Modification to Registration & Certification for Permits by Rule

Hilcorp Energy Company

Federal Gayette Lease Tank Battery
Galveston County, Texas
RN 102527579

Permits by Rule Claimed: 106.352, 106.359, 106.492 & 106.512

April 2019

Prepared In Accordance With
30 TAC Chapter 106

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Introduction

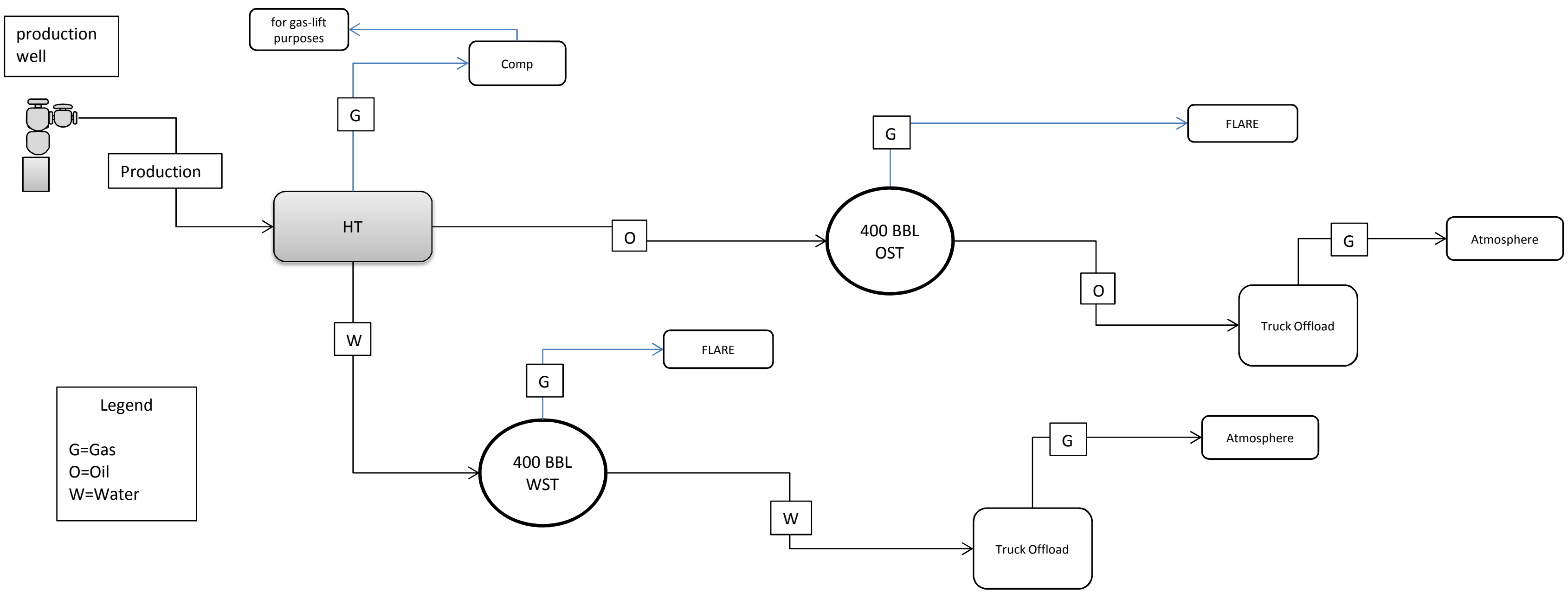
This documentation demonstrates that the Federal Gayette Lease Tank Battery in Galveston County qualifies for an authorization under Permits by Rule 106.352, 106.359, & 106.512. This site is located approximately 8.92 miles southeast of League City, TX located in Galveston County [Lat. = 29˚ 23' 9.41"; Long. = -95˚ 2' 39.83"- (1983 Datum)]. This documentation has been prepared in accordance with 30 TAC Chapter 106.

Process Summary

The Gayette facility is an oil and gas production facility that produces hydrocarbons from natural gas reservoirs through deep wells. The oil, gas, and salt water are separated at the surface. Gas is compressed and routed offsite for sales. Oil is routed to on-site tanks for storage and subsequently hauled offsite by tank truck for sales. Produced water is routed to another facility for disposal. Vapors from the crude oil and produced water storage tanks will be vented to a continuously burning flare for controlling emissions. The flare's pilot will be fueled propane stored on-site.

Simplified Process Flow Diagram

Hilcorp Energy Company
Federal Gayette Lease Tank Battery
Galveston County, TX



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Federal Gayette Lease Tank Battery
Galveston County, TX

EQUIPMENT LIST

Emission Point ID:	PBR:	Footnote:	Emission Point Description:	Construction Date:	Routes To:	Operating Rate/Capacity	Operating Schedule:			Applicable Requirement(s)?	
							Hrs/Day or (Hrs/Yr)	Days/Wk	Wks/Yr	Yes	No
T1	106.352	a	400 bbl Crude Oil Storage Tank	Prior to 8/23/2011	T1	13,505 BOPY	24	7	52.143		√
T2	106.352	a	400 bbl Crude Oil Storage Tank	Prior to 8/23/2011	T2	54,750 BWPY	24	7	52.143		√
FLARE	106.492		Process Flare Pilot Gas	Prior to 2014	FLARE	N/A	24	7	52.143		√
TRUCKLOAD	106.352		Truckloading	Prior to 2014	TRUCKLOAD	13,505 BOPY	(71)	-	-		√
FUGITIVES	106.352		Site-Wide Fugitives	Prior to 2014	FUGITIVES	N/A	24	7	52.143		√
11-13-MSS	106.359		Site-Wide MSS Emissions	Prior to 2014	11-13-MSS	b	-	-	-		√
12-19-ICE-ES	106.512	c	Internal Combustion Engine-Exhaust Stack (Caterpillar G3306; Gas Compressor)	7/5/2005	12-19-ICE-ES	145 HP	24	7	52.143	√	

Footnotes:

a *Vapors are routed to the control flare (FLARE) for combustion.*
b *Operating schedule varies with activity.*
c *Date refers to manufacturers date.*

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Federal Gayette Lease Tank Battery
Galveston County, TX

Maximum Annual Emission Rates										
Emission Point ID:	**Footnote:**	**Emission Point Description:**	**Criteria Pollutant Potential Emission Rate (Tons/Yr):**							
			PM_{10}	**$PM_{2.5}$**	**SO_2**	**NO_x**	**CO**	**VOC**	**H2S**
T1		400 bbl Crude Oil Storage Tank	0.00	0.00	0.00	0.00	0.00	0.07	0.00
T2		400 bbl Crude Oil Storage Tank	0.00	0.00	0.00	0.00	0.00	0.07	0.00
FLARE		Process Flare Pilot Gas	0.00	0.00	0.00	0.12	0.24	1.07	0.00
TRUCKLOAD		Truckloading	0.00	0.00	0.00	0.00	0.00	0.14	0.00
FUGITIVES		Site-Wide Fugitives	0.00	0.00	0.00	0.00	0.00	0.87	0.00
11-13-MSS	a	Site-Wide MSS Emissions	0.00	0.00	0.00	0.00	0.00	0.87	0.00
12-19-ICE-ES		Internal Combustion Engine-Exhaust Stack (Caterpillar G3306; Gas Compressor)	0.10	0.10	0.00	0.70	4.20	0.69	0.00
CRITERIA POLLUTANT TOTALS:			**0.10**	**0.10**	**0.00**	**0.82**	**4.44**	**3.78**	**0.00**

Footnotes:
a **---** *Operating schedule varies with activity.*

TOXIC & HAZARDOUS AIR POLLUTANT TOTALS				
Non-VOC HAP/TAP:	**Annual Rate (TPY):**	**VOC HAP/TAP:**		**Annual Rate (TPY):**
-	-	*Acetaldehyde*		0.01
-	-	*Acrolein*		0.01
-	-	*Benzene*		0.03
-	-	*Formaldehyde*		0.38
-	-	*N-Hexane*		0.00
-	-	*Methanol*		0.01
-	-	*Toluene*		0.01
Subtotal:	*0.00*	Subtotal:		*0.45*
HAP/TAP TOTAL:		**0.45**		

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Maximum Hourly Emission Rates

Emission Point ID:	Footnote:	Emission Point Description:	Criteria Pollutant Potential Emission Rate (Lbs/Hr):						
			PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	VOC	H2S
T1		400 bbl Crude Oil Storage Tank	0.00	0.00	0.00	0.00	0.00	0.03	0.00
T2		400 bbl Crude Oil Storage Tank	0.00	0.00	0.00	0.00	0.00	0.03	0.00
FLARE		Process Flare Pilot Gas	0.00	0.00	0.00	0.03	0.06	0.24	0.00
TRUCKLOAD		Truckloading	0.00	0.00	0.00	0.00	0.00	5.92	0.00
FUGITIVES		Site-Wide Fugitives	0.00	0.00	0.00	0.00	0.00	0.20	0.00
11-13-MSS	a	Site-Wide MSS Emissions	0.00	0.00	0.00	0.00	0.00	0.20	0.00
12-19-ICE-ES		Internal Combustion Engine-Exhaust Stack (Caterpillar G3306; Gas Compressor)	0.02	0.02	0.00	0.16	0.96	0.16	0.00
CRITERIA POLLUTANT TOTALS:			**0.02**	**0.02**	**0.00**	**0.19**	**1.02**	**6.78**	**0.00**

Footnotes:
a --- *Operating schedule varies with activity.*

TOXIC & HAZARDOUS AIR POLLUTANT TOTALS				
Non-VOC HAP/TAP:	**Maximum Rate (Lb/Hr):**	**VOC HAP/TAP:**		**Maximum Rate (Lb/Hr):**
-	-	*Benzene*		0.01
-	-	*Ethylbenzene*		0.00
-	-	*Formaldehyde*		0.09
-	-	*N-Hexane*		0.00
-	-	*Toluene*		0.00
-	-	*Xylenes (mixed isomers)*		0.00
Subtotal:	*0.00*	Subtotal:		*0.10*
HAP/TAP TOTAL:		**0.10**		

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Hilcorp Energy Company
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POTENTIAL TITLE V APPLICABILITY

The following table will list all sites under common control and that are contiguous except for intervening road, railroad, right-of-way, or the like and that are located less than 1/4 mile apart and dependent on each other.

Contiguous Sites	PM	SO_2	NOx	CO	VOC	Total HAP
Federal Gayette Lease Tank Battery	0.10	0.00	0.82	4.44	3.78	0.45
TOTALS	**0.10**	**0.00**	**0.82**	**4.44**	**3.78**	**0.45**
Major Source Thresholds for Galveston County	**100**	**100**	**100**	**100**	**100**	**25**

The above table indicates that a Title V federal operating permit is not required.

Engine Compliance with National Ambient Air Quality Standards

The site is located in Galveston County which is located in TCEQ Region 12. According to data provided by TCEQ, the NO_2 background concentration is 75 µg/m^3. In accordance with 30 TAC 106.512 paragraph 6, the internal combustion engine at this site will demonstrate compliance using method A (via EPA SCREEN3 dispersion model). The appropriate NO_2 to NOx ratio to be applied is checked below:

Gas Compressor Engine (FIN: 12-19-ICE-ES)

Figure 1: 30 TAC 106.512(6)(A)			
Device	Q = NOx emission rate (g/hp-hr)	NO_2 / NOx ratio	applicable
IC engine	less than 2.0	0.4	
IC engine	2.0 thru 10.0	0.15 + (0.5/Q)	
IC engine	greater than 10.0	0.2	
Turbine		0.25	
Engine w/catalytic converter		0.85	✓

Engine Data					amb. temp (°F)	receptor ht (ft)
NOx (lb/hr)	stack ht (ft)	stk dia (in)	exit (ft/sec)	exit (°F)		
0.1598	**15**	**6**	**57.55**	**1101**	**75**	**20**
EPA SCREEN3 MODEL						
source	rate (g/s)	stack ht (M)	stack dia (M)	vel (M/S)	stk temp (K)	amb tmp (K)
point	0.02	4.57	0.15	17.55	867	297
recep ht (M)	urban/rural	downwash	complex	simple	meterology	auto
1.5	**R**	**N**	**N**	**Y**	**Full**	**Y**
terrain height above stack base (M)			min & max grid distance (M)			
0				**10**	**300**	
Results (highest µg/m^3) (1 hr avg)			NO_2 / NOx ratio			
10.66			**0.85**			
Background µg/m^3 (1 hour avg)			NO_2 µg/m^3 (1 hour avg)		NO_2 NAAQS (1 hour avg)	
75			**84**		188	

The NO_2 level of 2-18-ICE-ES is 9.06 µg/m^3 and when the background concentration is added the resultant NO_2 level is 84.06 µg/m^3. Since this is less than the NAAQS of 188 µg/m^3, compliance is therefore demonstrated. The SCREEN3 program results along with TCEQ supporting documentation is contained in Appendix C.

TCEQ Core Data Form

TCEQ Use Only

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission (If other is checked please describe in space provided.)

☐ New Permit, Registration or Authorization (Core Data Form should be submitted with the program application.)

☐ Renewal (Core Data Form should be submitted with the renewal form) ☒ Other Certification of Emission Limits

2. Customer Reference Number (if issued)	Follow this link to search for CN or RN numbers in Central Registry**	3. Regulated Entity Reference Number (if issued)
CN 600125991		RN 102527579

SECTION II: Customer Information

4. General Customer Information | 5. Effective Date for Customer Information Updates (mm/dd/yyyy)

☒ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership

☐ Change in Legal Name (Verifiable with the Texas Secretary of State or Texas Comptroller of Public Accounts)

The Customer Name submitted here may be updated automatically based on what is current and active with the Texas Secretary of State (SOS) or Texas Comptroller of Public Accounts (CPA).

6. Customer Legal Name (If an individual, print last name first: e.g.: Doe, John) | If new Customer, enter previous Customer below:

Hilcorp Energy Company

7. TX SOS/CPA Filing Number	8. TX State Tax ID (11 digits)	9. Federal Tax ID (9 digits)	10. DUNS Number (if applicable)

11. Type of Customer: ☐ Corporation ☐ Individual Partnership: ☐ General ☐ Limited

Government: ☐ City ☐ County ☐ Federal ☐ State ☐ Other ☐ Sole Proprietorship ☐ Other:

12. Number of Employees ☐ 0-20 ☐ 21-100 ☒ 101-250 ☐ 251-500 ☐ 501 and higher

13. Independently Owned and Operated? ☐ Yes ☐ No

14. Customer Role (Proposed or Actual) - as it relates to the Regulated Entity listed on this form. Please check one of the following:

☐ Owner ☐ Operator ☒ Owner & Operator

☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other:

15. Mailing Address: 1111 Travis Street

City Houston State TX ZIP 77002 ZIP + 4

16. Country Mailing Information (if outside USA) | 17. E-Mail Address (if applicable) mvicenik@hilcorp.com

18. Telephone Number	19. Extension or Code	20. Fax Number (if applicable)
(713) 209 - 2400		(713) 209 - 2401

SECTION III: Regulated Entity Information

21. General Regulated Entity Information (If `New Regulated Entity" is selected below this form should be accompanied by a permit application)

☐ New Regulated Entity ☐ Update to Regulated Entity Name ☒ Update to Regulated Entity Information

The Regulated Entity Name submitted may be updated in order to meet TCEQ Agency Data Standards (removal of organizational endings such as Inc, LP, or LLC).

22. Regulated Entity Name (Enter name of the site where the regulated action is taking place.)

Federal Gayette Lease Tank Battery

23. Street Address of the Regulated Entity: (No PO Boxes)							
	City		State		ZIP		ZIP + 4
24. County	Galveston						

Enter Physical Location Description if no street address is provided.

25. Description to Physical Location:	REGUIATED ENTITY LOCATION: FROM INTX HIGHWAY 6 & JACK BROOKS RD GO N ON JACK BROOKS RD APPROX 1.5 MI TO FACILITY ON L		
26. Nearest City		State	Nearest ZIP Code
Alta Loma		TX	77568

27. Latitude (N) In Decimal:	29.385948		28. Longitude (W) In Decimal:	-95.044396	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
29	23	9.41	-95	2	39.83

29. Primary SIC Code (4 digits)	30. Secondary SIC Code (4 digits)	31. Primary NAICS Code (5 or 6 digits)	32. Secondary NAICS Code (5 or 6 digits)
1311		211120	

33. What is the Primary Business of this entity? (Do not repeat the SIC or NAICS description.)

Oil & Gas Production

34. Mailing Address:	1111 Travis Street						
	City	Houston	State	TX	ZIP	77098	ZIP + 4
35. E-Mail Address:	mvicenik@hilcorp.com						

36. Telephone Number	37. Extension or Code	38. Fax Number (if applicable)
(713) 209 - 2400		( ) -

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Emissions Inventory Air	☐ Industrial Hazardous Waste
☐ Municipal Solid Waste	☒ New Source Review Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS
	Reg ID - 47023			
☐ Sludge	☐ Storm Water	☐ Title V Air	☐ Tires	☐ Used Oil
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name: Nicholas Fitzmorris, P.E.			41. Title: Project Manager
42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(337) 839 - 1075	223	(337) 839 - 1072	nfitzmorris@hlpengineering.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 6 and/or as required for the updates to the ID numbers identified in field 39.

Company:	Hilcorp Energy Company	Job Title:	Environmental Manager
Name(*In Print*):	Matt Vicenik	Phone:	(713) 209 - 2400
Signature:		Date:	

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer:	Model No.	Serial No.	Manufacture Date:
Caterpillar	G3306 NA	G6X01550	7/5/2005
Rebuilds Date: N/A	No. of Cylinders: 6	Compression Ratio: 10.5:1	EPN: 12-19-ICE

Application: ☒ Gas Compression ☐ Electric Generation ☐ Refrigeration ☐ Emergency/Stand by

☒ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☐ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☐ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☒ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating**:** 145 | Proposed Horsepower Rating: 145

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (ºF)	Exit Velocity (FPS)
15	0.5	1101	57.55

II. Fuel Data

Type of Fuel: ☒ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☐ Diesel

Fuel Consumption (BTU/bhp-hr):7775 | Heat Value: (HHV) | (LHV)

Sulfur Content (grains/100 scf - weight %):

III. Emission Factors (Before Control)

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
13.47		13.47		0.00		0.49		0.27			

Source of Emission Factors: ☒ Manufacturer Data ☐ AP-42 ☐ Other (specify):

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
0.5		3.0		0.00		0.49		0.27			

Method of Emission Control: ☒ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):____

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☒ Yes ☐ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☐ NSPS IIII ☒ Title 30 Chapter 117 - List County: Galveston_______________

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

AIR QUALITY REQUIREMENTS

40 CFR 60 Subpart K, Ka and Kb - Standards for Storage Vessels for Petroleum Liquids.

DOES NOT APPLY: The tanks are prior to lease custody transfer and the storage capacity of each is less than 10,000 bbls.

40 CFR Part 60-Subpart JJJJ - National Emission Standards for Hazardous Air Pollutants

40 CFR 60.4230(a)(4)(iii) & (a)(5) - DOES NOT APPLY: The engines (FIN: 12-19-ICE) at this site was not manufactured on or after July 1, 2008 and have not been modified or reconstructed since June 12, 2006.

40 CFR 63 Subpart ZZZZ - Reciprocating Internal Combustion Engines MACT Standard.

This site would not be classified as a major source of Hazardous Air Pollutants. (FIN:12-19-ICE) is applicable to the requirements of this subpart which incorporates existing reciprocating internal combustion engines. Please note the following requirements associated with this subpart, which Hilcorp must comply with:

a.) Change oil and filter every 1,440 hours of operation or annually, whichever comes first; and
b.) Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and
c.) Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace if necessary.

40 CFR Part 60 Subpart OOOO - Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

40 CFR 60.5365(d) - Pneumatic controllers at this site are not continuous bleed natural gas-driven pneumatic controllers.

The gas compressor commenced construction prior to 8/23/2011 and is not an affected facility under this subpart

40 CFR Part 60 Subpart OOOOa - Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

40 CFR 60.5365a(d) - Pneumatic controllers at this site were constructed prior to 9/18/2015 and is not affected under this subpart.

The gas compressor commenced construction prior to 9/18/2015 and is not an affected facility under this subpart.

The wellsite has not commenced construction, modification or reconstruction and not an affected facility under this subpart.

40 CFR Part 64 - Compliance Assurance Monitoring

DOES NOT APPLY: This site should be classified as a minor source under the Part 70 permitting program, considering the existing control measures.

40 CFR Part 70 - State Operating Permit Programs

DOES NOT APPLY: This site would not be classified as a "major" source under this program, considering the existing control measures.

30 TAC §101.201 - Emissions Event Reporting and Recordkeeping Requirements

The owner/operator of a regulated entity should keep records of any applicable emissions events and notify TCEQ of the event as specified in this section.

30 TAC §106.359 - Planned Maintenance, Startup, and Shutdown (MSS) at Oil and Gas Handling and Production Facilities

106.359(a) - This section authorizes emissions from planned MSS facilities and activities, and any associated emission capture and control facilities.

106.359(d) - Best Management Practices - each permit holder should establish, implement, and update, as appropriate, a program to maintain and repair facilities. Record of conducted planned MSS activities should be kept.

30 TAC §106.8 - Recordkeeping

Owners and operators of sites authorized under a Permit by Rule (PBR) must keep a copy of each PBR and all applicable conditions and requirements at the site. The owner/operator must also keep records demonstrating compliance with any general and/or PBR conditions.

30 TAC §106.352 - Oil & Gas Facilities

106.352(2) - This site operates as an oil & gas production operation which handles gases and liquids associated with the production and processing of fluids found in geologic formations beneath the earth's surface whose total emissions do not exceed the thresholds of this program as demonstrated herein.

30 TAC §106.492 - Flares (FIN: FLARE)

106.492 (1) - The flare at this site meets the design requirements for tip velocity and heat release as specified in this section (refer to calculations in Appendix A). Also note that this flare is equipped with an automatic ignition system and does not emit any reduced sulfur compounds.

106.492 (2) - The gas stream burned by this flare has a lower heating value greater than 200 BTU/ft^3. This flare does not burn sulfur, chlorine, or compounds or either element. No liquids are burned in the flare.

30 TAC §111.111(a)(4)- Flare

Visible emissions from process gas flare shall not be permitted for more than five minutes in any two hour period, except during periods of upset as defined in **§**101.11(a).

(i) Anytime there is an operational change in the flare that requires a permit amendment, compliance shall be determined using Method 22, Method 9 or an alternate test method approved by the executive director and EPA. The observation period for this compliance demonstration shall be no less than two hours unless noncompliance is determined in a shorter time period or operational changes are made to the flare that stop any observed smoking: and

(ii) by a daily notation in the flare operation log that the flare was observed including the time of day and whether or not the flare was smoking. The flare operator shall record at least 98% of these required observations. If smoking is detected, compliance with the emission limits shall be determined using Method 22, Method 9, or an alternate test approved by the executive director and EPA.

30 TAC §106.512 - Engines and Turbines

106.512 (1) - The gas compressor engine (FIN: 12-19-ICE), is rated at less than 240 horsepower and does not require registration with the Office of Permitting, Remediation, and Registration in Austin.

106.512 (5) - Fuel gas should not contain more than ten grains of total sulfur per 100 dry standard cubic feet. If using field gas that contains more than 1.5 grains of H_2S or 30 grains of sulfur per 100 scf, the engine owner/operator should maintain records that document quarterly hydrogen sulfide and total sulfur content and demonstrate that SO_2 emissions do not exceed 25 tons per year.

106.512 (6) - Compliance with the National Ambient Air Quality Standard (NAAQS) is demonstrated in this application by use of dispersion modeling.

30 TAC §117.2000 - Combustion Control at Minor Sources in Ozone Nonattainment Areas

117.2010 - This site is located in the Houston-Galveston-Brazoria Ozone Nonattainment Area and the stationary, reciprocating internal combustion engine (FIN: 12-19-ICE) at this site must meet the NO_x emission limit of 0.5 g/hp-hr and the CO emission limit of 3.0 g/hp-hr.

117.2030 - This engine is controlled using nonselective catalytic reduction and must also be equipped with an automatic air-fuel ratio (AFR) controller.

117.2035 - MONITORING : The owner/operator of each unit subject to §117.2010 of this title (relating to Emission Specifications) and subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) shall install, calibrate, maintain, and operate totalizing fuel flow meters with an accuracy of ±5%, to individually and continuously measure the gas and liquid fuel usage. [A computer that collects, sums, and stores electronic data from continuous fuel flow meters in an acceptable totalizer. For the purpose of compliance with this subsection for units having pilot fuel supplied by a separate fuel system or from an unmonitored portion of the same fuel system, the fuel flow to pilots may be calculated using the manufacturer’s design flow rates rather than measured with a fuel flow meter. The calculated pilot fuel flow rate must be added to the monitored fuel flow when fuel flow is totalized.]

117.2035 - TESTING: The owner/operator of the engine must conduct an initial engine stack test with measure NOx, CO, and O_2 emissions. The stack test must be conducted within 60 days following initial engine start-up to verify that actual emission rates are in compliance with the limits established in this PBR. Retesting is required within 60 days after any modification that could reasonably be expected to increase NOx emissions.

117.2045 - The owner or operator shall maintain written or electronic records of annual fuel usage, NO_x and CO emission measurements, catalytic converter, AFR, or other emissions-related control system maintenance, including the date and nature of corrective actions taken, initial engine stack test, and daily average horsepower for at least five years.

Hilcorp Energy Company - Federal Gayette Lease Tank Battery				
Area Source Analysis - General Requirements 40 CFR 63.1(b)(3) and 63.10(b)(3)				
Process	*Potential (Uncontrolled) Toxic Totals (TPY)*	*Highest Potential (Uncontrolled) Toxic Substances (TPY)*	*Toxic Totals (Federally Enforceable)*	*Single Highest (Fed. Enf.) Toxic/Amount in TPY*
Glycol Dehydration	N/A	N/A	N/A	N/A
Storage Tanks	N/A	N/A	N/A	N/A
Combustion Turbines	N/A	N/A	N/A	N/A
Reciprocating Internal Combustion Engines	0.46	Formaldehyde/0.38;	0.46	Formaldehyde/0.38;
TOTALS:	**0.46**	**Formaldehyde/0.38**	**0.46**	**Formaldehyde/0.38**

Facility Type: Oil and Gas Production
SICC: 1311

Based on the values above, resulting from the potential throughput rates and/or the operational limits reflected in this application and to be established within this authorization, this site is determined to be an area source of HAP under this program.

Permit by Rule 106.4 General Requirements

§106.4. Requirements for Permitting by Rule.

(a) To qualify for a permit by rule, the following general requirements must be met.

(1) Total actual emissions authorized under permit by rule from the facility shall not exceed 250 tons per year (tpy) of carbon monoxide (CO) or nitrogen oxides (NO_x); or 25 tpy of volatile organic compounds (VOC) or sulfur dioxide (SO_2) or inhalable particulate matter (PM_{10}); or 25 tpy of any other air contaminant except carbon dioxide, water, nitrogen, methane, ethane, hydrogen, and oxygen.

(2) Any facility or group of facilities, which constitutes a new major stationary source, as defined in §116.12 of this title (relating to Nonattainment Review Definitions), or any modification which constitutes a major modification, as defined in §116.12 of this title, under the new source review requirements of the Federal Clean Air Act (FCAA), Part D (Nonattainment) as amended by the FCAA Amendments of 1990, and regulations promulgated thereunder, must meet the permitting requirements of Chapter 116, Subchapter B of this title (relating to New Source Review Permits) and cannot qualify for a permit by rule under this chapter. Persons claiming a permit by rule under this chapter should see the requirements of §116.150 of this title (relating to New Major Source or Major Modification in Ozone Nonattainment Areas) to ensure that any applicable netting requirements have been satisfied.

(3) Any facility or group of facilities, which constitutes a new major stationary source, as defined in 40 Code of Federal Regulations (CFR) §52.21, or any change which constitutes a major modification, as defined in 40 CFR §52.21, under the new source review requirements of the FCAA, Part C (Prevention of Significant Deterioration) as amended by the FCAA Amendments of 1990, and regulations promulgated thereunder, must meet the permitting requirements of Chapter 116, Subchapter B of this title and cannot qualify for a permit by rule under this chapter.

(4) Unless at least one facility at an account has been subject to public notification and comment as required in Chapter 116, Subchapter B or Subchapter D of this title (relating to New Source Review Permits or Permit Renewals), total actual emissions from all facilities permitted by rule at an account shall not exceed 250 tpy of CO or NO_x; or 25 tpy of VOC or SO_2 or PM_{10}; or 25 tpy of any other air contaminant except carbon dioxide, water, nitrogen, methane, ethane, hydrogen, and oxygen.

(5) Construction or modification of a facility commenced on or after the effective date of a revision of this section or the effective date of a revision to a specific permit by rule in this chapter must meet the revised requirements to qualify for a permit by rule.

(6) A facility shall comply with all applicable provisions of the FCAA, §111 (Federal New Source Performance Standards) and §112 (Hazardous Air Pollutants), and the new source review requirements of the FCAA, Part C and Part D and regulations promulgated thereunder.

(7) There are no permits under the same commission account number that contain a condition or conditions precluding the use of a permit by rule under this chapter.

(8) The proposed facility or group of facilities shall obtain allowances for NO_x if they are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

(b) No person shall circumvent by artificial limitations the requirements of §116.110 of this title (relating to Applicability).

(c) The emissions from the facility shall comply with all rules and regulations of the commission and with the intent of the TCAA, including protection of health and property of the public, and all emissions control equipment shall be maintained in good condition and operated properly during operation of the facility.

(d) Facilities permitted by rule under this chapter are not exempted from any permits or registrations required by local air pollution control agencies. Any such requirements must be in accordance with TCAA, §382.113 and any other applicable law.

Adopted March 7, 2001 Effective March 29, 2001

§106.6. Registration of Emissions.

(a) An owner or operator may certify and register the maximum emission rates from facilities permitted by rule under this chapter in order to establish federally-enforceable allowable emission rates which are below the emission limitations in §106.4 of this title (relating to Requirements for Permitting by Rule).

(b) All representations with regard to construction plans, operating procedures, and maximum emission rates in any certified registration under this section become conditions upon which the facility permitted by rule shall be constructed and operated.

(c) It shall be unlawful for any person to vary from such representation if the change will cause a change in the method of control of emissions, the character of the emissions, or will result in an increase in the discharge of the various emissions, unless the certified registration is first revised.

(d) The certified registration must include documentation of the basis of emission estimates and a written statement by the registrant certifying that the maximum emission rates listed on the registration reflect the reasonably anticipated maximums for operation of the facility.

(e) Certified registrations used to demonstrate that Chapter 122 of this title (relating to Federal Operating Permits) does not apply to a source shall be submitted on the required form to the executive director; to the appropriate commission regional office; and to all local air pollution control agencies having jurisdiction over the site.

(1) Certified registrations established prior to the effective date of this rule shall be submitted on or before February 3, 2003.

(2) Certified registrations established on or after the effective date of this rule shall be submitted no later than the date of operation.

(f) All certified registrations shall be maintained on-site and be provided immediately upon request by representatives of the commission or any local air pollution control agency having jurisdiction over the site. If however, the site normally operates unattended, certified registrations and records demonstrating compliance with the certified registration must be maintained at an office within Texas having day-to-day operational control of the site. Upon request, the commission shall make any such records of compliance available to the public in a timely manner.

(g) Copies of certified registrations shall be included in permit applications subject to review under Chapter 116, Subchapter B of this title (relating to New Source Review Permits).

§106.8. Recordkeeping

(a) Owners or operators of facilities and sources that are de minimis as designated in §116.119 of this title (relating to De Minimis Facilities or Sources) are not subject to this section.

(b) Owners or operators of facilities operating under a permit by rule (PBR) in Subchapter C of this chapter (relating to Domestic and Comfort Heating and Cooling) or under those PBRs that only name the type of facility and impose no other conditions in the PBR itself do not need to comply with specific recordkeeping requirements of subsection (c) of this section. A list of these PBRs will be available through the commission's Austin central office, regional offices, and the commission's website. Upon request from the commission or any air pollution control program having jurisdiction, claimants must provide information that would demonstrate compliance with §106.4 of this title (relating to Requirements for Permitting by Rule), or the general requirements, if any, in effect at the time of the claim, and the PBR under which the facility is authorized.

(c) Owners or operators of all other facilities authorized to be constructed and operate under a PBR must retain records as follows:

(1) maintain a copy of each PBR and the applicable general conditions of §106.4 of this title or the general requirements, if any, in effect at the time of the claim under which the facility is operating. The PBR and general requirements claimed should be the version in effect at the time of construction or installation or changes to an existing facility, whichever is most recent. The PBR holder may elect to comply with a more recent version of the applicable PBR and general requirements;

(2) maintain records containing sufficient information to demonstrate compliance with the following:

(A) all applicable general requirements of §106.4 of this title or the general requirements, if any, in effect at the time of the claim; and

(B) all applicable PBR conditions;

(3) keep all required records at the facility site. If however, the facility normally operates unattended, records must be maintained at an office within Texas having day-to-day operational control of the plant site;

(4) make the records available in a reviewable format at the request of personnel from the commission or any air pollution control program having jurisdiction;

(5) beginning April 1, 2002, keep records to support a compliance demonstration for any consecutive 12-month period. Unless specifically required by a PBR, records regarding the quantity of air contaminants emitted by a facility to demonstrate compliance with §106.4 of this title prior to April 1, 2002 are not required under this section; and

(6) for facilities located at sites designated as major in accordance with §122.10(13) of this title (relating to General Definitions) or subject to or potentially subject to any applicable federal requirement, retain all records demonstrating compliance for at least five years. For facilities located at all other sites, all records demonstrating compliance must be retained for at least two years. These

record retention requirements supercede any retention conditions of an individual PBR.

Adopted October 10, 2001 Effective November 1, 2001

§106.13. References to Standard Exemptions and Exemptions from Permitting.

The authorizations formerly known as standard exemptions and exemptions from permitting are referred to as permits by rule in this title. Types of facilities and changes within facilities authorized by those standard exemptions and exemptions from permitting continue to be authorized unless modifications or changes to those facilities has caused them to no longer meet the conditions of the former standard exemption or exemption from permitting and the general requirements of this subchapter.

Adopted August 9, 2000 Effective September 4, 2000

§106.50 Registration Fees for Permits by Rule

(a) A registrant who submits a permit by rule (PBR) registration for review by the commission shall remit one of the following fees with the PI-7 registration form:

(1) $100 for:

(A) small businesses, as defined in Texas Government Code, §2006.001;

(B) non-profit organizations; and

(C) municipalities, counties, and independent school districts with populations or districts of 10,000 or fewer residents, according to the most recently published census; or

(2) $450 for all other entities.

(b) This fee does not apply to:

(1) a certification submitted solely for the purpose of establishing a federally enforceable emissions limit under §106.6 of this title (relating to Registration of Emissions);

(2) a remediation project conducted under §106.533 of this title (relating to Remediation); or

(3) resubmittal of previously reviewed registrations, if received within six months of a written response on the original action.

(c) This fee is for PBR registrations that are received on or after November 1, 2002.

(d) All PBR fees will be remitted in the form of a check, certified check, electronic funds transfer, or money order made payable to the Texas Commission on Environmental Quality (TCEQ) and submitted concurrently with the registration to the TCEQ, P.O. Box 13088, MC 214, Austin, Texas 78711-3087. No fees will be refunded.

PBR 106.352 - Oil & Gas Production Facility Regulation

§106.352. Oil and Gas Production Facilities.

Any oil or gas production facility, carbon dioxide separation facility, or oil or gas pipeline facility consisting of one or more tanks, separators, dehydration units, free water knockouts, gunbarrels, heater treaters, natural gas liquids recovery units, or gas sweetening and other gas conditioning facilities, including sulfur recovery units at facilities conditioning produced gas containing less than two long tons per day of sulfur compounds as sulfur are permitted by rule, provided that the following conditions of this section are met. This section applies only to those facilities named which handle gases and liquids associated with the production, conditioning, processing, and pipeline transfer of fluids found in geologic formations beneath the earth's surface.

(1) Compressors and flares shall meet the requirements of §106.512 and §106.492 of this title (relating to Stationary Engines and Turbines, and Flares).

(2) Total emissions, including process fugitives, combustion unit stacks, separator, or other process vents, tank vents, and loading emissions from all such facilities constructed at a site under this section shall not exceed 25 tons per year (tpy) each of sulfur dioxide (SO_2), all other sulfur compounds combined, or all volatile organic compounds (VOC) combined; and 250 tpy each of nitrogen oxide and carbon monoxide. Emissions of VOC and sulfur compounds other than SO_2 must include gas lost by equilibrium flash as well as gas lost by conventional evaporation.

(3) Any facility handling sour gas shall be located at least 1/4 mile from any recreational area or residence or other structure not occupied or used solely by the owner or operator of the facility or the owner of the property upon which the facility is located.

(4) Total emissions of sulfur compounds, excluding sulfur oxides, from all vents shall not exceed 4.0 pounds per hour (lb/hr) and the height of each vent emitting sulfur compounds shall meet the following requirements, except in no case shall the height be less than 20 feet:

Total as Hydrogen Sulfide, lb/hr	Minimum vent height, feet
0.27	20
0.60	30
1.94	50
3.00	60
4.00	68

NOTE: Other values may be interpolated.

(5) Before operation begins, facilities handling sour gas shall be registered with the commission's Office of Permitting, Remediation, and Registration in Austin using Form PI-7 along with supporting documentation that all requirements of this section will be met. For facilities constructed under §106.353 of this title (relating to Temporary Oil and Gas Facilities), the registration is required before operation under this section can begin. If the facilities cannot meet this section, a permit under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) is required prior to continuing operation of the facilities.

Adopted August 9, 2000 Effective September 4, 2000

PBR 106.492 - Flare Regulations

§106.492. Flares.

Smokeless gas flares which meet the following conditions of this section are permitted by rule:

(1) design requirements.

(A) The flare shall be equipped with a flare tip designed to provide good mixing with air, flame stability, and a tip velocity less than 60 feet per second (ft/sec) for gases having a lower heating value less than 1,000 British thermal units per cubic foot (Btu/ft^3) or a tip velocity less than 400 ft/sec for gases having a lower heating value greater than 1,000 Btu/ft^3.

(B) The flare shall be equipped with a continuously burning pilot or other automatic ignition system that assures gas ignition and provides immediate notification of appropriate personnel when the ignition system ceases to function. A gas flare which emits no more than 4.0 pounds per hour (lb/hr) of reduced sulfur compounds, excluding sulfur oxides, is exempted from the immediate notification requirement, provided the emission point height meets the requirements of §106.352(4) of this title (relating to Oil and Gas Production Facilities).

(C) A flare which burns gases containing more than 24 parts per million by volume (ppmv) of sulfur, chlorine, or compounds containing either element shall be located at least 1/4 mile from any recreational area or residence or other structure not occupied or used solely by the owner or operator of the flare or the owner of the property upon which the flare is located.

(D) The heat release of a flare which emits sulfur dioxide (SO_2) or hydrogen chloride (HCl) shall be greater than or equal to the following values:

For HCl $Q = 2.73 \times 10^5 \times HCl$

For SO_2 $Q = 0.53 \times 10^5 \times SO_2$

Where Q = heat release, British thermal units per hour, based on lower heating value

HCl = HCl emission rate, lb/hr

SO_2 = SO_2 emission rate, lb/hr

(2) operational conditions.

(A) The flare shall burn a combustible mixture of gases containing only carbon, hydrogen, nitrogen, oxygen, sulfur, chlorine, or compounds derived from these elements. When the gas stream to be burned has a net or lower heating value of more than 200 Btu/ft^3 prior to the addition of air, it may be considered combustible.

(B) A flare which burns gases containing more than 24 ppmv of sulfur, chlorine, or compounds containing either element shall be registered with the commission's Office of Permitting, Remediation, and Registration in Austin using Form PI-7 prior to construction of a new flare or prior to the use of an existing flare for the new service.

(C) Under no circumstances shall liquids be burned in the flare.

Adopted August 9, 2000 Effective September 4, 2000

PBR 106.512 - Engine and Turbine Regulations

§106.512. Stationary Engines and Turbines.

Gas or liquid fuel-fired stationary internal combustion reciprocating engines or gas turbines that operate in compliance with the following conditions of this section are permitted by rule.

(1) The facility shall be registered by submitting the commission's Form PI-7, Table 29 for each proposed reciprocating engine, and Table 31 for each proposed gas turbine to the commission's Office of Permitting, Remediation, and Registration in Austin within ten days after construction begins. Engines and turbines rated less than 240 horsepower (hp) need not be registered, but must meet paragraphs (5) and (6) of this section, relating to fuel and protection of air quality. Engine hp rating shall be based on the engine manufacturer's maximum continuous load rating at the lesser of the engine or driven equipment's maximum published continuous speed. A rich-burn engine is a gas-fired spark-ignited engine that is operated with an exhaust oxygen content less than 4.0% by volume. A lean-burn engine is a gas-fired spark-ignited engine that is operated with an exhaust oxygen content of 4.0% by volume, or greater.

(2) For any engine rated 500 hp or greater, subparagraphs (A) - (C) of this paragraph shall apply.

(A) The emissions of nitrogen oxides (NO_x) shall not exceed the following limits:

(i) 2.0 grams per horsepower-hour (g/hp-hr) under all operating conditions for any gas-fired rich-burn engine;

(ii) 2.0 g/hp-hr at manufacturer's rated full load and speed, and other operating conditions, except 5.0 g/hp-hr under reduced speed, 80-100% of full torque conditions, for any spark-ignited, gas-fired lean-burn engine, or any compression-ignited dual fuel-fired engine manufactured new after June 18, 1992;

(iii) 5.0 g/hp-hr under all operating conditions for any spark-ignited, gas-fired, lean-burn two-cycle or four-cycle engine or any compression-ignited dual fuel-fired engine rated 825 hp or greater and manufactured after September 23, 1982, but prior to June 18, 1992;

(iv) 5.0 g/hp-hr at manufacturer's rated full load and speed and other operating conditions, except 8.0 g/hp-hr under reduced speed, 80-100% of full torque conditions for any spark-ignited, gas-fired, lean-burn four-cycle engine, or any compression-ignited dual fuel-fired engine that:

(I) was manufactured prior to June 18, 1992, and is rated less than 825 hp; or

(II) was manufactured prior to September 23, 1982;

(v) 8.0 g/hp-hr under all operating conditions for any spark-ignited, gas-fired, two-cycle lean-burn engine that:

(I) was manufactured prior to June 18, 1992, and is rated less than 825 hp; or

(II) was manufactured prior to September 23, 1982;

(vi) 11.0 g/hp-hr for any compression-ignited liquid-fired engine.

(B) For such engines which are spark-ignited gas-fired or compression-ignited dual fuel-fired, the engine shall be equipped as necessary with an automatic air-fuel ratio (AFR) controller which maintains AFR in the range required to meet the emission limits of subparagraph (A) of this paragraph. An AFR controller shall be deemed necessary for any engine controlled with a non-selective catalytic reduction (NSCR) converter and for applications where the fuel heating value varies more than ± 50 British thermal unit/standard cubic feet from the design lower heating value of the fuel. If an NSCR converter is used to reduce NO_x, the automatic controller shall operate on exhaust oxygen control.

(C) Records shall be created and maintained by the owner or operator for a period of at least two years, made available, upon request, to the commission and any local air pollution control agency having jurisdiction, and shall include the following:

(i) documentation for each AFR controller, manufacturer's, or supplier's recommended maintenance that has been performed, including replacement of the oxygen sensor as necessary for oxygen sensor-based controllers. The oxygen sensor shall be replaced at least quarterly in the absence of a specific written recommendation;

(ii) documentation on proper operation of the engine by recorded measurements of NO_x and carbon monoxide (CO) emissions as soon as practicable, but no later than seven days following each occurrence of engine maintenance which may reasonably be expected to increase emissions, changes of fuel quality in engines without oxygen sensor-based AFR controllers which may reasonably be expected to increase emissions, oxygen sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x and CO concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x and CO analyzers shall also be acceptable for this documentation;

(iii) documentation within 60 days following initial engine start-up and biennially thereafter, for emissions of NO_x and CO, measured in accordance with United States Environmental Protection Agency (EPA) Reference Method 7E or 20 for NO_x and Method 10 for CO. Exhaust flow rate may be determined from measured fuel flow rate and EPA Method 19. California Air Resources Board Method A-100 (adopted June 29, 1983) is an acceptable alternate to EPA test methods. Modifications to these methods will be subject to the prior approval of the Source and Mobile Monitoring Division of the commission. Emissions shall be measured and recorded in the as-found operating condition; however, compliance determinations shall not be established during start-up, shutdown, or under breakdown conditions. An owner or operator may submit to the appropriate regional office a report of a valid emissions test performed in Texas, on the same engine, conducted no more than 12 months prior to the most recent start of construction date, in lieu of performing an emissions test within 60 days following engine start-up at the new site. Any such engine shall be sampled no less frequently than biennially (or every 15,000 hours of elapsed run time, as recorded by an elapsed run time meter) and upon request of the executive director. Following the initial compliance test, in lieu of performing stack sampling on a biennial calendar basis, an owner or operator may elect to install and operate an elapsed operating time meter and shall test the engine within 15,000 hours of engine operation after the previous emission test. The owner or operator who elects to test on an operating hour schedule shall submit in writing, to the appropriate regional office, biennially after initial sampling, documentation of the actual recorded hours of engine operation since the previous emission test, and an estimate of the date of the next required sampling.

(3) For any gas turbine rated 500 hp or more, subparagraphs (A) and (B) of this paragraph shall apply.

(A) The emissions of NO_x shall not exceed 3.0 g/hp-hr for gas-firing.

(B) The turbine shall meet all applicable NO_x and sulfur dioxide (SO_2) (or fuel sulfur) emissions limitations, monitoring requirements, and reporting requirements of EPA New Source Performance Standards Subpart GG--Standards of Performance for Stationary Gas Turbines. Turbine hp rating shall be based on turbine base load, fuel lower heating value, and International Standards Organization Standard Day Conditions of 59 degrees Fahrenheit, 1.0 atmosphere and 60% relative humidity.

(4) Any engine or turbine rated less than 500 hp or used for temporary replacement purposes shall be exempt from the emission limitations of paragraphs (2) and (3) of this section. Temporary replacement engines or turbines shall be limited to a maximum of 90 days of operation after which they shall be removed or rendered physically inoperable.

(5) Gas fuel shall be limited to: sweet natural gas or liquid petroleum gas, fuel gas containing no more than ten grains total sulfur per 100 dry standard cubic feet, or field gas. If field gas contains more than 1.5 grains hydrogen sulfide or 30 grains total sulfur compounds per 100 standard cubic feet (sour gas), the engine owner or operator shall maintain records, including at least quarterly measurements of fuel hydrogen sulfide and total sulfur content, which demonstrate that the annual SO_2 emissions from the facility do not exceed 25 tons per year (tpy). Liquid fuel shall be petroleum distillate oil that is not a blend containing waste oils or solvents and contains less than 0.3% by weight sulfur.

(6) There will be no violations of any National Ambient Air Quality Standard (NAAQS) in the area of the proposed facility. Compliance with this condition shall be demonstrated by one of the following three methods:

(A) ambient sampling or dispersion modeling accomplished pursuant to guidance obtained from the executive director. Unless otherwise documented by actual test data, the following nitrogen dioxide (NO_2)/NO_x ratios shall be used for modeling NO_2 NAAQS;

Device	NO_x Emission Rate (Q) g/hp-hr	NO_2/NO_x Ratio

IC Engine	Less than 2.0	0.4
IC Engine	2.0 thru 10.0	0.15 +(0.5/Q)
IC Engine	Greater than 10.0	0.2
Turbines	0.25	
IC Engine with catalytic converter		0.85

(B) all existing and proposed engine and turbine exhausts are released to the atmosphere at a height at least twice the height of any surrounding obstructions to wind flow. Buildings, open-sided roofs, tanks, separators, heaters, covers, and any other type of structure are considered as obstructions to wind flow if the distance from the nearest point on the obstruction to the nearest exhaust stack is less than five times the lesser of the height, Hb, and the width, Wb, where:

Hb = maximum height of the obstruction, and
Wb = projected width of obstruction =

$$2\sqrt{\frac{lw}{3.141}}$$

where:

L = length of obstruction
W = width of obstruction

(C) the total emissions of NO_x (nitrogen oxide plus NO_2) from all existing and proposed facilities on the property do not exceed the most restrictive of the following:

(i) 250 tpy;

(ii) the value (0.3125 D) tpy, where D equals the shortest distance in feet from any existing or proposed stack to the nearest property line.

(7) Upon issuance of a standard permit for electric generating units, registrations under this section for engines or turbines used to generate electricity will no longer be accepted, except for:

(A) engines or turbines used to provide power for the operation of facilities registered under the Air Quality Standard Permit for Concrete Batch Plants;

(B) engines or turbines satisfying the conditions for facilities permitted by rule under Subchapter E of this title (relating to Aggregate and Pavement); or

(C) engines or turbines used exclusively to provide power to electric pumps used for irrigating crops.

Adopted May 23, 2001 Effective June 13, 2001

Reportable Emission Events

§101.201. Emissions Event Reporting and Recordkeeping Requirements

(a) The following requirements for reportable emissions events apply.

(1) As soon as practicable, but not later than 24 hours after the discovery of an emissions event, the owner or operator of a regulated entity shall:

(A) determine if the event is a reportable emissions event; and

(B) notify the commission office for the region in which the regulated entity is located, and all appropriate local air pollution control agencies with jurisdiction, if the emissions event is reportable.

(2) The initial 24-hour notification for reportable emissions events, with the exception of emissions from boilers or combustion turbines referenced in the definition of reportable quantity (RQ) in §101.1 of this title (relating to Definitions) for each regulated entity, must at a minimum, identify for each emissions point with emissions that exceed an RQ:

(A) the name of the owner or operator of the regulated entity experiencing an emissions event;

(B) the commission Regulated Entity Number of the regulated entity experiencing an emissions event, if a Regulated Entity Number exists, or if there is not a Regulated Entity Number, the air account number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the release and a contact telephone number;

(C) the common name of the process units or areas, the common name of the facilities that incurred the emissions event, and the common name of the emission points where the unauthorized emissions exceeded an RQ were released to the atmosphere;

(D) the date and time of the discovery of the emissions;

(E) the estimated duration of the emissions;

(F) the compound descriptive type of the individually listed compounds or mixtures of air contaminants released during the emissions event, in the definition of RQ in §101.1 of this title that are known through common process knowledge, past engineering analysis, or testing to have equaled or exceeded the RQ;

(G) the estimated total quantities for those compounds or mixtures described in subparagraph (F) of this paragraph;

(H) the best known cause of the emissions event at the time of the initial 24-hour notification, if known; and

(I) the actions taken, or being taken, to correct the emissions event and minimize the emissions.

(3) The initial 24-hour notification for reportable emissions events for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title must identify for each emission point with excess opacity that exceeds the RQ by more than 15%:

(A) the name of the owner or operator of the regulated entity experiencing an emissions event;

(B) the commission Regulated Entity Number of the regulated entity experiencing an emissions event, if a Regulated Entity Number exists, or if there is not a Regulated Entity Number, the air account number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the release and a contact telephone number;

(C) the best known cause of the emissions event, if known at the time of notification;

(D) the common name of the process units or areas, the common name of the facilities that experienced the emissions event, and the common name of the emission points where the unauthorized opacity that exceeded the RQ occurred;

(E) the date and time of the discovery of the emissions event;

(F) the estimated duration or expected duration of the emissions;

(G) the estimated opacity; and

(H) the actions taken, or being taken, to correct the emissions event and minimize the emissions.

(4) The owner or operator of a regulated entity experiencing a reportable emissions event that also requires an initial notification under §327.3 of this title (relating to Notification Requirements) may satisfy the initial 24-hour notification requirements of this section by complying with the requirements under §327.3 of this title.

(b) The owner or operator of a regulated entity experiencing an emissions event shall create a final record of all reportable and non-reportable emissions events as soon as practicable, but no later than two weeks after the end of an emissions event. Final records must be maintained on-site for a minimum of five years and be made readily available upon request to commission staff or personnel of any air pollution program with jurisdiction. If a regulated entity is not normally staffed, records of emissions events may be maintained at the staffed location within Texas that is responsible for the day-to-day operations of the regulated entity.

(1) The final record of a reportable emissions event must identify for all emission points involved in the emissions event:

(A) the name of the owner or operator of the regulated entity experiencing an emissions event;

(B) the commission Regulated Entity Number of the regulated entity experiencing an emissions event, if a Regulated Entity Number and air account number exists, or if there is not a Regulated Entity Number, the air account number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the release and a contact telephone number;

(C) the physical location of the points at which emissions to the atmosphere occurred;

(D) the common name of the process units or areas, the common name and the agency-established facility identification number of the facilities that experienced the emissions event, and the common name and the agency-established emission point numbers where the unauthorized emissions were released to the atmosphere. Owners or operators of those facilities and emission points that the agency has not established facility identification numbers or emission point numbers for are not required to provide the facility identification numbers and emission point numbers in the report, but are required to provide the common names in the report.

(E) the date and time of the discovery of the emissions event;

(F) the estimated duration of the emissions;

(G) the compound descriptive type of all individually listed compounds or mixtures of air contaminants in the definition of RQ in §101.1 of this title, from all emission points involved in the emissions event, that are known through common process knowledge or past engineering analysis or testing to have been released during the emissions event, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title. Compounds or mixtures of air contaminants, that have an RQ greater than or equal to 100 pounds and the amount released is less than ten pounds in a 24-hour period, are not required to be specifically listed in the report, instead these compounds or mixtures of air contaminants may be identified together as "other";

(H) the estimated total quantities for those compounds or mixtures described in subparagraph (G) of this paragraph; the preconstruction authorization number or rule citation of the standard permit, permit by rule, or rule, if any, governing the facilities involved in the emissions event; and the authorized emissions limits, if any, for the facilities involved in the emissions events, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title, which record only the authorized opacity limit and the estimated opacity during the emissions event. Good engineering practice and methods must be used to provide reasonably accurate representations for emissions and opacity. Estimated emissions from compounds or mixtures of air contaminants that are identified as "other" under subparagraph (G) of this paragraph, are not required for each individual compound or mixture of air contaminants, however, a total estimate of emissions must be provided for the category identified as "other";

(I) the basis used for determining the quantity of air contaminants emitted, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title;

(J) the best known cause of the emissions event at the time of reporting;

(K) the actions taken, or being taken, to correct the emissions event and minimize the emissions; and

(L) any additional information necessary to evaluate the emissions event.

(2) Records of non-reportable emissions events must identify:

(A) the name of the owner or operator of the regulated entity experiencing an emissions event;

(B) the commission Regulated Entity Number and air account number of the regulated entity experiencing an emissions event, if a Regulated Entity Number and air account number exists, of if there is not a Regulated Entity Number, the air account number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the release and a contact telephone number;

(C) the physical location of the points at which emissions to the atmosphere occurred;

(D) the common name of the process units or areas, the common name and the agency-established facility identification number of the facilities that experienced the emissions event, and the common name and the agency-established emission point numbers where the unauthorized emissions were released to the atmosphere. Owners or operators of those facilities and emission points that the commission has not established facility identification numbers or emission point numbers for are not required to provide the facility identification numbers and emission point numbers in the report, but are required to provide the common names in the report;

(E) the date and time of the discovery of the emissions event;

(F) the estimated duration of the emissions;

(G) the compound descriptive type of the individually listed compounds or mixtures of air contaminants, in the definition of RQ in §101.1 of this title, from all emission points involved in the emissions event, that are known through common process knowledge or past engineering analysis, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title and that were unauthorized. Compounds or mixtures of air contaminants, that have an RQ greater than or equal to 100 pounds and the amount released is less than ten pounds in a 24-hour period, are not required to be specifically listed in the report, instead these compounds or mixtures of air contaminants may be identified together as "other";

(H) the estimated total quantities and the authorized emissions limits for those compounds or mixtures described in subparagraph (G) of this paragraph; the preconstruction authorization number or rule citation of the standard permit, permit by rule, or rule, if any, governing the facilities involved in the emissions event; and the authorized emissions limits, if any, for the facilities involved in the emissions events, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title, which record only the authorized opacity limit and the estimated opacity during the emissions event. Good engineering practice and methods must be used to provide reasonably accurate representations for emissions and opacity. Estimated emissions from compounds or mixtures of air contaminants that are identified as "other" under subparagraph (G) of this paragraph, are not required for each individual compound or mixture of air contaminants, however, a total estimate of emissions must be provided for the category identified as "other";

(I) the basis used for determining the quantity of air contaminants emitted, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title;

(J) the best known cause of the emissions event at the time of recording;

(K) the actions taken, or being taken, to correct the emissions event and minimize the emissions; and

(L) any additional information necessary to evaluate the emissions event.

(c) For all reportable emissions events, if the information required in subsection (b) of this section differs from the information provided in the initial 24-hour notification under subsection (a) of this section, the owner or operator of the regulated entity shall submit a copy of the final record to the commission office for the region in which the regulated entity is located and to appropriate local air pollution agencies with jurisdiction no later than two weeks after the end of the emissions event. If the owner or operator does not submit a record under this subsection, the information provided in the initial 24-hour notification under subsection (a) of this section will be the final record of the emissions event, provided the initial 24-hour notification was submitted electronically in accordance with subsection (g) of this section.

(d) The owner or operator of a boiler or combustion turbine, as defined in §101.1 of this title, fueled by natural gas, coal, lignite, wood, or fuel oil containing hazardous air pollutants at a concentration of less than 0.02% by weight, that is equipped with a continuous emission monitoring system that completes a minimum of one operating cycle (sampling, analyzing, and data recording) for each successive 15-minute interval, and is required to submit excess emission reports by other state or federal requirements, is exempt from creating, maintaining, and submitting final records of reportable and non-reportable emissions events of the boiler or combustion turbine under subsections (b) and (c) of this section if the notice submitted under subsection (a) of this section contains the information required under subsection (b) of this section.

(e) As soon as practicable, but not later than 24 hours after the discovery of an excess opacity event, as defined in §101.1 of this title, where the owner or operator was not already required to provide an initial 24-hour notification under subsection (a)(2) or (3) of this section, the owner or operator shall notify the commission office for the region in which the regulated entity is located, and all appropriate local air pollution control agencies with jurisdiction. In the notification, the owner or operator shall identify:

(1) the name of the owner or operator of the regulated entity experiencing the excess opacity event;

(2) the commission Regulated Entity Number and air account number of the regulated entity experiencing an opacity event, if a Regulated Entity Number and air account number exists, or if there is not a Regulated Entity Number, the air account number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the release and a contact telephone number;

(3) the physical location of the excess opacity event;

(4) the common name of the process units or areas, the common name of the facilities where the excess opacity event occurred, and the common name of the emission points where the excess opacity event occurred;

(5) the date and time of the discovery of the excess opacity event;

(6) the estimated duration of the excess opacity;

(7) the estimated opacity;

(8) the authorized opacity limit for the facilities having the excess opacity event;

(9) the best known cause of the excess opacity event at the time of the notification; and

(10) the actions taken, or being taken, to correct the excess opacity event.

(f) The owner or operator of any regulated entity subject to the provisions of this section shall perform, upon request by the executive director or any air pollution control agency with jurisdiction, a technical evaluation of each emissions event. The evaluation must include at least an analysis of the probable causes of each emissions event and any necessary actions to prevent or minimize recurrence. The evaluation must be submitted in writing to the executive director and to the appropriate local air pollution agencies with jurisdiction within 60 days from the date of request. The 60-day period may be extended by the executive director. Additionally, the owner or operator of a regulated entity experiencing an emissions event must provide, in writing, additional or more detailed information regarding the emissions event when requested by the executive director or any air pollution control agency with jurisdiction, within the time established in the request.

(g) On and after January 1, 2003, notifications and reports required in subsection (c) of this section must be submitted electronically to the commission using the electronic forms provided by the commission. On and after January 1, 2004, notifications required in subsections (a) and (e) of this section must be submitted via commission's secure Web server, facsimile, or electronic mail to the commission using electronic forms provided by the commission. Notwithstanding the requirement to report initial 24-hour notifications electronically after January 1, 2004, the owner or operator of a regulated entity experiencing a reportable emissions event that also requires an initial notification under §327.3 of this title, is not required to report the event electronically under this subsection provided the owner or operator complies with the requirements under §327.3 of this title and in subsections (a) and (c) of this section. If the initial notification is not submitted by using an online form on the commission's secure Web server, the owner or operator must submit the identical information on the commission's secure Web server within 48 hours of discovery of the event. In the event the commission's server is unavailable due to technical failures or scheduled maintenance, events may be reported via facsimile to the appropriate regional office. The commission will provide an alternative means of notification in the event that the commission's electronic reporting system is inoperative. Electronic notification and reporting is not required for small businesses that meet the small business definition in Texas Water Code, §5.135(g)(2) and to appropriate local air pollution control agencies with jurisdiction. Small businesses shall provide notifications and reporting by any viable means that meet the time frames required by this section.

(h) Annual emissions event reporting: beginning in calender year 2007, on or before March 31 of each calendar year or as directed by the executive director, each owner or operator of a regulated entity, as definedin §101.1 of this title that is subject to reporting under §101.10 of this title (relating to Emissions Inventory Requirements), and those that are not subject to reporting under §101.10 of this title, but are located in nonattainment, maintenance, early action compact areas, Nueces County, and San Patricio County, that experienced at least one emissions event during the calendar year shall report to the executive director, and all appropriate local air pollution control agencies with jurisdiction, the following:

(1) the total number of reportable and the total number of non-reportable emissions events experienced at the regulated entity;

(2) the estimated total quantities for all compounds or mixtures of air contaminants, by compound or mixture, in the definition of RQ in §101.1 of this title that, by facility, were emitted during emissions events at the regulated entity. Compounds or mixtures of air contaminants, that have an RQ greater than or equal to 100 pounds and the amount released is less than one pound in a 24-hour period, are not required to be included in the report. Good engineering practice and methods must be used to provide reasonably accurate representations for emissions and opacity. This paragraph does not apply to boilers and combustion turbines referenced in the definition of RQ in §101.1 of this title that must report only the estimated opacities during emissions events and duration of unauthorized opacity; and

(3) owners and operators of regulated entities that are not subject to reporting under §101.10 of this title must provide annual emissions event reporting electronically by using an online form on the commission's secure Web server. The commission will provide an alternative means of reporting in the event that the commission's electronic reporting system is inoperative. If the commission's server is unavailable due to technical failures or scheduled maintenance, the annual reports may be provided through alternative means to the executive director. Annual electronic reporting is not required for small businesses that meet the small business definition in Texas Water Code, §5.135(g)(2) and to appropriate local air pollution control agencies with jurisdiction. Small businesses shall provide annual reporting by any viable means that meet the time frames required by this section.

(4) owners and operators of regulated entities that are subject to reporting under §101.10 of this title must provide the information required by this subsection as part of their reporting under §101.10 of this

title.

Adopted December 14, 2005 Effective January 5, 2006

(88) Reportable emissions event--Any emissions event that in any 24-hour period, results in an unauthorized emission from any emissions point equal to or in excess of the reportable quantity as defined in this section.

(89) Reportable quantity (RQ)--Is as follows:

(A) for individual air contaminant compounds and specifically listed mixtures by name or Chemical Abstracts Service (CAS) number, either:

(i) the lowest of the quantities:

(I) listed in 40 Code of Federal Regulations (CFR) Part 302 , Table 302.4, the column "final RQ";

(II) listed in 40 CFR Part 355, Appendix A, the column "Reportable Quantity"; or

(III) listed as follows:

(-a-) acetaldehyde - 1,000 pounds, except in the Houston-Galveston-Brazoria (HGB) and Beaumont-Port Arthur (BPA) ozone nonattainment areas as defined in paragraph (71)(E)(i) and (iii) of this section, where the RQ must be 100 pounds;

(-b-) butanes (any isomer) - 5,000 pounds;

(-c-) butenes (any isomer, except 1,3-butadiene) - 5,000 pounds, except in the HGB and BPA ozone nonattainment areas as defined in paragraph (71)(E)(i) and (iii) of this section, where the RQ must be 100 pounds;

(-d-) carbon monoxide - 5,000 pounds;

(-e-) 1-chloro-1,1-difluoroethane (HCFC-142b) - 5,000 pounds;

(-f-) chlorodifluoromethane (HCFC-22) - 5,000 pounds;

(-g-) 1-chloro-1-fluoroethane (HCFC-151a) - 5,000 pounds;

(-h-) chlorofluoromethane (HCFC-31) - 5,000 pounds;

(-i-) chloropentafluoroethane (CFC-115) - 5,000 pounds;

(-j-) 2-chloro-1,1,1,2-tetrafluoroethane (HCFC-124) - 5,000 pounds;

(-k-) 1-chloro-1,1,2,2 tetrafluoroethane (HCFC-124a) - 5,000 pounds;

(-l-) 1,1,1,2,3,4,4,5,5,5-decafluoropentane (HFC 43-10mee) - 5,000 pounds;

(-m-) decanes (any isomer) - 5,000 pounds;

(-n-) 1,1-dichloro-1-fluoroethane (HCFC-141b) - 5,000 pounds;

(-o-) 3,3-dichloro-1,1,2,2-pentafluoropropane (HCFC-225ca) - 5,000 pounds;

(-p-) 1,3-dichloro-1,1,2,2,3-pentafluoropropane (HCFC-225cb) - 5,000 pounds;

(-q-) 1,2-dichloro-1,1,2,2-tetrafluoroethane (CFR-114) - 5,000 pounds;

(-r-) 1,1,-dichlorotetrafluoroethane (CFC-114a) - 5,000 pounds;

(-s-) 1,2-dichloro-1,1,2-trifluoroethane (HCFC-123a) - 5,000 pounds;

(-t-) 1,1-difluoroethane (HFC-152a) - 5,000 pounds;

(-u-) difluoromethane (HFC-32) - 5,000 pounds;

(-v-) ethanol - 5,000 pounds;

(-w-) ethylene - 5,000 pounds, except in the HGB and BPA ozone nonattainment areas as defined in paragraph (71)(E)(i) and (iii) of this section, where the RQ must be 100 pounds;

(-x-) ethylfluoride (HFC-161) - 5,000 pounds;

(-y-) 1,1,1,2,3,3,3-heptafluoropropane (HFC-227ea);

(-z-) 1,1,1,3,3,3-hexafluoropropane (HFC-236fa) - 5,000 pounds;

(-aa-) 1,1,1,2,3,3-hexafluoropropane (HFC-236ea) - 5,000 pounds;

(-bb-) hexanes (any isomer) - 5,000 pounds;
(-cc-) isopropyl alcohol - 5,000 pounds;
(-dd-) mineral spirits - 5,000 pounds;
(-ee-) octanes (any isomer) - 5,000 pounds;
(-ff-) oxides of nitrogen - 200 pounds in ozone nonattainment, ozone maintenance, early action compact areas, Nueces County, and San Patricio County, and 5,000 pounds in all other areas of the state, which should be used instead of the RQs for nitrogen oxide and nitrogen dioxide provided in 40 CFR Part 302, Table 302.4, the column "final RQ";
(-gg-) pentachlorofluoroethane (CFR-111) - 5,000 pounds;
(-hh-) 1,1,1,3,3-pentafluorobutane (HFC-365mfc) - 5,000 pounds;
(-ii-) pentafluoroethane (HFC-125) - 5,000 pounds;
(-jj-) 1,1,2,2,3-pentafluoropropane (HFC-245ca) - 5,000 pounds;
(-kk-) 1,1,2,3,3-pentafluoropropane (HFC-245ea) - 5,000 pounds;
(-ll-) 1,1,1,2,3-pentafluoropropane (HFC-245eb) - 5,000 pounds;
(-mm-) 1,1,1,3,3-pentafluoropropane (HFC-245fa) - 5,000 pounds;
(-nn-) pentanes (any isomer) - 5,000 pounds;
(-oo-) propane - 5,000 pounds;
(-pp-) propylene - 5,000 pounds, except in the HGB and BPA ozone nonattainment areas as defined in paragraph (71)(E)(i) and (iii) of this section, where the RQ must be 100 pounds;
(-qq-) 1, 1, 2, 2-terachlorodifluoroethane (CFR -112) - 5,000 pounds;
(-rr-) 1,1,1,2-tetrachlorodifluoroethane (CFC-112a) - 5,000 pounds;
(-ss-) 1,1,2,2-tetrafluoroethane (HFC-134) - 5,000 pounds;
(-tt-) 1,1,1,2-tetrafluoroethane (HFC-134a) - 5,000 pounds;
(-uu-) 1,1,2-trichloro-1,2,2-trifluoroethane (CFR-113) - 5,000 pounds;
(-vv-) 1,1,1-trichloro-2,2,2-trilfloroethane (CFC-113a) - 5,000 pounds;
(-ww-) 1,1,1-trifluoro-2,2-dichloroethane (HCFC-123) - 5,000 pounds;
(-xx-) 1,1,1-trifluoroethane (HFC-143a) - 5,000 pounds;
(-yy-) trifluoromethane (HFC-23) - 5,000 pounds; or
(-zz-) toluene - 1,000 pounds, except in the HGB and BPA ozone nonattainment areas as defined in paragraph (71)(E)(i) and (iii) of this section, where the RQ must be 100 pounds;

(ii) if not listed in clause (i) of this subparagraph, 100 pounds;

(B) for mixtures of air contaminant compounds:

(i) where the relative amount of individual air contaminant compounds is known through common process knowledge or prior engineering analysis or testing, any amount of an individual air contaminant compound that equals or exceeds the amount specified in subparagraph (A) of this paragraph;
(ii) where the relative amount of individual air contaminant compounds in subparagraph (A)(i) of this paragraph is not known, any amount of the mixture that equals or exceeds the amount for any single air contaminant compound that is present in the mixture and listed in subparagraph (A)(i) of this paragraph;
(iii) where each of the individual air contaminant compounds listed in subparagraph (A)(I) of this paragraph are known to be less than 0.02% by weight of the mixture, and each of the other individual air contaminant compounds covered by subparagraph (A)(ii) of this paragraph are known to be less than 2.0% by weight of the mixture, any total amount of the mixture of air contaminant compounds greater than or equal to 5,000 pounds; or
(iv) where natural gas excluding carbon dioxide, water, nitrogen, methane, ethane, noble gases, hydrogen, and oxygen or air emissions from crude oil are known to be in an amount greater than or equal to 5,000 pounds or the associated hydrogen sulfide and mercaptans in a total amount greater than 100 pounds, whichever occurs first;

(C) for opacity from boilers and combustion turbines as defined in this section fueled by natural gas, coal, lignite, wood, fuel oil containing hazardous air pollutants at a concentration of less than 0.02% by weight, opacity that is equal to or exceeds 15 additional percentage points above the applicable limit, averaged over a six-minute period. Opacity is the only RQ applicable to boilers and combustion turbines described in this paragraph; or

(D) for facilities where air contaminant compounds are measured directly by a continuous emission monitoring system providing updated readings at a minimum 15-minute interval an amount, approved by the executive director based on any relevant conditions and a screening model, that would be reported prior to ground level concentrations reaching at any distance beyond the closest regulated entity property line:

(i) less than one-half of any applicable ambient air standards; and
(ii) less than two times the concentration of applicable air emission limitations.

Maintenance, Startup, and Shutdown Activities

§101.211. Scheduled Maintenance, Startup and Shutdown Reporting and Recordkeeping Requirements.

(a) The owner or operator of a regulated entity conducting a scheduled maintenance, startup, or shutdown activity shall notify the commission office for the region in which the regulated entity is located and all appropriate local air pollution control agencies with jurisdiction at least ten days prior to any scheduled maintenance, startup, or shutdown activity that is expected to cause an unauthorized emission that equals or exceeds the reportable quantity (RQ) as defined in §101.1 of this title (relating to Definitions), by emissions point in any 24-hour period and/or an activity where the owner or operator expects only an excess opacity event as defined in §101.1 of this title. If notice cannot be given ten days prior to a scheduled maintenance, startup, or shutdown activity, notification must be given as soon as practicable prior to the scheduled activity. Maintenance, startup, or shutdown activities where the actual emissions exceed the emissions in the notification by more than an RQ or for which a notification was not submitted prior to the activity are either upsets or unplanned maintenance, startup, or shutdown activities, depending upon the reason for exceeding the estimate. Excess opacity events where unauthorized emissions result are emissions events. Owners and operators of a regulated entity with emissions events shall report such events as emissions events in accordance with the requirements in §101.201 of this title, or this section as applicable and §101.222 of this title (relating to Demonstrations).

(1) The notification for a scheduled maintenance, startup, or shutdown activity, except for boilers and combustion turbines referenced in the definition of RQ in §101.1 of this title, must identify:

(A) the name of the owner or operator;

(B) the commission Regulated Entity Number of the regulated entity, if a Regulated Entity Number and air account number exist(s), or if there is not a Regulated Entity Number, the air number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the release and a contact telephone number;

(C) the physical location of the points at which emissions from the scheduled maintenance, startup, or shutdown activity will occur;

(D) the type of scheduled maintenance, startup, or shutdown activity and the reason for the scheduled activity;

(E) the expected date and time of the scheduled maintenance, startup, or shutdown activity, and expected duration of any maintenance activity;

(F) the common name of the process units or areas, the common name and the agency-established facility identification number of the facilities that will be involved in the emissions activity, and the common name and the agency-established emission point numbers where the unauthorized emissions may be released to the atmosphere. Owners or operators of those facilities and emission points that the agency has not established facility identification numbers or emission point numbers for are not required to provide the facility identification numbers and emission point numbers in the report, but are required to provide the common names in the report;

(G) the expected duration of the emissions from the scheduled maintenance, startup, or shutdown activity;

(H) the compound descriptive type of the individually listed compounds or mixtures of air contaminants, in the definition of RQ in §101.1 of this title, for all emission points involved in the emissions activity, that through common process knowledge or past engineering analysis or testing are expected to equal or exceed the RQ. Compounds or mixtures of air contaminants, that have an RQ greater than or equal to 100 pounds and the amount released is less than ten pounds in a 24-hour period, are not required to be specifically listed in the report, instead these compounds or mixtures of air contaminants may be identified together as "other";

(I) the estimated total quantities for those compounds or mixtures described in subparagraph (H) of this paragraph; the preconstruction authorization number or rule citation of the standard permit, permit by rule, or rule, if any, governing the facilities involved in the activity; authorized emissions limits, if any, for the facilities involved in the emissions activity, and, if applicable, the estimated opacity and the authorized opacity limit. Good engineering practice and methods must be used to provide reasonably accurate representations for emissions and opacity. Estimated emissions from compounds or mixtures of air contaminants that are identified as "other" under subparagraph (H) of this paragraph, are not required for each individual compound or mixture of air contaminants, however, a total estimate of emissions must be provided for the category identified as "other";

(J) the basis used for determining the quantity of air contaminants to be emitted; and

(K) the actions taken to minimize the emissions from the scheduled maintenance, startup, or shutdown activity.

(2) The notification for a scheduled maintenance, startup, or shutdown activity involving a boiler or combustion turbine referenced in the definition of RQ in §101.1 of this title, or where the owner or operator expects only an excess opacity event and the owner or operator was not already required to provide a notification under paragraph (1) of this subsection, must identify:

(A) the name of the owner or operator;

(B) the commission Regulated Entity Number of the regulated entity, if a Regulated Entity Number and air account number exist(s), or if there is not a Regulated Entity Number, the air account number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the release and a contact telephone number;

(C) the physical location of the scheduled maintenance, startup, or shutdown activity;

(D) the type of scheduled maintenance, startup, or shutdown activity and the reason for the scheduled activity;

(E) the common name of the process units or areas, the common name and the agency-established facility identification numbers of the facility that experienced the excess opacity event, and the common name and the agency-established emission point numbers where the excess opacity event occurred. Owners or operators of those facilities and emission points that the agency has not established facility identification numbers or emission point numbers for are not required to provide the facility identification numbers and emission point numbers in the report, but are required to provide the common names in the report;

(F) the expected date and time of the scheduled maintenance, startup, or shutdown activity, and expected duration of any maintenance activity;

(G) the estimated duration of the emissions from the scheduled maintenance, startup, or shutdown activity;

(H) the estimated opacity and the authorized opacity limit for those emission points that unauthorized opacity is expected; and

(I) the actions taken, or being taken, to minimize the emissions from the scheduled maintenance, startup, or shutdown activity.

(b) The owner or operator of a regulated entity conducting a scheduled maintenance, startup, or shutdown activity shall create a final record of all scheduled maintenance, startup, and shutdown activities with unauthorized emissions, or with opacity exceedances from boilers and combustion turbines referenced in the definition of RQ in §101.1 of this title. The final record must be created as soon as practicable, but no later than two weeks after the end of each scheduled activity. Final records must be maintained on-site for a minimum of five years and be made readily available upon request to commission staff or personnel of any air pollution program with jurisdiction. If a regulated entity is not normally staffed, records of scheduled maintenance, startup, and shutdown activities may be maintained at the staffed location within Texas that is responsible for day-to-day operations of the regulated entity. Such scheduled activity records must identify:

(1) for owners and operators of regulated entities that were required to notify under subsection (a) of this section:

(A) the name of the owner or operator;

(B) the commission Regulated Entity Number of the regulated entity, if a Regulated Entity Number and air account number exist(s), or if there is not a Regulated Entity Number, the air account number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the regulated entity and a contact telephone number;

(C) the physical location of the scheduled points at which emissions from the maintenance, startup, or shutdown activity occurred;

(D) the type of scheduled maintenance, startup, or shutdown activity and the reason for the scheduled activity;

(E) the common name of the process units or areas, the common name and the agency-established facility identification number of the facilities that experienced the emissions activity, and the common name and the agency-established emission point numbers where the unauthorized emissions were released to the atmosphere. Owners or operators of those facilities and emission points that the agency has not established facility identification numbers or emission point numbers for are not required to provide the facility identification numbers and emission point numbers in the report, but are required to provide the common names in the report;

(F) the date and time of the scheduled maintenance, startup, or shutdown activity, and the duration of any maintenance activity;

(G) the duration of the emissions from the scheduled maintenance, startup, or shutdown activity;

(H) the compound descriptive type of all individually listed compounds or mixtures of air contaminants, in the definition of RQ in §101.1 of this title, involved in the emissions activity, that are known through common process knowledge or past engineering analysis or testing to have been released during the scheduled maintenance, startup, or shutdown activity, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title. Compounds or mixtures of air contaminants, that have an RQ greater than or equal to 100 pounds and the amount released is less than ten pounds in a 24-hour period, are not required to be specifically listed in the report instead these compounds or mixtures of air contaminants may be identified together as "other";

(I) the estimated total quantities and the authorized emissions limits for those compounds or mixtures described in subparagraph (H) of this paragraph; the preconstruction authorization number or rule citation of the standard permit, permit by rule, or rule, any, governing the facilities involved in the scheduled maintenance, startup, or shutdown activity; authorized emissions limits, if any, for the facility involved in the scheduled maintenance, startup, or shutdown activity, and, if applicable, the estimated opacity and authorized opacity limit, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title that record only the authorized opacity limit and the estimated opacity during the emissions event. Good engineering practice and methods must be used to provide reasonably accurate representations for emissions and opacity. Estimated emissions from compounds or mixtures of air contaminants that are identified as "other" under subparagraph (H) of this paragraph are not required for each individual compound or mixture of air contaminants; however, a total estimate of emissions must be provided for the category identified as "other";

(J) the basis used for determining the quantity of air contaminants to be emitted, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title; and

(K) the actions taken to minimize the emissions from the scheduled maintenance, startup, or shutdown activity.

(2) for owners and operators of regulated entities that were not required to notify under subsection (a) of this section:

(A) the name of the owner or operator;

(B) the commission Regulated Entity Number of the regulated entity if a Regulated Entity Number and air account number exist(s), or if there is not a Regulated Entity Number, the air account number of the regulated entity. If a Regulated Entity Number and air account number do not exist, then identify the location of the release and a contact telephone number;

(C) the physical location of the scheduled points at which emissions from the maintenance, startup, or shutdown activity occurred;

(D) the type of scheduled maintenance, startup, or shutdown activity and the reason for the scheduled activity;

(E) the common name of the process unit or areas, the common name and the agency-established facility identification numbers of the facilities that experienced the emissions activity , and the common name and the agency-established emission point numbers where the unauthorized emissions were released to the atmosphere. Owners or operators of those facilities and emission points that the agency has not established facility identification numbers or emission point numbers for are not required to provide the facility identification numbers and emission point numbers in the report, but are required to provide the common names in the report;

(F) the date and time of the scheduled maintenance, startup, or shutdown activity, and the duration of any maintenance activity;

(G) the duration of the emissions from the scheduled maintenance, startup, or shutdown activity;

(H) the compound descriptive type of the individually listed compounds or mixtures of air contaminants, in the definition of RQ in §101.1 of this title, that are known through common process knowledge, past engineering analysis, except for boilers or combustion turbines referenced in the definition of RQ in §101.1 of this title and that were unauthorized. Compounds or mixtures of air contaminants, that have an RQ greater than or equal to 100 pounds and the amount released is less than ten pounds in a 24-hour period, are not required to be specifically listed in the record instead these compounds or mixtures of air contaminants may be identified together as "other"; and

(I) the estimated total quantities and the authorized emissions limits for those compounds or mixtures described in subparagraph (H) of this paragraph. Good engineering practice and methods must be used to provide reasonably accurate representations for emissions and opacity. Estimated emissions from compounds or mixtures of air contaminants that are identified as "other" under subparagraph (H) of this paragraph are not required for each individual compound or mixture of air contaminants, however, a total estimate of emissions must be provided for the category identified as "other."

(c) For any scheduled maintenance, startup, or shutdown activity for which an initial notification was submitted under subsection (a) of this section, which does not provide all the information required in subsection (b) of this section or if the information has changed from the prior notification, the owner or operator of the regulated entity shall submit a final record as required by subsection (b) of this section to the commission office for the region in which the regulated entity is located and to appropriate local air pollution agencies with jurisdiction no later than two weeks after the end of the scheduled activity. If the owner or operator does not submit a record under this subsection, the information provided under subsection (a) of this section will be the final record of the scheduled activity.

(d) The owner or operator of a boiler or combustion turbine as defined in §101.1 of this title fueled by natural gas, coal, lignite, wood, or fuel oil containing hazardous air pollutants at a concentration of less than 0.02% by weight, that is equipped with a continuous emission monitoring system that completes a minimum of one operating cycle (sampling, analyzing, and data recording) for each successive 15-minute interval, and is required to submit excess emissions reports by other state or federal rules, is exempt from creating, maintaining, and submitting final records of scheduled maintenance, startup, and shutdown activities with unauthorized emissions under subsections (b) and (c) of this section, if the notice submitted under subsection (a) of this section contains the information required under subsection (b) of this section.

(e) The executive director may specify the amount, time, and duration of emissions that will be allowed during the scheduled maintenance, startup, or shutdown activity. The owner or operator of any source subject to the provisions of this section shall submit a technical plan for any scheduled maintenance, startup, or shutdown activity when requested by the executive director with a copy to the appropriate local air pollution agencies with jurisdiction. The plan must contain a detailed explanation of the means by which emissions will be minimized during the scheduled maintenance, startup, or shutdown activity. For those emissions that must be released into the atmosphere, the plan must include the reasons such emissions cannot be reduced further.

(f) For annual scheduled maintenance, startup, and shutdown activity reporting on or before March 31 of each calendar year beginning in calender year 2007, or as directed by the executive director, each owner or operator of a regulated entity site, as defined in §101.1 of this title that is subject to reporting under §101.10 of this title (relating to Emissions Inventory Reporting), and those that are not subject to reporting under §101.10 of this title but are located in nonattainment, maintenance, early action compact areas, Nueces County, and San Patricio County, that experienced at least one scheduled maintenance, startup, and shutdown activity during the calendar year must report to the executive director, and all appropriate local air pollution control agencies with jurisdiction:

(1) the number of reportable and non-reportable scheduled maintenance, startup, and shutdown activities experienced at the regulated entity; and

(2) the estimated total quantities for all compounds or mixtures, by compound or mixture, of air contaminants, in the definition of RQ in §101.1 of this title that, by facility, emitted during scheduled maintenance, startup, and shutdown activities at the regulated entity. Compounds or mixtures of air contaminants, that have an RQ greater than or equal to 100 pounds and the amount released is less than one pound in a 24-hour period, are not required to be included in the report. Good engineering practice and methods must be used to provide reasonably accurate representations for emissions and opacity. This paragraph does not apply to boilers and combustion turbines referenced in the definition of RQ in §101.1 of this title, that must report only the estimated opacities during emissions events and duration of unauthorized opacity; and

(3) owners and operators of regulated entities that are not subject to reporting under §101.10 of this title must report annual total emissions resulting from all scheduled maintenance, startup, and shutdown activities electronically by using an online form on the commission's secure Web server. The commission will provide an alternative means of reporting in the event that the commission's electronic reporting system is inoperative. If the commission's server is unavailable due to technical failures or scheduled maintenance, the annual reports may be reported to the executive director. Annual electronic reporting is not required for small businesses that meet the small business definition in Texas Water Code, §5.135(g)(2) and to appropriate local air pollution control agencies with jurisdiction. Small businesses shall provide annual reporting by any viable means that meet the time frames required by this section; and

(4) owners and operators of regulated entities that are subject to reporting under §101.10 of this title must provide the information required by this subsection as part of their reporting under §101.10 of this title.

Adopted December 14, 2005 Effective January 5, 2006

Emission Calculations

POINT SOURCE I.D. NUMBER: ***12-19-ICE-ES***

EMISSION SOURCE DESCRIPTION: ***Internal Combustion Engine-Exhaust Stack (Caterpillar G3306; Gas Compressor)***

DATA:

Emission Source:	***Internal Combustion Engine***
Make/Model/Type:	***Caterpillar/G3306/4-Stroke Rich Burn***
Annual Hours of Operation:	***8760***
Maximum HP @ 1800-rpms: ***(provided by manufacturers specs)***	***145***
Brake Specific Fuel Consumption: ***(BTU/BHP-Hr; from manuf. Specs.)***	***7,775***
VOC Weight % of Fuel Gas:	***22.3***
Fuel Gas Heat Rating: ***(BTU/scf; taken from a representative wet gas analysis)***	***1220***
Max. H2S Concentration in Fuel Gas (ppmv):	***4***
Fuel Source:	***Field Gas***

Max. Hourly Energy Output (HP-Hr)	=	HP Rating x 1-hour	=	***145***
Max. Annual Energy Output (HP-Hr/Yr)	=	HP Rating x Annual Operating Hours	=	***1,270,200***

EMISSION FACTORS:

Unless otherwise noted, average emission factors were taken from GRI-HAPCalc ®3.01 for a 4-Stroke Rich-Burn Engine, using the "GRI Field Test Data" emission factor set.
HAP compounds with emission factors less than 0.001 gms/bhp-hr are not reported.
PM_{10}, $PM_{2.5}$, 1,3-Butadiene, Acetaldehyde, Acrolein & PAH emission factors are taken from Chapter 3.2 of AP-42, 5th Edition, Supplement F, July 2000 for large bore natural gas-fired internal combustion engines; using brake specific fuel consumption (BSFC) noted above.
SO_2 emission factor based on 100% conversion of sulfur compounds in fuel gas, using H_2S fuel composition noted above.
NOx & CO emission factors meet the requirements for non-attainment areas.
Formaldehyde is taken from manufacturers specs.
VOC is taken from manufacturers specs and increased to include formaldehyde.

EMISSION CALCULATIONS:

POLLUTANT:	**UNCONTROLLED EMISSION FACTOR (Grams/BHP-Hr)**	**CALCULATED EMISSION RATES:**		
		Average Hourly (lb/hr):	**Maximum Hourly (lb/hr):**	**Annual (TPY):**
PM_{10} (filterable + condensable)	0.0685	0.0219	0.0219	0.0958
$PM_{2.5}$ (filterable + condensable)	0.0685	0.0219	0.0219	0.0958
Sulfur Dioxide	0.0020	0.0006	0.0006	0.0027
Nitrogen Oxides	0.5000	0.1598	0.1598	0.7001
Carbon Monoxide	3.0000	0.9590	0.9590	4.2005
NMEHC (expressed as VOC)	0.4900	0.1566	0.1566	0.6861
1,3-Butadiene (TAP)	0.0023	0.0007	0.0007	0.0033
Acetaldehyde (TAP)	0.0098	0.0031	0.0031	0.0138

POLLUTANT:	UNCONTROLLED EMISSION FACTOR (Grams/BHP-Hr)	CALCULATED EMISSION RATES:		
		Average Hourly (lb/hr):	Maximum Hourly (lb/hr):	Annual (TPY):
Acrolein (TAP)	0.0093	0.0030	0.0030	0.0130
Benzene (TAP)	0.0221	0.0071	0.0071	0.0309
Formaldehyde (TAP)	0.2700	0.0863	0.0863	0.3780
Methanol (TAP)	0.0067	0.0021	0.0021	0.0093
PAH (TAP)	0.0005	0.0002	0.0002	0.0007
Toluene (TAP)	0.0071	0.0023	0.0023	0.0099
Xylenes (TAP)	0.0017	0.0005	0.0005	0.0024
Total TAPs		0.11	0.11	0.46
Total VOC-TAPs		0.11	0.11	0.46
Total VOC		**0.16**	**0.16**	**0.69**

Data use subject to license.

www.delorme.com

TN
MN (2.0°E)

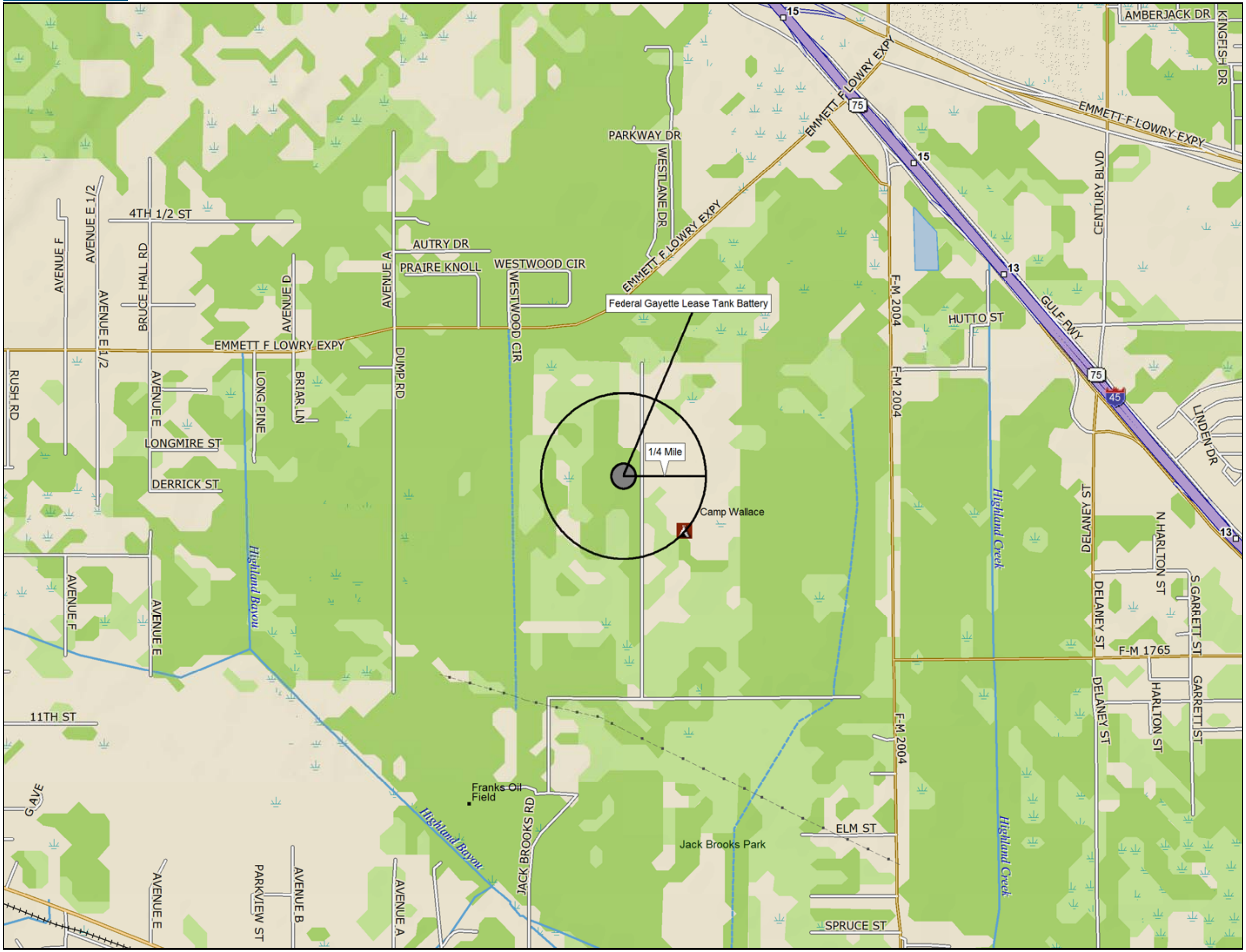
Scale 1 : 100,000

1" = 1.58 mi

Data Zoom 11-0

DELORME

Topo North America™ 9



Data use subject to license.

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TN

MN (2.0°E)

Scale 1 : 25,000

0 600 1200 1800 2400 3000 ft

0 200 400 600 800 1000 m

1" = 2,083.3 ft

Data Zoom 13-0

Analysis ID: 24-7077-24 Alternate ID: Use Contract Values: No

Name Hillcorp (Rig #1- Hite #5) Custody Meter Company Name: Southcross Energy

Effective Date:	06/01/2015 09:00	Saturated HV:	1207.2	Sample Date:	06/15/2015
Valid Thru Date:	12/31/2078 00:00	As Del. HV:		Sample ID:	
Last Update:	07/06/2015 12:43	Dry HV:	1228.1	Sample Type:	Spot
Data Acqusition:		Measured HV:		Sample Pressure Base:	14.730
Data Source:	Lab Analysis	WOBBE:	1454.2	Sample Temperature:	86.0
Real Relative	0.7132	Water Content:		Sample Pressure:	490.0
Status:	Active			Lab Code:	

Component	% Mol	GPM
Methane	82.3460	
Ethane	7.3050	1.9598
Propane	5.6660	1.5659
I Butane	1.1320	0.3716
N Butane	1.3030	0.4121
I Pentane	0.3330	0.1222
N Pentane	0.2350	0.0855
Hexanes +	0.3020	0.1322
Nitrogen	0.1510	
CO2	1.2230	
Oxygen	0.0040	
H2O	0.0000	
CO	0.0000	
H2S	0.0000	
Hydrogen	0.0000	
Helium	0.0000	
Argon	0.0000	
Total	100.0000	4.6493

Sample Comments:

Configuration Comments:

HEC_Analysis ID: 24-7077-24

COMPONENT	mole %	MOLE FRACTION	MW	fuel weight	WT frac	Wt %	dh*	Heat Value (BTU/SCF)	Carbon Weight %	C-H
Nitrogen	0.1510	0.002	28.0134	0.04	0.0021	0.2055	0	0.00	0.0000	0
Hydrogen Sulfide	0.0000	0.000	34.08	0.00	0.0000	0.0000	637.1	0.00	0.0000	0
Carbon Dioxide	1.2230	0.012	44.01	0.54	0.0261	2.6146	0	0.00	0.1469	0
Methane	82.3460	0.823	16.043	13.21	0.6417	64.1747	1010	831.69	9.8817	0.25
Ethane	7.3050	0.073	30.07	2.20	0.1067	10.6706	1770	129.27	1.7529	0.33333
Propane	5.6660	0.057	44.097	2.50	0.1214	12.1373	2516	142.56	2.0401	0.375
I-Butane	1.1320	0.011	58.123	0.66	0.0320	3.1962	3252	36.81	0.5434	0.4
N-Butane	1.3030	0.013	58.123	0.76	0.0368	3.6790	3262	42.51	0.6255	0.4
I-Pentane	0.3330	0.003	72.15	0.24	0.0117	1.1671	4001	13.32	0.1998	0.41667
N-Pentane	0.2350	0.002	72.15	0.17	0.0082	0.8236	4009	9.42	0.1410	0.41667
Other hexanes	0.1928	0.002	86.177	0.17	0.0081	0.8072	4750	9.16	0.1388	0.42857
N-hexane	0.0447	0.000	86.177	0.04	0.0019	0.1870	4756	2.12	0.0322	0.42857
heptane	0.0207	0.000	100.204	0.02	0.0010	0.1010	5503	1.14	0.0174	0.4375
iso-octane	0.0081	0.000	114.231	0.01	0.0004	0.0447	6232	0.50	0.0077	0.4444
octanes+	0.0145	0.000	144.231	0.02	0.0010	0.1016	6500	0.94	0.0174	0.4444
benzene	0.0100	0.000	78.114	0.01	0.0004	0.0379	3742	0.37	0.0072	1
toluene	0.0086	0.000	92.141	0.01	0.0004	0.0385	4475	0.39	0.0072	0.875
ethylbenzene	0.0004	0.000	106.167	0.00	0.0000	0.0022	5222	0.02	0.0004	0.8
xylene	0.0022	0.000	106.167	0.00	0.0001	0.0112	5209	0.11	0.0021	0.8
TOTALS	**100.00**	**1.000**		**20.59**	**1.0000**	**100.0000**		***1220***	***15.5617***	

		sg	**0.7098**		
hexanes+	0.3020	**VOC wt%**	**22.3346**	Carbon wt%	75.59487
		Toxic wt%	**0.3216**		

July 13, 2010

FESCO, Ltd.
1100 Fesco Avenue - Alice, Texas 78332

For: Hilcorp Energy Company
P. O. Box 280
Refugio, Texas 78377-0280

Date Sampled: 06/23/2010

Date Analyzed: 07/01/2010

Sample: Federal Gayatt No.1

Job Number: J03792

FLASH LIBERATION OF HYDROCARBON LIQUID		
	Separator HC Liquid	Stock Tank
Pressure, psig	40	0
Temperature, °F	101	70
Gas Oil Ratio (1)	-----	21.8
Gas Specific Gravity (2)	-----	1.100
Separator Volume Factor (3)	1.0302	1.000

STOCK TANK FLUID PROPERTIES	
Shrinkage Recovery Factor (4)	0.9707
Oil API Gravity at 60 °F	36.81
Reid Vapor Pressure, psi (5)	1.81

Quality Control Check			
	Sampling Conditions	Test Samples	
Cylinder No.	-----	W-985*	W-1031
Pressure, psig	40	56	56
Temperature, °F	101	72	72

(1) - Scf of flashed vapor per barrel of stock tank oil
(2) - Air = 1.000
(3) - Separator volume / Stock tank volume
(4) - Fraction of first stage separator liquid
(5) - Absolute pressure at 100 deg F
Analyst: J. G.
* Sample used for flash study
Base Conditions: 14.65 PSI & 60 °F

Certified: FESCO, Ltd. - Alice, Texas

David Dannhaus 361-661-7015

July 13, 2010

FESCO, Ltd.
1100 Fesco Ave. - Alice, Texas 78332

For: Hilcorp Energy Company
P. O. Box 280
Refugio, Texas 78377-0280

Sample: Federal Gayatt No. 1
Gas Evolved from Hydrocarbon Liquid Flashed
From 40 psig & 101 °F to 0 psig & 70 °F

Date Sampled: 06/23/2010

Job Number: 03792.001

CHROMATOGRAPH EXTENDED ANALYSIS - SUMMATION REPORT

COMPONENT	MOL%	GPM
Hydrogen Sulfide*	< 0.001	
Nitrogen	0.105	
Carbon Dioxide	1.552	
Methane	46.690	
Ethane	20.581	5.473
Propane	15.646	4.268
Isobutane	5.083	1.654
n-Butane	4.606	1.413
2-2 Dimethylpropane	0.092	0.035
Isopentane	1.775	0.645
n-Pentane	1.193	0.430
Hexanes	1.672	0.644
Heptanes Plus	1.306	0.506
Totals	100.000	15.058

Computed Real Characteristics Of Heptanes Plus:

Specific Gravity	3.252	(Air=1)
Molecular Weight	93.35	
Gross Heating Value	4789	BTU/CF

Computed Real Characteristics Of Total Sample:

Specific Gravity	1.100	(Air=1)
Compressibility (Z)	0.9911	
Molecular Weight	31.59	
Gross Heating Value		
Dry Basis	1810	BTU/CF
Saturated Basis	1779	BTU/CF

*Hydrogen Sulfide tested in laboratory by Stained Tube Method (GPA 2377)
Results: <0.013 Gr/100 CF, <0.2 PPMV or <0.001 Mol %

Base Conditions: 14.650 PSI & 60 Deg F

Certified: FESCO, Ltd. - Alice, Texas

David Dannhaus 361-661-7015

Analyst: PB
Processor: MRF
Cylinder ID: F-7

CHROMATOGRAPH EXTENDED ANALYSIS
TOTAL REPORT

C5 :

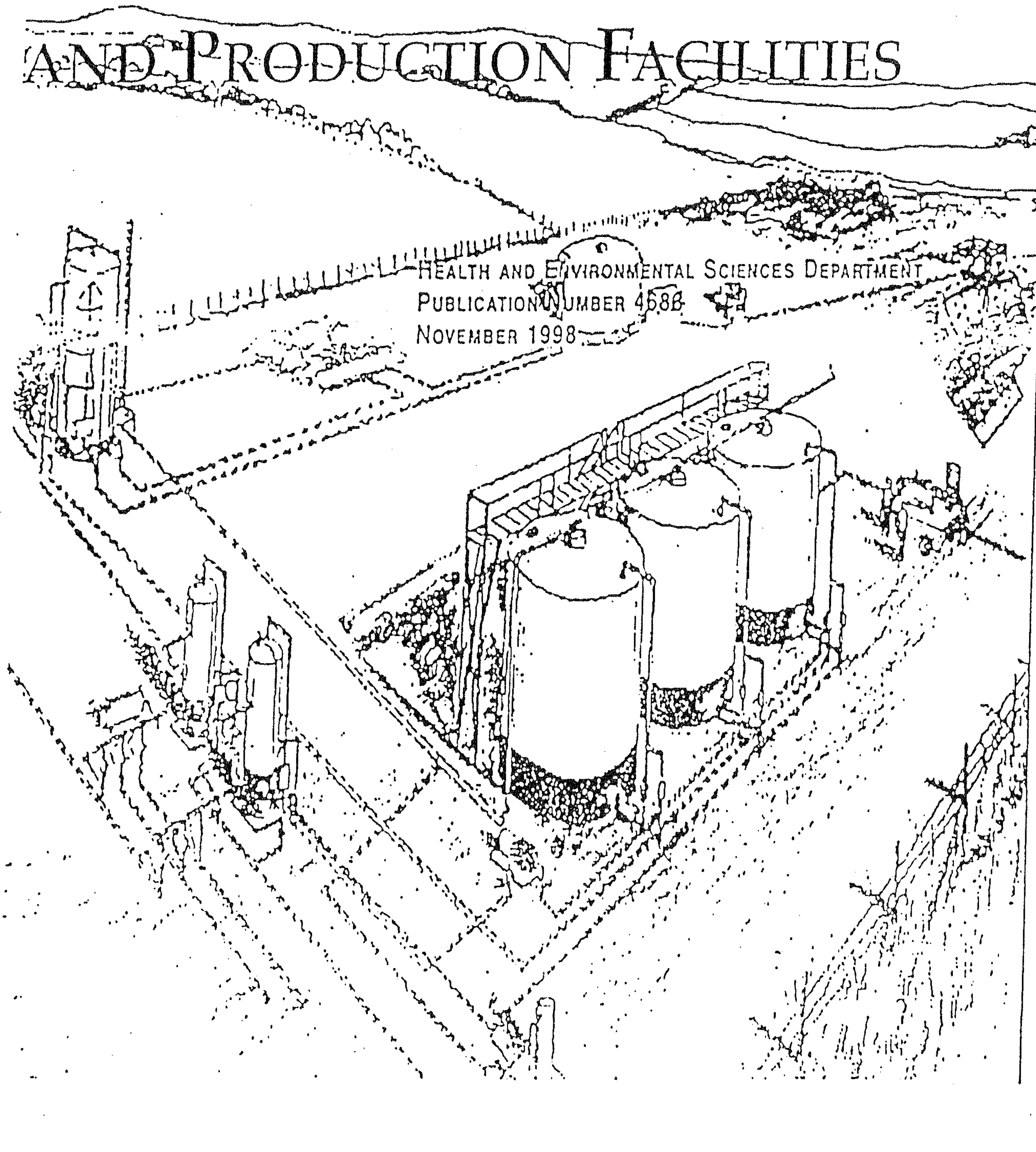
	COMPONENT	MOL %	GPM	WT %
	Hydrogen Sulfide*	< 0.001		< 0.001
	Nitrogen	0.105		0.093
	Carbon Dioxide	1.552		2.162
	Methane	46.690		23.711
	Ethane	20.561	5.473	19.591
	Propane	15.545	4.258	21.700
	Isobutane	5.083	1.654	9.352
	n-Butane	4.606	1.413	8.291
C5	2,2 Dimethylpropane	0.092	0.035	0.210
	Isopentane	1.775	0.646	4.054
	n-Pentane	1.193	0.430	2.726
C6	2,2 Dimethylbutane	0.069	0.029	0.188
C5	Cyclopentane	0.072	0.030	0.160
C6	2,3 Dimethylbutane	0.086	0.035	0.235
C6	2 Methylpentane	0.373	0.154	1.018
C6	3 Methylpentane	0.279	0.113	0.761
	n-Hexane	0.693	0.283	1.891
	Methylcyclopentane	0.232	0.080	0.618
	Benzene	0.093	0.026	0.230
C6	Cyclohexane	0.261	0.088	0.695
C7	2-Methylhexane	0.061	0.028	0.194
C7	3-Methylhexane	0.054	0.024	0.171
	2,2,4 Trimethylpentane	0.000	0.000	0.000
C7	Other C7's	0.160	0.069	0.502
C7	n-Heptane	0.092	0.042	0.292
C7	Methylcyclohexane	0.169	0.068	0.525
	Toluene	0.043	0.014	0.126
C8	Other C8's	0.093	0.043	0.324
C8	n-Octane	0.015	0.008	0.054
	Ethylbenzene	0.002	0.001	0.007
X9	M & P Xylenes	0.007	0.003	0.024
	O-Xylene	0.001	0.000	0.003
C9	Other C9's	0.017	0.009	0.068
C9	n-Nonane	0.002	0.001	0.008
C10	Other C10's	0.003	0.002	0.013
C10	n-Decane	0.001	0.001	0.005
C10	Undecanes (11)	0.000	0.000	0.000
	Totals	100.000	15.058	100.000

Computed Real Characteristics Of Total Sample:

Specific Gravity ---------- 1.100 (Air=1)
Compressibility (Z) ---------- 0.9911
Molecular Weight ---------- 31.59
Gross Heating Value
Dry Basis ---------- 1810 BTU/CF
Saturated Basis ---------- 1779 BTU/CF

Institute

Correlation Equations to Predict Reid Vapor Pressure and Properties of Gaseous Emissions for Exploration and Production Facilities



Health and Environmental Sciences Department

Publication Number 4683

November 1998

Table 3-2 summarizes Pearson correlation coefficients (r) calculated for the sales oil RVP relative to the other variables. Better correlations are indicated as |r| approaches 1. Table 3-2 shows that sales oil APIG is the best predictor of RVP. (Note that the sales oil bubble point is an equally good predictor, r = 0.78.)

Table 3-2. Single-parameter correlation coefficients for RVP.

Variable	Pearson Correlation With RVP
SP	0.52
ln(SP)	0.51
ST	-0.37
APIG	0.79

REGRESSION ANALYSIS

A multivariate linear regression was developed, represented by the equation shown below.

$$RVP = 0.003 + 0.075 \ln(SP) - 0.016\ ST + 0.165\ APIG \qquad \text{(Equation 3-4)}$$

The correlation coefficient for Equation 3-4 (r = 0.80) is not significantly better than the single-parameter coefficient for sales oil APIG shown in Table 3-2. Therefore, the single-parameter fit based on sales oil APIG is recommended for use (see Figure 3-2).

$$RVP = -1.699 + 0.179\ APIG \qquad \text{(Equation 3-5)}$$

The error of the estimate (E) is one measure of the performance of a model or assumption, where the error equals the observed value (Obs) less the estimated value (Est), E = Obs - Est. In Figure 3-2, it is obvious that the error associated with the regression line is much less than the error associated with the default assumption, RVP = 5 psia.

$$P = \exp\left\{\left[\left(\frac{2{,}799}{T+459.6}\right) - 2.227\right]\log_{10}(RVP) - \left(\frac{7{,}261}{T+459.6}\right) + 12.82\right\}$$

Where:

P = stock true vapor pressure, in pounds per square inch absolute.
T = stock temperature, in degrees Fahrenheit.
RVP = Reid vapor pressure, in pounds per square inch.

Note: This equation was derived from a regression analysis of points read off Figure 7.1-13a over the full range of Reid vapor pressures, slopes of the ASTM distillation curve at 10 percent evaporated, and stock temperatures. In general, the equation yields *P* values that are within +0.05 pound per square inch absolute of the values obtained directly from the nomograph.

Figure 7.1-13b. Equation for true vapor pressure of crude oils with a Reid vapor pressure of 2 to 15 pounds per square inch.[4]

$$P = \exp\left\{\left[0.7553 - \left(\frac{413.0}{T+459.6}\right)\right]S^{0.5}\log_{10}(RVP) - \left[1.854 - \left(\frac{1{,}042}{T+459.6}\right)\right]S^{0.5}\right.$$
$$\left. + \left[\left(\frac{2{,}416}{T+459.6}\right) - 2.013\right]\log_{10}(RVP) - \left(\frac{8{,}742}{T+459.6}\right) + 15.64\right\}$$

Where:

P = stock true vapor pressure, in pounds per square inch absolute.
T = stock temperature, in degrees Fahrenheit.
RVP = Reid vapor pressure, in pounds per square inch.
S = slope of the ASTM distillation curve at 10 percent evaporated, in degrees Fahrenheit per percent.

Note: This equation was derived from a regression analysis of points read off Figure 7.1-14a over the full range of Reid vapor pressures, slopes of the ASTM distillation curve at 10 percent evaporated, and stock temperatures. In general, the equation yields *P* values that are within +0.05 pound per square inch absolute of the values obtained directly from the nomograph.

Figure 7.1-14b. Equation for true vapor pressure of refined petroleum stocks with a Reid vapor pressure of 1 to 20 pounds per square inch.[4]

$A = 15.64 - 1.854\ S^{0.5} - (0.8742 - 0.3280\ S^{0.5})\ln(RVP)$
$B = 8{,}742 - 1{,}042\ S^{0.5} - (1{,}049 - 179.4\ S^{0.5})\ln(RVP)$
where:
RVP = stock Reid vapor pressure, in pounds per square inch
ln = natural logarithm function
S = stock ASTM-D86 distillation slope at 10 volume percent evaporation (°F/vol %)

Figure 7.1-15. Equations to determine vapor pressure constants A and B for refined petroleum stocks.[8]

Table 7.1-2. PROPERTIES (M_V, P_{VA}, W_L) OF SELECTED PETROLEUM LIQUIDS[a]

Petroleum Liquid	Vapor Molecular Weight at 60°F, M_V (lb/lb-mole)	Liquid Density At 60°F, W_L (lb/gal)	True Vapor Pressure, P_{VA} (psi)						
			40°F	50°F	60°F	70°F	80°F	90°F	100°F
Crude oil RVP 5	50	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7
Distillate fuel oil No. 2	130	7.1	0.0031	0.0045	0.0065	0.0090	0.012	0.016	0.022
Gasoline RVP 7	68	5.6	2.3	2.9	3.5	4.3	5.2	6.2	7.4
Gasoline RVP 7.8	68	5.6	2.5929	3.2079	3.9363	4.793	5.7937	6.9552	8.2952
Gasoline RVP 8.3	68	5.6	2.7888	3.444	4.2188	5.1284	6.1891	7.4184	8.8344
Gasoline RVP 10	66	5.6	3.4	4.2	5.2	6.2	7.4	8.8	10.5
Gasoline RVP 11.5	65	5.6	4.087	4.9997	6.069	7.3132	8.7519	10.4053	12.2949
Gasoline RVP 13	62	5.6	4.7	5.7	6.9	8.3	9.9	11.7	13.8
Gasoline RVP 13.5	62	5.6	4.932	6.0054	7.2573	8.7076	10.3774	12.2888	14.4646
Gasoline RVP 15.0	60	5.6	5.5802	6.774	8.1621	9.7656	11.6067	13.7085	16.0948
Jet kerosene	130	7.0	0.0041	0.0060	0.0085	0.011	0.015	0.021	0.029
Jet naphtha (JP-4)	80	6.4	0.8	1.0	1.3	1.6	1.9	2.4	2.7
Residual oil No. 6	190	7.9	0.00002	0.00003	0.00004	0.00006	0.00009	0.00013	0.00019

[a] References 10 and 11

5.2 Transportation And Marketing Of Petroleum Liquids[1-3]

5.2.1 General

The transportation and marketing of petroleum liquids involve many distinct operations, each of which represents a potential source of evaporation loss. Crude oil is transported from production operations to a refinery by tankers, barges, rail tank cars, tank trucks, and pipelines. Refined petroleum products are conveyed to fuel marketing terminals and petrochemical industries by these same modes. From the fuel marketing terminals, the fuels are delivered by tank trucks to service stations, commercial accounts, and local bulk storage plants. The final destination for gasoline is usually a motor vehicle gasoline tank. Similar distribution paths exist for fuel oils and other petroleum products. A general depiction of these activities is shown in Figure 5.2-1.

5.2.2 Emissions And Controls

Evaporative emissions from the transportation and marketing of petroleum liquids may be considered, by storage equipment and mode of transportation used, in four categories:

1. Rail tank cars, tank trucks, and marine vessels: loading, transit, and ballasting losses.
2. Service stations: bulk fuel drop losses and underground tank breathing losses.
3. Motor vehicle tanks: refueling losses.
4. Large storage tanks: breathing, working, and standing storage losses. (See Chapter 7, "Liquid Storage Tanks".)

Evaporative and exhaust emissions are also associated with motor vehicle operation, and these topics are discussed in AP-42 *Volume II: Mobile Sources.*

5.2.2.1 Rail Tank Cars, Tank Trucks, And Marine Vessels -
Emissions from these sources are from loading losses, ballasting losses, and transit losses.

5.2.2.1.1 Loading Losses -
Loading losses are the primary source of evaporative emissions from rail tank car, tank truck, and marine vessel operations. Loading losses occur as organic vapors in "empty" cargo tanks are displaced to the atmosphere by the liquid being loaded into the tanks. These vapors are a composite of (1) vapors formed in the empty tank by evaporation of residual product from previous loads, (2) vapors transferred to the tank in vapor balance systems as product is being unloaded, and (3) vapors generated in the tank as the new product is being loaded. The quantity of evaporative losses from loading operations is, therefore, a function of the following parameters:

- Physical and chemical characteristics of the previous cargo;
- Method of unloading the previous cargo;
- Operations to transport the empty carrier to a loading terminal;
- Method of loading the new cargo; and
- Physical and chemical characteristics of the new cargo.

The principal methods of cargo carrier loading are illustrated in Figure 5.2-2, Figure 5.2-3, and Figure 5.2-4. In the splash loading method, the fill pipe dispensing the cargo is lowered only part way into the cargo tank. Significant turbulence and vapor/liquid contact occur during the splash

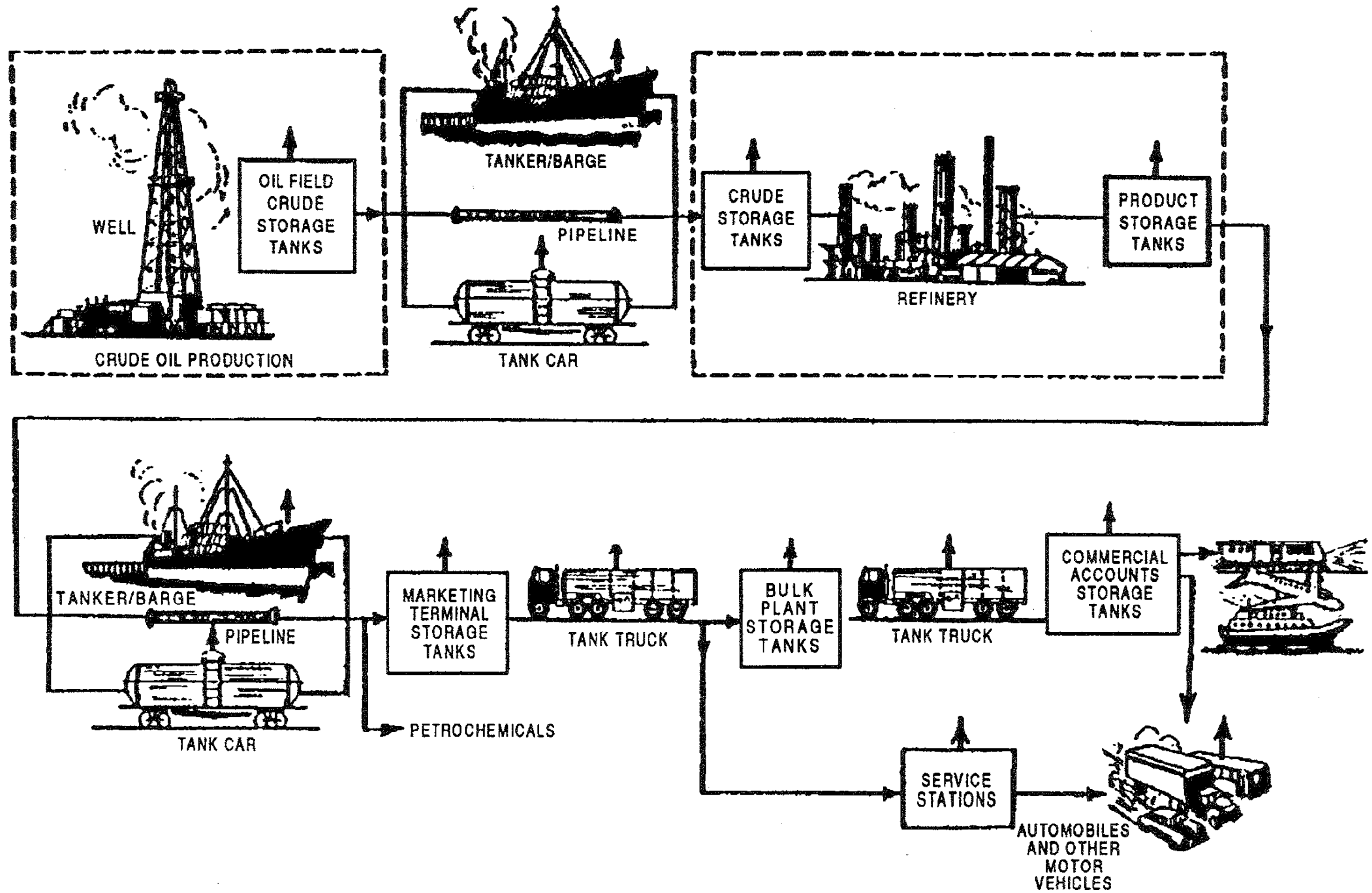


Figure 5.2-1. Flow sheet of petroleum production, refining, and distribution systems.
(Points of organic emissions are indicated by vertical arrows.)

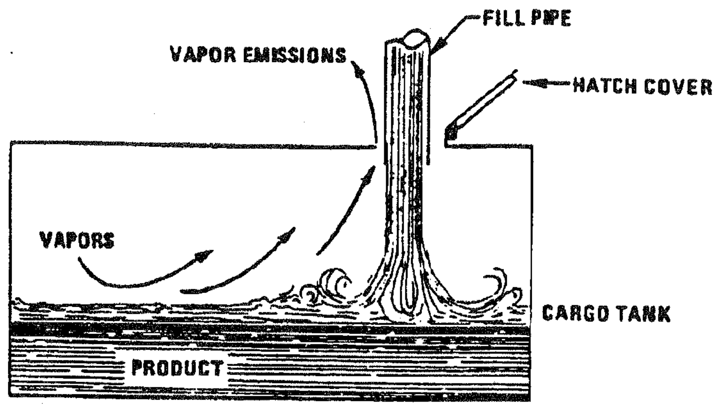


Figure 5.2-2. Splash loading method.

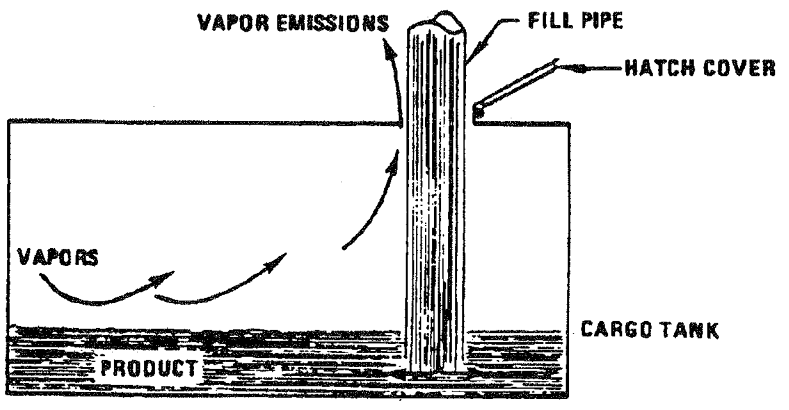


Figure 5.2-3. Submerged fill pipe.

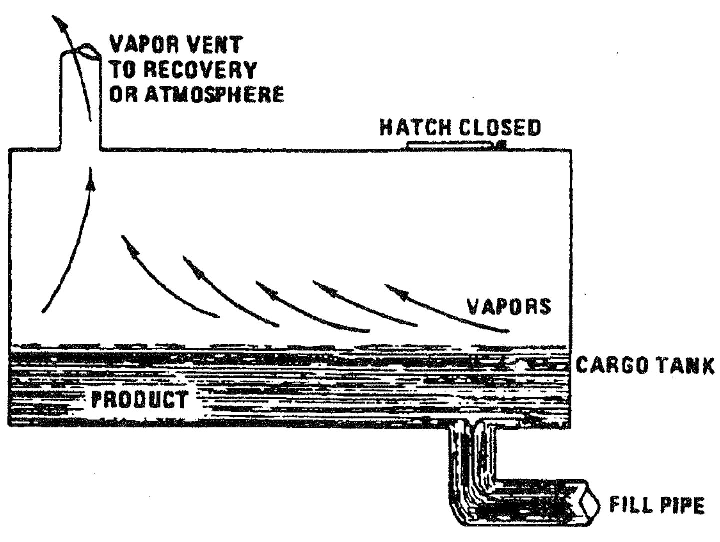


Figure 5.2-4. Bottom loading.

loading operation, resulting in high levels of vapor generation and loss. If the turbulence is great enough, liquid droplets will be entrained in the vented vapors.

A second method of loading is submerged loading. Two types are the submerged fill pipe method and the bottom loading method. In the submerged fill pipe method, the fill pipe extends almost to the bottom of the cargo tank. In the bottom loading method, a permanent fill pipe is attached to the cargo tank bottom. During most of submerged loading by both methods, the fill pipe opening is below the liquid surface level. Liquid turbulence is controlled significantly during submerged loading, resulting in much lower vapor generation than encountered during splash loading.

The recent loading history of a cargo carrier is just as important a factor in loading losses as the method of loading. If the carrier has carried a nonvolatile liquid such as fuel oil, or has just been cleaned, it will contain vapor-free air. If it has just carried gasoline and has not been vented, the air in the carrier tank will contain volatile organic vapors, which will be expelled during the loading operation along with newly generated vapors.

Cargo carriers are sometimes designated to transport only one product, and in such cases are practicing "dedicated service". Dedicated gasoline cargo tanks return to a loading terminal containing air fully or partially saturated with vapor from the previous load. Cargo tanks may also be "switch loaded" with various products, so that a nonvolatile product being loaded may expel the vapors remaining from a previous load of a volatile product such as gasoline. These circumstances vary with the type of cargo tank and with the ownership of the carrier, the petroleum liquids being transported, geographic location, and season of the year.

One control measure for vapors displaced during liquid loading is called "vapor balance service", in which the cargo tank retrieves the vapors displaced during product unloading at bulk plants or service stations and transports the vapors back to the loading terminal. Figure 5.2-5 shows a tank truck in vapor balance service filling a service station underground tank and taking on displaced gasoline vapors for return to the terminal. A cargo tank returning to a bulk terminal in vapor balance service normally is saturated with organic vapors, and the presence of these vapors at the start of submerged loading of the tanker truck results in greater loading losses than encountered during nonvapor balance, or "normal", service. Vapor balance service is usually not practiced with marine vessels, although some vessels practice emission control by means of vapor transfer within their own cargo tanks during ballasting operations, discussed below.

Emissions from loading petroleum liquid can be estimated (with a probable error of ±30 percent)[4] using the following expression:

$$L_L = 12.46 \frac{SPM}{T} \qquad (1)$$

where:

L_L = loading loss, pounds per 1000 gallons (lb/10^3 gal) of liquid loaded

S = a saturation factor (see Table 5.2-1)
P = true vapor pressure of liquid loaded, pounds per square inch absolute (psia) (see Figure 7.1-5, Figure 7.1-6, and Table 7.1-2)
M = molecular weight of vapors, pounds per pound-mole (lb/lb-mole) (see Table 7.1-2)
T = temperature of bulk liquid loaded, °R (°F + 460)

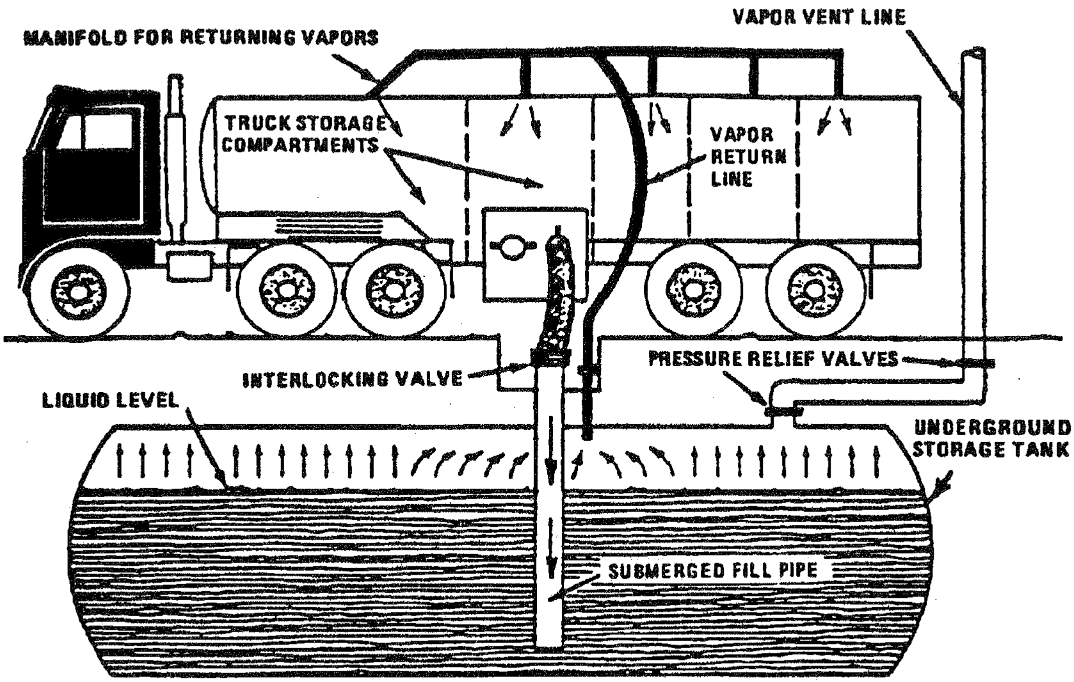


Figure 5.2-5. Tank truck unloading into a service station underground storage tank and practicing "vapor balance" form of emission control.

Table 5.2-1. SATURATION (S) FACTORS FOR CALCULATING PETROLEUM LIQUID LOADING LOSSES

Cargo Carrier	Mode Of Operation	S Factor
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading: dedicated normal service	1.45
	Splash loading: dedicated vapor balance service	1.00
Marine vessels[a]	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

[a] For products other than gasoline and crude oil. For marine loading of gasoline, use factors from Table 5.2-2. For marine loading of crude oil, use Equations 2 and 3 and Table 5.2-3.

The saturation factor, S, represents the expelled vapor's fractional approach to saturation, and it accounts for the variations observed in emission rates from the different unloading and loading methods. Table 5.2-1 lists suggested saturation factors.

Emissions from controlled loading operations can be calculated by multiplying the uncontrolled emission rate calculated in Equation 1 by an overall reduction efficiency term:

$$\left(1 - \frac{\text{eff}}{100}\right)$$

The overall reduction efficiency should account for the capture efficiency of the collection system as well as both the control efficiency and any downtime of the control device. Measures to reduce loading emissions include selection of alternate loading methods and application of vapor recovery equipment. The latter captures organic vapors displaced during loading operations and recovers the vapors by the use of refrigeration, absorption, adsorption, and/or compression. The recovered product is piped back to storage. Vapors can also be controlled through combustion in a thermal oxidation unit, with no product recovery. Figure 5.2-6 demonstrates the recovery of gasoline vapors from tank trucks during loading operations at bulk terminals. Control efficiencies for the recovery units range from 90 to over 99 percent, depending on both the nature of the vapors and the type of control equipment used.[5-6] However, not all of the displaced vapors reach the control device, because of leakage from both the tank truck and collection system. The collection efficiency should be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water).[7] A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) should be assumed for trucks passing the NSPS-level annual test (3 inches pressure change) A collection efficiency of 70 percent should be assumed for trucks not passing one of these annual leak tests[6].

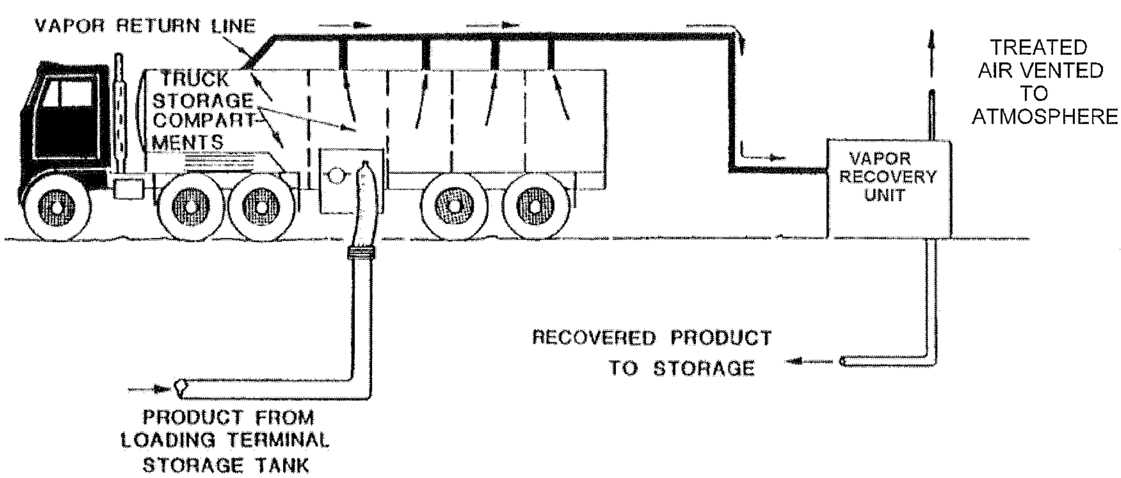


Figure 5.2-6. Tank truck loading with vapor recovery.

Sample Calculation -

Loading losses (L_L) from a gasoline tank truck in dedicated vapor balance service and practicing vapor recovery would be calculated as follows, using Equation 1:

Design basis -

Cargo tank volume is 8000 gal
Gasoline Reid vapor pressure (RVP) is 9 psia
Product temperature is 80°F
Vapor recovery efficiency is 95 percent
Vapor collection efficiency is 98.7 percent (NSPS-level annual leak test)

Loading loss equation -

$$L_L = 12.46 \frac{SPM}{T} \left(1 - \frac{eff}{100}\right)$$

where:

S = saturation factor (see Table 5.2-1) - 1.00
P = true vapor pressure of gasoline (see Figure 7.1-6) = 6.6 psia
M = molecular weight of gasoline vapors (see Table 7.1-2) = 66
T = temperature of gasoline = 540°R
eff = overall reduction efficiency (95 percent control x 98.7 percent collection) = 94 percent

$$L_L = 12.46 \frac{(1.00)(6.6)(66)}{540} \left(1 - \frac{94}{100}\right)$$

$$= 0.60 \text{ lb}/10^3 \text{gal}$$

Total loading losses are:

$$(0.60 \text{ lb}/10^3 \text{ gal})(8.0 \times 10^3 \text{ gal}) = 4.8 \text{ pounds (lb)}$$

Measurements of gasoline loading losses from ships and barges have led to the development of emission factors for these specific loading operations.[8] These factors are presented in Table 5.2-2 and should be used instead of Equation 1 for gasoline loading operations at marine terminals. Factors are expressed in units of milligrams per liter (mg/L) and pounds per 1000 gallons (lb/10^3 gal).

Table 5.2-2 (Metric And English Units). VOLATILE ORGANIC COMPOUND (VOC) EMISSION FACTORS FOR GASOLINE LOADING OPERATIONS AT MARINE TERMINALS[a]

Vessel Tank Condition	Previous Cargo	Ships/Ocean Barges[b]		Barges[b]	
		mg/L Transferred	$lb/10^3$ gal Transferred	mg/L Transferred	$lb/10^3$ gal Transferred
Uncleaned	Volatile[c]	315	2.6	465	3.9
Ballasted	Volatile	205	1.7	—[d]	—[d]
Cleaned	Volatile	180	1.5	ND	ND
Gas-freed	Volatile	85	0.7	ND	ND
Any condition	Nonvolatile	85	0.7	ND	ND
Gas-freed	Any cargo	ND	ND	245	2.0
Typical overall situation[e]	Any cargo	215	1.8	410	3.4

[a] References 2,9. Factors are for both VOC emissions (which excludes methane and ethane) and total organic emissions, because methane and ethane have been found to constitute a negligible weight fraction of the evaporative emissions from gasoline. ND = no data.
[b] Ocean barges (tank compartment depth about 12.2 m [40 ft]) exhibit emission levels similar to tank ships. Shallow draft barges (compartment depth 3.0 to 3.7 m [10 to 12 ft]) exhibit higher emission levels.
[c] Volatile cargoes are those with a true vapor pressure greater than 10 kilopascals (kPa) (1.5 psia).
[d] Barges are usually not ballasted.
[e] Based on observation that 41% of tested ship compartments were uncleaned, 11% ballasted, 24% cleaned, and 24% gas-freed. For barges, 76% were uncleaned.

In addition to Equation 1, which estimates emissions from the loading of petroleum liquids, Equation 2 has been developed specifically for estimating emissions from the loading of crude oil into ships and ocean barges:

$$C_L = C_A + C_G \tag{2}$$

where:

C_L = total loading loss, $lb/10^3$ gal of crude oil loaded
C_A = arrival emission factor, contributed by vapors in the empty tank compartment before loading, $lb/10^3$ gal loaded (see Note below)
C_G = generated emission factor, contributed by evaporation during loading, $lb/10^3$ gal loaded

Note: Values of C_A for various cargo tank conditions are listed in Table 5.2-3.

5.2-3 (English Units). AVERAGE ARRIVAL EMISSION FACTORS, C_A, FOR CRUDE OIL LOADING EMISSION EQUATION[a]

Ship/Ocean Barge Tank Condition	Previous Cargo	Arrival Emission Factor, $lb/10^3$ gal
Uncleaned	Volatile[b]	0.86
Ballasted	Volatile	0.46
Cleaned or gas-freed	Volatile	0.33
Any condition	Nonvolatile	0.33

[a] Arrival emission factors (C_A) to be added to generated emission factors (C_G) calculated in Equation 3 to produce total crude oil loading loss (C_L). Factors are for total organic compounds; VOC emission factors average about 15% lower, because VOC does not include methane or ethane.
[b] Volatile cargoes are those with a true vapor pressure greater than 10 kPa (1.5 psia).

This equation was developed empirically from test measurements of several vessel compartments.[8] The quantity C_G can be calculated using Equation 3:

$$C_G = 1.84\ (0.44\ P - 0.42)\ \frac{M\,G}{T} \tag{3}$$

where:

P = true vapor pressure of loaded crude oil, psia (see Figure 7.1-5 and Table 7.1-2)
M = molecular weight of vapors, lb/lb-mole (see Table 7.1-2)
G = vapor growth factor = 1.02 (dimensionless)
T = temperature of vapors, °R (°F + 460)

Emission factors derived from Equation 3 and Table 5.2-3 represent total organic compounds. Volatile organic compound (VOC) emission factors (which exclude methane and ethane because they are exempted from the regulatory definition of "VOC") for crude oil vapors have been found to range from approximately 55 to 100 weight percent of these total organic factors. When specific vapor composition information is not available, the VOC emission factor can be estimated by taking 85 percent of the total organic factor.[3]

5.2.2.1.2 Ballasting Losses -

Ballasting operations are a major source of evaporative emissions associated with the unloading of petroleum liquids at marine terminals. It is common practice to load several cargo tank compartments with sea water after the cargo has been unloaded. This water, termed "ballast", improves the stability of the empty tanker during the subsequent voyage. Although ballasting practices vary, individual cargo tanks are ballasted typically about 80 percent, and the total vessel 15 to 40 percent, of capacity. Ballasting emissions occur as vapor-laden air in the "empty" cargo tank is displaced to the atmosphere by ballast water being pumped into the tank. Upon arrival at a loading port, the ballast water is pumped from the cargo tanks before the new cargo is loaded. The ballasting of cargo tanks reduces the quantity of vapors returning in the empty tank, thereby reducing the quantity of vapors emitted during subsequent tanker loading. Regulations administered by the U. S. Coast Guard require that, at marine terminals located in ozone nonattainment areas, large tankers with crude oil washing systems contain the organic vapors from ballasting.[10] This is accomplished principally by displacing the vapors during ballasting into a cargo tank being simultaneously unloaded. In other areas, marine vessels emit organic vapors directly to the atmosphere.

Equation 4 has been developed from test data to calculate the ballasting emissions from crude oil ships and ocean barges[8]:

$$L_B = 0.31 + 0.20\ P + 0.01\ PU_A \tag{4}$$

where:

L_B = ballasting emission factor, lb/10^3 gal of ballast water
P = true vapor pressure of discharged crude oil, psia (see Figure 7.1-5 and Table 7.1-2)
U_A = arrival cargo true ullage, before dockside discharge, measured from the deck, feet; (the term "ullage" here refers to the distance between the cargo surface level and the deck level)

Table 5.2-4 lists average total organic emission factors for ballasting into uncleaned crude oil cargo compartments. The first category applies to "full" compartments wherein the crude oil true ullage just before cargo discharge is less than 1.5 meters (m) (5 ft). The second category applies to lightered, or short-loaded, compartments (part of cargo previously discharged, or original load a partial fill), with an arrival true ullage greater than 1.5 m (5 ft). It should be remembered that these tabulated emission factors are examples only, based on average conditions, to be used when crude oil vapor pressure is unknown. Equation 4 should be used when information about crude oil vapor pressure and cargo compartment condition is available. The following sample calculation illustrates the use of Equation 4.

5.2-4 (Metric And English Units). TOTAL ORGANIC EMISSION FACTORS FOR CRUDE OIL BALLASTING[a]

	Average Emission Factors			
	By Category		Typical Overall[b]	
Compartment Condition Before Cargo Discharge	mg/L Ballast Water	lb/10^3 gal Ballast Water	mg/L Ballast Water	lb/10^3 gal Ballast Water
Fully loaded[c]	111	0.9	129	1.1
Lightered or previously short loaded[d]	171	1.4		

[a] Assumes crude oil temperature of 16°C (60°F) and RVP of 34 kPa (5 psia). VOC emission factors average about 85% of these total organic factors, because VOCs do not include methane or ethane.
[b] Based on observation that 70% of tested compartments had been fully loaded before ballasting. May not represent average vessel practices.
[c] Assumed typical arrival ullage of 0.6 m (2 ft).
[d] Assumed typical arrival ullage of 6.1 m (20 ft).

AIR REQUIRED TO STROKE VALVE

Act Size	Stem Tvl	Diaph.	AIR REQUIRED TO SWITCH (SCF) @ 15 (psig)	@ 20 (psig)	@ 30 (psig)	Nominal Effective Area
9	0.625	F	0.052	0.065	0.092	
9	0.750	F	0.079	0.096	0.119	
9	1.000	M	0.050	0.060	0.080	35
9	1.250	M	0.091	0.111	0.126	
12	0.625	F	0.116	0.150	0.218	
12	1.000	F	0.151	0.184	0.254	
12	1.250	M	0.128	0.153	0.202	70
12	1.500	M	0.150	0.178	0.234	
12	2.000	M	0.201	0.245	0.311	
14	0.625	M	0.155	0.189	0.257	
14	1.250	M	0.244	0.270	0.361	
14	1.500	M	0.253	0.303	0.404	85
14	2.000	M	0.313	0.374	0.495	
18	1.250	M	0.504	0.620	0.849	
18	1.500	M	0.556	0.680	0.927	
18	2.000	M	0.696	0.844	1.317	
18	2.750	M	0.838	1.009	1.350	180
18	3.000	M	0.922	1.110	1.473	
18	4.000	M	1.057	1.266	1.681	

F = Flat
M = Molded
* SCF = Standard Cubic Feet

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Facility/Compound Specific Fugitive Emission Factors

Equipment/Service	Ethylene Oxide[1]	Phosgene[2]	Butadiene[3]	Petroleum Marketing Terminal[4]	Gas and Oil Production Operations[5]				Refinery[6]
					Gas	Heavy Oil <20°API	Light Oil >20°	Water/Light Oil	
Valves					0.00992	0.0000185	0.0055	0.000216	
Gas/Vapor	0.000444	0.00000216	0.001105	0.0000287					0.059
Light Liquid	0.00055	0.00000199	0.00314	0.0000948					0.024
Heavy Liquid				0.0000948					0.00051
Pumps	0.042651	0.0000201	0.05634		0.00529	0.00113[10]	0.02866	0.000052	
Light Liquid				0.00119					0.251
Heavy Liquid				0.00119					0.046
Flanges/Connectors	0.000555	0.00000011	0.000307		0.00086	0.00000086	0.000243	0.000006	0.00055
Gas/Vapor				0.000092604					
Light Liquid				0.00001762					
Heavy Liquid				0.0000176					
Compressors	0.000767		0.000004		0.0194	0.0000683	0.0165	0.0309	1.399
Relief Valve	0.000165	0.0000162	0.02996		0.0194	0.0000683	0.0165	0.0309	0.35
Open-ended Lines[7]	0.001078	0.00000007	0.00012		0.00441	0.000309	0.00309	0.00055	0.0051
Sampling[8]	0.000088		0.00012						0.033
Connectors					0.00044	0.0000165	0.000463	0.000243	
Other[9]					0.0194	0.0000683	0.0165	0.0309	
Gas/Vapor				0.000265					
Liquid				0.000287					
Process Drains					0.0194	0.0000683	0.0165	0.0309	0.07

Notes: All factors are in units of (lb/hr)/component.

1. Monitoring must occur at a leak definition of 500 ppmv. No additional control credit can be applied to these factors. Emission factors are from EOIC Fugitive Emission Study, summer 1988.
2. Monitoring must occur at a leak definition of 50 ppmv. No additional control credit can be applied to these factors. Emission factors are from Phosgene Panel Study, summer 1988.
3. Monitoring must occur at a leak definition of 100 ppmv. No additional control credit can be applied to these factors. Emission factors are from Randall, J.L., et al., Radian Corporation. Fugitive Emissions from the 1,3-butadiene Production Industry: A Field Study. Final Report. Prepared for the 1,3-Butadiene Panel of the Chemical Manufacturers Association. April 1989.
4. Control credit is included in the factor; no additional control credit can be applied to these factors. Monthly AVO inspection required.
5. Factors give the total organic compound emission rate. Multiply by the weight percent of non-methane, non-ethane organics to get the VOC emission rate.
6. Factors are taken from EPA Document EPA-453/R-95-017, November 1995, Page 2-13.
7. The 28 Series quarterly LDAR programs require open-ended lines to be equipped with an appropriately sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.
8. Emission factor for Sampling Connections is in terms of pounds per hour per sample taken.
9. For Petroleum Marketing Terminals “Other” includes any component excluding fittings, pumps, and valves. For Oil and Gas Production Operations, “Other” includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents.
10. No Heavy Oil - Pump factor was derived during the API study. The factor is the SOCMI without C_2 Heavy Liquid-Pump factor with a 93% reduction credit for the physical inspection.

Statement of Applicability – NSPS Subpart JJJJ/NESHAP Subpart ZZZZ

Applicability based on Rule Citation: 40 CFR Part 60 NSPS Subpart JJJJ and Part 63 Subpart ZZZZ for Stationary SI Internal Combustion Engines.

This Engine has been found to be **EXEMPT from NSPS Subpart JJJJ** standards and other requirements by virtue of its manufacture date, construction date, modified or reconstruction date, stroke/burn type, fuel type, use type, and or max HP rating. This engine **TRIGGERS NESHAP Subpart ZZZZ Maintenance and Record Keeping Requirements only unless non-remote status applies.** EGC's Maintenance plan and unit maintenance records are available upon request. Records will be kept 5 years beginning Oct. 19, 2013.

Engine ID: Unit 168

Serial Number: G6X01550

Engine Make/Model: Caterpillar G3306NA

HP: 145

Owner: Energy Gas Compression

Fuel Type: Natural Gas

Use: Gas Compression/Non-Emergency

Emission Controls: NSCR Catalyst and Air Fuel Ratio Controls installed

Date Manufactured: Pre 2008 (7/5/2005)

Reconstruction Date: This engine has not been reconstructed beyond the 50% cost of new as of December 2017.

This Engine Analysis Determination is based on CVR's current understanding and knowledge of the engine and U.S. EPA regulations and guidance pursuant to 40 C.F.R. Part 60, Subpart JJJJ, and Part 63, Subpart ZZZZ. Any change in law or in the federal, state, or local interpretation of existing law may result in the engine being subject to additional or different legal requirements. This information is based on CVR's experience and interpretation and is not offered as a legal opinion or advice to your company. Additionally, any reconstruction or modification to the engine could result in the applicability of other Subparts or other legal requirements to this engine and create legal compliance responsibilities for your company.

G3306

GAS ENGINE TECHNICAL DATA

CATERPILLAR®

ENGINE SPEED (rpm):	1800	RATING STRATEGY:	STANDARD
COMPRESSION RATIO:	10.5	APPLICATION:	GAS COMPRESSION
JACKET WATER OUTLET (°F):	210	RATING LEVEL:	CONTINUOUS
ASPIRATION:	NA	FUEL:	NAT GAS
COOLING SYSTEM:	JW+OC	FUEL SYSTEM:	LPG IMPCO
CONTROL SYSTEM:	MAG		WITH CUSTOMER SUPPLIED AIR FUEL RATIO CONTROL
EXHAUST MANIFOLD:	WC	FUEL PRESSURE RANGE(psig): (See note 1)	1.5-10.0
COMBUSTION:	CATALYST SETTING	FUEL METHANE NUMBER:	80
EXHAUST OXYGEN (% O2):	0.5	FUEL LHV (Btu/scf):	905
		ALTITUDE CAPABILITY AT 77°F INLET AIR TEMP. (ft):	500

RATING		NOTES	LOAD	100%	75%	50%
ENGINE POWER	(WITHOUT FAN)	(2)	bhp	145	109	72
ENGINE EFFICIENCY	(ISO 3046/1)	(3)	%	32.7	30.6	26.7
ENGINE EFFICIENCY	(NOMINAL)	(3)	%	32.7	30.6	26.7
ENGINE DATA						
FUEL CONSUMPTION	(ISO 3046/1)	(4)	Btu/bhp-hr	7775	8328	9513
FUEL CONSUMPTION	(NOMINAL)	(4)	Btu/bhp-hr	7775	8328	9513
AIR FLOW (77°F, 14.7 psia)	(WET)	(5) (6)	ft3/min	208	167	125
AIR FLOW	(WET)	(5) (6)	lb/hr	922	738	556
FUEL FLOW (60ºF, 14.7 psia)			scfm	21	17	13
INLET MAN. PRESSURE		(7)	in Hg(abs)	26.2	21.8	17.6
INLET MAN. TEMPERATURE	(MEASURED IN PLENUM)	(8)	°F	88	89	93
TIMING		(9)	°BTDC	30	30	30
EXHAUST TEMPERATURE - ENGINE OUTLET		(10)	°F	1101	1067	1037
EXHAUST GAS FLOW (@engine outlet temp, 14.5 psia)	(WET)	(11) (6)	ft3/min	678	532	393
EXHAUST GAS MASS FLOW	(WET)	(11) (6)	lb/hr	978	784	590
EMISSIONS DATA - ENGINE OUT						
NOx (as NO2)		(12)(13)	g/bhp-hr	13.47	12.01	9.72
CO		(12)(14)	g/bhp-hr	13.47	12.01	9.72
THC (mol. wt. of 15.84)		(12)(14)	g/bhp-hr	2.20	2.50	3.23
NMHC (mol. wt. of 15.84)		(12)(14)	g/bhp-hr	0.33	0.38	0.48
NMNEHC (VOCs) (mol. wt. of 15.84)		(12)(14)(15)	g/bhp-hr	0.22	0.25	0.32
HCHO (Formaldehyde)		(12)(14)	g/bhp-hr	0.27	0.31	0.33
CO2		(12)(14)	g/bhp-hr	485	525	602
EXHAUST OXYGEN		(12)(16)	% DRY	0.5	0.5	0.5
LAMBDA		(12)(16)		1.01	1.01	1.00
ENERGY BALANCE DATA						
LHV INPUT		(17)	Btu/min	18768	15077	11482
HEAT REJECTION TO JACKET WATER (JW)		(18)(23)	Btu/min	6049	5251	4459
HEAT REJECTION TO ATMOSPHERE		(19)	Btu/min	751	603	459
HEAT REJECTION TO LUBE OIL (OC)		(20)(23)	Btu/min	990	859	729
HEAT REJECTION TO EXHAUST (LHV TO 77°F)		(21)(22)	Btu/min	4837	3758	2763
HEAT REJECTION TO EXHAUST (LHV TO 350°F)		(21)	Btu/min	3451	2638	1903

CONDITIONS AND DEFINITIONS

Engine rating obtained and presented in accordance with ISO 3046/1. (Standard reference conditions of 77°F, 29.60 in Hg barometric pressure.) No overload permitted at rating shown. Consult the altitude deration factor chart for applications that exceed the rated altitude or temperature.

Emission levels are at engine exhaust flange prior to any after treatment. Values are based on engine operating at steady state conditions. Tolerances specified are dependent upon fuel quality. Fuel methane number cannot vary more than ± 3. Part Load data requires customer supplied air fuel ratio control.

For notes information consult page three.

FUEL USAGE GUIDE

CAT METHANE NUMBER	<8	8	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	100
SET POINT TIMING	-	21	21	21	21	21	21	22	23	24	25	26	27	28	29	30	30	30
DERATION FACTOR	0	0.56	0.60	0.70	0.80	0.90	1	1	1	1	1	1	1	1	1	1	1	1

ALTITUDE DERATION FACTORS AT RATED SPEED

INLET AIR TEMP °F	0	1000	2000	3000	4000	5000	6000	7000	8000	9000	10000	11000	12000
130	0.93	0.89	0.86	0.83	0.80	0.77	0.74	0.71	0.68	0.65	0.63	0.60	0.58
120	0.94	0.91	0.88	0.84	0.81	0.78	0.75	0.72	0.69	0.66	0.64	0.61	0.59
110	0.96	0.92	0.89	0.86	0.82	0.79	0.76	0.73	0.70	0.68	0.65	0.62	0.60
100	0.98	0.94	0.91	0.87	0.84	0.81	0.78	0.75	0.72	0.69	0.66	0.63	0.61
90	0.99	0.96	0.92	0.89	0.85	0.82	0.79	0.76	0.73	0.70	0.67	0.65	0.62
80	1	0.98	0.94	0.90	0.87	0.84	0.80	0.77	0.74	0.71	0.69	0.66	0.63
70	1	0.99	0.96	0.92	0.89	0.85	0.82	0.79	0.76	0.73	0.70	0.67	0.64
60	1	1	0.98	0.94	0.90	0.87	0.84	0.80	0.77	0.74	0.71	0.68	0.66
50	1	1	0.99	0.96	0.92	0.89	0.85	0.82	0.79	0.76	0.73	0.70	0.67

ALTITUDE (FEET ABOVE SEA LEVEL)

MINIMUM SPEED CAPABILITY AT THE RATED SPEED'S SITE TORQUE (RPM)

INLET AIR TEMP °F	0	1000	2000	3000	4000	5000	6000	7000	8000	9000	10000	11000	12000
130	1000	1010	1050	1090	1140	1180	1230	1280	1330	1380	1440	1500	1560
120	1000	1000	1030	1070	1120	1160	1210	1250	1310	1360	1420	1470	1540
110	1000	1000	1020	1060	1100	1140	1180	1230	1280	1330	1390	1450	1510
100	1000	1000	1000	1040	1080	1120	1160	1210	1260	1310	1370	1420	1480
90	1000	1000	1000	1020	1060	1100	1140	1190	1240	1290	1340	1400	1460
80	1000	1000	1000	1000	1040	1080	1120	1170	1220	1270	1320	1370	1430
70	1000	1000	1000	1000	1020	1060	1100	1150	1190	1240	1290	1350	1400
60	1000	1000	1000	1000	1000	1040	1080	1130	1170	1220	1270	1320	1380
50	1000	1000	1000	1000	1000	1020	1060	1100	1150	1200	1240	1300	1350

ALTITUDE (FEET ABOVE SEA LEVEL)

FUEL USAGE GUIDE:

This table shows the derate factor and full load set point timing required for a given fuel. Note that deration and set point timing adjustment may be required as the methane number decreases. Methane number is a scale to measure detonation characteristics of various fuels. The methane number of a fuel is determined by using the Caterpillar methane number calculation.

ALTITUDE DERATION FACTORS:

This table shows the deration required for various air inlet temperatures and altitudes. Use this information along with the fuel usage guide chart to help determine actual engine power for your site. The derate factors shown do not take into account external cooling system capacity. The derate factors provided assume the external cooling system can maintain the specified cooling water temperatures, at site conditions.

ACTUAL ENGINE RATING:

To determine the actual rating of the engine at site conditions, one must consider separately, limitations due to fuel characteristics and air system limitations. The Fuel Usage Guide deration establishes fuel limitations. The Altitude/Temperature deration factor and RPC (reference the Caterpillar Methane Program) are added together to establish air system limitations. To determine the actual power available, take the lowest rating between 1) and 2).

1) Fuel Usage Guide Deration
2) 1-((1-Altitude/Temperature Deration) + (1-RPC))

MINIMUM SPEED CAPABILITY AT THE RATED SPEED'S SITE TORQUE (RPM):

This table shows the minimum allowable engine turndown speed where the engine will maintain the Rated Speed's Torque for the given ambient conditions.

NOTES:

1. Fuel pressure range specified is to the engine fuel pressure regulator. Additional fuel train components should be considered in pressure and flow calculations.
2. Engine rating is with one engine driven jacket water pump. Tolerance is ± 3% of full load.
3. ISO 3046/1 engine efficiency tolerance is (+)0, (-)5% of full load % efficiency value. Nominal engine efficiency tolerance is ± 5.0% of full load % efficiency value.
4. ISO 3046/1 fuel consumption tolerance is (+)5, (-)0% of full load data. Nominal fuel consumption tolerance is ± 5.0% of full load data.
5. Air flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 5 %.
6. Inlet and Exhaust Restrictions must not exceed A&I limits based on full load flow rates from the standard technical data sheet.
7. Inlet manifold pressure is a nominal value with a tolerance of ± 5 %.
8. Inlet manifold temperature is a nominal value with a tolerance of ± 9°F.
9. Timing indicated is for use with the minimum fuel methane number specified. Consult the appropriate fuel usage guide for timing at other methane numbers.
10. Exhaust temperature is a nominal value with a tolerance of (+)63°F, (-)54°F.
11. Exhaust flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 6 %.
12. Emissions data is at engine exhaust flange prior to any after treatment.
13. NOx values are the maximum values expected under steady state conditions.
14. CO, CO2, THC, NMHC, NMNEHC, and HCHO values are "Not to Exceed" levels. THC, NMHC, and NMNEHC do not include aldehydes.
15. VOCs - Volatile organic compounds as defined in US EPA 40 CFR 60, subpart JJJJ
16. Exhaust Oxygen tolerance is ± 0.2.
17. LHV rate tolerance is ± 5.0%.
18. Heat rejection to jacket water value displayed includes heat to jacket water alone. Value is based on treated water. Tolerance is ± 10% of full load data.
19. Heat rejection to atmosphere based on treated water. Tolerance is ± 50% of full load data.
20. Lube oil heat rate based on treated water. Tolerance is ± 20% of full load data.
21. Exhaust heat rate based on treated water. Tolerance is ± 10% of full load data.
22. Heat rejection to exhaust (LHV to 77°F) value shown includes unburned fuel and is not intended to be used for sizing or recovery calculations.
23. Total Jacket Water Circuit heat rejection is calculated as: (JW x 1.1) + (OC x 1.2). Heat exchanger sizing criterion is maximum circuit heat rejection at site conditions, with applied tolerances. A cooling system safety factor may be multiplied by the total circuit heat rejection to provide additional margin.

ENGINE POWER (bhp):	145	COOLING SYSTEM:	JW+OC
ENGINE SPEED (rpm):	1800		
EXHAUST MANIFOLD:	WC	JACKET WATER OUTLET (°F):	210

Free Field Mechanical and Exhaust Noise

SOUND PRESSURE LEVEL (dB)											
			Octave Band Center Frequency (OBCF)								
100% Load Data			**dB(A)**	**63 Hz**	**125 Hz**	**250 Hz**	**500 Hz**	**1 kHz**	**2 kHz**	**4 kHz**	**8 kHz**
Mechanical Sound	Distance from the Engine (ft)	3.3	91.7	72.4	82.4	83.4	84.9	86.9	86.4	81.9	77.9
		23.0	81.7	65.6	76.1	74.1	72.6	78.1	76.1	70.6	65.6
		49.2	75.7	59.6	70.1	68.1	66.6	72.1	70.1	64.6	59.6
Exhaust Sound	Distance from the Engine (ft)	4.9	110.4	109	111	109	101	104	104.5	102	99
		23.0	97	95.5	98	91	86.5	89	90.5	91.5	87.5
		49.2	90.4	90.2	93.2	87.7	80.7	82.7	83.2	84.7	79.7

SOUND PARAMETER DEFINITION:

Data Variability Statement:

Sound data presented by Caterpillar has been measured in accordance with ISO 6798 in a Grade 3 test environment. Measurements made in accordance with ISO 6798 will result in some amount of uncertainty. The uncertainties depend not only on the accuracies with which sound pressure levels and measurement surface areas are determined, but also on the 'near-field error' which increases for smaller measurement distances and lower frequencies. The uncertainty for a Grade 3 test environment, that has a source that produces sounds that are uniformly distributed in frequency over the frequency range of interest, is equal to 4 dB (A-weighted). This uncertainty is expressed as the largest value of the standard deviation.

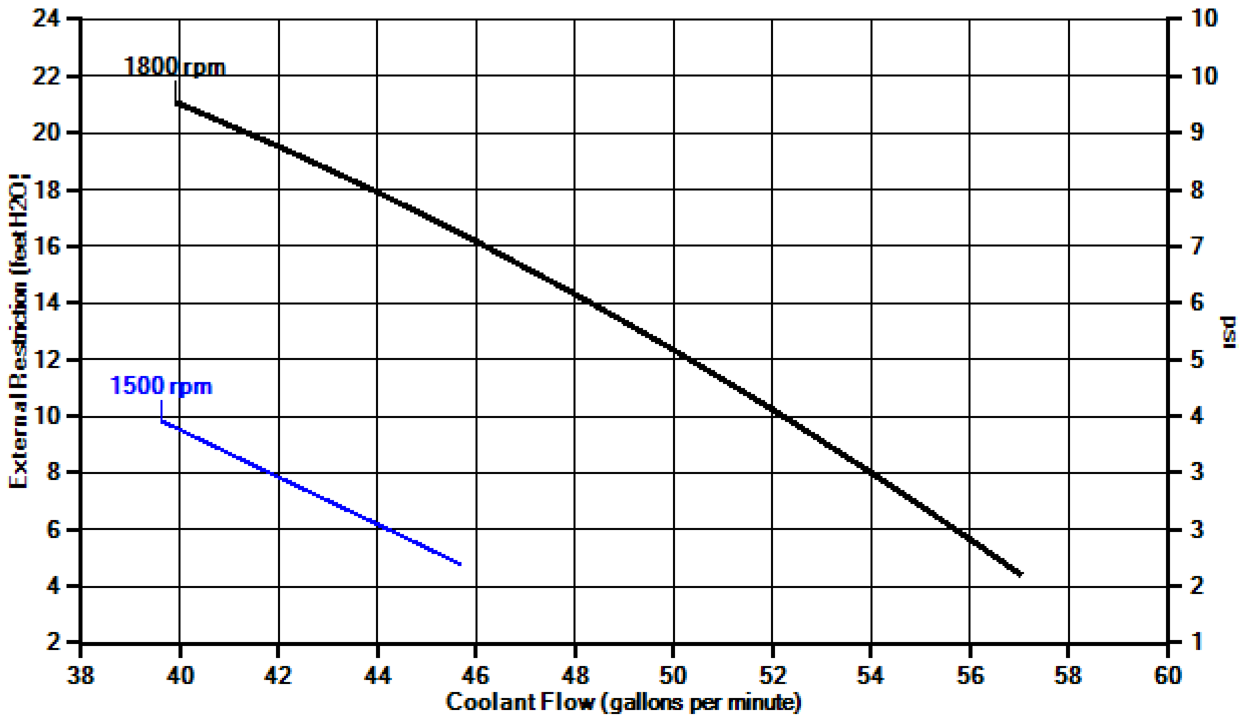
G3306

GAS ENGINE TECHNICAL DATA

CATERPILLAR®

ENGINE POWER (bhp):	145		
ENGINE SPEED (rpm):	1800		
EXHAUST MANIFOLD:	WC	JACKET WATER OUTLET (°F):	210
		COOLING SYSTEM:	JW+OC
		INLET MANIFOLD AIR TEMP (ºC):	NA

Jacket Water System



Coolant Flow vs. Allowable External Restriction

Engine Speed (rpm)	1500	1800
Flow (GPM)	Restriction (feet H2O)	
40	9.5	21.0
42	7.8	19.5
44	6.2	17.9
46		16.2
48		14.3
50		12.3
52		10.2
54		8.0
56		5.7

Notes:
- 7N6210 JW Pump
- Drive Ratio 1:1
- Curves indicate maximum allowable external resistance.
- Do not project curves beyond range shown.
- PSI conversion based on specific gravity of 1.0

```
04/09/19

20:17:53
  ***  SCREEN3 MODEL RUN  ***
  *** VERSION DATED 96043 ***

 12-19-ICE-ES

 SIMPLE TERRAIN INPUTS:
    SOURCE TYPE             =        POINT
    EMISSION RATE (G/S)     =      .200000E-01
    STACK HEIGHT (M)        =       4.5000
    STK INSIDE DIAM (M)     =        .1500
    STK EXIT VELOCITY (M/S)=      17.5500
    STK GAS EXIT TEMP (K)  =     867.0000
    AMBIENT AIR TEMP (K)   =     297.0000
    RECEPTOR HEIGHT (M)    =       1.5000
    URBAN/RURAL OPTION     =        RURAL
    BUILDING HEIGHT (M)    =        .0000
    MIN HORIZ BLDG DIM (M) =        .0000
    MAX HORIZ BLDG DIM (M) =        .0000

 THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
 THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


 BUOY. FLUX =     .636 M**4/S**3;  MOM. FLUX =     .593 M**4/S**2.

 *** FULL METEOROLOGY ***

 **********************************
 *** SCREEN AUTOMATED DISTANCES ***
 **********************************

 *** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES
***

   DIST     CONC             U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
    (M)   (UG/M**3)   STAB  (M/S)  (M/S)    (M)   HT (M)   Y (M)   Z (M)
DWASH
 -------  ----------  ----  -----  -----  ------  ------  ------  ------  ---
--
     10.   .3618E-02    2     5.0    5.0  1600.0    7.55    2.36    1.29
NO
    100.   10.29        3     2.5    2.5   800.0   10.61   12.58    7.64
NO
    200.   8.990        4     2.0    2.0   640.0   12.13   15.72    8.77
NO
    300.   7.482        4     1.5    1.5   480.0   14.68   22.80   12.44
NO

 MAXIMUM 1-HR CONCENTRATION AT OR BEYOND    10. M:
     70.   10.66        3     4.0    4.0  1280.0    8.32    9.14    5.55
NO

  DWASH=   MEANS NO CALC MADE (CONC = 0.0)
```

```
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 ********************************************
 *  SUMMARY OF TERRAIN HEIGHTS ENTERED FOR  *
 *    SIMPLE ELEVATED TERRAIN PROCEDURE     *
 ********************************************

      TERRAIN        DISTANCE RANGE (M)
       HT (M)       MINIMUM     MAXIMUM
      -------      --------    --------
           0.           10.        300.

     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC    DIST TO   TERRAIN
  PROCEDURE         (UG/M**3)    MAX (M)    HT (M)
--------------     -----------   -------   -------
SIMPLE TERRAIN       10.66           70.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
```