLC 601 West 5th Avenue, Suite 310 Anchorage, AK 99501
Stationary Source Name:		**Kustatan Production Facility**
Location:		60º 43´ 28" North; 151º 45´ 36" West
Physical Address:		West Forelands of Cook Inlet Alaska
Owner:		**Cook Inlet Energy, LLC** 601 West 5th Avenue, Suite 310 Anchorage, AK 99501
Operator:		Cook Inlet Energy, LLC 601 West 5th Avenue, Suite 310 Anchorage, AK 99501
Permittee's Responsible Official:		Leland Tate Senior Vice President/COO 601 West 5th Avenue, Suite 310 Anchorage, AK 99501
Designated Agent:		David Kumar, Production Mgr 601 West 5th Avenue, Suite 310 Anchorage, AK 99501 (907) 433 3822; dkumar@glacieroil.com
Stationary Source and Building Contact:		David Kumar/Jennifer Anderson 601 West 5th Avenue, Suite 310 Anchorage, AK 99501 (907) 433 3822; dkumar@glacieroil.com (907) 433 3822; jhenderson@glacieroil.com
Fee Contact:		Jennifer Anderson, R&C Mgr 601 West 5th Avenue, Suite 310 Anchorage, AK 99501 (907) 433 3822; jhenderson@glacieroil.com
Permit Contact:		Jennifer Anderson, R&C Mgr 601 West 5th Avenue, Suite 310 Anchorage, AK 99501 (907) 433 3822; jhenderson@glacieroil.com
Process Description:	SIC Code	1311: Crude Petroleum and Natural Gas Production
	NAICS Code:	211111: Crude Petroleum and Natural Gas Extraction

[18 AAC 50.040(j)(3) & 50.326(a)]
[40 C.F.R. 71.5(c)(1) & (2)]

Section 2. Emissions Unit Inventory and Description

Emissions units listed in Table A have specific monitoring, recordkeeping, or reporting conditions in this permit. Except as noted elsewhere in the permit, emissions unit descriptions and ratings are given for identification purposes only.

Table A - Emissions Unit Inventory

EU ID	Tag No.	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Installation or Construction Date
Turbine Generators						
1	G-157A	Taurus 60-T7301S	Turbine Generator #1	5,652 kW	Lean fuel	2002
2	G-157B	Taurus 60-T7301S	Turbine Generator #2	5,652 kW	Lean fuel	2002
2a	G-157C	Taurus 60-T7301S	Turbine Generator #3	5,652 kW	Lean fuel	2003
Heaters						
3	V-115A	NATCO Natural Draft Burners	Heater Treater #1	6.2 MMBtu/hr	Raw fuel gas	2002
4	V-115B	NATCO Natural Draft Burners	Heater Treater #2	6.2 MMBtu/hr	Raw fuel gas	2002
5	V-115C	NATCO Natural Draft Burners	Heater Treater #3	6.2 MMBtu/hr	Raw fuel gas	2002
6	H-112A	NATCO Natural Draft Burners	Crude Heater #1	8.0 MMBtu/hr	Raw fuel gas	2002
7	H-112B	NATCO Natural Draft Burners	Crude Heater #2	8.0 MMBtu/hr	Raw fuel gas	2002
8	H-112C	NATCO Natural Draft Burners	Crude Heater #3	8.0 MMBtu/hr	Raw fuel gas	2002
Diesel Engines						
9	P-115	Cummins 6BTA5.9	Fire Water Pump	160 hp	Diesel	2002
9a	B-2	Caterpillar 3406C	Backup Generator	530 hp	Diesel	2002
Miscellaneous Equipment						
10	H-150	Tornado TTI-SLT, Serial No. 2-3061	Process Flare	0.8 MMBtu/hr (1.92 mmscf/hr)	Raw fuel gas	2002
Storage Tanks						
12	T-133	Crude Tank No.1	Crude Storage Tank	10,000 bbls	N/A	2002
13	T-134	Crude Tank No.2	Crude Storage Tank	10,000 bbls	N/A	2002
14	T-135	Crude Tank No.3	Crude Storage Tank	10,000 bbls	N/A	2002
15	T140	Slop Oil Tank	Slop Oil Tank	10,000 bbls	N/A	2002
16	T-142	Produced Water Tank	Produced Water Tank	10,000 bbls	N/A	2002

[18 AAC 50.326(a)]
[40 C.F.R. 71.5(c)(3)]

Section 3. State Requirements

Visible Emissions Standard

1. Industrial Process and Fuel-Burning Equipment Visible Emissions. The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 10 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

[18 AAC 50.040(j), 50.055(a)(1), & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

1.1. For EU IDs 1 through 8, burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions unit burned only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.

1.2. For EU ID 9, as long as the emissions unit does not operate for more than 500 hours in a calendar year, monitoring shall consist of an annual compliance certification under Condition 71 with the visible emissions standard. Otherwise, monitor, record and report in accordance with Conditions 2 - 4 for the remainder of the permit term.

a. Monitor and record the monthly and calendar year-to-date operating hours.

b. Report the calendar year-to-date operating hours in the operating report under Condition 70 for the period covered by the report.

1.3. For EU ID 9a, as long as the emissions unit does not operate for more than 243 hours in a consecutive 12 months period, monitoring shall consist of an annual compliance certification under Condition 71 with the visible emissions standard. Otherwise, monitor, record and report in accordance with Conditions 2 - 4 for the remainder of the permit term.

a. Report the consecutive 12 months operating hours for each month, as described in Condition 17.3.b.

1.4. For EU ID 10, monitor, record and report in accordance with Condition 5.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Visible Emissions Monitoring, Recordkeeping, and Reporting (MR&R)

Liquid Fuel-burning Emissions Units (EU IDs 9 and 9a)

2. Visible Emissions Monitoring. When required by any of Conditions 1.2 or 1.3, or in the event of replacement of any of EU IDs 9 and 9a during the permit term, the Permittee shall observe the exhaust of the emissions unit for visible emissions using either the Method 9 Plan under Condition 2.3 or the Smoke/No-Smoke Plan under Condition 2.4.

2.1. The Permittee may change visible emissions monitoring plan for an emissions unit at any time unless prohibited from doing so by Condition 2.5.

2.2. The Permittee may for each unit elect to continue the visible emissions monitoring schedule in effect from the previous permit at the time a renewed permit is issued, if applicable.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

2.3. **Method 9 Plan.** For all 18-minute observations in this plan, observe exhaust, following 40 C.F.R. 60, Appendix A-4, Method 9, adopted by reference in 18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.

a. **First Method 9 Observation**. Except as provided in Condition 2.2 or Condition 2.5.c(ii), for EU IDs 9 and 9a, observe exhaust for 18 minutes within six months after the issue date of this permit. For any emissions unit, observe exhaust for 18 minutes within 14 calendar days after changing from the Smoke/No-Smoke Plan of Condition 2.4.

(i) For any emissions unit replaced during the term of this permit, observe exhaust for 18 minutes within 30 days of startup.

(ii) For each existing emissions unit that exceeds the applicable operational threshold in Conditions 1.2 or 1.3, observe the exhaust for 18 minutes of operations within 30 days after the calendar month during which that threshold has been exceeded, or within 30 days of the unit's next scheduled operations, whichever is later.

b. **Monthly Method 9 Observations**. After the first Method 9 observation, perform 18-minute observations at least once in each calendar month that an emissions unit operates.

c. **Semiannual Method 9 Observations**. After observing emissions for three consecutive operating months under Condition 2.3.b, unless a six-minute average is greater than 15 percent and one or more observations are greater than 20 percent, perform 18-minute observations:

(i) within six months after the preceding observation, or

(ii) for an emissions unit with intermittent operations, within 30 days of startup following six months after the preceding observation.

d. **Annual Method 9 Observations**. After at least two semiannual 18-minute observations, unless a six-minute average is greater than 15 percent and one or more individual observations are greater than 20 percent, perform 18-minute observations:

(i) within 12 months after the preceding observation; or

(ii) for an emissions unit with intermittent operations, within 30 days of startup following twelve months after the preceding observation

e. **Increased Method 9 Frequency**. If a six-minute average opacity is observed during the most recent set of observations to be greater than 15 percent and one or more observations are greater than 20 percent, then increase or maintain the 18-minute observation frequency for that emissions unit to at least monthly intervals as described in Condition 2.3.b, until the criteria in Condition 2.3.c for semiannual monitoring are met.

2.4. **Smoke/No Smoke Plan.** Observe the exhaust for the presence or absence of visible emissions, excluding condensed water vapor.

a. **Initial Monitoring Frequency**. Observe the exhaust during each calendar day that an emissions unit operates.

b. **Reduced Monitoring Frequency**. After the emissions unit has been observed on 30 consecutive operating days, if the emissions unit operated without visible smoke in the exhaust for those 30 days, then observe emissions at least once in every calendar month that an emissions unit operates.

c. **Smoke Observed**. If smoke is observed, either begin the Method 9 Plan of Condition 2.3 or perform the corrective action required under Condition 2.5

2.5. **Corrective Actions Based on Smoke/No Smoke Observations**. If visible emissions are present in the exhaust during an observation performed under the Smoke/No Smoke Plan of Condition 2.4, then the Permittee shall either follow the Method 9 Plan of Condition 2.3 or

a. initiate actions to eliminate smoke from the emissions unit within 24 hours of the observation;

b. keep a written record of the starting date, the completion date, and a description of the actions taken to reduce smoke; and

c. after completing the actions required under Condition 2.5.a,

(i) make smoke/no smoke observations in accordance with Condition 2.4

(A) at least once per day for the next seven operating days and until the initial 30 day observation period is completed; and

(B) continue as described in Condition 2.4.b; or

(ii) if the actions taken under Condition 2.5.a do not eliminate the smoke, or if subsequent smoke is observed under the schedule of Condition 2.5.c(i)(A), then observe the exhaust using the Method 9 Plan unless the Department gives written approval to resume observations under the Smoke/No Smoke Plan; after observing smoke and making observations under the Method 9 Plan, the Permittee may at any time take corrective action that eliminates smoke and restart the Smoke/No Smoke Plan under Condition 2.4.a.

3. Visible Emissions Recordkeeping. When required by any of Conditions 1.2 or 1.3, or in the event of replacement of any of EU IDs 9 and 9a during the permit term, the Permittee shall keep records as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(ii)]

3.1. If using the Method 9 Plan of Condition 2.3,

a. the observer shall record

(i) the name of the stationary source, emissions unit and location, emissions unit type, observer's name and affiliation, and the date on the Visible Emissions Observation Form in Section 11;

(ii) the time, estimated distance to the emissions location, sun location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), plume background, and operating mode (load or fuel consumption rate or best estimate if unknown) on the sheet at the time opacity observations are initiated and completed;

(iii) the presence or absence of an attached or detached plume and the approximate distance from the emissions outlet to the point in the plume at which the observations are made;

(iv) opacity observations to the nearest five percent at 15-second intervals on the Visible Emission Observation Form in Section 11, and

(v) the minimum number of observations required by the permit; each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.

b. To determine the six-minute average opacity, divide the observations recorded on the record sheet into sets of 24 consecutive observations; sets need not be consecutive in time and in no case shall two sets overlap; for each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24; record the average opacity on the sheet.

c. Calculate and record the highest six-minute and 18-consecutive-minute averages observed.

3.2. If using the Smoke/No Smoke Plan of Condition 2.4, record the following information in a written log for each observation and submit copies of the recorded information upon request of the Department:

a. the date and time of the observation;

b. from Table A, the ID of the emissions unit observed;

c. whether visible emissions are present or absent in the exhaust;

d. a description of the background to the exhaust during the observation;

e. if the emissions unit starts operation on the day of the observation, the startup time of the emissions unit;

f. name and title of the person making the observation; and

g. operating rate (load or fuel consumption rate).

4. Visible Emissions Reporting. When required by any of Conditions 1.2 or 1.3, or in the event of replacement of any of EU IDs 9 or 9a during the permit term, the Permittee shall report visible emissions as follows:

[18 AAC 50.040(j), 50.326(j) & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

4.1. Include in each operating report required under Condition 70:

a. which visible emissions plan of Condition 2 was used for each emissions unit; if more than one plan was used, give the time periods covered by each plan;

b. for each emissions unit under the Method 9 Plan,

(i) copies of the observation results (i.e. opacity observations) for each emissions unit that used the Method 9 Plan, except for the observations the Permittee has already supplied to the Department; and

(ii) a summary to include:

(A) number of days observations were made;

(B) highest six-minute and 18-consecutive-minute averages observed; and

(C) dates when one or more observed six-minute averages were greater than 20 percent;

c. for each emissions unit under the Smoke/No Smoke Plan, the number of days that smoke/no smoke observations were made and which days, if any, that smoke was observed; and

d. a summary of any monitoring or recordkeeping required under Conditions 2 and 3 that was not done;

4.2. Report under Condition 69:

a. the results of Method 9 observations that exceed an average of 20 percent opacity for any six-minute period; and

b. if any monitoring under Condition 2 was not performed when required, report within three days of the date the monitoring was required.

Flares (EU ID 10)

5. **Visible Emissions MR&R.** The Permittee shall observe one daylight flare event[1] within 12 months of the preceding flare event observation. If no event exceeds 1 hour within that 12-month period, then the Permittee shall observe the next daylight flare event.

5.1. Monitor visible emissions during flare events using Method 9 for 18 minutes.

5.2. Record the following information for observed events:

a. the flare EU ID number;

b. results of the Method-9 observations;

c. reason(s) for flaring;

d. date, beginning and ending time of event; and

e. volume of gas flared.

5.3. Monitoring of a flare event may be postponed for safety or weather reasons, or because a qualified observer is not available. If monitoring of a flare event is postponed for any of the reasons described in this condition, the Permittee shall include in the next operating report required by Condition 70 an explanation of the reason the event was not monitored.

5.4. Attach copies of the records required by Condition 5.2 with the operating report required by Condition 70 for the period covered by that report.

5.5. Report under Condition 69 whenever the opacity standard in Condition 1 is exceeded.

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Particulate Matter Emissions Standard

6. **Industrial Process and Fuel-Burning Equipment Particulate Matter.** The Permittee shall not cause or allow particulate matter emitted from EU EU IDs 1 through 10 listed in Table A to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

[18 AAC 50.040(j), 50.055(b)(1) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

6.1. For EU IDs 1 through 8, burn only gas as fuel. Monitoring for these emissions units shall consist of a statement in each operating report under Condition 70 indicating whether each of these emissions units fired only gas during the period covered by the report. Report under Condition 69 if any fuel other than gas is burned.

[1] For purposes of this permit, a "*flare event*" is flaring of gas for greater than one hour as a result of scheduled release operations, i.e. maintenance or well testing activities. It does not include non-scheduled release operations, i.e. process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations.

6.2. For EU ID 9, as long as the emissions unit does not operate for more than 500 hours in a calendar year, monitoring shall consist of an annual compliance certification under Condition 71 with the particulate matter emissions standard. Otherwise, monitor, record and report in accordance with Conditions 7 - 9 for the remainder of the permit term for that emissions unit.

a. Comply with Conditions 1.2.a and 1.2.b

6.3. For EU 9a, as long as the emissions unit does not operate for more than 243 hours in a consecutive 12 months period, monitoring shall consist of an annual compliance certification under Condition 71 with the particulate matter emissions standard. Otherwise, monitor, record and report in accordance with Conditions 7 - 9 for the remainder of the permit term for that emissions unit.

a. Comply with Condition 1.3.a.

6.4. For EU ID 10, the Permittee must annually certify compliance under Condition 71 with the particulate matter standard.

[18 AAC 50.040(j), 50.326(j) & 50.346(c)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Particulate Matter MR&R

Liquid Fuel-Burning Engines (EU IDs 9 and 9a)

7. Particulate Matter Monitoring. The Permittee shall conduct source tests on diesel engines, EU IDs 9 and 9a, to determine the concentration of particulate matter in the exhaust of each emissions unit as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

7.1. Except as exempted in Condition 7.4, within six months of exceeding the criteria of Conditions 7.2.a or 7.2.b, either

a. conduct a particulate matter source test according to requirements set out in Section 6; or

b. make repairs so that emissions no longer exceed the criteria of Condition 7.2; to show that emissions are below those criteria, observe visible emissions as described in Condition 2.3 under load conditions comparable to those when the criteria were exceeded.

7.2. Conduct the particulate matter source test or make repairs according to Condition 7.1 if

a. 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity greater than 20 percent; or

b. for an emissions unit with an exhaust stack diameter that is less than 18 inches, 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity that is greater than 15 percent and not more than 20 percent, unless the Department has waived this requirement in writing.

7.3. During each one-hour particulate matter source test run, observe the exhaust for 60 minutes in accordance with Method 9 and calculate the average opacity that was measured during each one-hour test run. Submit a copy of these observations with the source test report.

7.4. The automatic particulate matter source test requirements in Conditions 7.1 and 7.2 are waived for an emissions unit if a particulate matter source test on that unit has shown compliance with the particulate matter standard during this permit term.

8. **Particulate Matter Recordkeeping.** The Permittee shall keep records of the results of any particulate matter testing and visible emissions observations conducted under Condition 7.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(ii)]

9. **Particulate Matter Reporting.** The Permittee shall report as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

9.1. Report under Condition 69

a. within 30 days of the end of the month in which the source testing occur, if the results of any particulate matter source test conducted under Condition 7.1.a exceeds the particulate matter emissions limit; or

b. within the next 24 hours of the date compliance with Condition 7.1 was required, if the Permittee did not comply with either Condition 7.1.a or 7.1.b when required;

9.2. Report observations in excess of the threshold of Condition 7.2.b within 30 days of the end of the month in which the observations occur;

9.3. In each operating report under Condition 70, include:

a. the dates, EU ID(s), and results when an observed 18-minute average was greater than an applicable threshold in Condition 7.2;

b. a summary of the results of any particulate matter testing under Condition 7; and

c. copies of any visible emissions observation results (opacity observations) greater than the thresholds of Condition 7.2, if they were not already submitted.

Sulfur Compound Emissions Standard

10. **Sulfur Compound Emissions.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EU IDs 1 through 10 listed in Table A to exceed 500 parts per million (ppm) averaged over three hours.

[18 AAC 50.040(j), 50.055(c) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

Sulfur Compound MR&R

Fuel Oil[2] (EU IDs 9 and 9a)

11. **Sulfur Content of Fuel Oil**. The Permittee shall comply with Condition 16.

12. **Fuel Oil Sulfur Compounds Monitoring and Recordkeeping**. The Permitte shall monitor and record as follows:

12.1. If the fuel grade requires a sulfur content less than 0.5 percent by weight, keep receipts that specify fuel grade and amount; or

12.2. If the fuel grade does not require a sulfur content less than 0.5 percent by weight, keep receipts that specify fuel grade and amount and

a. test the fuel for sulfur content of each shipment; or

b. obtain test results showing the sulfur content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent.

12.3. Fuel testing under Condition 12.2.a must follow an appropriate method listed in 18 AAC 50.035 or another method approved in writing by the Department.

13. **Fuel Oil Sulfur Compounds Reporting.** The Permittee shall report as follows:

13.1. If sulfur content of the fuel burned in EU IDs 9 or 9a exceeds 0.5 percent by weight, the Permittee shall report under Condition 70.

13.2. The Permittee shall include in the operating report required by Condition 70

a. a list of the fuel grades received at the stationary source during the reporting period;

b. for any grade with a maximum fuel sulfur greater than 0.5 percent sulfur, the fuel sulfur of each shipment; and

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)]

Fuel Gas (EU IDs 1 through 8 and 10)

14. The Permittee will comply with the limit in Condition 10 as follows:

14.1. **Hydrogen sulfide (H_2S) Content of Gas Burned in EU IDs 1, 2, and 2a.** For EU IDs 1, 2, and 2a, the Permittee shall comply with Condition 30.

14.2. **H_2S Content of Gas Burned in EU IDs 3 – 8 and 10**. For EU IDs 3 through 8 and 10, the H_2S content of the gas burned in the emission units shall not exceed 700 parts per million by volume (ppmv)[3].

[2] *Oil* means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil, as defined in 40 C.F.R. 60.41b.

[3] Permittee assumed 700 ppmv H_2S in estimating SO_2 emissions from EU IDs 3-8 and 10.

14.3. **Fuel Gas Sulfur Compounds Monitoring.** For EU IDs 1, 2, 2a, 3 through 8, and 10, the Permittee shall analyze a representative sample of each fuel (raw fuel gas and lean fuel gas) monthly to determine the H_2S content using either ASTM D4810-88 (Reapproved 1999), D4913-89 (Reapproved 1995), or a listed method approved in 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1).

a. If total H_2S content of the gas burned in the emission units exceeds 100 ppmv, then monitor weekly. If H_2S content of the gas burned in the emission units exceeds 700 ppmv, then monitor the H_2S content of the gas daily.

14.4. **Fuel Gas Sulfur Compound Recordkeeping.** The Permittee shall keep records of the H_2S content analysis required under Condition 14.3.

14.5. **Fuel Gas Sulfur Compound Reporting.** The Permittee shall report as follows:

a. Notify the Department at the end of the month for which the fuel gas H_2S content initially exceeds the Condition 14.3 monthly monitoring threshold of 100 ppmv.

b. Notify the Department at the end of the month for which the fuel gas H_2S content initially exceeds the Condition 14.3.a weekly monitoring threshold of 700 ppmv.

c. Report as excess emissions, in accordance with Condition 69, whenever the fuel combusted causes sulfur compound emissions to exceed the standard of Condition 10.

d. Include copies of the records required by Condition 14.4 with the operating report required by Condition 70 for the period covered by the report.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Preconstruction Permit [4] Requirements

Ambient Air Quality Standards

15. Ambient air quality standards compliance for the stationary source operation is demonstrated at the posted boundary specified in Cook Inlet Energy's Access Control Plan set out in Section 11. Establish and maintain ambient air boundaries as described in Section 11.

[Minor Permit No. AQ0741MSS02, Condition 4, 2/23/2015]
[18 AAC 50.326(a)]
[40 C.F.R. 71.2&71.6(a)(1) & (3)]

16. **SO_2 Requirements**. Limit the fuel sulfur content of the diesel fuel burned at the Kustatan Production Facility to no greater than 0.5 percent by weight.

[4] *Preconstruction Permit* refers to federal PSD permits, state-issued permits-to-operate issued on or before January 17, 1997 (these permits cover both construction and operations), construction permits issued on or after January 18, 1997, and minor permits issued on or after October 1, 2004.

16.1. Monitor and record as described in Condition 12.

16.2. Report as described in Condition 13.

[Minor Permit No. AQ0741MSS02, Condition 5, 2/23/2015]
[18 AAC 50.326(a)]
[40 C.F.R. 71.2&71.6(a)(1) & (3)]

Limits to Avoid Classification as PSD Major Source.

17. Nitrogen Oxides (NOx) Emission Limits.

17.1. Limit NOx emissions from EU IDs 1, 2, and 2a as follows:

a. Install "SoLoNOx" low NOx combustion technology on EU IDs 1, 2, and 2a;

b. Limit combined NOx emissions from EUs 1, 2 and 2a to no greater than 64.5 tons per 12-month rolling period, expressed as NO_2.

17.2. **Monitoring, Recording, and Reporting** NOx Emissions for EU IDs 1, 2, and 2a.

a. Calculate and record the NOx emissions, expressed as NO_2 for each monthly period and 12 month rolling period using hours of operation and the following emission factors[5]:

(i) 3.9 pounds per hour (lb/hr) for EU 1

(ii) 4.1 lb/hr for EU 2; and

(iii) 6.6 lb/hr for EU 2a; and

b. Verify NOx emission factors from the source testing required by Condition 29.1.a. Use exhaust properties determined by 40 CFR 60 Appendix A, Method 19, for each load tested. Use higher heating value throughout the analysis.

c. In the first operating report due after the Department approval of the source test results, calculate and report the NOx emissions using the worst case emission factor for each of the emission units based on the latest source test results for each these emission units. Alternatively, upon Department written approval, the Permittee may recalculate emissions using the new emission factors beginning effective with the month in which the source test was conducted.

d. Report the cumulative total monthly and 12-month rolling NOx emissions, expressed as NO_2, from EUs 1, 2 and 2a in the operating report required by Condition 70.

17.3. Limit operations of EU 9a to no more than 500 hours per 12-month rolling period.

[5] Emission factors are from most recent Department approved source test at the time of permit issuance plus 10% to adjust for load and temperature.

a. Monitor and record the hours of operation of EU 9a for each calendar month.

b. Report the cumulative total monthly and 12 month rolling hours of operation of EU 9a in the operating report required Condition 70.

[Minor Permit No. AQ0741MSS02, Condition 6, 2/23/2015]
[18 AAC 50.326(a)]
[40 C.F.R. 71.2&71.6(a)(1) & (3)]

18. Carbon Monoxide (CO) Emissions Limits for EU IDs 1, 2, 2a, and 10.

18.1. For EU ID 10, limit the fuel gas burned to no more than 70 million standard cubic feet (MMscf) in any 12-month rolling period.

a. Monitor the fuel gas burned in EU ID 10 for each calendar month. Use flow meters and totalizers accurate to ±10%. Calculate and record the 12-month rolling fuel gas burned for each month of the reporting period, by the end of the following month.

b. Report in the operating report required by Condition 70 the 12-month rolling fuel gas burned recorded in 18.1.a for each month of the reporting period.

18.2. For EUs 1, 2 and 2a, limit combined total CO emissions to less than 136 tons per 12-month rolling period.

18.3. Operate EUs 1, 2 and 2a at all times, except at startup, shutdown, and performance and emission tests at no less than the lower of either 50% load or the minimum load for which the most recent CO emission source tests were conducted.

18.4. **Monitoring, Recording and Reporting** for EU IDs 1, 2, and 2a:

a. Verify CO emission factors from applicable measurements from the source testing required by Condition 29.1.a. Use exhaust properties determined by 40 CFR 60 Appendix A, Method 19, for each load tested. Use higher heating value throughout the analysis.

b. If the combined emission factors for EUs 1, 2 and 2a for worst case operation exceed 31 lb/hr[6], calculate and record the CO emissions for each month and 12 month rolling period for the period preceding submission of the source test results. Use hours of operation and the worst case emission factor for each unit in the calculations.

c. For each of EUs 1, 2 and 2a, monitor the date, time, duration and reason for all operations less than the load listed in Condition 18.3.

d. Report in the operating report required by Condition 70 the cumulative 12-month rolling CO emission from EUs 1, 2, and 2a recorded in Condition

[6] Combined emission factor of 31 lb/hr for units 1, 2 and 2a is equivalent to 136 tpy of unlimited operations.

18.4.b for each month of the reporting period. The Permittee is exempt from reporting CO emissions prior to submission of source test results.

[Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015]
[18 AAC 50.326(a)]
[40 C.F.R. 71.2 & 71.6(a)(1) & (3)]

19. Volatile Organic Compounds (VOC) Emission Limits – Tank Closed Vent System. Equip the crude tanks, slop oil tank and produced water tank, EU IDs 12 through 16, with a closed vent system and control device meeting the following specifications:

19.1. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions;

19.2. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater

[Minor Permit No. AQ0741MSS02, Condition 7, 2/23/2015]
[18 AAC 50.326(a)]
[40 C.F.R. 71.2 & 71.6(a)(1) & (3)]

Insignificant Emissions Units

20. For emissions units at the stationary source that are insignificant as defined in 18 AAC 50.326(e)-(i) that are not listed in this permit, the following apply:

20.1. **Visible Emissions Standard**: The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from an industrial process, fuel-burning equipment, or an incinerator to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

[18 AAC 50.050(a) & 50.055(a)(1)]

20.2. **Particulate Matter Standard**: The Permittee shall not cause or allow particulate matter emitted from an industrial process or fuel-burning equipment to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

[18 AAC 50.055(b)(1)]

20.3. **Sulfur Standard**: The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from an industrial process or fuel-burning equipment, to exceed 500 ppm averaged over three hours.

[18 AAC 50.055(c)]

20.4. General MR&R for Insignificant Emissions Units:

a. The Permittee shall submit the compliance certifications of Condition 71 based on reasonable inquiry;

b. The Permittee shall comply with the requirements of Condition 52;

c. The Permittee shall report in the operating report required by Condition 70 if an emissions unit has historically been classified as insignificant because of actual emissions less than the thresholds of 18 AAC 50.326(e) and current actual emissions become greater than any of those thresholds; and

d. No other monitoring, recordkeeping or reporting is required.

[18 AAC 50.346(b)(4)]

Section 4. Federal Requirements

40 C.F.R. Part 60 New Source Performance Standards (NSPS)

Subpart A – General Provisions

21. **NSPS Subpart A Notification.** For any affected facility[7] or existing facility[8] regulated under NSPS requirements in 40 C.F.R. 60, the Permittee shall furnish the Department and EPA written notification or, if acceptable to both the EPA and the Permittee, electronic notification, as follows:

[18 AAC 50.035 & 50.040(a)(1)]
[40 C.F.R. 60.7(a) & 60.15(d), Subpart A]

21.1. A notification of the date construction (or reconstruction as defined under 40 C.F.R. 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

[40 C.F.R. 60.7(a)(1), Subpart A]

21.2. A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

[40 C.F.R. 60.7(a)(3), Subpart A]

21.3. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 C.F.R. 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include:

a. information describing the precise nature of the change,

b. present and proposed emission control systems,

c. productive capacity of the facility before and after the change, and

d. the expected completion date of the change.

[40 C.F.R. 60.7(a)(4), Subpart A]

21.4. Any proposed replacement of an existing facility, for which the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, postmarked as soon as practicable, but no less than 60 days before commencement of replacement, and including the following information:

[40 C.F.R. 60.15(d), Subpart A]

a. the name and address of owner or operator,

[7] *Affected facility* means, with reference to a stationary source, any apparatus to which a standard applies, as defined in 40 C.F.R. 60.2.

[8] *Existing facility* means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type, as defined in 40 C.F.R. 60.2.

b. the location of the existing facility,

c. a brief description of the existing facility and the components that are to be replaced,

d. a description of the existing and proposed air pollution control equipment,

e. an estimate of the fixed capital cost of the replacements, and of constructing a comparable entirely new facility,

f. the estimated life of the existing facility after the replacements, and

g. a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements .

22. NSPS Subpart A Startup, Shutdown, & Malfunction Requirements. The Permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EU IDs 1, 2, and 2a, any malfunction of the associated air pollution control equipment, or any periods during which a continuous monitoring system (CMS) or monitoring device for EU IDs 1, 2, or 2a is inoperative.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(b), Subpart A]

23. NSPS Subpart A Excess Emissions and Monitoring Systems Performance (EEMSP) Report. The Permittee shall submit an EEMSP[9, 10] report and / or summary report form for EU IDs 1, 2, and 2a[11] to the Department and to EPA. Submit the report semiannually. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(c), Subpart A]

23.1. The magnitude of excess emissions computed in accordance with 40 C.F.R. 60.13(h)(3), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period.

[40 C.F.R. 60.7(c)(1), Subpart A]

23.2. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of EU IDs 1, 2, and 2a the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

[40 C.F.R. 60.7(c)(2), Subpart A]

9 The Federal EEMSP report is not the same as the State excess emission report required by Condition 69.

10 Periods of excess emissions and monitor downtime for units subject to the NSPS Subpart GG SO_2 limit (EU IDs 1 & 2) are defined in 40 C.F.R. 60.334(j)(2).

11 Condition 24 describes the summary report form requirements. See Conditions 24.1 and 24.2 for information on when the EEMSP report of Condition 23 is required to be submitted along with the summary report form of Condition 24.

23.3. The date and time identifying each period during which a CMS was inoperative except for zero and span checks and the nature of any repairs or adjustments.

[40 C.F.R. 60.7(c)(3), Subpart A]

23.4. When no excess emissions have occurred or the CMS have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 C.F.R. 60.7(c)(4), Subpart A]

24. NSPS Subpart A EEMSP Summary Report Form. The Permittee shall submit to the Department and to EPA one "summary report form" in the format shown in Figure 1 of 40 C.F.R. 60.7 (see Attachment A of the Statement of Basis) for each pollutant monitored for EU IDs 1, 2, and 2a.:

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(c) & (d), Subpart A]

24.1. If the total duration of excess emissions for the reporting period is less than one percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than five percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in Condition 23 need not be submitted unless requested by the Administrator, or

[40 C.F.R. 60.7(d)(1), Subpart A]

24.2. If the total duration of excess emissions for the reporting period is one percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is five percent or greater of the total time for the reporting period, the summary report form and the excess emissions report described in Condition 23 shall both be submitted.

[40 C.F.R. 60.7(d)(2), Subpart A]

25. NSPS Subpart A Performance (Source) Tests. The Permittee shall shall conduct source tests according to Section 6 and as required in this condition on any affected facility at such times as may be required by the EPA, and shall provide the Department and EPA with a written report of the results of the source tests.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.8(a), Subpart A]

26. NSPS Subpart A Good Air Pollution Control Practice. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate EU IDs 1, 2, and 2a including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. The Administrator will determine whether acceptable operating and maintenance procedures are being used based on information available, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance records, and inspections of EU IDs 1, 2, and 2a.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.11(d), Subpart A]

27. **NSPS Subpart A Credible Evidence.** For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of the standards set forth in Conditions 29 or 30, nothing in 40 C.F.R. Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 1, 2, and 2a would have been in compliance with applicable requirements of 40 C.F.R. Part 60 if the appropriate performance or compliance test or procedure had been performed.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.11(g), Subpart A]

28. **NSPS Subpart A Concealment of Emissions.** The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of a standard set forth in Conditions 29 and 30. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.12, Subpart A]

NSPS, Subpart GG Requirements

29. **NSPS Subpart GG NOx Standard.** The Permittee shall not allow the exhaust gas concentration of NOx from EU IDs 1, 2, and 2a, listed in Table A, to exceed 173.6 ppmvd at 15 percent O_2 dry exhaust basis, International Standards Organization corrected.

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.332(a)(2) & (d), Subpart GG]

29.1. **Monitoring**. The Permittee shall comply with the following:

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(i) & (c)(6)]

a. **Periodic Testing**. For each turbine subject to Condition 29 that operates for 400 hours or more in any consecutive 12-month period during the life of this permit, the Permittee shall satisfy either Condition 29.1.a(i) or 29.1.a(ii).

(i) For existing turbines whose latest emissions source testing was certified as operating at less than or equal to 90 percent of the limit shown in Condition 29, the Permittee shall conduct a NOx and O_2 source test under 40 C.F.R. 60, Appendix A, Method 20, or Method 7E and either Method 3 or 3A, within the first applicable criteria below in the noted timeframe no later than April 4, 2022, except as set out in Conditions 29.1.a(i)(C) and 29.1.a(ii):

(A) Within 5 years of the latest performance test, or

(B) Within 1 year of the the effective date of this permit if the last source test occurred greater than five years prior to the effective date of this permit and the 400-hour threshold was triggered within 6 months of the permit's effective date, or

(C) Within 1 year after exceeding 400 hours of operation in a 12-month period if the last source test occurred greater than 4 years prior to the exceedance.

(ii) For existing turbines whose latest emissions source testing was certified as operating at greater than 90 percent of the limit shown in Condition 29, the Permittee shall conduct a NOx and O_2 source test under 40 C.F.R. 60, Appendix A, Method 20, or Method 7E and either Method 3 or 3A, annually until two consecutive tests show performance results certified at less than or equal to 90 percent of the limit of Condition 29.

b. **Substituting Test Data**. The Permittee may use a Method 20, or Method 7E and either Method 3 or 3A, , test under Condition 29.1.a performed on only one of a group of turbines to satisfy the requirements of those conditions for the other turbines in the group if

(i) the Permittee demonstrates that test results are less than or equal to 90 percent of the emission limit of Condition 29, and are projected under Condition 29.1.c to be less than or equal to 90 percent of the limit at maximum load;

(ii) for any source test conducted after the effective date of this permit, the Permittee identifies in a source test plan under Condition 61

(A) the turbine to be tested;

(B) the other turbines in the group that are to be represented by the test; and

(C) why the turbine to be tested is representative, including that each turbine in the group

(1) is located at a stationary source operated and maintained by the Permittee;

(2) is tested under close to identical ambient conditions;

(3) is the same make and model and has identical injectors and combustor;

(4) uses the same fuel type from the same supply origin.

(iii) The Permittee may not use substitute test results to represent emissions from a turbine or group of turbines if that turbine or group of turbines is operating at greater than 90 percent of the emission limit of Condition 29.

c. **Load**. The Permittee shall comply with the following:

(i) Conduct all tests under Condition 29.1 in accordance with 40 C.F.R. 60.335(b)(2), except as otherwise approved in writing by the Department, or by EPA if the circumstances at the time of the EPA approval are still valid. For the highest load condition, if it is not possible to operate the turbine during the test at maximum load, the Permittee will test the turbine when operating at the highest load achievable by the turbine under the ambient and stationary source operating conditions in effect at the time of the test.

(ii) Demonstrate in the source test plan for any test performed after the effective date of this permit whether the test is scheduled when maximum NOx emissions are expected.

(iii) If the highest operating rate tested is less than the maximum load of the tested turbine or another turbine represented by the test data,

(A) for each such turbine the Permittee shall provide to the Department as an attachment to the source test report

(1) additional test information from the manufacturer or from previous testing of units in the group of turbines; if using previous testing of the group of turbines, the information must include all available test data for the turbines in the group, and

(2) a demonstration based on the additional test information that projects the test results from Condition 29.1 to predict the highest load at which emissions will comply with the limit in Condition 29;

(B) the Permittee shall not operate any turbine represented by the test data at loads for which the Permittee's demonstration predicts that emissions will exceed the limit of Condition 29;

(C) the Permittee shall comply with a written finding prepared by the Department that

(1) the information is inadequate for the Department to reasonably conclude that compliance is assured at any load greater than the test load, and that the Permittee must not exceed the test load,

(2) the highest load at which the information is adequate for the Department to reasonably conclude that compliance assured is less than maximum load, and the Permittee must not exceed the highest load at which compliance is predicted, or

(3) the Permittee must retest during a period of greater expected demand on the turbine, and

(D) the Permittee may revise a load limit by submitting results of a more recent approved source test done at a higher load, and, if necessary, the accompanying information and demonstration described in Condition 29.1.c(iii)(A); the new limit is subject to any new Department finding under Condition 29.1.c(iii)(C) and

(iv) In order to perform an emission test required by Conditions 29.1.a and 29.1.b, the Permittee may operate a turbine at a higher load than that prescribed by Condition 29.1.c(iii).

(v) For the purposes of Conditions 29.1 through 29.3, maximum load means the hourly average load that is the smallest of

(A) 100 percent of manufacturer's design capacity of the gas turbine at ISO standard day conditions;

(B) the highest load allowed by an enforceable condition that applies to the turbine; or

(C) the highest load possible considering permanent physical restraints on the turbine or the equipment which it powers.

29.2. **Recordkeeping**. The Permittee shall keep records as follows:

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(ii) & (c)(6)]

a. The Permittee shall comply with the following for each turbine for which a demonstration under Condition 29.1.c(iii) does not show compliance with the limit of Condition 29 at maximum load.

(i) The Permittee shall keep records of

(A) load; or

(B) as approved by the Department, surrogate measurements for load and the method for calculating load from those measurements.

(ii) Records in Condition 29.2.a shall be hourly or otherwise as approved by the Department.

(iii) Within one month after submitting a demonstration under Condition 29.1.c(iii)(A)(2) that predicts that the highest load at which emissions will comply is less than maximum load, or within one month of a Department finding under Condition 29.1.c(iii)(C), whichever is earlier, the Permittee shall propose to the Department how they will measure load or load surrogates, and shall propose and comply with a schedule for installing any necessary equipment and beginning monitoring. The Permittee shall comply with any subsequent Department direction on the load monitoring methods, equipment, or schedule.

b. For any turbine subject to Condition 29, that will operate less than 400 hours in any 12 consecutive months, the Permittee shall keep monthly records of the hours of operation.

29.3. **Reporting**. The Permittee shall keep report as follows

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(iii) & (c)(6)]

a. In each operating report under Condition 70 the Permittee shall list for each turbine tested or represented by testing at less than maximum load and for which the Permittee must limit load under Condition 29.1.c(iii)

(i) the load limit;

(ii) the turbine identification; and

(iii) the highest load recorded under Condition 29.2.a during the period covered by the operating report.

b. In each operating report under Condition 70 for each turbine for which Condition 29.1 has not been satisfied because the turbine normally operates less than 400 hours in any 12 consecutive months, the Permittee shall identify

(i) the turbine;

(ii) the highest number of operating hours for any 12 consecutive months ending during the period covered by the report; and

(iii) any turbine that operated for 400 or more hours.

c. The Permittee shall report under Condition 69 if

(i) a test result exceeds the emission standard;

(ii) Method 20, or Method 7E and either Method 3 or 3A, testing is required under Condition 29.1.a(i) or 29.1.a(ii) but not performed, or

(iii) the turbine was operated at a load exceeding that allowed by Conditions 29.1.c(iii)(B) and 29.1.c(iii)(C); exceeding a load limit is deemed a single violation rather than a multiple violation of both monitoring and the underlying emission limit.

[18 AAC 50.220(a) - (c) & 50.040(a)(1)]
[40 C.F.R. 60.8(b), Subpart A]

30. **NSPS Subpart GG Sulfur Standard.** The Permittee shall comply with either the SO_2 standard in Condition 30.1, or the fuel sulfur content standard in Condition 30.2 below:

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.333, Subpart GG]

30.1. Do not allow the exhaust gas concentration of SO_2 from EU IDs 1, 2, and 2a, listed in Table A, to exceed 150 ppmvd corrected to 15 percent O_2, or

[40 C.F.R. 60.333(a), Subpart GG]

30.2. Do not allow the sulfur content for the fuel burned in EU IDs 1, 2, and 2a to exceed 0.8 percent by weight.

[40 C.F.R. 60.333(b), Subpart GG]

30.3. **Monitoring**. The Permittee shall monitor compliance with the standards listed in this condition, as follows:

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.334 & 60.335, Subpart GG]

a. Monitor the total sulfur content of the fuel being fired in the turbine, except as provided in Condition 30.3.b. The sulfur content of the fuel must be determined using total sulfur methods described in 40 C.F.R. 60.335(b)(10) and Condition 30.4. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4,000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86, which measure the major sulfur compounds may be used.

[40 C.F.R. 60.334(h)(1), Subpart GG]

b. The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 C.F.R. 60.331(u), regardless of whether an existing custom schedule approved by the Administrator requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration[12]:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data, which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in 40 C.F.R. 75, Appendix D, Section 2.3.1.4 or 2.3.2.4 is required.

[40 C.F.R. 60.334(h)(3), Subpart GG]

c. For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

[40 C.F.R. 60.334(h)(4), Subpart GG]

[12] Periodic fuel sulfur monitoring under Condition 30.3.a and reporting under Conditions 23, 24, and 30.6 do not apply to Subpart GG turbines that have demonstrated that natural gas fuel meets the definition of 40 C.F.R. 60.331(u) as set out by Condition 30.3.b. Per 40 C.F.R. 60.334(i)(3)(i), a custom sulfur monitoring schedule under 60.334(i)(3)(ii)(A) is acceptable without prior Administrative approval.

d. The frequency of determining the sulfur content of the fuel shall be as follows:

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 60.334(i), Subpart GG]

(i) **Gaseous fuel.** For owners and operators that elect not to demonstrate sulfur content using options in Condition 30.3.b, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

[40 C.F.R. 60.334(i)(2), Subpart GG]

(ii) **Custom schedules**. Notwithstanding the requirements of Condition 30.3.d(i), operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 C.F.R. 60.334(i)(3)(i) and (i)(3)(ii), custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in Condition 30. The two custom sulfur monitoring schedules set forth in 40 C.F.R. 60.334(i)(3)(i)(A) through (D) and 60.334(i)(3)(ii) are acceptable without prior Administrative approval.

[40 C.F.R. 60.334(i)(3), Subpart GG]

30.4. **Test Methods and Procedures**. If the owner or operator is required under Conditions 30.3.a or 30.3.d(ii) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using Condition 30.4.a:

[18 AAC 50.040(a)(2)(V)]
[40 C.F.R. 60.335(b), Subpart GG]

a. For gaseous fuels, ASTM D1072-80, 90; D3246-81, 92, 96; D4468-85; or D6667-01. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

[40 C.F.R. 60.335(b)(10)(2), Subpart GG]

b. The fuel analyses required under Condition 30.4 may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[40 C.F.R. 60.335(b)(11), Subpart GG]

30.5. **Recordkeeping**. Keep records as required by Condition 30.3 and 30.4, and in accordance with Condition 65.

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(ii)]

30.6. **Reporting**. For each affected unit that periodically determines the fuel sulfur content under Condition 30.3.a, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with 40 C.F.R. 60.7(c) as summarized in Condition 23 except where otherwise approved by a custom fuel monitoring schedule. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction as described by 40 C.F.R. 60.334(j)(2).

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 60.334(j), Subpart GG]

40 C.F.R. 63 NESHAP

Subpart A – General Provisions

31. National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart A. For stationary compression ignition internal combustion engines (CI ICE) EU IDs 9 and 9a, you must comply with the applicable requirements of 40 C.F.R. 63 Subpart A in accordance with the provisions for applicability of Subpart A in NESHAP Subpart ZZZZ, Table 8.

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 63.1-63.15, Subpart A]
[40 C.F.R. 63.6665 & Table 8, NESHAP Subpart ZZZZ]

RICE Subject to NESHAP Subpart ZZZZ

32. Management Practices for RICEs at an Area Source of HAPs. For EU IDs 9 and 9a, you must comply with the applicable requirements in Table 2d to 40 C.F.R. 63, Subpart ZZZZ.

32.1. **Management Practices for Stationary Emergency[13] CI RICE**: For EU ID 9, you must comply with the following management practices:

a. Change oil and filter every 500 hours of operation or annually, whichever comes first;

b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary

c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

[40 C.F.R. 63.6603(a) and Table 2d, Item 4]

[13] If EU ID 9 is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required under Condition 32.1, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the Permittee may delay the management practice until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated.

[40 C.F. R. 63, Footnote 2 to Table 2d, Subpart ZZZZ]

32.2. **Management Practices for Non-Emergency Stationary CI RICEs > 500 hp at Area Sources not Accessible by the Federal Aid Highway System**: For EU ID 9a, you must comply with te following management practices:

a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;

b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary

c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

[40 C.F.R. 63.6603(a) & (b) and Table 2d, Item 1]

33. General Requirements: For EU IDs 9 and 9a, you must comply with the following:

[18 AAC 50.040(c)(23), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)(i)]

33.1. **Good Air Pollution Control Practices.** At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[40 C.F.R. 63.6605(b)]

33.2. **Operation and Maintenance Requirements**.

a. You must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[40 C.F.R. 63.6625(e)]

b. You must minimize the engine’s time spent at idle and minimize the engine’s startup time at startup to a period need for appropriate and safe loading of the engine, not to exceed 30 minutes

[40 C.F.R. 63.6625(h) & Table 2d, Column 3]

33.3. **Hour Meter**. For emergency engine EU ID 9, you must install a non-resettable hour meter if one is not already installed.

[40 C.F.R. 63.6625(f)]

33.4. **Oil Analysis Program for CI Engines**. You have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Condition 32. The oil analysis must be performed at the same frequency specified for changing the oil in Condition 32. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[40 C.F.R. 63.6625(i)]

34. Operating Hour Limits for Emergency Engine, EU ID 9.

34.1. **Operating Hour Limits for Emergency Engine.** You must operate the emergency stationary RICE according to the requirements in Conditions 34.1.a - 34.1.c. In order for the engine to be considered an emergency stationary RICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in Conditions 34.1.a - 34.1.c, is prohibited. If you do not operate the engine according to the requirements in Conditions 34.1.a - 34.1.c, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.

[18 AAC 50.040(c)(23)]
[40 C.F.R. 63.6640(f)]

a. There is no time limit on the use of emergency stationary RICE in emergency situations.

[40 C.F.R. 63.6640(f)(1)]

b. You may operate the emission units for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of these units is limited to 100 hours per calendar year. The Permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

[40 C.F.R. 63.6640(f)(2)]

c. You may operate the emission units up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing under Condition 34.1.b. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[40 C.F.R. 63.6640(f)(3) & (4)]

NESHAP Subpart ZZZZ Monitoring

35. Continuous Compliance: For EU IDs 9 and 9a, you must comply with the following:

[18 AAC 50.040(c)(23), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)(i)]

35.1. You must demonstrate continuous compliance with requirements in Condition 32 according to methods specified in Conditions 35.1.a and 35.1.b.

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or

b. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[40 C.F.R. 63.6640(a) & Table 6, Item 9, Subpart ZZZZ]

c. You must also report each instance in which you did not meet the requirements in Table 8 to NESHAP Subpart ZZZZ that apply to you.

[40 C.F.R. 63.6640(e)]

36. Recordkeeping. For EU IDs 9 and 9a, you must comply with the following:

36.1. Keep record of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan.

[40 C.F.R. 63.6655(e)]

36.2. For EU ID 9, keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. Document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

[40 C.F.R. 63.6655(f)]

36.3. Keep records in a form suitable and readily available for expeditious review according to 40 C.F.R. 63.10(b)(1).

[40 C.F.R. 63.6660(a)]

a. Keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or record.

[40 C.F.R. 63.6660(b)]

b. Keep records readily accessible in hard copy or electronic form for at least five years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 C.F.R. 63.6660(c)]

c. All the records may be maintained offsite.

[40 C.F.R. 63.10(b)(1)]
[Table 8 to NESHAP, Subpart ZZZZ]

37. **Reporting**. For EU IDs 9 and 9a, you must include in the operating report required by Condition 70, a report of deviations as defined in 40 C.F.R. 63.6675 for each instance in which an applicable requirement in 40 C.F.R. 63, Subpart A as specified in Table 8 to Subpart ZZZZ was not met.

[40 C.F.R. 63.6640(e), 63.6650(f)]

40 C.F.R. Part 61 NESHAP

Subpart A – General Provisions & Subpart M – Asbestos

38. The Permittee shall comply with the requirements set forth in 40 C.F.R. 61.145, 61.150, and 61.152 of Subpart M, and the applicable sections set forth in 40 C.F.R. 61, Subpart A and Appendix A.

[18 AAC 50.040(b)(1) & (2)(F), & 50.326(j)]
[40 C.F.R. 61, Subparts A & M, and Appendix A]

40 C.F.R. Part 82 Protection of Stratospheric Ozone

39. **40 C.F.R. Part 82 Protection of Stratospheric Ozone**

39.1. **Subpart F – Recycling and Emissions Reduction**. The Permittee shall comply with the standards for recycling and emissions reduction of refrigerants set forth in 40 C.F.R. 82, Subpart F.

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82, Subpart F]

39.2. **Subpart G – Significant New Alternatives.** The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.174 (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82.174(b) through (d), Subpart G]

39.3. **Subpart H – Halons Emissions Reduction.** The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.270 (Protection of Stratospheric Ozone Subpart H – Halon Emissions Reduction).

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82.270(b) through (f), Subpart H]

General NSPS and NESHAP Requirements

40. NESHAP Applicability Determinations. The Permittee shall determine rule applicability and designation of affected sources under NESHAPs for Source Categories (40 C.F.R. 63) in accordance with the procedures described in 40 C.F.R. 63.1(b) and 63.10(b)(3). If a source becomes affected by an applicable subpart of 40 C.F.R. 63, the Permittee shall comply with such standard by the compliance date established by the Administrator in the applicable subpart, in accordance with 40 C.F.R. 63.6(c).

40.1. After the effective date of any relevant standard promulgated by the Administrator under this part, an owner or operator who constructs a new affected source that is not major-emitting or reconstructs an affected source that is not major-emitting that is subject to such standard, or reconstructs a source such that the source becomes an affected source subject to the standard, must notify the Administrator and the Department of the intended construction or reconstruction. The notification must be submitted in accordance with the procedures in 40 C.F.R. 63.9(b).

[18 AAC 50.040(c)(1), 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(ii)]
[40 C.F.R. 63.1(b), 63.5(b)(4), 63.6(c)(1), & 63.10(b)(3)]

41. NSPS and NESHAP Reports. The Permittee shall:

41.1. **Reports:** Except for federal reports and notices submitted through EPA's CDX/CEDRI online reporting system, attach to the operating report required by Condition 70 for the period covered by the report, a copy of any NSPS and NESHAPs reports submitted to the U.S. Environmental Protection Agency (EPA) Region 10. For reports submitted through CDX/CEDRI, state in the operating report the date and a brief description of each of the online reports submitted during the reporting period; and

41.2. **Waivers**: Upon request by the Department, provide a written copy of any EPA-granted alternative monitoring requirement, custom monitoring schedule or waiver of the federal emission standards, recordkeeping, monitoring, performance testing, or reporting requirements. The Permittee shall keep a copy of each U.S. EPA-issued monitoring waiver or custom monitoring schedule with the permit.

[18 AAC 50.326(j)(4) & 50.040(j)]
[40 C.F.R. 60.13, 63.10(d) & (f) & 40 C.F.R. 71.6(c)(6)]

Section 5. General Conditions

Standard Terms and Conditions

42. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

[18 AAC 50.326(j)(3), 50.345(a) & (e)]

43. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and re-issuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

[18 AAC 50.326(j)(3), 50.345(a) & (f)]

44. The permit does not convey any property rights of any sort, nor any exclusive privilege.

[18 AAC 50.326(j)(3), 50.345(a) & (g)]

45. **Administration Fees.** The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-403.

[18 AAC 50.326(j)(1), 50.400, & 50.403]
[AS 37.10.052(b) & AS 46.14.240]

46. **Assessable Emissions.** The Permittee shall pay to the Department annual emission fees based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities 10 tons per year or greater. The quantity for which fees will be assessed is the lesser of

46.1. the stationary source's assessable potential to emit of 309 TPY; or

46.2. the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12-month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:

a. an enforceable test method described in 18 AAC 50.220;

b. material balance calculations;

c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

d. other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.

[18 AAC 50.040(j)(3), 50.035, 50.326(j)(1), 50.346(b)(1), 50.410, & 50.420]
[40 C.F.R. 71.5(c)(3)(ii)]

47. **Assessable Emission Estimates.** Emission fees will be assessed as follows:

47.1. no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Ste 303, PO Box 111800, Juneau, AK 99811-1800; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

47.2. if no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set out in Condition 46.1.

[18 AAC 50.040(j)(3), 50.326(j)(1), 50.346(b)(1), 50.410, & 50.420]
[40 C.F.R. 71.5(c)(3)(ii)]

48. **Good Air Pollution Control Practice.** The Permittee shall do the following for EU IDs 3 through 8, 10 and 12 through 16.

48.1. perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;

48.2. keep records of any maintenance that would have a significant effect on emissions; the records may be kept in electronic format; and

48.3. keep a copy of either the manufacturer's or the operator's maintenance procedures.

[18 AAC 50.326(j)(3), & 50.346(b)(5)]

49. **Dilution.** The Permittee shall not dilute emissions with air to comply with this permit. Monitoring shall consist of an annual certification that the Permittee does not dilute emissions to comply with this permit.

[18 AAC 50.045(a)]

50. **Reasonable Precautions to Prevent Fugitive Dust.** A person who causes or permits bulk materials to be handled, transported, or stored, or who engages in an industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air.

[18 AAC 50.045(d), 50.040(e), 50. 326(j)(3), & 50.346(c)]

50.1. The Permittee shall keep records of:

a. complaints received by the Permittee and complaints received by the Department and conveyed to the Permittee; and

b. any additional precautions that are taken

(i) to address complaints described in Condition 50.1.a or to address the results of Department inspections that found potential problems; and

(ii) to prevent future dust problems.

50.2. The Permittee shall report according to Condition 52.

51. Stack Injection. The Permittee shall not release materials other than process emissions, products of combustion, or materials introduced to control pollutant emissions from a stack at a stationary source constructed or modified after November 1, 1982, except as authorized by a minor or construction permit, Title V permit, or air quality control permit issued before October 1, 2004.

[18 AAC 50.055(g)]

52. Air Pollution Prohibited. No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property.

[18 AAC 50.110, 50.040(e), 50.326(j)(3) & 50.346(a)]
[40 C.F.R. 71.6(a)(3)]

52.1. **Monitoring, Recordkeeping, and Reporting** for Condition 52:

a. If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions according to Condition 69.

b. As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 52.

c. The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

(i) after an investigation because of a complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 52; or

(ii) the Department notifies the Permittee that it has found a violation of Condition 52.

d. The Permittee shall keep records of

(i) the date, time, and nature of all emissions complaints received;

(ii) the name of the person or persons that complained, if known;

(iii) a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 52; and

(iv) any corrective actions taken or planned for complaints attributable to emissions from the stationary source.

e. With each stationary source operating report under Condition 70, the Permittee shall include a brief summary report which must include

(i) the number of complaints received;

(ii) the number of times the Permittee or the Department found corrective action necessary;

(iii) the number of times action was taken on a complaint within 24 hours; and

(iv) the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

f. The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

53. Technology-Based Emission Standard. If an unavoidable emergency, malfunction (as defined in 18 AAC 50.235(d)), or non-routine repair (as defined in 18 AAC 50.990(64), causes emissions in excess of a technology-based emission standard[14] listed in Conditions 29, 30 and 39 (refrigerants), the Permittee shall

53.1. take all reasonable steps to minimize levels of emissions that exceed the standard, and

53.2. report in accordance with Condition 69; the report must include information on the steps taken to mitigate emissions and corrective measures taken or to be taken.

[18 AAC 50.235(a), 50.326(j)(4), & 50.040(j)(4)]
[40 C.F.R. 71.6(c)(6)]

Open Burning Requirements

54. Open Burning. If the Permittee conducts open burning at this stationary source, the Permittee shall comply with the requirements of 18 AAC 50.065. The Permittee shall:

54.1. keep written records to demonstrate that the Permittee complies with the limitations in this condition and the requirements of 18 AAC 50.065. Upon request by the Department, submit copies of the records; and

54.2. include this condition in the annual certification required under Condition 71.

[18 AAC 50.065, 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3)]

[14] As defined in 18 AAC 50.990(106), the term "*technology-based emission standard*" means a best available control technology (BACT) standard; a lowest achievable emission rate (LAER) standard; a maximum achievable control technology (MACT) standard established under 40 C.F.R. 63, Subpart B, adopted by reference in 18 AAC 50.040(c); a standard adopted by reference in 18 AAC 50.040(a) or (c); and any other similar standard for which the stringency of the standard is based on determinations of what is technologically feasible, considering relevant factors.

Section 6. General Source Testing and Monitoring Requirements

55. Requested Source Tests. In addition to any source testing explicitly required by the permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

[18 AAC 50.220(a) & 50.345(a) & (k)]

56. Operating Conditions. Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

[18 AAC 50.220(b)]

56.1. at a point or points that characterize the actual discharge into the ambient air; and

56.2. at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

57. Reference Test Methods. The Permittee shall use the following test methods when conducting source testing for compliance with this permit:

57.1. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60.

[18 AAC 50.220(c)(1)(A) & 50.040(a)]
[40 C.F.R. 60]

57.2. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(b) must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 61.

[18 AAC 50.040(b) & 50.220(c)(1)(B)]
[40 C.F.R. 61]

57.3. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) must be conducted in accordance with the source test methods and procedures specified in 40 C.F.R. 63.

[18 AAC 50.040(c) & 50.220(c)(1)(C)]
[40 C.F.R. 63]

57.4. Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in Reference Method 9. The Permittee may use the form in Section 11 to record data.

[18 AAC 50.030 & 50.220(c)(1)(D)]

57.5. Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals, and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

[18 AAC 50.040(a)(3) & 50.220(c)(1)(E)]
[40 C.F.R. 60, Appendix A]

57.6. Source testing for emissions of $PM_{2.5}$ and PM_{10} must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

[18 AAC 50.035(b)(2) & 50.220(c)(1)(F)]
[40 C.F.R. 51, Appendix M]

57.7. Source testing for emissions of any pollutant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

[18 AAC 50.040(c)(32) & 50.220(c)(2)]
[40 C.F.R. 63, Appendix A, Method 301]

58. Excess Air Requirements. To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emissions unit type, corrected to standard conditions (dry gas at 68°F and an absolute pressure of 760 millimeters of mercury).

[18 AAC 50.220(c)(3) & 50.990(102)]

59. Test Exemption. The Permittee is not required to comply with Conditions 61, 62 and 63 when the exhaust is observed for visible emissions by Method 9 Plan (Condition 2.3) or Smoke/No Smoke Plan (Condition 2.4).

[18 AAC 50.345(a)]

60. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

[18 AAC 50.345(a) & (l)]

61. Test Plans. Except as provided in Condition 59, before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 55 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

[18 AAC 50.345(a) & (m)]

62. Test Notification. Except as provided in Condition 59, at least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and the time the source test will begin.

[18 AAC 50.345(a) & (n)]

63. **Test Reports.** Except as provided in Condition 59, within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in Condition 66. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

[18 AAC 50.345(a) & (o)]

64. **Particulate Matter Calculations.** In source testing for compliance with the particulate matter standards in Conditions 6 and 20.2, the three-hour average is determined using the average of three one-hour test runs. The source test must account for those emissions caused by routine maintenance activities by ensuring that at least one test run includes the emissions caused by the routine maintenance activity and is conducted under conditions that lead to representative emissions from that activity. The emissions must be quantified using the following equation:

$$E = E_M\left[(A+B)\times\frac{S}{R\times A}\right]+E_{NM}\left[\frac{(R-S)}{R}-\frac{BS}{R\times A}\right]$$

Where:

E	=	the total particulate matter emissions of the emissions unit in grains per dry standard cubic foot (gr/dscf)
E_M	=	the particulate matter emissions in gr/dscf measured during the test that included the routine maintenance activity
E_{NM}	=	the arithmetic average of particulate matter emissions in gr/dscf measured by the test runs that did not include the routine maintenance activity
A	=	the period of routine maintenance activity occurring during the test run that included routine maintenance activity, expressed to the nearest hundredth of an hour
B	=	the total period of the test run, less A
R	=	the maximum period of emissions unit operation per 24 hours, expressed to the nearest hundredth of an hour
S	=	the maximum period of routine maintenance activity per 24 hours, expressed to the nearest hundredth of an hour

[18 AAC 50.220(f)]

Section 7. General Recordkeeping and Reporting Requirements

Recordkeeping Requirements

65. **Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:

[18 AAC 50.040(a)(1) & 50.326(j)]
[40 C.F.R 60.7(f), Subpart A, 40 C.F.R 71.6(a)(3)(ii)(B)]

65.1. Copies of all reports and certifications submitted pursuant to this section of the permit; and

65.2. Records of all monitoring required by this permit, and information about the monitoring including:

a. the date, place, and time of sampling or measurements;

b. the date(s) analyses were performed;

c. the company or entity that performed the analyses;

d. the analytical techniques or methods used;

e. the results of such analyses; and,

f. the operating conditions as existing at the time of sampling or measurement.

Reporting Requirements

66. **Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: *"Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete."* Excess emission reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

66.1. The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if

a. a certifying authority registered under AS 09.80.020 verifies that the electronic signature is authentic; and

b. the person providing the electronic signature has made an agreement, with the certifying authority described in Condition 66.1.a, that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.

[18 AAC 50.345(a) & (j), 50.205, & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

67. Submittals. Unless otherwise directed by the Department or this permit, the Permittee shall submit reports, compliance certifications, and/or other submittals required by this permit, certified in accordance with Condition 66, to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The Permittee shall submit the documents either by hard copy or electronically.

67.1. Provide electronic submittals, either by:

a. E-mail under a cover letter using dec.aq.airreports@alaska.gov; or

b. using the Department's Air Online Services at http://dec.alaska.gov/applications/air/airtoolsweb/.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

68. Information Requests. The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke and reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the Federal Administrator.

[18 AAC 50.345(a) & (i), 50.200, & 50.326(a) & (j)]
[40 C.F.R. 71.5(a)(2) & 71.6(a)(3)]

69. Excess Emissions and Permit Deviation Reports.

69.1. Except as provided in Condition 52, the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

a. in accordance with 18 AAC 50.240(c), as soon as possible after the event commences or is discovered, report

(i) emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable;

b. in accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology-based emission standard;

c. report all other excess emissions and permit deviations

(i) within 30 days after the end of the month during which the excess emissions or deviation occurred, except as provided in Condition 69.1.c(iii); or

(ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under Condition 69.1.c(i); and

(iii) for failure to monitor, as required in Conditions 4.2.b and 9.1.b and other applicable conditions of this permit.

69.2. When reporting either excess emissions or permit deviations, the Permittee shall report using either the Department's online form, which can be found at http://dec.alaska.gov/applications/air/airtoolsweb, http://dec.alaska.gov/air/ap/docs/eeform.pdf, or if the Permittee prefers, the form contained in Section 14 of this permit. The Permittee must provide all information called for by the form that is used.

69.3. If requested by the Department, the Permittee shall provide a more detailed written report to follow up an excess emissions report.

[18 AAC 50.235(a)(2), 50.240(c), 50.326(j)(3), & 50.346(b)(2) & (3)]

70. **Operating Reports.** During the life of this permit[15], the Permittee shall submit to the Department an operating report by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

70.1. The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

70.2. When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 70.1, the Permittee shall identify

a. the date of the deviation;

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventive measures taken and the date(s) of such actions; or

70.3. when excess emissions or permit deviations have already been reported under Condition 69 the Permittee shall cite the date or dates of those reports.

70.4. The operating report must include, for the period covered by the report, a listing of emissions monitored under Conditions 2.3.e, 2.4.c, and 29.1.a which trigger additional testing or monitoring, whether or not the emissions monitored exceed an emission standard. The Permittee shall include in the report.

a. the date of the emissions;

b. the equipment involved;

[15] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

c. the permit condition affected; and

d. the monitoring result which triggered the additional monitoring.

70.5. **Transition from expired to renewed permit**. For the first period of this renewed operating permit, also provide the previous permit's operating report elements covering that partial period immediately preceding the effective date of this renewed permit.

[18 AAC 50.346(b)(6) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

71. Annual Compliance Certification. Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report according to Condition 67.

71.1. Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. identify each term or condition set forth in Section 3 through Section 9, that is the basis of the certification;

b. briefly describe each method used to determine the compliance status;

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification.

71.2. **Transition from expired to renewed permit**. For the first period of this renewed operating permit, also provide the previous permit's annual compliance certification report elements covering that partial period immediately preceding the effective date of this renewed permit.

71.3. In addition, submit a copy of the report directly to the Clean Air Act Compliance Manager, US EPA Region 10, Mail Stop: OCE-101, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101.

[18 AAC 50.205, 50.345(a) & (j), & 50.326(j)]
[40 C.F.R. 71.6(c)(5)]

72. Emission Inventory Reporting. The Permittee shall submit to the Department reports of actual emissions, by emissions unit, of CO, Ammonia (NH_3), NOx, PM_{10}, $PM_{2.5}$, SO_2, VOCs and Lead (and lead compounds) using the form in Section 15 of this permit, as follows:

72.1. Each year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds:

a. 250 TPY of NH_3, PM_{10}, $PM_{2.5}$ or VOCs; or

b. 2,500 TPY of CO, NOx or SO_2.

72.2. Every third year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds:

a. 5 tons per year of lead (and lead compounds), or

b. 1,000 TPY of CO; or

c. 100 TPY of SO_2, NH_3, PM_{10}, $PM_{2.5}$, NOx or VOCs.

72.3. For reporting under Condition 72.2, the Permittee shall report in 2018 for calendar year 2017, 2021 for calendar year 2020, 2024 for calendar year 2023, etc., in accordance with the Environmental Protection Agency set schedule.

72.4. Include in the report required by this condition, the required data elements contained within the form in Section 15 or those contained in Table 2A of Appendix A to Subpart A of 40 C.F.R. 51 for each stack associated with an emissions unit.

[18 AAC 50.346(b)(8) & 50.200]
[40 C.F.R. 51.15, 51.30(a)(1) & (b)(1), & 40 C.F.R. 51, Appendix A to Subpart A]

Section 8. Permit Changes and Renewal

73. Permit Applications and Submittals. The Permittee shall comply with the following requirements for submitting application information to the US Environmental Protection Agency (EPA):

73.1. The Permittee shall provide a copy of each application for modification or renewal of this permit, including any compliance plan, or application addenda, at the time the application or addendum is submitted to the Department;

73.2. The information shall be submitted to the Part 70 Operating Permit Program, US EPA Region 10, AWT-150, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101.

73.3. To the extent practicable, the Permittee shall provide to EPA applications in portable document format (pdf); MS Word format (.doc); or other computer-readable format compatible with EPA's national database management system; and

73.4. The Permittee shall maintain records as necessary to demonstrate compliance with this condition.

[18 AAC 50.040(j)(7), 50.326(a) & 50.346(b)(7)]
[40 C.F.R. 71.10(d)(1)]

74. Emissions Trading. No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in the permit.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(8)]

75. Off Permit Changes. The Permittee may make changes that are not addressed or prohibited by this permit other than those subject to the requirements of 40 C.F.R. Part 72 through 78 or those that are modifications under any provision of Title I of the Act to be made without a permit revision, provided that the following requirements are met:

75.1. Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition;

75.2. Provide contemporaneous written notice to EPA and the Department of each such change, except for changes that qualify as insignificant under 18 AAC 50.326(d) – (i). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change;

75.3. The change shall not qualify for the shield under 40 C.F.R. 71.6(f);

75.4. The Permittee shall keep a record describing changes made at the stationary source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(12)]

76. **Operational Flexibility.** The Permittee may make CAA Section 502(b)(10)[16] changes within the permitted stationary source without requiring a permit revision if the changes are not modifications under any provision of Title I of the Act and the changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emissions or in terms of total emissions):

76.1. The Permittee shall provide EPA and the Department with a written notification no less than seven days in advance of the proposed change.

76.2. For each such change, the notification required by Condition 76.1 shall include a brief description of the change within the permitted stationary source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.

76.3. The permit shield described in 40 C.F.R. 71.6(f) shall not apply to any change made pursuant to Condition 76.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(13)]

77. **Permit Renewal.** To renew this permit, the Permittee shall submit to the Department[17] an application under 18 AAC 50.326 no sooner than **October 4, 2020** and no later than **October 4, 2021**. The renewal application shall be complete before the permit expiration date listed on the cover page of this permit. Permit expiration terminates the stationary source's right to operate unless a timely and complete renewal application has been submitted consistent with 40 C.F.R. 71.7(b) and 71.5(a)(1)(iii).

[18 AAC 50.040(j)(3), 50.326(c) & (j)(2)]
[40 C.F.R. 71.5(a)(1)(iii) & 71.7(b) & (c)(1)(ii)]

[16] As defined in 40 C.F.R. 71.2, CAA Section 502(b)(10) changes are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.

[17] Submit permit applications to the Department's Anchorage office. The current address is: Air Permit Intake Clerk, ADEC, 555 Cordova Street, Anchorage, AK 99501.

Section 9. Compliance Requirements

General Compliance Requirements

78. Compliance with permit terms and conditions is considered to be compliance with those requirements that are

78.1. included and specifically identified in the permit; or

78.2. determined in writing in the permit to be inapplicable.

[18 AAC 50.326(j)(3) & 50.345(a) & (b)]

79. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

79.1. an enforcement action;

79.2. permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280; or

79.3. denial of an operating permit renewal application.

[18 AAC 50.040(j), 50.326(j) & 50.345(a) & (c)]

80. For applicable requirements with which the stationary source is in compliance, the Permittee shall continue to comply with such requirements.

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(c)(3) & 71.5(c)(8)(iii)(A)]

81. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

[18 AAC 50.326(j)(3) & 50.345(a) & (d)]

82. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

82.1. enter upon the premises where a source subject to the permit is located or where records required by the permit are kept;

82.2. have access to and copy any records required by the permit;

82.3. inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

82.4. sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

[18 AAC 50.326(j)(3) & 50.345(a) & (h)]

Compliance Schedule

83. For applicable requirements that will become effective during the permit term, the Permittee shall meet such requirements on a timely basis.

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(c)(3) & 71.5(c)(8)(iii)(B)]

Section 10. Permit As Shield from Inapplicable Requirements

In accordance with AS 46.14.290, and based on information supplied in the permit application, this section of the permit contains the requirements determined by the Department not to be applicable to the stationary source.

84. Nothing in this permit shall alter or affect the following:

84.1. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section; or

84.2. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(f)(3)(i) & (ii)]

85. Table B identifies the emissions units that are not subject to the specified requirements at the time of permit issuance. If any of the requirements listed in Table B becomes applicable during the permit term, the Permittee shall comply with such requirements on a timely basis including, but not limited to, providing appropriate notification to EPA, obtaining a construction permit and/or an operating permit revision.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(f)(1)(ii)]

Table B - Permit Shields Granted

EU ID	Non-Applicable Requirements	Reason for Non-Applicability
1, 2, 2a	40 C.F.R. 60.332(a)(1)	Standard applies to Electric Utility Stationary Gas Turbines. The turbines are not Electric Utility Stationary Gas Turbines, as defined in subpart
	40 C.F.R. 60.334(a), (b) & (d) – Monitoring of Operations	Applies only to turbines equipped with water injection to control NOx emissions. Turbines not equipped with water injection to control NOx.
	40 C.F.R. 60.334(h)(1) & (2), (i), & (j) – Monitoring of Operations	Applies to turbines monitoring for fuel sulfur, fuel nitrogen, or for turbines using CEMs or parametric monitoring for NOx. The turbines burn natural gas. For nitrogen monitoring, the Permittee does not claim an allowance for fuel bound nitrogen.
	40 C.F.R. 60.335(a) & (b) – Test Methods and Procedures	Obsolete requirements –initial source tests completed.
	40 C.F.R. 60, Subpart KKKK	This requirement only applies to units that commenced construction, modification, or reconstruction after February 18, 2005. The permit shield applies to currently installed units until modified, reconstructed or replaced.
	40 C.F.R. 63, Subpart YYYY	Stationary source is not a major source of HAPs.
3 - 8	40 C.F.R. 63 Subpart DDDDD	Stationary source is not a major source of HAPs.
	40 C.F.R. 63 Subpart JJJJJJ	Units are process heaters, not boilers and burn gas
9	40 C.F.R. 63.6603(b), 63.6604, 63.6625(c), (d), 63.6625(g), 63.6645(a), (b), (c), (d), (e), (f), 63.6655(c)	EU ID 9 is an existing emergency stationary CI RICE at an area source of HAP emissions in Alaska not accessible by the Federal Aid Highway System.

9a	40 C.F.R. 63.6603(a), 63.6604, 63.6625(c), (d), (f), (g), 63.6645(a), (b), (c), (d), (e), (f), 63.6655(c), (f)	EU ID 9a is an existing non-emergency stationary CI RICE greater than 300 HP located at an area source of HAP emissions in Alaska not accessible by the Federal Aid Highway System.
9 and 9a	40 C.F.R. 60, Subpart IIII	Only applies to emission units that commenced construction, modification or reconstruction after July 11, 2005. The permit shield only applies to currently installed units until modified, reconstructed or replaced.
	40 C.F.R. 63.6600, 63.6601, 63.6602, 63.6610, 63.6611	Stationary source is not a major source of HAPs.
	40 C.F.R. 63.6605(a), 63.6630, 63.6635, 63.6640, 63.6650, 63.6655(a), (d)	The emission units are not subject to emission limitations or operating limitations.
	40 C.F.R. 63, Subpart ZZZZ §§63.6612, 63.6615, 63.6620, 63.6645 (g) & (h)	The emission units are not subject to performance tests or other compliance demonstrations.
	40 C.F.R. 63.6625(a), (b), 63.6655(b)	Not required to use a CEMS, CPMS, or a CMS.
12 - 16	40 C.F.R. 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels	The storage vessels are exempt from Subpart Kb under 40 C.F.R. 60.110b(d)(4). The tanks have capacity ≤1,589.874 m^3 used for petroleum or condensate stored, processed, or treated before custody transfer.
Nonroad Engines	18 AAC 50.055, Industrial processes and fuel-burning equipment	Nonroad (mobile) internal combustion engines are not included in the definition of fuel-burning equipment under 18 AAC 50.990.
Stationary Source Wide	40 C.F.R. 60, Subparts B, C, Cc, F, G, H, I, J, M, N, Na, O, S, T, U, V, WW, X, Y, Z, AA, AAa, Bb CC, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, BBB, DDD, FFF, GGG, HHH, III, JJJ, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW.	Not an affected stationary source, operation, or industry.
	40 C.F.R. Cb, Cd, Ce, D, Da, Db, Dc, E, Ea, Eb, Ec, K, Ka, L, P, Q, R, DD, AAA, KKK, AAAA, BBBB, CCCC, DDDD, EEEE, JJJJ.	No affected facility within stationary source.
	40 C.F.R. 60, Subpart LLL – SO_2 Emissions from Onshore Natural Gas Plants	No affected source within the stationary source, the natural gas processing skid at Kustatan does not contain a sweetening unit.
	40 C.F.R. 61, Subpart J – Equipment Leaks of Benzene	Stationary source does not contain any equipment in benzene service (>10% by weight).
	40 C.F.R. 61, Subpart V	Per 40 C.F.R. 61.240(b), a stationary source must be subject to a specific subpart of 40 C.F.R. 61 to be subject to Subpart V.
	40 C.F.R. 61 Subpart B, C, D, E, F, H, I, K, L, N, O, P, Q, R, T, W, Y, BB, and FF	No affected facility within stationary source.
	40 C.F.R. 63, NESHAPs – Subparts F, G, J, L, M, N, L, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, II, JJ, KK, LL, MM, OO, SS, VV, XX, YY, CCC, DDD, EEE, GGG, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR,	Not an affected stationary source, operation or industry, or no affected emission units within the stationary source.

	SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, AAAAA, BBBBB, CCCCC, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS, TTTTT, DDDDDD, EEEEEE, FFFFFF, and GGGGGG	
	40 C.F.R. 63, NESHAPs – Subpart H	Stationary source does not contain any equipment intended to operate in organic hazardous air pollutant service (equipment contain fluids that is at least 5% by weight of total organic HAPs).
	40 C.F.R. 63, NESHAPs – Subparts HH and HHH	Stationary source is not a major source of HAPs as defined in 40 C.F.R. 63.760(s). Area sources are exempt from the subpart if an affected source (i.e., triethylene glycol dehydration unit) does not exist at the stationary source.
	40 C.F.R. 82, Subpart A	Stationary source does not produce, transform, destroy, import or export Class I or Group I or II substances or products.
	40 C.F.R. 82.30, Subpart B	Stationary source does not service motor vehicle air conditioners.
	40 C.F.R. 82.60, Subpart C	Stationary source does not manufacture or distribute Class I and II products or substances.
	40 C.F.R. 82.80, Subpart D	Subpart applies only to Federal departments, agencies, and instrumentalities.
	40 C.F.R. 82.100, Subpart E	Stationary source does not manufacture or distribute Class I and II products or substances
	40 C.F.R. 82.158, Subpart F	Stationary source does not manufacture or import recovery and recycling equipment.
	40 C.F.R. 82.174(a), Subpart G	Stationary source does not manufacture substitute chemicals or products for ozone depleting compounds.
	40 C.F.R. 82.270(a), Subpart H	Stationary source does not manufacture halon.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(f)(1)(ii)]

Section 11. Kustatan Production Facility Public Access Control Plan

Purpose

The purpose of this Public Access Control Plan for the Kustatan Production Site is to protect the general public from public health and safety hazards incident to the heavy industrial activity planned at the Cook Inlet Energy, LLC, Kustatan Production Site property on the West Foreland, Cook Inlet, Alaska. The planned activity involves exploratory drilling for potential petroleum production. Cook Inlet Energy, LLC has established these reasonable restrictions on general public access to attain adequate protection of public health and welfare.

Cook Inlet Energy, LLC is committed to fully and adequately protecting the health and safety of its work force by meeting or exceeding the standards for air exposure of the Occupational Safety and Health Administration (OSHA) and, where the general public has access, the National and Alaska Ambient Air Quality Standards (AAQS). A primary purpose of this plan is to delineate the area to be protected and controlled for occupational health and safety from the area that is subject to unrestricted, general public access where AAQS are applicable. A secondary purpose is to ensure that reasonable measures are in place to accomplish reasonable restrictions on public access. The boundary is reflected in Figure 1 of the reference document, the Ambient Air Boundary Map.

General Information

The Kustatan Production site is located on the West Foreland, Cook Inlet, Alaska. The site is on property owned by Cook Inlet Energy, LLC. The nearest community to the site is Nikiski, approximately 9 kilometers to the east. Cook Inlet lies between the site and Nikiski. Cook Inlet Energy, LLC's West McArthur River Unit Production Facilities are located approximately 8 kilometers north of the site.

Currently, the site is accessible only by helicopter and boat. Because the area is roadless, Cook Inlet is effective as a physical barrier to prevent public access. A second effective physical barrier is the steep, 150- to 200-foot high bluff that must be climbed to access the West Foreland.

Cook Inlet Energy, LLC has constructed a private road from the company's West McArthur River Unit Production Facilities to the site. The public will not be allowed to use this road. As a practical matter, few people are traversing the area that will be impacted by the Kustatan Production Site. The few people that may be in the area would be primarily at the Kustatan Fish Camp. This camp is on property owned by Cook Inlet Energy, LLC. This fish camp has a small boat dock but is officially off-limits to the general public. To be conservative, the fish camp is treated as accessible to the public for the purposes of this plan.

In addition to the physical barrier cited above, public access to the site will be restricted using strategically located signs. These signs will be posted at the fish camp boat dock, the trail leading from the fish camp to the top of the bluff, and at the point the Cook Inlet Energy, LLC road enter the site.

Public Access Control Measures

The area surrounding the Kustatan Production site is remote, isolated, and physically prohibitive to travel. Cook Inlet Energy, LLC owns the area within the ambient air quality boundary and has the legal right to restrict public access. No established trails or cabin sites exist within the restricted area. In addition, no public need or use exists for the land within the restricted area.

Cook Inlet and high angle bluffs prohibit snowmobile and all-terrain vehicle travel. Walking is difficult, and in places, impossible.

Signs will be posted along the two theoretically potential access routes. These two routes are Cook Inlet Energy, LLC's private access road from the West McArthur River Unit Production Facilities and the walking trail from the Kustatan fish camp to the top of the bluff. Three signs will be posted, one each at the:

- Fish camp boat dock;
- Point the foot trail to the top of the bluff exists the fish camp; and
- Point of entry to the site of the Cook Inlet Energy, LLC road from the West McArthur River Unit Production Facilities.

The sign specifications are:

- Each sign will be 4 feet by 6 feet and will be mounted on posts
- Each sign will be inspected semi-annually and will be repaired or replaced, as necessary.
- Each sign will be free of visible obstructions.
- Each sign will read:

COOK INLET ENERGY, LLC, PETROLEUM EXPLORATION AND PRODUCTION OPERATIONS

INDUSTRIAL AREA

DANGER

OIL PRODUCTION AND FLARING IN PROGRESS

NO UNAUTHORIZED VISITORS BEYOND THIS POINT

[Minor Permit No. AQ0741MSS02, Section 8, 2/23/2015]
[18 AAC 50.326(a)]

Section 12. Visible Emissions Forms

VISIBLE EMISSIONS OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, “Visual Determination of the Opacity of Emissions from Stationary Sources.” Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form: for a more detailed discussion of each part of the form, refer to “Instructions for Use of Visible Emission Observation Form.”

- Source Name: full company name, parent company or division or subsidiary information, if necessary.
- Address: street (not mailing or home office) address of facility where visible emissions observation is being made.
- Phone (Key Contact): number for appropriate contact.
- Stationary Source ID Number: number from NEDS, agency file, etc.
- Process Equipment, Operating Mode: brief description of process equipment (include type of facility) and operating rate, % capacity, and/or mode (e.g. charging, tapping, shutdown).
- Control Equipment, Operating Mode: specify type of control device(s) and % utilization, control efficiency.
- Describe Emission Point: for identification purposes, stack or emission point appearance, location, and geometry; and whether emissions are confined (have a specifically designed outlet) or unconfined (fugitive).
- Height Above Ground Level: stack or emission point height relative to ground level; can use engineering drawings, Abney level, or clinometer.
- Height Relative to Observer: indicate height of emission point relative to the observation point.
- Distance from Observer: distance to emission point; can use rangefinder or map.
- Direction from Observer: direction plume is traveling from observer.
- Describe Emissions and Color: include physical characteristics, plume behavior (e.g., looping, lacy, condensing, fumigating, secondary particle formation, distance plume visible, etc.), and color of emissions (gray, brown, white, red, black, etc.). Note color changes in comments section.
- Visible Water Vapor Present?: check “yes” if visible water vapor is present.
- If Present, is Plume…: check “attached” if water droplet plume forms prior to exiting stack, and “detached” if water droplet plume forms after exiting stack.
- Point in Plume at Which Opacity was Determined: describe physical location in plume where readings were made (e.g., 1 ft above stack exit or 10 ft. after dissipation of water plume).
- Describe Plume Background: object plume is read against, include texture and atmospheric conditions (e.g., hazy).
- Background Color: sky blue, gray-white, new leaf green, etc.
- Sky Conditions: indicate cloud cover by percentage or by description (clear, scattered, broken, overcast).
- Wind Speed: record wind speed; can use Beaufort wind scale or hand-held anemometer to estimate.
- Wind Direction From: direction from which wind is blowing; can use compass to estimate to eight points.
- Ambient Temperature: in degrees Fahrenheit or Celsius.
- Wet Bulb Temperature: can be measured using a sling psychrometer
- RH Percent: relative humidity measured using a sling psychrometer; use local US Weather Bureau measurements only if nearby.
- Source Layout Sketch: include wind direction, sun position, associated stacks, roads, and other landmarks to fully identify location of emission point and observer position.
- Draw North Arrow: to determine, point line of sight in direction of emission point, place compass beside circle, and draw in arrow parallel to compass needle.
- Sun’s Location: point line of sight in direction of emission point, move pen upright along sun location line, mark location of sun when pen’s shadow crosses the observer’s position.
- Observation Date: date observations conducted.
- Start Time, End Time: beginning and end times of observation period (e.g., 1635 or 4:35 p.m.).
- Data Set: percent opacity to nearest 5%; enter from left to right starting in left column. Use a second (third, etc.) form, if readings continue beyond 30 minutes. Use dash (-) for readings not made; explain in adjacent comments section.
- Comments: note changing observation conditions, plume characteristics, and/or reasons for missed readings.
- Range of Opacity: note highest and lowest opacity number.
- Observer’s Name: print in full.
- Observer’s Signature, Date: sign and date after performing VE observation.
- Organization: observer’s employer.
- Certified By, Date: name of “smoke school” certifying observer and date of most recent certification.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM - VISIBLE EMISSIONS OBSERVATION FORM

Page No.___________

Stationary Source Name	Type of Emission Unit	
Emission Unit Location		
City	State	Zip
Phone # (Key Contact)	Stationary Source ID Number	
Process Equipment	Operating Mode	
Control Equipment	Operating Mode	
Describe Emission Point/Location		
Height above ground level	Height relative to observer	Clinometer Reading
Distance From Observer Start End	Direction From Observer Start End	
Describe Emissions & Color Start	End	
Visible Water Vapor Present? If yes, determine approximate distance from the stack exit to where the plume was read No Yes		
Point in Plume at Which Opacity Was Determined		
Describe Plume Background Start End	Background Color Start End	
Sky Conditions: Start	End	
Wind Speed Start End	Wind Direction From Start End	
Ambient Temperature	Wet Bulb Temp	RH percent
SOURCE LAYOUT SKETCH: 1 Stack or Point Being Read 2 Wind Direction From 3 Observer Location 4 Sun Location 5 North Arrow 6 Other Stacks		

Observation Date		Start Time			End Time
Sec / Min	0	15	30	45	Comments
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Range of Opacity
Minimum Maximum

I have received a copy of these opacity observations Print Name: Signature:	Print Observer's Name Observer's Signature Date Observer's Affiliation:
Title Date	Certifying Organization Certified By: Date

Data Reduction:

Duration of Observation Period (minutes):	Duration Required by Permit (minutes):
Number of Observations:	Highest Six–Minute Average Opacity (%):
Number of Observations exceeding 20%:	
In compliance with six-minute opacity limit? (Yes or No)	Highest 18-Consecutive –Minute Average Opacity (%)(engines and turbines only)

Average Opacity Summary:

Set Number	Time			Opacity		Comments
	Start	End		Sum	Average	

Section 13. SO_2 Material Balance Calculation

If a fuel shipment contains more than 0.75 percent sulfur by weight, calculate the three-hour exhaust concentration of SO_2 using the following equations:

A. = 31,200 x [**wt%S_{fuel}**] = 31,200 x ________ = ____________

B. = 0.148 x [**wt%S_{fuel}**] = 0.148 x ________ = ____________

C. = 0.396 x [**wt%C_{fuel}**] = 0.396 x ________ = ____________

D. = 0.933 x [**wt%H_{fuel}**] = 0.933 x ________ = ____________

E. = B + C + D = ________ + ________ + __________ = __________

F. = 20.9 – [**vol%$_{dry}O_{2,\ exhaust}$**] = 20.9 – ________ = __________

G. = [**vol%$_{dry}O_{2,\ exhaust}$**] ÷ F = _______ ÷ _______ = _________

H. = 1 + G = 1 + _________ = ___________

I. = E x H = ___________ x _________ = ___________

SO_2 concentration = A ÷ I = _________ ÷ ________ = _________ ppm

The **wt%S_{fuel}, wt%C_{fuel},** and **wt%H_{fuel}** are equal to the weight percents of sulfur, carbon, and hydrogen in the fuel. These percentages should total 100%.

The fuel weight percent of sulfur (wt%S_{fuel}) is obtained pursuant to Condition 11. The fuel weight percents of carbon and hydrogen are obtained from the fuel refiner.

The volume percent of oxygen in the exhaust (**vol%$_{dry}O_{2,\ exhaust}$**) is obtained from oxygen meters, manufacturer's data, or from the most recent analysis under 40 C.F.R. 60, Appendix A-2, Method 3, adopted by reference in 18 AAC 50.040(a), at the same engine load used in the calculation.

Enter all of the data in percentages without dividing the percentages by 100. For example, if **wt%S_{fuel}** = 1.0%, then enter 1.0 into the equations not 0.01 and if **vol%$_{dry}O_{2,\ exhaust}$** = 3.00%, then enter 3.00, not 0.03.

[18 AAC 50.346(c)]

Section 14. Notification Form[18]

Kustatan Production **Facility**	AQ0741TVP03
Stationary Source Name	**Air Quality Permit Number.**
Cook **Inlet Energy**	
Company Name	

When did you discover the Excess Emissions/Permit Deviation?

Date: ______ / ______ / __________ Time: ______ :/ ______

When did the event/deviation occur?

Begin: Date: _____ / _____ / ________ Time: ______ : _____ (please use 24-hr clock.)

End: Date: _____ / _____ / ________ Time: ______ : _____ (please use 24-hr clock)

What was the duration of the event/deviation? ____ : ____ (hrs:min) or ________ days

(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for Notification: (please check only 1 box and go to the corresponding section)

☐ Excess Emissions – Complete Section 1 and Certify

☐ Deviation from Permit Condition – Complete Section 2 and Certify

☐ Deviations from COBC, CO, or Settlement Agreement – Complete Section 2 and Certify

Section 1. Excess Emissions

(a) **Was the exceedance** ☐ Intermittent or ☐ Continuous

(b) **Cause of Event** (Check one that applies):

☐ Start Up/Shut Down ☐ Natural Cause (weather/earthquake/flood)

☐ Control Equipment Failure ☐ Schedule Maintenance/Equipment Adjustment

☐ Bad Fuel/Coal/Gas ☐ Upset Condition ☐ Other ____________________

(c) **Description**
Describe briefly, what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance.

(d) **Emissions Units Involved:**
Identify the emissions unit involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

EU ID	EU Name	Permit Condition Exceeded/Limit/Potential Exceedance

[18] Revised as of September 27, 2010.

(e) **Type of Incident** (please check only one):

☐ Opacity _____ %	☐ Venting _______ gas/scf	☐ Control Equipment Down
☐ Fugitive Emissions	☐ Emission Limit Exceeded	☐ Recordkeeping Failure
☐ Marine Vessel Opacity	☐ Flaring	☐ Other

(f) **Unavoidable Emissions:**

Do you intend to assert that these excess emissions were unavoidable? ☐ Yes ☐ No

Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐ Yes ☐ No

Certify Report (go to end of form)

Section 2. Permit Deviations

(a) **Permit Deviation Type** (check only one box corresponding with the section in the permit):

☐ Emissions Unit-Specific

☐ Failure to Monitor/Report

☐ General Source Test/Monitoring Requirements

☐ Recordkeeping/Reporting/Compliance Certification

☐ Standard Conditions Not Included in the Permit

☐ Generally Applicable Requirements

☐ Reporting/Monitoring for Diesel Engines

☐ Insignificant Emissions Unit

☐ Stationary Source Wide

☐ Other Section: ________________________________ (Title of section and section number of your permit).

(b) **Emissions Unit Involved:**

Identify the emissions units involved in the event, using the same identification number and name as in the permit. List the corresponding permit conditions and the deviation.

EU ID	EU Name	Permit Condition/ Potential Deviation

(c) **Description of Potential Deviation:**

Describe briefly what happened and the cause. Include the parameters/operating conditions and the potential deviation.

(d) **Corrective Actions:**

Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence.

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name: ________________ Title: ________________ Date: ________

Signature: ________________ Phone Number: ________________

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To Submit this Report:

1. Fax to: 907-451-2187

   Or

2. Email to: DEC.AQ.Airreports@alaska.gov

   Or

3. Mail to: ADEC
   Air Permits Program
   610 University Avenue
   Fairbanks, AK 99709-3643

   Or

4. Phone Notifications: 907-451-5173

   Phone notifications require a written follow-up report.

   Or

5. Submission of information contained in this report can be made electronically at the following website: *http://dec.alaska.gov/applications/air/airtoolsweb/* or *http://dec.alaska.gov/air/ap/docs/eeform.pdf*

If submitted online, report must be submitted by an authorized E-Signer for the stationary source.

[18 AAC 50.346(b)(3)]

Section 15. Emission Inventory Form

ADEC Reporting Form **Emission Inventory Reporting** **State of Alaska Department of Environmental Conservation** **Division of Air Quality**	**Emission Inventory Year- [ ]**

<u>Mandatory information is highlighted in bright yellow. Make additional copies as needed.</u>

Stationary Source Detail		
Inventory start date		
Inventory end date		
ADEC ID or Permit Number		
EPA ID:		
Census Area/ Community		
Facility Name		
Facility Physical Location	**Address:**	
	City, State, Zip Code:	
	Latitude:	**Longitude:**
	Legal Description:	
Owner Name & Address & contact number	**Owner Name:**	
	Owner Address:	
	Phone Number:	
Mailing Contact Information	**Mailing Address:**	
Line of Business (NAICS)		
Line of Business (SIC)		
Facility Status:		

Emissions Unit Data			
Specifications			
ID		**Design Capacity**	
Description			
Emissions Unit Status			
Manufacturer		**Manufactured Year**	
Model Number		**Serial Number**	
Regulations			
Regulation/Description:			
Control Equipment (List All if applicable):			
ID			
System Description	-		
Equipment Type(s)			
Manufacturer			
Model			
Control Efficiency (%)			
Capture Efficiency (%)			
Pollutants Controlled		**Reduction Efficiency (%):**	
		Reduction Efficiency (%):	

Processes	
Process	**Primary Process**
SCC Code	(ex. 20100201)
	>
	>
Material Processed	
Period Start	
Period End	
Throughput (units)	
Summer %	
Fall %	
Winter %	
Spring %	

Operational Schedule					
Days/Week					
Hours/Day					
Weeks/Year					
Hours/Year					
Fuel Characteristics					
Heat Content	**Elem. Sulfur Content (%)**	**H_2S Sulfur Content**		**Ash Content (if applicable)**	
Heating					
Heat Input	**Heat Output**		**Heat Values Convention**		
Emissions Operating Type:					
Pollutant	**Emission Factor (EF)**	**EF Numerator**	**EF Denominator**	**EF Source**	**Tons**
Carbon Monoxide (CO)					
Nitrogen Oxides (NOx)					
PM_{10} Primary (PM_{10}-PRI)					
$PM_{2.5}$ Primary ($PM_{2.5}$-PRI)					
Sulfur Dioxide (SO_2)					
Ammonia (NH_3)					
Lead and lead compounds					
Volatile Organic Compounds (VOC)					
Emissions' Release Point					
Release Point ID					
Apportion%					

Process	**Secondary Process**
SCC Code	(ex. 20100201)
	>
	>
	>
	>

Material Processed	
Period Start	
Period End	
Throughput (units)	
Summer %	
Fall %	
Winter %	
Spring %	
Operational Schedule	
Days/Week	
Hours/Day	
Weeks/Year	
Hours/Year	

Fuel Characteristics			
Heat Content	**Elem. Sulfur Content (%)**	**H_2S Sulfur Content**	**Ash Content (if applicable)**

Heat Input	**Heat Output**	**Heat Values Convention**

Emissions Operating Type:					
Pollutant	**Emission Factor (EF)**	**EF Numerator**	**EF Denominator**	**EF Source**	**Tons**
Carbon Monoxide (CO)					
Nitrogen Oxides NOx					
PM_{10} Primary (PM_{10}-PRI)					
$PM_{2.5}$ Primary ($PM_{2.5}$-PRI)					
Sulfur Dioxide (SO_2)					
Ammonia (NH_3)					
Lead and lead compounds					
Volatile Organic Compounds (VOC)					

Emissions' Release Point					
Release Point ID					
Apportion%					

Stack Detail (Release Point)	
> Specifications	
ID	
Type	
Description	
Stack Status	
> Stack Parameters	
Stack Height (ft)	
Stack Diameter (ft)	
Exit Gas Temp (F)	
Exit Gas Velocity (fps)	
Exit Gas Flow Rate (acfm)	
> Geographic Coordinate	
Latitude	
Longitude	
Datum	
Accuracy (meters)	
Base Elevation (meters)	

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name:__________________________________Title________________________Date ____________

Signature:_____________________________________ Phone number_________________________________

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To submit this report:

1. Fax this form to: 907-465-5129; or
2. E-mail to: DEC.AQ.airreports@alaska.gov; or
3. Mail to: ADEC
   Air Permits Program
   410 Willoughby Ave., Suite 303
   PO Box 111800
   Juneau, AK 99811-1800

Or

4. Direct data entry for emission inventory can be done through the Air Online System (AOS). A myAlaska account is needed to gain access and a profile needs to be set up in Permittee Portal.
   http://dec.alaska.gov/Applications/Air/airtoolsweb/.

[18 AAC 50.346(b)(9)]

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL OPERATING PERMIT

ADMINISTRATIVE AMENDMENT TO INCORPORATE MINOR PERMIT CONDITIONS

Permit No. AQ0741TVP03
Application No. AQ0741MSS03
Revision 1: April 26, 2018

Issue Date: April 4, 2017
Expiration Date: April 4, 2022

The Department of Environmental Conservation, under the authority of AS 46.14, 18 AAC 50.326, and 40 CFR 71.7(d)(1)(v) incorporates the provisions of Minor Permit AQ0741MSS03, issued April 26, 2018, into Operating Permit AQ0741TVP03 Revision 1 by administrative amendment.

These permits are issued to Cook Inlet Energy, LLC for the Kustatan Production Facility.

This action is a final action for the purposes of establishing an operating permit shield under 40 CFR 71.7(d)(4).

Aaron Simpson

FOR: Jim Plosay, Manager
Air Permits Program

Table 1

Changes due to AQ0741MSS03	
The following conditions of Operating Permit AQ0741TVP03 listed in Column 1 of this table are replaced by the conditions of Minor Permit AQ0741MSS03 listed in Column 2, with one exception. All references to the operating reports (Condition 70) in the Operating Permit, remain as originally written.	
Column 1 **Operating Permit AQ0741TVP03 Conditions**	**Column 2** **Minor Permit AQ0741MSS03 Conditions.**
Table A: Emissions Unit Inventory	Table 1: EU Inventory
Condition 14: Fuel Gas (EU IDs 1 through 8 and 10)	No Equivalent: However, all references to EU 2a are considered void since EU 2a is no longer listed in the EU Inventory.
Condition 17: NOx Emission Limits	Condition 7: NOx Emission Limits
Condition 18: CO Emission Limits	Condition 8: CO Emission Limits (includes “malfunctions” in the list of exceptions).
Conditions 22 – 24, and 26 - 27: Various NSPS Subpart A Requirements	No Equivalent: However, all references to EU 2a are considered void since EU 2a is no longer listed in the EU Inventory.
Conditions 29 - 30: Various NSPS Subpart GG Requirements	No Equivalent: However, all references to EU 2a are considered void since EU 2a is no longer listed in the EU Inventory.
Condition 45: Administration Fees	Condition 2: Administration Fees
Condition 46.1: Assessable potential to emit	Condition 3.1: Assessable potential to emit
Table B – Permit Shields Granted	No Equivalent: However, all references to EU 2a are considered void since EU 2a is no longer listed in the EU Inventory.

The authority line for each provision listed in Column 1 of Table 1 is changed by adding Minor Permit AQ0741MSS03, issued April 26, 2018.

The Technical Analysis Report for Minor Permit AQ0268MSS03, issued April 26, 2018, is incorporated by reference as a supplement to the Statement of Basis for Revision 1 to Operating Permit AQ0741TVP03.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Minor Permit: **AQ0741MSS03** **Preliminary Date – March 22, 2018**

Rescinds Permit: AQ0741MSS02

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0741MSS03 to the Permittee listed below.

Permittee:	**Cook Inlet Energy, LLC** 601 W. 5th Avenue, Suite 310 Anchorage, AK 99501
Stationary Source:	**Kustatan Production Facility**
Project:	Revisions To Permit AQ0741MSS02
Permit Contact:	Jennifer Henderson, (907) 433-3807 jhenderson@glacieroil.com

The Permittee requested Minor Permit AQ0741MSS03 under 18 AAC 50.508(6) in order to revise the terms and conditions of an existing Title I permit. Minor Permit This permit AQ0741MSS03 satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

The Permittee may operate under the terms and conditions of this minor permit upon issuance.

____

Jim Plosay, Manager
Air Permits Program

G:\AQ\PERMITS\AIRFACS\Cook Inlet Energy\Kustatan (741)\Minor\AQ0741MSS03\Prelim\AQ0741MSS03 Permit and TAR.docx

Table of Contents

Abbreviations and Acronyms

AAC....................Alaska Administrative Code
ADEC.................Alaska Department of Environmental Conservation
AS.......................Alaska Statutes
ASTM.................American Society for Testing and Materials
bbl.......................barrels
C.F.R. ....Code of Federal Regulations
CAA....................Clean Air Act
CO ....carbon monoxide
Department ....Alaska Department of Environmental Conservation
EU.......................emissions unit
gal ....gallons
hp ....horsepower
ID........................emissions unit identification number
kW ....kiloWatts
MMBtu/hr............million British thermal units per hour
MMSCF................million standard cubic feet
MW ....MegaWatts
NO_2......................nitrogen dioxide
NOx ....nitrogen oxides
PM-10...................particulate matter less than or equal to a nominal 10 microns in diameter
ppm ....parts per million
PSD ....prevention of significant deterioration
tpy.........................tons per year
VOC ....volatile organic compound [as defined in 40 C.F.R. 51.100(s)]

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to install and operate the EUs listed in Table 1 in accordance with the terms and conditions of this permit and the minor permit application. The information in Table 1 is for identification purposes only, unless otherwise noted in the permit. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – EU Inventory

EU	EU ID	EU Name	EU Description	Fuel Used	Rating
		Turbine Generators			
1	G-157A	Turbine Generator # 1	Taurus 60-T7300S	Lean fuel gas	5.652 MW
2	G-157B	Turbine Generator # 2	Taurus 60-T7300S	Lean fuel gas	5.652 MW
		Heaters			
3	V-115A	Heater Treater # 1	NATCO Natural Draft Burners	Raw fuel gas	6.2 MMBtu/hr
4	V-115B	Heater Treater # 2	NATCO Natural Draft Burners	Raw fuel gas	6.2 MMBtu/hr
5	V-115C	Heater Treater # 3	NATCO Natural Draft Burners	Raw fuel gas	6.2 MMBtu/hr
6	H-112A	Crude Heater # 1	NATCO Natural Draft Burners	Raw fuel gas	8 MMBtu/hr
7	H-112B	Crude Heater # 2	NATCO Natural Draft Burners	Raw fuel gas	8 MMBtu/hr
8	H-112C	Crude Heater # 3	NATCO Natural Draft Burners	Raw fuel gas	8 MMBtu/hr
		Diesel Engines			
9	P-115	Fire Water Pump		Diesel fuel	200 hp
9a		Backup Generator		Diesel fuel	320 kW
		Miscellaneous Equipment			
10a	H-100	Small Space Heaters		Diesel Fuel	0.5 MMBtu/hr
10	H-150	Process Flare		Raw fuel gas	0.8 MMBtu/hr
		Storage Tanks			
12	T-133	Crude Oil Tank # 1	Fixed Roof		10,000 bbl
13	T-134	Crude Oil Tank # 2	Fixed Roof		10,000 bbl
14	T-135	Crude Oil Tank # 3	Fixed Roof		10,000 bbl
15	T-140	Slop Oil Tank			10,000 bbl
16	T-142	Produced Water Tank			10,000 bbl
	T-146	Utility Tank			500 bbl
	T-156	Small Diesel Tank			5,000 gal

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

Section 2 Fee Requirements

2. **Administration Fees.** The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-499.

3. **Assessable Emissions**. The Permittee shall pay to the Department annual emission fees based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities 10 tons per year or greater. The quantity for which fees will be assessed is the lesser of:

   3.1 the stationary source's assessable potential to emit of 336 tpy; or

   3.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:

      a. an enforceable test method described in 18 AAC 50.220;

      b. material balance calculations;

      c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035;

      d. other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.

4. **Assessable Emission Estimates.** Emission fees will be assessed as follows:

   4.1 no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Suite 303, PO Box 111800, Juneau, AK 99811-1800; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

   4.2 if no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set out in Condition 3.1.

Section 3 Ambient Air Quality Standards and Increments

5. Ambient air quality standards compliance for the stationary source operation is demonstrated at the posted boundary specified in Cook Inlet Energy, LLC's Access Control Plan set out in Section 7. Establish and maintain ambient air boundaries as described in Section 7.

6. Sulfur Dioxide Requirements.

   6.1 Limit the fuel sulfur content of the liquid fuels burned at the Kustatan Production Facility to no greater than 0.5 percent by weight.

      a. If the fuel grade requires a sulfur content less than 0.5 percent by weight, keep receipts that specify fuel grade and amount; or

      b. If the fuel grade does not require a sulfur content less than 0.5 percent by weight, keep receipts that specify fuel grade and amount and

         (i) Test the fuel for sulfur content of each shipment; or

         (ii) Obtain test results showing the sulfur content of the fuel from the supplier or refinery; the test results must include a statement signed by the supplier or refinery of what fuel they represent.

      c. Fuel testing under Condition 6.1b(i) must follow an appropriate method listed in 18 AAC 50.035 or another method approved in writing by the Department.

   6.2 Report in the operating report required in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 a list of the fuel grades received at the stationary source during the reporting period.

Section 4 Limits to Avoid Classification as PSD Major Source

7. **Oxides of Nitrogen (NOx) Emission Limits**

7.1 Limit NOx emissions from EU 1 and 2 as follows:

a. Install "SoLoNOx" low NOx combustion technology;

b. Limit combined NOx emissions from EUs 1 and 2 to no greater than 64.5 tons per 12-month rolling period, expressed as NO_2.

7.2 Monitoring and Recording for EUs 1 and 2:

a. Calculate and record the NOx emissions, expressed as NO_2 for each monthly period and 12-month rolling period using hours of operation and the following emission factors:[1]

(i) 3.9 lb/hr for EU 1; and

(ii) 4.1 lb/hr for EU 2.

b. Verify NOx emission factors from source testing required in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50. Use exhaust properties determined by 40 CFR 60 Appendix A, Method 19, for each load tested. Use the higher heating value throughout the analysis.

c. In the first operating report due after the Department approval of the source test results, calculate and report the NOx emissions using the worst case emission factor for each of the EUs based on source test results. Alternatively, upon Department written approval, the Permittee may recalculate emissions using the new emission factors beginning effective with the month in which the source test was conducted.

7.3 Report the cumulative total monthly and 12-month rolling NOx emissions, expressed as NO_2, from EUs 1 and 2 in the operating report as described in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50.

7.4 Limit operations of EU 9a to no more than 500 hours per 12-month rolling period.

7.5 Monitor and record the hours of operation of EU 9a for each calendar month.

7.6 Report the cumulative total monthly and 12 month rolling hours of operation of EU 9a in the operating report required in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50.

[1] The NOx emission factors for EUs 1 and 2 are from source tests approved by the Department on February 17, 2015, plus 10 percent to adjust for load and temperature.

8. **Carbon Monoxide (CO) Emission Limits**

8.1 For EUs 1 and 2, limit combined total CO emissions to less than 136 tons per 12-month rolling period.

8.2 For EU 10, limit the fuel gas burned to no more than 70 MMscf in an 12-month rolling period.

8.3 Operate EUs 1 and 2 at all times, except at startup, shutdown, malfunction, and performance and emission tests at no less than the lower of either 50 percent load or the minimum load for which CO emission source tests were conducted.

8.4 Monitoring and Recording for EUs 1 and 2:

a. Verify CO emission factors from source testing required in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50. Use exhaust properties determined by Method 19, for each load tested. Use the higher heating value throughout the analysis.

b. If the combined emission factors for EUs 1 and 2 for worst case operation exceed 31 lb/hr,[2] calculate and record the CO emissions for each month and 12-month rolling period for the period preceding submission of the source test results. Use hours of operation and the worst case emission factor for each unit in the calculations.

c. For both EU 1and 2, monitor the date, time, duration and reason for all operations less than the load listed in Condition 8.3.

8.5 Monitor the fuel gas burned in EU 10 for each calendar month. Use flow meters and totalizers accurate to ±10 percent. Calculate and record the 12-month rolling fuel gas burned for each month of the reporting period, by the end of the following month.

8.6 Report in the operating report described in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 for each month of the reporting period:

a. The cumulative 12-month rolling CO emissions from EUs 1and 2 recorded in Condition 8.4b.

b. The 12-month rolling fuel gas burned in EU 10 recorded in Condition 8.5.

9. **Volatile Organic Compound (VOC) Emission Limits**

9.1 Equip the crude tanks, slop oil tank and produced water tank, EUs 12 through 16, with a closed vent system and control device meeting the following specifications:

a. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions;

b. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.

[2] Combined emission factor of 31 lb/hr for EUs 1 and 2 is equivalent to 136 tpy of unlimited operations.

Section 5 Standard Permit Conditions

10. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

    10.1 an enforcement action; or

    10.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

11. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

12. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

13. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

14. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 6 Permit Documentation

Date	Document Details
February 28, 2018	Application for Minor Permit AQ0741MSS03 received.
February 9, 2015	Comments from Cook Inlet Energy regarding the preliminary permit decision for Minor Permit AQ0741MSS02.
October 7, 2014	Application for Minor Permit AQ0741MSS02 received.
September 23, 2014	Meeting between SLR, Cook Inlet Energy, and Department.
March 18, 2013	The Department received a notarized Assignment of Ownership form from Pacific Energy Resources, Ltd. (PERL) to Cook Inlet Energy, LLC.
December 4, 2007	Letter from Forest Oil to the Department. Request to administratively revise Minor Permit AQ0741MSS01 for transfer of ownership.
July 12, 2007	Letter from Forest Oil to the Department. Request to administratively revise Minor Permit AQ0741MSS01.
May 22, 2007	Comments from Forest Oil regarding the preliminary permit decision for Minor Permit AQ0741MSS01.
April 4, 2007	Email to Alan Schuler: Supplemental modeling information.
March 28, 2007	Email to Alan Schuler: Supplemental modeling information.
March 14, 2007	Email from Al Trbovich (Hoefler Consulting) to Alan Schuler: Attached SO_2 Q-D Analysis and Modeling Results Summary.
March 2, 2007	Email from JR Wilcox to Zeena Siddeek: Revisions to emissions calculations to reflect change of ORL for flare.
February 22, 2007	Email from JR Wilcox to Zeena Siddeek: Revisions to emissions calculations.
February 15, 2007	Email to Alan Schuler: Modeling assessment
February 9, 2007	Email from JR Wilcox to Zeena Siddeek: Revisions to permit application.
February 6, 2007	Email from JR Wilcox to Zeena Siddeek: Attached vendor data for new emergency generator.
February 1, 2007	Email from JR Wilcox to Zeena Siddeek: Revisions to permit application.
January 17, 2007	Email from JR Wilcox to Zeena Siddeek pertaining to aggregation information of Kustatan and Osprey.
December 28, 2006	Email from JR Wilcox to Zeena Siddeek: Revisions to Owner Requested Limits with attached turbine operation data.
November 1, 2006	Permit application from Forest Oil with Request to Amend Permits 741CP02 and 696CP03 for the Kustatan/Osprey Source, West Foreland.

Section 7 Kustatan Production Site Public Access Control Plan

Purpose

The purpose of this Public Access Control Plan for the Kustatan Production Site is to protect the general public from public health and safety hazards incident to the heavy industrial activity planned at the Cook Inlet Energy, LLC property on the West Foreland, Cook Inlet, Alaska. The planned activity involves exploratory drilling for potential petroleum production. Cook Inlet Energy, LLC has established these reasonable restrictions on general public access to attain adequate protection of public health and welfare.

Cook Inlet Energy, LLC is committed to fully and adequately protecting the health and safety of its work force by meeting or exceeding the standards for air exposure of the Occupational Safety and Health Administration (OSHA) and, where the general public has access, the National and Alaska Ambient Air Quality Standards (AAQS). A primary purpose of this plan is to delineate the area to be protected and controlled for occupational health and safety from the area that is subject to unrestricted, general public access where AAQS are applicable. A secondary purpose is to ensure that reasonable measures are in place to accomplish reasonable restrictions on public access. The boundary is reflected in Figure 1, the Ambient Air Boundary Map.

General Information

The Kustatan Production site is located on the West Foreland, Cook Inlet, Alaska. The site is on property owned by Cook Inlet Energy, LLC. The nearest community to the site is Nikiski, approximately 9 kilometers to the east. Cook Inlet lies between the site and Nikiski. Cook Inlet Energy, LLC's West McArthur River Unit Production Facilities are located approximately 8 kilometers north of the site.

Currently, the site is accessible only by helicopter and boat. Because the area is roadless, Cook Inlet is effective as a physical barrier to prevent public access. A second effective physical barrier is the steep, 150- to 200-foot high bluff that must be climbed to access the West Foreland.

Cook Inlet Energy, LLC has constructed a private road from the company's West McArthur River Unit Production Facilities to the site. The public will not be allowed to use this road. As a practical matter, few people are traversing the area that will be impacted by the Kustatan Production Site. The few people that may be in the area would be primarily at the Kustatan Fish Camp. This camp is on property owned by Cook Inlet Energy, LLC. This fish camp has a small boat dock but is officially off-limits to the general public. To be conservative, the fish camp is treated as accessible to the public for the purposes of this plan.

In addition to the physical barrier cited above, public access to the site will be restricted using strategically located signs. These signs will be posted at the fish camp boat dock, the trail leading from the fish camp to the top of the bluff, and at the point the Cook Inlet Energy road enter the site.

Public Access Control Measures

The area surrounding the Kustatan Production site is remote, isolated, and physically prohibitive to travel. Cook Inlet Energy, LLC owns the area within the ambient air quality boundary and has the legal right to restrict public access. No established trails or cabin sites exist within the restricted area. In addition, no public need or use exists for the land within the restricted area. Cook Inlet and high angle bluffs prohibit snowmobile and all-terrain vehicle travel. Walking is difficult, and in places, impossible.

Signs will be posted along the two theoretically potential access routes. These two routes are Cook Inlet Energy, LLC's private access road from the West McArthur River Unit Production Facilities and the walking trail from the Kustatan fish camp to the top of the bluff. Three signs will be posted, one each at the:

- Fish camp boat dock;
- Point the foot trail to the top of the bluff exists the fish camp; and
- Point of entry to the site of the Cook Inlet Energy, LLC road from the West McArthur River Unit Production Facilities.

The sign specifications are:

- Each sign will be 4 feet by 6 feet and will be mounted on posts
- Each sign will be inspected semi-annually and will be repaired or replaced, as necessary.
- Each sign will be free of visible obstructions.
- Each sign will read:

COOK INLET ENERGY, LLC PETROLEUM EXPLORATION AND PRODUCTION OPERATIONS

INDUSTRIAL AREA
DANGER
OIL PRODUCTION AND FLARING IN PROGRESS

NO UNAUTHORIZED VISITORS BEYOND THIS POINT