P 274 007 692

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED
NOT FOR INTERNATIONAL MAIL
(See Reverse)

Sent to Sue Cummings Exxon Company, USA	
Street and No. P.O. Box 61707	
P.O., State and ZIP Code New Orleans, LA 70161-1797	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt showing to whom and Date Delivered	
Return Receipt showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$
Postmark or Date Mailed: 09/15/87 Permit: AC 57-131370	

PS Form 3800, June 1985 ☆ U.S.G.P.O. 1985-480-794

PS Form 3811, July 1983 447-845

SENDER: Complete items 1, 2, 3 and 4.

Put your address in the "RETURN TO" space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for service(s) requested.

1. ☒ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:
Sue Cummings
Operations Manager/Eastern Div.
Exxon Company, USA
P.O. Box 61707
New Orleans, LA 70161-1797

4. Type of Service:
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail

Article Number
P 274 007 692

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X

6. Signature – Agent
X

7. Date of Delivery
SEP 21 1987

8. Addressee's Address *(ONLY if requested and fee paid)*

DOMESTIC RETURN RECEIPT

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF PERMIT

Ms. Sue Cummings
Operations Manager
Eastern Division
Exxon Company, USA
Post Office Box 61707
New Orleans, LA 70161-1797

September 16, 1987

Enclosed is construction permit No. AC 57-131370 to Exxon Company, USA, to build a permanent crude oil production installation. This permit is issued pursuant to Section 403, Florida Statutes.

Any Party to this permit has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this permit is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

for Dick Thomas

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality Management

Copy furnished to:

E. Middleswart, NW Dist.
R.L. Bruce, Jr., P.E.
A. Broussard
C. Martin

Final Determination

Exxon Company, USA
Santa Rosa County

Crude Oil Production Installation

Permit Number
AC 57-131370

Florida Department of Environmental Regulation
Bureau of Air Quality Management
Central Air Permitting

September 16, 1987

Final Determination

The application by the Exxon Company, USA to construct a permanent crude oil production installation has been reviewed by the Bureau of Air Quality Management. The installation will be located at a facility consisting of the McLellan Field and the subterranean crude oil and gas reservoir. The McLellan Field is located near Munson, Florida in Santa Rosa County. Public notice of the Department's Intent to Issue the permit appeared in the Pensacola News Journal on July 30, 1987.

Copies of the Technical Evaluation and Preliminary Determination and associated materials have been available for public inspection at the Northwest District Office in Pensacola and at the Bureau of Air Quality Management Office in Tallahassee.

Comments about the proposed permit were received from the Exxon Company, USA (Exxon). The comments and the Department's responses are as follows:

Comment: Exxon objects to the statement in Section II of the Technical Evaluation and Preliminary Determination which defines the subterranean crude oil and gas reservoir as part of the facility. The company states, "No emissions result from the reservoir; therefore, non-air pollution sources should not be included as part of major facility".

Response: The Department has not changed the statement defining the subterranean reservoir as part of the facility. A review, based on the applicant's comment, indicates the Department's position is technically sound and in keeping with Chapters 17-2 and 17-4, FAC.

Comment: Exxon has asked the Department to change the statement in Section III.A.(1) of the Technical Evaluation and Preliminary Determination which indicates that all connections will be welded. The company would like the reference to indicate that most connections will be welded. The company states that pipes less than 2" in diameter will have screwed connections and some connections will be flanged. Exxon pointed out that the fugitive emission calculations already take this into account.

Response: The Department has reviewed the basis for the fugitive emission calculations and concurs that most connections are to be welded. But in recognition of this change, Specific Condition #16 has been added to the permit. This condition requires the company to maintain all connections and flanges in a tight and leak-free condition.

Comment: Exxon objects to the fact that the number of crude oil wells (four) have been specified throughout both the Technical

Evaluation and Preliminary Determination, and the permit. The company says the wells are not air pollution sources and should not be regulated.

Response: The Department has retained the specification of the number of crude oil wells in both the Technical Evaluation and Preliminary Determination, and the permit. A review, based on the applicant's comment, indicates that the Department's position is both technically sound and in keeping with Chapters 17-2 and 17-4, FAC.

Comment: Exxon has asked that Specific Condition #1 be changed to read, "The flow of crude oil from the four crude oil production wells shall not exceed 1600 barrels per day, as measured at the separator crude oil outlet". The company indicates that the original requirement to measure crude oil flow at the heater treater outlet presents technical difficulties. The company has also asked that the requirement to measure crude oil flow in pounds be changed to allow the measurement of crude oil flow in barrels. The company's routine practice is to measure crude oil flow in barrels. The applicant has asked that the maximum allowable production rate be specified only in terms of a maximum daily value. The reasons cited are: 1) The installation was designed on the basis of maximum daily flow; and, 2) The applicant would like to increase maximum hourly production in the event that the installation is shutdown for a portion of a day.

Response: Specific Condition #1 has been changed to partially respond to the applicant's request. But, a maximum hourly restriction on the number of barrels is retained. The maximum hourly emissions were the Department's basis for reasonable assurance about the potential of the installation and associated subterranean reservoir to emit.

Comment: Exxon has requested that Specific Condition #2 be changed to reflect that crude oil flow is to be monitored and recorded in keeping with the requested changes to Specific Condition #1.

Response: Specific Condition #2 has also been changed to partially reflect the applicant's request. The condition still meets the Department's needs for purposes of verification, inspection, and compliance testing.

Comment: Exxon has asked that Specific Condition #3 be amended to allow the use of propane as a fuel during periods of startup and emergency. The company believes that there may be times when there will not be a sufficient quantity of fuel gas available from the 3-phase separators to startup the installation. The company has also suggested the possibility of certain incidents that might interrupt the supply of fuel gas from the four 3-phase separators.

Response: Specific Condition #3 has been changed to respond to the applicant's needs. There are not expected to be any substantial changes to the pollutant emissions specified in the Technical Evaluation and Preliminary Determination. Even with a worst case estimated increase of 780 pounds per year, total sulfur dioxide emissions would still be less than one ton.

Comment: Exxon has asked that Specific Condition #11 be changed to require each affected source to be operated at either 90% to 100% of the producing capability or at 90% to 100% of the permitted capacity during compliance testing. The company says the wells will not be capable of producing at 90% to 100% of the permitted capacity on demand. The permitted capacity of the installation is a maximum that will only be achieved on occasion.

Response: Specific Condition #11 has been changed to respond to the technical limitation described by the applicant. With certain restrictions, the Department will allow the compliance testing to be conducted at less than 90% of the permitted capacity.

Comment: Exxon has asked that the expiration date of the construction permit be extended from March 31, 1988 to May 31, 1989. The additional time is needed for the company to complete the drilling of all four wells, compliance testing, and submission of applications for operation permits.

Response: The expiration date has been amended pursuant to the applicant's request. Specific Condition #17 has been added to allow the applicant to production test and commercially operate the installation as each crude oil well is completed.

Comment: Exxon wants to retain the records required by the permit at their Jay/LEC Administrative Offices.

Response: Pursuant to the applicant's request, Specific Condition #18 has been added.

The final action of the Department is the issuance of the permit with the changes discussed above.

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

PERMITTEE:
Exxon Company, USA
Eastern Division
P. O. Box 61707
New Orleans, LA 70161-1707

Permit Number: AC 57-131370
Expiration Date: May 31, 1989
County: Santa Rosa
Latitude/Longitude: 30° 59' 08" N
86° 50' 24" W
Project: McLellan Permanent Production Installation

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rule(s) 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the construction of the McLellan permanent crude oil production installation consisting of 4 crude oil production wells; 4 three-phase separators; a heater treater with a 500,000 Btu per hour heat input capacity; a slop oil storage vessel with a capacity of 250 barrels; 2 saltwater storage vessels--each with a capacity of 400 barrels; 2 crude oil storage vessels--each with a capacity of 1,000 barrels; 4 120 brake horsepower engines; a 100 brake horsepower engine; a 50 brake horsepower engine; a complete vapor recovery system; a vapor recovery compressor; a flare with horizontal (T-bar) flare tip; a fuel gas scrubber; a flare gas scrubber; and a sump. The maximum production capacity of the installation is 18,824 lbs/hr and 1600 barrels/day of crude oil. The project is located at the McLellan Field, Section 33, Township 6 North, Range 26 West, Munson, Santa Rosa County, Florida.

The construction and operation shall be in accordance with the attached permit applications, plans, documents, and drawings except as noted in the Specific Conditions of this permit.

Attachments:

1. Application to Construct an Air Pollution Source, DER Form 17-1.202(1), received March 5, 1987.
2. C. H. Fancy's letter dated April 3, 1987.
3. Exxon's letter with attached revised Application to Construct an Air Pollution Source, DER Form 17-1.202(1), received June 10, 1987.
4. Technical Evaluation and Preliminary Determination dated July 24, 1987.
5. Final Determination dated September 14, 1987.

PERMITTEE:
Exxon Company, USA

Permit Number: AC 57-131370
Expiration Date: May 31, 1989

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the state. Only the Trustees of the Internal Improvement Trust Fund may express state opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

GENERAL CONDITIONS:

6. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

a. Having access to and copying any records that must be kept under the conditions of the permit;

b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately notify and provide the Department with the following information:

a. a description of and cause of non-compliance; and

b. the period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance.

GENERAL CONDITIONS:

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the Department, may be used by the Department as evidence in any enforcement case arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Compliance with New Source Performance Standards.

14. The permittee shall comply with the following monitoring and record keeping requirements:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the department, during the course of any unresolved enforcement action.

GENERAL CONDITIONS:

b. The permittee shall retain at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be at least three years from the date of the sample, measurement, report or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the date(s) analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be submitted or corrected promptly.

SPECIFIC CONDITIONS:

1. The flow of crude oil from the four crude oil production wells shall not exceed 67 barrels per hour and 1600 barrels per day as determined by the sum total of crude oil flow measured at the outlet of each of the four 3-phase separators.

2. A calibrated device to continuously monitor the number of barrels of crude oil flowing from each of the four 3-phase separators shall be installed as close to the crude oil outlet of each separator as reasonably possible. Each device shall provide a display of the current number of barrels per hour of oil flowing from the outlet of the associated separator. The total daily flow of crude oil from the

SPECIFIC CONDITIONS:

outlet of each of the four 3-phase separators shall be recorded and the production for that day summed on a daily basis. Each device shall be recalibrated at least once annually.

3. Each of the engines, the heater treater, and the flare pilot shall be fueled only by gas generated in the four 3-phase separators. Commercial propane gas may be used in the engines, heater treater, and flare pilot only during periods of startup and temporary interruption of 3-phase separator gas supply. The use of propane shall be subject to the provisions of Rules 17-2.250 and 17-4.13, FAC.

4. Visible emissions from each of the engines and the heater treater shall not exceed 5% opacity as a 6-minute average, except an average of 20% opacity during one 6-minute period in any hour shall be allowed. EPA Method 9 shall be used for the compliance determinations.

5. A 98% efficient smokeless flare of the type shown in Illustration VIII of the application shall be installed and equipped with an automatic reignition system. All volatile organic compounds from the 3-phase separators (except those used as fuel), the heater treater, and storage vessels shall be burned by the flare.

6. Pursuant to 40 CFR 60.18, General Control Device Requirements, revised as of July 1, 1986, the flare shall be subject to the following requirements:

a. No visible emissions, except for periods not to exceed a total of 5 minutes during any consecutive 2 hours. EPA Method 22 and the requirements of 40 CFR 60.18(f)(1) shall be used to determine compliance.

b. The flare shall be designed for and operated with an exit velocity equal to or greater than 60 feet per second and less than 400 feet per second. Compliance shall be determined using the procedure in 40 CFR 60.18(f)(4), and either EPA Method 2, 2A, 2C, or 2D (as appropriate).

c. The net heating value of gas combusted by the flare shall be greater than 1,000 Btu per standard cubic foot. Compliance shall be determined pursuant to 40 CFR 60.18(f)(3).

d. The flare shall be operated at all times that the installation is operated. The presence of a flare pilot flame shall be continuously monitored and recorded using a thermocouple or other equivalent device to detect the presence of a flame.

SPECIFIC CONDITIONS:

e. EPA Method 15 shall be used to determine whether reduced sulfur concentrations in the gas stream to be flared exceed 11 ppm at dry standard conditions (14.7 psia and 68°F).

7. Pursuant to Rule 17-2.620(2), FAC, Objectionable Odor Prohibited, the installation shall not emit any objectionable odors.

8. Each tanker truck shall be equipped with a vapor balance system which shall be properly connected so that all displaced vapors will be vented to the crude oil storage vessels during custody transfer of crude oil. The system shall be properly operated and maintained.

9. A spill prevention control and countermeasure plan acceptable to the Department shall be developed by the applicant. This plan shall be submitted with the application for an operation permit. If approved, the plan shall become a condition of the operation permit.

10. Since personnel will not be present at the installation 24 hours per day--each source of emissions shall be inspected each day during daylight hours. Pursuant to Rule 17-2.250(5), FAC--the applicable requirements of Rules 17-2.250 and 17-4.130, FAC, shall be immediately complied with upon discovery of excess emissions.

11. The permitted sources shall be tested for compliance with Specific Conditions 4 and 6.a. through d. annually. The test required by Specific Condition 6.e. shall also be conducted annually. The installation and each affected source shall be operated at 90% to 100% of either the total maximum hourly producing capability of all installed wells or the permitted maximum hourly capacity of the installation, whichever is less, during compliance testing. If compliance is demonstrated at less than 90% of the maximum permitted hourly capacity, then:

a. The maximum hourly operation rate shall not exceed that at which compliance was demonstrated by more than 10%, except as allowed by Specific Condition No. 17.

b. An operation rate of up to 100% of the maximum permitted hourly capacity shall be allowed if additional testing first demonstrates compliance at the desired higher operation rate.

12. All source sampling shall be performed and test results shall be submitted in accordance with the applicable provisions Rule 17-2.700, FAC, Stationary Point Source Emissions Test Procedures, which includes 15 days advance notification of any compliance test to the Department's NW District office--Air Programs and the submission of test reports to the Department's NW District office--Air Programs within 45 days after testing is completed.

PERMITTEE:
Exxon Company, USA

Permit Number: AC 57-131370
Expiration Date: May 31, 1989

SPECIFIC CONDITIONS:

13. An operations report for this installation shall be submitted each calendar year pursuant to Rule 17-4.140, FAC, Reports. The report shall be for the preceding calendar year.

14. All compliance test reports and other reports shall identify each source and include the assigned APIS number. The assigned APIS numbers are:

Emission Source	APIS Number
120 bhp Engine at well 33-1	10 PEN 5700 3201
120 bhp Engine at well 34-2	10 PEN 5700 3202
120 bhp Engine at well 34-3	10 PEN 5700 3203
120 bhp Engine at well 28-4	10 PEN 5700 3204
100 bhp Engine	10 PEN 5700 3205
50 bhp Engine	10 PEN 5700 3206
Heater Treater	10 PEN 5700 3207
Flare	10 PEN 5700 3208

Refer to Illustration V in the application for the well numbers.

15. After satisfactory completion of the initial compliance test and prior to 90 days before the expiration date of this permit, a complete application for an operation permit shall be submitted to the NW District office. The permittee shall continue to operate in compliance with the terms of this construction permit until its expiration date or until the issuance of an operation permit.

16. All connections, fittings, and flanges shall be maintained in a tight and leak-free condition.

17. Prior to the expiration date of this construction permit, the installation and affected sources may be operated at a maximum hourly rate more than 10% higher than that at which it was last tested for a period of 90 days following the completion of each of the crude oil wells 34-3 and 28-4. This shall be contingent upon the following:

a. No crude oil well shall be commercially operated without first conducting tests to demonstrate that the installation and each affected source is in compliance with the conditions of this permit.

PERMITTEE:
Exxon Company, USA

Permit Number: AC 57-131370
Expiration Date: May 31, 1989

SPECIFIC CONDITONS:

b. The first compliance test pursuant to Specific Conditions No. 4 and No. 6.a. through d. and the first test pursuant to Specific Condition No. 6.e. shall be conducted no later than December 31, 1987.

18. All records required by this permit shall be retained at the Exxon Company, JAY/LEC Administrative Office, Post Office Box 351, Oil Plant Road (2 miles west of Jay off SR 4), Jay, Florida 32565.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION

Dale Twachtmann, Secretary

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION) Clair Fancy	Initial	
	Date	
2.	Initial	
	Date	
3.	Initial	
	Date	
4.	Initial	
	Date	

REMARKS:

DER

SEP 15 1987

BAQM

INFORMATION

- Review & Return
- Review & File
- Initial & Forward

DISPOSITION

- Review & Respond
- Prepare Response
- For My Signature
- For Your Signature
- Let's Discuss
- Set Up Meeting
- Investigate & Report
- Initial & Forward
- Distribute
- Concurrence
- For Processing
- Initial & Return

FROM:

DATE

PHONE

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

TO: Dale Twachtmann

THRU: Howard Rhodes

FROM: Clair Fancy

DATE: September 11, 1987

SUBJ: Approval of Construction Permit No. AC 57-131370
Exxon Company, USA

Attached for your approval and signature is a construction permit to build a permanent crude oil production installation. No comments were received during the public notice period.

Day 90 after which this permit will be issued by default is September 21, 1987.

The Bureau recommends approval and signature.

CHF/MJ/s

attachment

RECEIVED
SEP 14 1987
Office of the Secretary

Check Sheet

Company Name: Exxon
Permit Number: AC 57-131370
PSD Number:
County:
Permit Engineer:
Others involved:

Application:
- [x] Initial Application
- [x] Incompleteness Letters
- [x] Responses
- [x] Final Application (if applicable)
- [ ] Waiver of Department Action
- [ ] Department Response

Intent:
- [x] Intent to Issue
- [x] Notice to Public
- [x] Technical Evaluation
- [ ] BACT Determination
- [x] Unsigned Permit

Attachments:
- [ ]
- [ ]
- [ ]

- [ ] Correspondence with:
  - [ ] EPA
  - [ ] Park Services
  - [ ] County
  - [ ] Other
- [x] Proof of Publication
- [ ] Petitions - (Related to extensions, hearings, etc.)

D EXTENSION TO FILE PETITION

Final Determination:
- [x] Final Determination
- [x] Signed Permit
- [ ] BACT Determination

Post Permit Correspondence:
- [ ] Extensions
- [ ] Amendments/Modifications
- [ ] Response from EPA
- [ ] Response from County
- [ ] Response from Park Services

In the folder labeled as follows there are documents, listed below, which were not reproduced in this electronic file. Those documents can be found in the supplementary documents file drawer. Folders in that drawer are arranged alphabetically, then by permit number.

Folder Name: Exxon Company
AC 57-131370

Period During Which DOCUMENT WAS SUBMITTED (APPLICATION, PD & TE, FINAL DETERMINATION, POST PERMIT)	Detailed Description
???	1. EPA STANDARDS OF PERFORMANCE WITH ENGINEER HIGHLIGHTS/NOTES

Final Determination

Exxon, USA's application for a permit to construct a permanent crude oil-production installation

Comment Company

Section II of Exxon, USA objects to the statement in the Technical Evaluation and Preliminary Determination which defines the subterranean crude oil and gas reservoir as part of the facility. The company states, "No emissions result from the reservoir; therefore, non-air pollution sources should not be included as part of major facility.

Response

The Department has not changed the statement defining the subterranean oil and gas reservoir as part of the facility. This statement is in keeping with the definition of a source in Rule 17-2.100(176), FAC, because the reservoir contains the crude oil and associated gas. Without this reservoir the McLellan installation would probably not be needed. So, the reservoir, once tapped, becomes an appurtenance to the source and a part of the facility to be included in the permit pursuant to Rule 17-4.020(9), FAC. In

Response

The Department has not changed the statement defining the subterranean reservoir as part of the facility. A review, based on the applicant's comment, indicates that the Department's position is both technically sound and in keeping with Chapters 17-2 and 17-4, FAC.

(2)

#Compliance with the applicant's request would invalidate the Department's reasonable assurance (Rules 17-[redacted]200, and 17-[redacted]070, FAC, about the potential to emit (Rule 17-2.100(147), FAC) and the applicability of Prevention of Significant Deterioration (Rule 17-2.500, FAC) to this and other similar projects. The extent of and the ability of the reservoir to yield crude oil and gas is critical to these.

addition, if the reservoir were merely vented to the surface volatile organic compounds would be emitted to the atmosphere. The Department's statement is also in keeping with the definition of a facility in Rule 17-2.100(72), FAC, because the crude oil and associated gas are confined by the reservoir. The crude oil and associated gas are fluids that have the ability to flow within the confines of the reservoir. The crude oil and associated gas constitutes the contiguous property under common control. The extent of the property is defined by the confines of the reservoir.

→

Comment

Exxon, USA has asked the Department to change the reference in Section III.A.(1) of the Technical Evaluation and Preliminary Determination which indicates that all connections will be welded. The company would like the reference to indicate that most connections will be welded. The company states, that pipes less than 2" will have screwed connections and some ~~welded~~ connections will be flanged. Exxon, USA points out that the fugitive emission calculations already take this into account.

Response

The Department has reviewed the basis for the fugitive emission calculations and concurs. But, in recog-

nition of this change Specific Condition 16 has been added to the permit. This condition requires the company to maintain all connections and flanges in a tight and leak-free condition.

Comment

Exxon, USA objects to fact that the number of crude oil wells (four) have been specified throughout both the Technical Evaluation and Preliminary Determination, and the permit. The company says the wells are not air pollution sources and should not be regulated.

Response

The Department has retained the specification of the number of wells in both the Technical Evaluation and Preliminary Determination, and the permit. The specification of the number of crude oil wells is in keeping with the definition of a stationary source in Rule 17-2.100(176), FAC. The wells are required to convey the crude oil and associated gas to the surface. If it were not for the wells there would be no need for an installation at the McLellan Field. If the wells were constructed and simply allowed to remain open to the atmosphere volatile organic compounds would be emitted. So, without the installation, the wells

Response

The Department has retained the specification of the number of crude oil wells in both the Technical Evaluation and Preliminary Determination and the permit. A review, based on the applicant's comment, indicates that the Department's position is both technically sound and in keeping with Chapters 17-2 and 17-4, FAC.

a stack pursuant to Rule 17-2.100(177), FAC, and would become an emission point pursuant to Rule 17-2.100(62), FAC. Thus, the wells are clearly an appurtenance to the stationary source pursuant to Rule 17-2.100(176), FAC, and subject to permitting pursuant to the definition of a permit in Rule 17-4.020(9), FAC.

Additionally, the number of wells and the estimated maximum production rate from each well was specified in the permit application. This information along with the type, size, capacity, and number of pieces of equipment to be installed was critical element of the Department's reasonable assurance (Rules 17-2.200 and 17-4.070, FAC) about the installation's potential to emit pursuant to Rule 17-2.100(147), FAC. Compliance with the applicant's request would invalidate the Department's reasonable assurance.

The number of wells also provides the Department with a means to ensure that the installation has been constructed in accordance with the permit. Construction in keeping with the permit application is a requirement of the third paragraph on the first page of each permit.

Comment

Exxon, USA has asked that Specific Condition 1 be changed to read, "The flow of crude oil from the four crude oil production wells shall not exceed

1600 barrels per day, as measured at the separator crude oil outlet". The company indicates that the original requirement to measure crude oil flow at the heater treater outlet presents technical difficulties. The company has also asked that the requirement to measure crude oil flow in pounds be changed to allow the measurement of crude oil flow in barrels. The company's routine practice is to measure crude oil flow in barrels. The applicant has asked that the maximum allowable production rate be specified only in terms of a maximum daily value. The reasons citedare: (1) The installation was designed on the basis of maximum daily flow; and, (2) The applicant would like to increase maximum hourly production in the event that the installation is shut down for a portion of a day.

Response

The Department has considered this request. Specific Condition 1 has been changed such that flow is to be measured in barrels at the crude oil outlets of the four three-phase separators. The houcly restriction on maximum flow has not been removed; but, a daily restriction has been added for the convenience of the applicant with regard to record keeping. Both restrictions will be applicable. The houcly restriction was retained for twereasons. First,

Response

Specific Condition 1 has been changed to partially respond to the applicant's request. But, a maximum hourly restriction on the number of barrels is retained. The maximum hourly emissions were the Department's basis for reasonable assurance about the potential of the installation and associated subterranean reservoir to emit.

the applicant submitted emission estimates that were based on a maximum ~~hourly~~ crude oil flow rate of approximately 67 barrels per hour. The Department relied upon the estimates and the hourly rate in determining the potential to emit and proposing to issue the permit. Second, the required compliance testing methods are based on sample collection periods of less than one day. A daily restriction alone would prevent a determination of whether the installation was being operated at its maximum rate during a compliance test."

Exxon, USA will need to submit an application for a modification with appropriate fees if a higher hourly or daily operation rate is desired.

Comment

Exxon, USA has requested that Specific Condition 2 be changed to reflect that crude oil flow is to be monitored and recorded in keeping with the requested changes to Specific Condition 1.

Response

The Department has considered the applicant's requested changes to Specific Condition 2. This specific condition has been amended to reflect those changes that the Department has made to Specific Condition 1. The applicant will be allowed

Response

Specific Condition 2 has been changed to partially reflect the applicant's request. The condition still meets the Department's needs for purposes of verification, inspection, and compliance testing.

to continuously monitor the crude oil flow from each of the four 3-phase separators and record and sum the flow on a daily basis. But, the applicant will be required to equip each calibrated measurement device with a display. The display is to show the current number of barrels per hour of crude oil flowing from each associated separator.

Comment

Exxon, USA has asked that Specific Condition 3 be amended to allow the use of propane as a fuel during periods of startup and emergency. The company believes that there may be times when there will not be a sufficient quantity of fuel gas available from the 3-phase separators to startup the installation. The company has also suggested the possibility of certain incidents that might interrupt the supply of fuel gas from the four 3-phase separators.

Response

~~The Department has amended Specific Condition 3 to respond to the applicant's needs. The use of propane gas during periods of startup and for emergency situations is not expected to increase emissions of any pollutant above those already specified in either the permit or the Technical [illegible] of a startup or emergency situation would about one-half of

Response

Specific Condition 3 has been changed to respond to the applicant's expressed needs. The use of propane during periods of startup and temporary interruption of 3-phase separator gas supplies should not substantially affect pollutant emissions. The only known increase would be at worst about 780 pounds per year of sulfur dioxide. Even with the increase sulfur dioxide emissions would be less than one ton per year.

Comment

Exxon, USA has asked that Specific Condition 11 be changed to require each affected source to be operated at 90% to 100% of the producing capability during compliance testing. The company says the wells will not be capable of producing at 90%-100% of capacity on demand. The permitted capacity of the installation will only be achieved on occasion.

~~Response~~

~~Specific Condition 11 has been changed to respond to both the situation described by the applicant and the policy of the Department. The applicant will be required to operate the installation~~ and each affected source ~~within 90% to 100% of either the producing capability of all installed wells or permitted capacity, whichever is less, during compliance tests. If the instal-~~

Response

Specific Condition 3 has been changed to respond to the applicant's expressed needs. The result will be a minor increase in sulfur dioxide emissions of 780 pounds per year. The emissions of all pollutants including sulfur dioxide will remain within the limits specified in the Technical Evaluation and Preliminary Determination.

Response

Specific Condition 11 has been changed to respond to the technical limitations described by the applicant. With certain restrictions, the Department will allow compliance testing to be conducted at less than 90% of the permitted capacity.

Comment

Exxon, USA has asked that the expiration date of the construction permit be extended from May 31, 1988 to May 31, 1989. The additional time is needed for the company to complete the drilling of all four wells, compliance testing, and submission of applications for operation permits.

Response

The expiration date has been amended to pursuant to the applicant's request. Specific Condition 17 has been added to allow the applicant to production test and commercially operate the installation as each crude oil well is completed.

Comment

Exxon, USA wants to retain the records required by the permit at their Jay/LEC Administrative Offices.

Response

Pursuant to the applicant's request, Specific Condition 18 has been added.

Fuel Consumption 4318.87 SCFH Gross Heat: 1223.978 $\frac{Btu}{SCF}$

Heat Input 5.2862 MBtu/Hr

H_2S = 9 ppm = 8.0779 EE-07 $\frac{lb}{ft^3}$ = 0.57 gr/100 ft^3

SO_2 = (4318.87 SCFH)(8.0779 EE-07 $\frac{lb}{SCF}$)($\frac{64}{34}$) = 0.0066 $\frac{lb}{hr}$ or 0.029 $\frac{T}{Y}$

Propane Gross Heat 2522 $\frac{Btu}{SCF}$ Butane 3261 $\frac{Btu}{SCF}$

Commercial Propane 2.5% - V/V Butane 15 gr/100 scf - S

Special Duty Propane " 10 gr/100 SCF - S

Propane Gross Heat	2522 $\frac{Btu}{SCF}$	21,560 $\frac{Btu}{lb}$	91,500 $\frac{Btu}{gal}$	
Butane Gross Heat	3261 $\frac{Btu}{SCF}$	21,180 $\frac{Btu}{lb}$	102,600 $\frac{Btu}{gal}$	
Propane Wt.	4.235 $\frac{lb}{gal\ liq.}$	36.28 $\frac{ft^3\ gas}{gal\ liq}$	8.55 $\frac{CF\ gas}{lb\ liq}$	
Butane Wt.	4.873 $\frac{lb}{gal\ liq.}$	31.46 $\frac{CF\ gas}{gal\ liq}$	6.50 $\frac{CF\ gas}{lb\ liq}$	assume

LPG Emission Factors Assumed By "AP-42 To Be The Same As Those For Natural Gas Combustion For All Pollutants Except S, For External Combustion Sources. So Same Assumpeion Reasonable For Engines

Commercial Propane Gross Heat 2,540 $\frac{Btu}{SCF}$ (Calculated)

Fuel Consumption = $\frac{\text{Heat Input}}{\text{Gross Heat}} = \frac{5.2862\ MBtu/Hr}{2,540\ \frac{Btu}{SCF}}$ = 2,081.18 $\frac{SCF}{Hr}$

SO_2 = (2,081.18 $\frac{SCF}{Hr}$)(0.15 $\frac{gr}{SCF}$)($\frac{1\ lb}{7000\ gr}$)(2) = 0.089 $\frac{lb}{hr}$ or 0.39 $\frac{T}{Y}$

The SO_2 increase would be 780 $\frac{lb}{Y}$ max.

PM
9-4-87
New Orleans, La

Airborne Exp:
MA4 327218426

File Copy

EXXON COMPANY, U.S.A.

POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
EASTERN DIVISION

September 3, 1987

Exxon Company, U.S.A.
McLellan Permanent Facility
Installation
Permit No. AC 57-131370
Waiver of 90 Day Time Limit
File: D-12-5(a)

DER
SEP 8 1987
BAQM

Mr. C. H. Fancy, Bureau Chief
Bureau of Air Quality Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

Dear Mr. Fancy:

Attached for your use is a waiver of the 90 day time limit for the above referenced permit. This waiver extends the permitting time by eight days to September 21, 1987 which corresponds to Exxon's eight day extension to file a petition for hearing granted by your office on August 17, 1987.

Sincerely yours,

EXXON CORPORATION

By: Sylvia A Bellone
for Charles A. Martin
Permit/Surveillance Supervisor
Eastern Division
Exxon Company, U.S.A.
(a division of Exxon Corporation)

AAB:mm(50B)
Attachment

c: Ms. Betsy Pittman ✓
Mr. Edwin Middleswart ✓
Ms. Rosemary Stein
Mike Harley 9-8-87 RBM

AIRBORNE EXPRESS

RECEIVER'S COPY

202 (5/86)

ORIGIN: MSY AIRBILL NO.: 3272184

FROM (COMPANY NAME): EXXON U S A

ADDRESS: STE 416
1555 POYDRAS ST

CITY: NEW ORLEANS STATE: LA ZIP CODE (REQUIRED): 70112

SENT BY (NAME/DEPT.): A. Broussard PHONE: 504-561-4226

TO (COMPANY NAME): Bureau of Air Quality Management

ADDRESS: Twin Towers Office Building
2600 Blair Stone Road

CITY: Tallahassee STATE: FL ZIP CODE (REQUIRED): 32301

ATTN. (NAME/DEPT.): Mr. C. H. Fancy PHONE:

DER
SEP 8 1987
BAQM

BILLING REFERENCE INFORMATION TO APPEAR ON INVOICE

RECEIVER'S AIRBORNE EXPRESS ACCOUNT NO.

TYPE OF PACKAGING

- ☐ EXPRESS/AD PACK ENVELOPE
- ☒ LETTER EXPRESS (UP TO 8 OZ.)
- ☐ EXPRESS PACK BOX/TUBE
- ☐ MAG TAPE PACK

DESCRIPTION OF CONTENTS

NO. OF PACKAGES	WEIGHT (LBS.)
1	4

SENDER'S C.O.D. $

ROUTING

TLH
DER
SE 8 1987
BAQM
3-B

BILL CHARGES TO (ASSUMED SENDER UNLESS OTHERWISE SPECIFIED)

- ☐ SENDER
- ☐ RECEIVER
- ☐ 3RD PARTY _____ AIRBORNE EXPRESS ACCOUNT NO.
- ☐ PAID IN ADVANCE $ _____ CHECK NUMBER _____

TYPE OF SPECIAL SERVICE (EXTRA CHARGES MAY APPLY)

- ☐ SPECIAL PICKUP
- ☐ SATURDAY DELIVERY
- ☐ SPECIAL DELIVERY _____ : TIME
- ☐ HOLD AT AIRBORNE FOR PICKUP (NO CHARGE)
- ☐

AIRBILL NO.	AIRBORNE SIGNATURE	DATE RECEIVED
	X	

WAIVER OF 90 DAY TIME LIMIT

UNDER SECTION 120.60(2), FLORIDA STATUTES

License (Permit, Certification) Application No. AC 57-131370
Applicant's Name: Exxon Company, U.S.A.

The undersigned has read Section 120.60(2), Florida Statutes, and fully understands the Applicant's rights under that section.

With regard to the above referenced license (permit, certification) application, the Applicant hereby with full knowledge and understanding of (his) (her) (its) rights under Section 120.60(2), Florida Statutes, waives the right under Section 120.60(2), Florida Statutes, to have the application approved or denied by the State of Florida Department of Environmental Regulation within the 90 day time period prescribed in Section 120.60(2), Florida Statutes. Said waiver is made freely and voluntarily by the Applicant, is in (his) (her) (its) self-interest, and without any pressure or coercion by anyone employed by the State of Florida Department of Environmental Regulation.

This waiver shall expire on the 21st day of September 19 87.

The undersigned is authorized to make this waiver on behalf of the applicant.

Signature

Sue Cummings
Name of Signee

8-28-87
Date

Sworn to and subscribed
before me this 28th day
of August 19 87.

Barbara T. Bevan

Barbara T. Bevan, Notary Public
Orleans Parish, Louisiana
My commission is issued for life.

Section 120.60, Florida Statutes

(2) When an application for a license is made as required by law, the agency shall conduct the proceedings required with reasonable dispatch and with due regard to the rights and privileges of all affected parties or aggrieved persons. Within 30 days after receipt of an application for a license, the agency shall examine the application, notify the applicant of any apparent errors or omissions, and request any additional information the agency is permitted by law to require. Failure to correct an error or omission or to supply additional information shall not be grounds for denial of the license unless the agency timely notified the applicant within this 30 day period. The agency shall notify the applicant if the activity for which he seeks a license is exempt from the licensing requirement and return any tendered application fee within 30 days after receipt of the original application or within 10 days after receipt of the timely requested additional information or correction of errors or omissions. Every application for license shall be approved or denied within 90 days after receipt of the original application or receipt of the timely requested additional information or correction of errors or omissions. Any application for a license not approved or denied within the 90-day period or within 15 days after conclusion of a public hearing held on the application, whichever is latest, shall be deemed approved and, subject to the satisfactory completion of an examination, if required as a prerequisite to licensure, [2](the license) shall be issued. The Public Service Commission, when issuing a license, and any other agency, if specifically exempted by law, shall be exempt from the time limitations within this subsection. Each agency, upon issuing or denying a license, shall state with particularity the grounds or basis for the issuance or denial of same, except where issuance is a ministerial act. On denial of a license application on which there has been no hearing, the denying agency shall inform the applicant of any right to a hearing pursuant to s. 120.57.

To: Mike
From: wmh
Subject: EXXON
Date: 8/21/87

Ashlyn called and said.

1. Wells do not have pumps on them now. They can produce 500 BPD oil for a couple days and then flow would drop to 100 BPD.

2. EXXON will install pump and do "down hole" work. This will result in 360 BPD oil being able to reach pump (my language) but the pump can only deliver 340 BPD. Will not get the high initial flow rates in I because pump/down hole work restricts flow

3. Conclusion is with pumps installed, EXXON cannot exceed proposed production rate. If you need clarification or more information, call Ashlyn

Ashlyn plans to extend 90 day from Sept 13 to Sept 21. Bruce suggested it not needed (you can write Final Ext. now?) Call and tell her to forget about extension.

To Willard Hanks

Date 8/21 Time 11:15

WHILE YOU WERE OUT

M Marilyn B.

of

Phone 504 561 4226
Area Code Number Extension

	TELEPHONED		PLEASE CALL
	CALLED TO SEE YOU		WILL CALL AGAIN
	WANTS TO SEE YOU		URGENT
			RETURNED YOUR CALL

Message

Operator

File Copy

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

EXXON COMPANY, U.S.A.,

Petitioner,

vs.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION,

Respondent.

OGC File 87- 1082

DER

AUG 21 1987

BAQM

ORDER ON REQUEST FOR AN EXTENSION OF TIME TO FILE PETITION FOR HEARING

This cause has come before me upon receipt of a request made by Petitioner, EXXON COMPANY, U.S.A, MCLELLAN PERMANENT PRODUCTION INSTALLATION, Permit No. AC 57-131370, pursuant to Rule 17-103.070, Florida Administrative Code, to grant an extension of time for it to file a petition for administrative proceeding. See Exhibit 1 attached.

Counsel for Petitioner has discussed this request with counsel for Respondent, State of Florida Department of Environmental Regulation (DER) and the DER has no objection to it. Therefore:

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is hereby granted. Petitioner shall have until August 21, 1987, to file a petition in this matter.

DONE and ORDERED this 17 day of August, 1987, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

DALE TWACHTMANN
Secretary

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: 904/488-4805

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to S120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

C. Hutchinson
Clerk

8-19-87
Date

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION) Mike Harvey BAQM	Initial	
	Date	
2.	Initial	
	Date	
3.	Initial	
	Date	
4.	Initial	
	Date	

REMARKS:

EXTOR order

DER

AUG 21 1987

BAQM

INFORMATION	
	Review & Return
	Review & File
	Initial & Forward

DISPOSITION	
	Review & Respond
	Prepare Response
	For My Signature
	For Your Signature
	Let's Discuss
	Set Up Meeting
	Investigate & Report
	Initial & Forward
	Distribute
	Concurrence
	For Processing
	Initial & Return

FROM: Betsy P.

DATE

PHONE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing ORDER ON REQUEST FOR EXTENSION OF TIME TO FILE PETITION FOR HEARING has been furnished by U.S. Mail to Charles A. Martin, Permit/Surveillance Supervisor and Rosemary Stein, Eastern Division, Exxon Company, U.S.A., Post Office Box 61707, New Orleans, Louisiana 70161-1707; this 19th day of August, 1987.

BETSY F. PITTMAN
Assistant General Counsel

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: (904)488-9730

Copied: Edwin Middleswart - NWD
Willard Hanbo
Mike Harley
Clair Fancy / Bill Thomas
8/21/87

File Copy

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

TO: Betsy Pittman

THRU: Clair Fancy
Willard Hanks

FROM: Mike Harley

DATE: August 19, 1987

SUBJ: Exxon, USA - McLellan Field--Draft Permit No. AC 57-131370

Exxon may be contacting you about two areas of substantive disagreement on the proposed permit for the McLellan Field.

Reservoir

First, Exxon does not believe that the subterranean oil reservoir should be considered to be part of the facility. Exxon cites the reference to stationary source in the definition of a facility, Rule 17-2.100(72), FAC, and the definition of a stationary source, Rule 17-2.100(176), FAC, as the basis for their opinion. We disagree.

The property under common control is the liquid (crude oil). This crude oil is a continuous layer within the reservoir which flows to the surface by natural or artificial means. The crude oil is physically confined to boundaries by the reservoir. So, the reservoir defines the extent of the property under common control. Also, the reservoir (once tapped) becomes an appurtenance to the installation that contains the raw material that the production installation processes. The crude oil contains dissolved gas which becomes the pollutant VOC when the pressure on the crude oil is relieved. The dissolved gas is important to Exxon because it enhances the ability of the oil to flow freely within the confines of the reservoir. The importance of our view is that it prevents an inappropriate avoidance of PSD. If Exxon's view were upheld, three installations identical to the McLellan Field could be constructed some distance apart, withdraw crude oil from the same reservoir, emit say 126 tons/year of VOC each, and avoid PSD review because the surface property lines are not contiguous.

Wells and Separators

Second, Exxon does not believe the number of crude oil production wells and 3-phase separators should be specified in the permit. Exxon cites the definition of stationary source in Rule 17-2.100(176), FAC, and the fact that DNR issues oil well permits as the basis for their opinion. Again we disagree.

The crude oil wells, and the 3-phase separators are clearly appurtenances to the source(s) which are essential to the production of the specific product (crude oil). The wells are required to convey the raw material to the surface. The 3-phase separators are needed to separate gas and water from the crude oil. The definition of a stationary source in Rule 17-2.100(176), FAC, and the definition of a permit in Rule 17-4.020(9), FAC, both include appurtenances. Also, note Rule 17-4.210, FAC. The quantity of oil and gas that each well and associated separator is capable of removing from the subterranean reservoir is important to determining the potential of the installation to emit pursuant to Rule 17-2.100(147), FAC. The number of wells and associated 3-phase separators are a critical element of the reasonable assurance required by Rules 17-2.200 and 17-4.070(1), FAC. The number of wells and separators is a necessary requirement of the permit so we can determine if the installation was constructed as represented by the application. This is a requirement of the third paragraph on the first page of the permit.

The argument that the DNR's issuance of permits for oil wells precludes the DER's issuance of permits for the same wells is not valid. These permits are issued for two different reasons. The DNR permits the construction of oil wells because the company is removing a natural resource (crude oil). The DER permits the construction of oil wells because these are installations that may reasonably be expected to result in air pollutant emissions. We believe the authority for this is found in Sections 403.061(14), 403.087(1), and 403.087(4) of the Florida Statutes and Rules 17-2.210, 17-4.030, 17-4.070(1), and 17-4.070(2), FAC. We do not think our issuance of a permit to construct oil wells as part of the installation has any bearing on the DNR permit activity. An analogy is the fact that issuance of an air pollution construction permit does not change the local building code requirements that the permittee must comply with or vice versa.

Suggestions

One test of the first argument by Exxon might be: "What would happen if someone started withdrawing oil from the reservoir at McLellan without Exxon's approval?" A test of the second argument might be: "Can Exxon remove oil from the reservoir without the wells and separators?"

Request

Please evaluate our position and determine if it is proper, legally supportable, and defensible. We would appreciate a response at your earliest convenience. If Exxon requests a hearing please discuss the scheduling with either Clair Fancy or Bill Thomas.

MH/ks

PM
8 Aug 87
airborne express

EXXON COMPANY, U.S.A.
POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
EASTERN DIVISION

August 14, 1987

McLellan Field
Production Facility Installation
Section 34, T6N, R26W
Santa Rosa County, Florida

DER
AUG 17 1987
BAQM

Mr. Bill Thomas
Chief Engineer
Bureau of Air Quality Management
Twin Towers Office Building
2600 Blairstone Road
Pensacola, Florida 32301

Dear Mr. Thomas:

After reviewing your Technical Evaluation, Preliminary Determination, and Draft Permit for the McLellan Field Permanent Facility Installation, Permit No. AC 57-131370, we have determined that certain conditions are not acceptable as written. Attached is a list of comments to these conditions with the reasons necessitating the changes. As agreed and documented in the letter to your office dated August 12, 1987, we have until August 21 to comment on this permit and request an administrative hearing.

We would like to meet with you to discuss these proposed changes at your convenience. Please Ashlyn Broussard (504) at 561-4226 if you have any questions.

Sincerely,

EXXON CORPORATION

By: RB for
Charles A. Martin
Permits/Surveillance Supervisor
Eastern Division
Exxon Company, U.S.A.
(a division of Exxon Corporation)

AAB:fab[45b]

c: Mr. C. Fancy
Mr. M. Harley - 8/17/87
Mr. E. Middleswart
Mr. J. Koogler
Mr. W. Harder - 8/17/87

BEST AVAILABLE COPY

AIRBORNE EXPRESS

RECEIVER'S COPY

202 (5/86)

ORIGIN AIRBILL NO. MSY 32722567

FROM (COMPANY NAME)
EXXON U S A
ADDRESS
STE 416
1515 POYDRAS ST
CITY NEW ORLEANS STATE LA ZIP CODE (REQUIRED) 70112
SENT BY (NAME/DEPT.) C A Martin PHONE 561-3301

TO (COMPANY NAME)
Bureau of Air Quality Mgmt
ADDRESS
2600 Blairstone Rd
CITY Tallahassee STATE FL ZIP CODE (REQUIRED) 32301
ATTN. (NAME/DEPT.) Bill Thomas, Chief Engr. PHONE

BILLING REFERENCE INFORMATION TO APPEAR ON INVOICE

RECEIVER'S AIRBORNE EXPRESS ACCOUNT NO.

TYPE OF PACKAGING
- ☐ EXPRESS/AD PACK ENVELOPE
- ☒ LETTER EXPRESS (UP TO 8 OZ.)
- ☐ EXPRESS PACK BOX/TUBE
- ☐ MAG-TAPE PACK

DESCRIPTION OF CONTENTS

NO. OF PACKAGES	WEIGHT (LBS.)
1	Ltr

SENDER'S C.O.D. $

ROUTING

DER
AUG 17 1987
BAQM
TLH 3B
32301

BILL CHARGES TO (ASSUMED SENDER UNLESS OTHERWISE SPECIFIED)
- ☐ SENDER
- ☐ RECEIVER
- ☐ 3RD PARTY _____ AIRBORNE EXPRESS ACCOUNT NO.
- ☐ PAID IN ADVANCE. $ _____
- CHECK NUMBER _____

TYPE OF SPECIAL SERVICE (EXTRA CHARGES MAY APPLY)
- ☐ SPECIAL PICKUP
- ☐ SATURDAY DELIVERY
- ☐ SPECIAL DELIVERY _____ : TIME
- ☐ HOLD AT AIRBORNE FOR PICKUP (NO CHARGE)
- ☐

AIRBORNE SIGNATURE

DATE RECEIVED

TO REMOVE COPY INSERT PENCIL

McLellan Field - Production Facilities Installation
Construction Permit Application

FDER TECHNICAL EVALUATION & DRAFT PERMIT	PROPOSED CHANGES	REASONS
TECHNICAL EVALUATION		
II. The McLellan field and the associated subterranean crude oil and gas reservoir is a major facility for emissions . . .	The McLellan production facility is a major facility for emissions . . .	No emissions result from reservoir; therefore, non-air pollution sources should not be included as part of major facility.
III.A.(1) Welding all connections	Welding most connections	All connections will not be welded. There will be some screwed and flanged connections: Pipe less than 2" will be screwed and some vessel connections will be flanged. Fugitive emission calculations take this into account.
• Four wells specified throughout technical evaluation.	Do not quantify number of wells.	The wells are not a source of emissions and therefore, should not be regulated.
DRAFT PERMIT		
Specific Conditions		
1. The flow of crude oil from the four crude oil production wells shall not exceed 18,824 pounds per hour as measured at the heater treater crude oil outlet.	The flow of crude oil from the four crude oil production wells shall not exceed 1,600 barrels per day, as measured at the separator crude oil outlet.	Heater treater valve dumps oil intermittently such that an accurate measurement cannot be achieved. Also, recirculating fluid from the slop oil tanks to the heater treater would cause inaccurate flow measurements. A more accurate measurement would be achieved downstream of the separator where flow is constant. The air permit application calculations were based on 1600 barrels/day crude oil throughput through the facility. The facility was designed based on this limitation. Turbine meters with net oil computers will measure the crude oil flow from the separators. A capacitance probe enables us to get net oil and net water volumes.

1. (cont'd)		Having an hourly maximum limitation could restrict crude oil production such that a total production of 1600 barrels/day would rarely be achieved, i.e., if field goes down for a portion of a day, wells could not increase production due to hourly maximum restrictions.
2. A calibrated device to continuously monitor and record the crude oil flow from the heater treater outlet shall be installed as close to the heater treater oil outlet as reasonably possible. The crude oil flow is to be measured in pounds per hour and the device is to be recalibrated at least annually.	A calibrated device to continuously monitor the crude oil flow from the separators' outlet shall be installed as close to the separators' oil outlet as reasonably possible. The flow will be recorded daily for each of the separators and summed for a total daily production. The crude oil flow is to be measured in barrels per day and the device is to be recalibrated at least annually.	(See Explanation Above)
3. Each of the engines, the heater treater, and the flare pilot shall be fueled only by gas generated in the three-phase separators.	Each of the engines, the heater treater, and the flare pilot shall be fueled primarily by gas generated in the three-phase separators supplemented with a propane supply for start-up/emergencies only.	When starting the field up, supplemental fuel is necessary to power each well's pumping unit engine. The propane will be turned off as soon as the wells start producing enough gas to power the engine.
11. . . . The installation and each affected source is to be operated at 90% to 100% of permitted capacity during compliance testing.	. . . The installation and each affected source is to be operated at 90%-100% of the well's producing capability during compliance testing.	The wells will not be capable of producing at 90%-100% of the permitted capacity on demand. The permitted capacity is a maximum value that will be achieved only on occasion.
• Four wells specified throughout permit.	Do not quantify number of wells.	The wells are not sources of emissions and therefore, should not be regulated.
• Expiration date: March 31, 1988	Expiration date: May 31, 1989	This is a more realistic estimate allowing for the drilling of wells needed to produce the field, compliance testing, and operating permit preparation and submittal.

Willard,

Monday 17 meeting ok Mike must be available

I talked to Exxon (Ashlyn Broussard). She says they cannot come on Tuesday the 18th instead they want to come on Monday the 17th The issues they want to disscuss are:

Don't Know flow. Need one prod. Mike needs evaluate

1. Prefer to measure downstream of separators rather than heater treater & ~~dec~~ described problems associated - This is a probable.

Tech. Eval, leak free Connect, What Welded What other type/where

2. Desire to change technical to read "welding most connections" instead of "welding all connections". This is a possible.

Retest if prod. exceeds that which existed last test by 10%

3. Desire requirement for testing at 90% - 100% of maximum to be changed to testing at maximum producing capacity as measured over last "x" number of days. Based on our previous discussion sounds like a possible

Exxon responsible violations. Need reasonable assuran. Interlocks?

4. ~~They~~ Wanted to know if we would back-off on inspection each day during daylight hours and may be forego weekends -- since they plan to install remote sensing system. Told them probably not.

only if interlocked

5. Wanted to know if we would back-off on requirement for recording presence of flare pilot. Told them probably not since not attended 24-hours. Should be simple to record since pilot is equipped with autorelight.

How often? How much propane? analysis fuel?

6. Want to change condition requiring engines to be fueled with gas from separators only to allow use of propane for startup. Pointed out they had said no startup fuel necessary. We'll have to think about.

No Comm. Oper. Without test. OK with each well test as started

7. Want to extend expiration date from March 31, 1988 to May 31, 1989 so that

(OVER--Important)

all four wells may be brought on-line. May be agreeable to conduct tests with 3 wells on-line since No. 3 should be completed Dec. 1987 and then tests with 4 wells on-line. Sounds like a possible.

8. They want us to remove number of wells and number of separators from permits. Told her that almost definitely not possible. The values in the permit were based on 4 wells at a specific production. She maintained that wells were not source of emissions. I ~~explained~~ said explained that wells were the avenue and ourfield people have to be able to verify that the facility was constructed as represented. Explained to her that this was fairly common practice. Told her that I ~~stated~~ said did not think we would back-off. PLEASE DON'T AT THIS TIME, OK -- NO MATTER HOW GOOD THE ARGUMENT SOUNDS -- IT'S A DOORWAY TO "DEBOTTLE-NECKING". Told her this would require substantive amendment, review, and renotice.

NO, permit based applic. To increase prod., new applic.

Ashlyn Broussard (504) 561-4226 will call you this AM about meeting and may discuss issues with you. Call me at home please # 878-1898.

Aug 17th meeting OK if mike available. Time?

Mike

8/14/87 - John Koogler — more wells to raise prod./NO UNLESS applic to amend; measure vol in lieu flow (OK); Daily Flow in lieu hrly - what does it do to emissions, how much fluctuations?; Revie[illegible] issues this memo briefly.

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION) Mike	Initial / Date
2.	Initial / Date
3.	Initial / Date
4.	Initial / Date

REMARKS:

Talked to Ashlyn at 4:15 PM Friday. Meeting set for 1 PM Monday (8/17/87) They have to leave Tallahassee at 4PM.

Told her we would listen, give limited response, and tell them their options if we disagree. Comments should be in around 10:30 Monday

FROM:

Mark

INFORMATION	
	Review & Return
	Review & File
	Initial & Forward

DISPOSITION	
	Review & Respond
	Prepare Response
	For My Signature
	For Your Signature
	Let's Discuss
	Set Up Meeting
	Investigate & Report
	Initial & Forward
	Distribute
	Concurrence
	For Processing
	Initial & Return

DATE 8-14-87

PHONE

PM
8-5-87
New Orleans, LA

File Copy

DER

AUG 7 1987

BAQM

EXXON COMPANY, U.S.A.
POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
EASTERN DIVISION

August 5, 1987

State of Florida Wells #34-2 and #33-1
McLellan Area
Section 34, T6N, R26W
Santa Rosa County, Florida

Mr. Edwin K. Middleswart
Florida Department of Environmental
Regulation
160 Governmental Center
Pensacola, Florida 32501

Dear Mr. Middleswart:

After discussions with Bill Thomas of your Tallahassee office, Exxon requests permission to flare gas and operate air emission sources during sequential 30-day tests (i.e., 30 days of production) of each of the above-captioned wells. These tests will be conducted in an effort to reduce the surface pressure on each well so artificial lift (engine and rod pumping units) can be safely installed in conjunction with the facility construction. Also, we plan to workover the State of Florida #33-1 well to remove paraffin deposits that have accumulated downhole. During the 30-day production period, the successfulness of this workover will be evaluated to determine whether further downhole work is necessary.

The combined production from both wells will be approximately 350 bbls/day of oil and 150 kcf/day of gas. All of the produced gas is sweet (maximum 9 ppm H_2S) and will be burned with a flare after primary separation from the oil. Exxon estimates total maximum VOC emissions from the stock tanks, flare, and gasoline engine will be 27.6 tons during the tests. NO_x, CO_2, and SO_2 emissions will be negligible.

We would like to begin testing the first well in early August. Your prompt attention and verbal response would be appreciated. You may contact me (504) 561-3301 or Ashlyn Broussard (504) 561-4226 concerning these well tests.

Sincerely,

EXXON CORPORATION

By: for Sylvia A. Bellow
Charles A. Martin
Permits/Surveillance Supervisor
Eastern Division
Exxon Company, U.S.A.
(a division of Exxon Corporation)

AAB:fab[45b]

c: Mr. Bill Thomas ✓ BT reviewed 8/7/87
Bureau of Air Quality Management
copied: Mike Harley 8/7/87 RBH

· file copy

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHWEST DISTRICT
160 GOVERNMENTAL CENTER
PENSACOLA, FLORIDA 32501-5794

August 13, 1987

DER
AUG 14 1987
BAQM

Mr. Charles A. Martin
Permits/Surveillance Supervisor
Eastern Division
Exxon Company, USA
Post Office Box 61707
New Orleans, Louisiana 70161-1707

Dear Mr. Martin:

By this letter, you may sequentially test wells #34-2 and #33-1, McLellan Area, for thirty (30) days each, in accordance with your request of August 5, 1987.

Sincerely,

Robert V. Kriegel
District Manager

RVK/jpl

cc: Mr. Bill Thomas
Bureau of Air Quality Management

Copied: Mike Harley
CHF/BT
8/14/87 mr

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION) Bill Thomas, BAQM - Tall	Initial / Date		1.
2. DER	Initial / Date		2.
3. AUG 14 1987	Initial / Date		3
4. BAQM	Initial / Date		4

REMARKS:

N. W.

INFORMATION	
	Review & Return
	Review & File
	Initial & Forward

DISPOSITION	
	Review & Respond
	Prepare Response
	For My Signature
	For Your Signature
	Let's Discuss
	Set Up Meeting
	Investigate & Report
	Initial & Forward
	Distribute
	Concurrence
	For Processing
	Initial & Return

FROM: Ed Middlewart, Pensacola - AIR

DATE 8/13/87

PHONE

PM
Air Borne express
Bill # 3272254 04
8/12/87

EXXON COMPANY, U.S.A.
POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
EASTERN DIVISION

DER

AUG 13 1987

BAQM

August 12, 1987

Exxon Company, U.S.A.
McLellan Permanent Production Installation
Permit No. AC 57-131370
Request for Extension of Time for Filing Petition
File: D-12-5(a)

Dale Twachtmann, Secretary
c/o Office of General Counsel
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Secretary Twachtmann:

On July 30, 1987 Exxon Company, U.S.A. received your Department's Intent to Issue Permit No. AC-57131370 for its permanent production facility at McLellan Field. Also enclosed were a draft permit, technical evaluation, and preliminary determination. Pursuant to the Intent to Issue, Exxon has until August 13, 1987 in which to file a petition for administrative proceedings in regards to this proposed action.

I am writing to request an extension of eight (8) additional days, to and including August 21, 1987, for the filing of a petition for administrative proceedings on the Department's proposed agency action with respect to the air construction permit. This request is made pursuant to Section 17-103.070 of the Florida Administrative Code, which provides that a timely request for extension of time shall toll the running of the time period in which to file an appropriate petition and has good course for granting extension of time for filing. Exxon would show the following:

> After its initial review of the permit, Exxon determined that certain specific conditions are of concern to Exxon and others may benefit from clarification. Granting this extension request will allow the parties an opportunity to further discuss Exxon's concerns regarding the draft permit in the hope of reaching a mutually acceptable resolution of these concerns without the need for initiation of formal administrative proceedings on this matter.

I hereby certify that Rosemary Stein of our legal staff discussed this request with Betsy Pittman, Assistant General Counsel for your Department, and Ms. Pittman does not object to the requested extension of time.

Accordingly, I respectfully request that you formally extend the time for filing of a petition for administrative proceedings regarding the Department's Intent to Issue Air Construction Permit No. AC-57-131370 for Exxon Company, U.S.A.'s McLellan Field to and including August 21, 1987.

Sincerely yours,

EXXON CORPORATION

By: Charles A. Martin

Charles A. Martin
Permit/Surveillance Supervisor
Eastern Division
Exxon Company, U.S.A.
(a division of Exxon Corporation)

AAB:fab[41]

c: Mr. Clare Fancy
Ms. Betsy Pittman

Copied: CHF/BT
Mike Harley } 8/13/87 mr

AIRBORNE EXPRESS SM

RECEIVER'S COPY

202 (5/86)

ORIGIN MSY AIRBILL NO. 3272254

Mailed 8/12/87

FROM (COMPANY NAME)
DN U S A

ADDRESS 416 S PCYDRAS ST

CITY NEW ORLEANS STATE LA ZIP CODE (REQUIRED) 70112

SENT BY (NAME/DEPT.) C.A. Martin PHONE

TO (COMPANY NAME) Bureau of Air Quality Mgm

ADDRESS 2600 Blairstone Rd

CITY Tallahassee STATE FL ZIP CODE (REQUIRED) 32301

ATTN. (NAME/DEPT.) Clare Fancy PHONE

BILLING REFERENCE INFORMATION TO APPEAR ON INVOICE

RECEIVER'S AIRBORNE EXPRESS ACCOUNT NO.

TYPE OF PACKAGING

- ☐ EXPRESS/AD PACK ENVELOPE
- ☒ LETTER EXPRESS (UP TO 8 OZ.)
- ☐ EXPRESS PACK BOX/TUBE
- ☐ MAG TAPE PACK

DESCRIPTION OF CONTENTS

NO. OF PACKAGES	WEIGHT (LBS.)
1	1

SENDER'S C.O.D. $

ROUTING

TLH
3-B

BILL CHARGES TO (ASSUMED SENDER UNLESS OTHERWISE SPECIFIED)

- ☐ SENDER
- ☐ RECEIVER
- ☐ 3RD PARTY _____ AIRBORNE EXPRESS ACCOUNT NO.
- ☐ PAID IN ADVANCE $ _____
- CHECK NUMBER _____

TYPE OF SPECIAL SERVICE (EXTRA CHARGES MAY APPLY)

- ☐ SPECIAL PICKUP
- ☐ SATURDAY DELIVERY
- ☐ SPECIAL DELIVERY _____ : TIME
- ☐ HOLD AT AIRBORNE FOR PICKUP (NO CHARGE)
- ☐

AIRBORNE SIGNATURE | DATE RECEIVED

Send to:
Ashlyn Broussard
Eastern Division
Exxon Company, USA
PO Box 61707
New Orleans, LA
70161-1707

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

	Initial	Date
1. TO: (NAME, OFFICE, LOCATION) Ashlyn Broussard Room 678		
2.		
3.		
4.		

REMARKS: Here is a copy of the waiver form that you requested. Bill Thomas asked that the duration of the waiver be kept as short as possible.

INFORMATION

- Review & Return
- Review & File
- Initial & Forward

DISPOSITION

- Review & Respond
- Prepare Response
- For My Signature
- For Your Signature
- Let's Discuss
- Set Up Meeting
- Investigate & Report
- Initial & Forward
- Distribute
- Concurrence
- For Processing
- Initial & Return

FROM: Mike Harley

DATE 08/10/87

PHONE 904 488-1344

WAIVER OF 90 DAY TIME LIMIT

UNDER SECTION 120.60(2), FLORIDA STATUTES

License (Permit, Certification) Application No._____

Applicant's Name:_____

The undersigned has read Section 120.60(2), Florida Statutes, and fully understands the Applicant's rights under that section.

With regard to the above referenced license (permit, certification) application, the Applicant hereby with full knowledge and understanding of (his) (her) (its) rights under Section 120.60(2), Florida Statutes, waives the right under Section 120.60(2), Florida Statutes, to have the application approved or denied by the State of Florida Department of Environmental Regulation within the 90 day time period prescribed in Section 120.60(2), Florida Statutes. Said waiver is made freely and voluntarily by the Applicant, is in (his) (her) (its) self-interest, and without any pressure or coercion by anyone employed by the State of Florida Department of Environmental Regulation.

This waiver shall expire on the _____ day of _____ 19____.

The undersigned is authorized to make this waiver on behalf of the applicant.

_____

Signature

_____

Name of Signee

Sworn to and subscribed before me this _____day of_____ 19____.

_____

Date

Section 120.60, Florida Statutes

(2) When an application for a license is made as required by law, the agency shall conduct the proceedings required with reasonable dispatch and with due regard to the rights and privileges of all affected parties or aggrieved persons. Within 30 days after receipt of an application for a license, the agency shall examine the application, notify the applicant of any apparent errors or omissions, and request any additional information the agency is permitted by law to require. Failure to correct an error or omission or to supply additional information shall not be grounds for denial of the license unless the agency timely notified the applicant within this 30 day period. The agency shall notify the applicant if the activity for which he seeks a license is exempt from the licensing requirement and return any tendered application fee within 30 days after receipt of the original application or within 10 days after receipt of the timely requested additional information or correction of errors or omissions. Every application for license shall be approved or denied within 90 days after receipt of the original application or receipt of the timely requested additional information or correction of errors or omissions. Any application for a license not approved or denied within the 90-day period or within 15 days after conclusion of a public hearing held on the application, whichever is latest, shall be deemed approved and, subject to the satisfactory completion of an examination, if required as a prerequisite to licensure, [2](the license) shall be issued. The Public Service Commission, when issuing a license, and any other agency, if specifically exempted by law, shall be exempt from the time limitations within this subsection. Each agency, upon issuing or denying a license, shall state with particularity the grounds or basis for the issuance or denial of same, except where issuance is a ministerial act. On denial of a license application on which there has been no hearing, the denying agency shall inform the applicant of any right to a hearing pursuant to s. 120.57.

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

DISTRICT ROUTING SLIP

TO: Ed Middleswart DATE: 08/04/87

C.C. TO:

	PENSACOLA	NORTHWEST DISTRICT	X
	PANAMA CITY	Northwest District Branch Office	
	TALLAHASSEE	Northwest District Branch Office	
	TAMPA	SOUTHWEST DISTRICT	
	ORLANDO	ST. JOHNS RIVER DISTRICT	
	JACKSONVILLE	NORTHEAST DISTRICT	
	GAINESVILLE	Northeast District Branch Office	
	FORT MYERS	SOUTH FLORIDA DISTRICT	
	PUNTA GORDA	South Florida District Branch Office	
	MARATHON	South Florida District Branch Office	
	WEST PALM BEACH	SOUTHEAST FLORIDA DISTRICT	
	PORT ST. LUCIE	Southeast Florida Subdistrict	

Reply Optional ☐ Date Due: _____ Reply Required ☐ Date Due: _____ Info. Only ☐

COMMENTS: Bill Thomas feels 30-day production test for the purposes stated in paragraph 1 of the letter looks O.K. This is not construction prior to obtaining permit -- since the test is necessary to ensure that the equipment authorized by the permit (pending) can be installed.

FROM: Mike Harley TEL.: 278-1344

Rev. 1/83

DER

AUG 4 1987

BAQM

PENSACOLA **News Journal**

PUBLISHED DAILY

PENSACOLA, ESCAMBIA COUNTY, FLORIDA

State of Florida,
County of Escambia.

Before the undersigned authority personally appeared
J. Diane Deal

who on oath says that she is Legal Advertising Supervisor of the Pensacola News Journal, a daily newspaper published at Pensacola in Escambia County, Florida; with general circulation in Escambia, Santa Rosa, Okaloosa and Walton Counties that the attached copy of advertisement, being a NOTICE in the matter of

Intent

_____ in the _____ Court,

was published in said newspaper in the issues of

July 30, 1987

Affiant further say that the said The Pensacola News Journal is a newspaper published at Pensacola, in said Escambia County, Florida, and that the said newspaper has heretofore been continuously published in said Escambia County, Florida, each day and has been entered as second class mail matter at the post office in Pensacola, in said Escambia County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

J. Diane Deal

Sworn to and subscribed before me this 30th **day of** July **, A.D., 19** 87

Billy J. Fenton

NOTARY PUBLIC.

My Commission Expires Oct. 16, 1987

cc'd: Clair, Mike 8/4/87 wmh

LEGAL NOTICE

State of Florida
Department of
Environmental
Regulation
Notice of Intent

The Department gives notice of its intent to issue a permit to Exxon Company, USA, to handle four production wells (McLellan Field) to be located along State Road 4 and Reedy Creek, near Munson, in Santa Rosa County, Florida. Other equipment proposed for that site are one heater treater, 2 separators, 6 engines and stock tanks. The pollutant emissions from the equipment installed will be controlled through various strategies, such as a flame arrestor, stack flare, vapor recovery unit, fuel gas scrubber and flare gas scrubber

Persons whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative determination (hearing) in accordance with Section 120.57, Florida Statutes. The petition must conform to the requirments of Chapters 17-103 and 28-5, Florida Administrative Code, and must be filed (received) in the Department's Office of General Counsel, 2600 Blair Stone Road, Twin Towers Office Building, Tallahassee, Florida 32399-2400, within fourteen (14) days of publication of this notice. Failure to file a petition within this time period constitutes a waiver of any right such person has to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the proposed agency action. Therefore, persons who may not wish to file a petition may wish to intervene in the proceeding. A petition for intervention must be filed pursuant to Rule 28-5.207, Florida Administrative code, at least five (5) days before the final hearing and be filed with the hearing officer if one has been assigned at the Division of Administrative Hearings, Department of administration, 2009, Apalachee Parkway, Tallahassee, Florida 32301. If no hearing officer has been assigned, the petition is to be filed with the Department's Office of General Counsel, 2600 Blair Stone Road, Tallahassee, florida 32399-2400. Failure to petition to intervene within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, Florida Statutes.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of
Environmental Regulation
Bureau of Air
Quality Management
2600 Blair Stone Road
Tallahassee, Florida
32399-2400

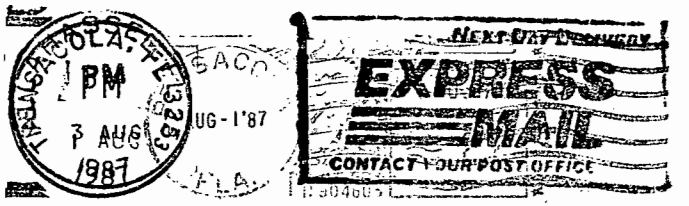
Dept. of
Environmental Regulation
Northwest District
160 Governmental Center
Pensacola, Florida 32501

Any person may send written comments on the proposed action to Mr. Bill Thomas at the Department's Tallahassee address. All comments mailed within 14 days of the publication of this notice will be considered in the Department's final determination.

LEGAL NO. 33186 1T
JULY 30, 1987

PENSACOLA
News Journal
One News Journal Plaza
Pensacola, Florida 32501

Received
8/4/87
in BAQM
wmh



Copies to
Clair
Mike

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality Mgt.
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, FL 32399-2400

PM
7.31.87
Mailed by: Airborne Express

fil

EXXON COMPANY, U.S.A.

POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
EASTERN DIVISION

July 31, 1987

State of Florida Wells #34-2 and #33-1
McLellan Area
Section 34, T6N, R26W
Santa Rosa County, Florida

Mr. Bill Thomas
Chief Engineer
Bureau of Air Quality Management
Twin Towers Office Building
2600 Blairstone Road
Tallahassee, Florida 32301

DER
AUG 3 1987
BAQM

Dear Mr. Thomas:

Exxon requests permission to flare gas and operate air emission sources during sequential 30-day tests (i.e., 30 days of production) of each of the above-captioned wells. These tests will be conducted in an effort to reduce the surface pressure on each well so artificial lift (engine and rod pumping units) can be safely installed in conjunction with the facility construction. Also, we plan to workover the State of Florida #33-1 well to remove paraffin deposits that have accumulated downhole. During the 30-day production period, the successfulness of this workover will be evaluated to determine whether further downhole work is necessary.

The combined production from both wells will be approximately 350 bbls/day of oil and 150 kcf/day of gas. All of the produced gas is sweet (maximum 9 ppm H_2S) and will be burned with a flare after primary separation from the oil. Exxon estimates total maximum VOC emissions from the stock tanks, flare, and gasoline engine will be 27.6 tons during the tests. NO_x, CO_2, and SO_2 emissions will be negligible.

We would like to begin testing the first well the week of August 3. Your prompt attention and verbal response would be appreciated. You may contact me (504) 561-3301 or Ashlyn Broussard (504) 561-4226 concerning these well tests.

Sincerely,

EXXON CORPORATION

Copied: Mike Harley
Clair Fancy
Bill Thomas
Jack Preece
8/4/87 wmh

By: Charles A. Martin

Charles A. Martin
Permits/Surveillance Supervisor
Eastern Division
Exxon Company, U.S.A.
(a division of Exxon Corporation)

AAB:fab[45b]

AIRBORNE EXPRESS SM

RECEIVER'S COPY

202 (5/86)

ORIGIN | AIRBILL NO.
BSY 32

FROM (COMPANY NAME)
[illegible] U S A

ADDRESS
STE 416
1555 POYDRAS ST

CITY | STATE | ZIP CODE (REQUIRED)
NEW ORLEANS | LA | 70112

SENT BY (NAME/DEPT.) | PHONE
C A Martin | 561-3301

TO (COMPANY NAME)
Bureau of Air Quality Mgmt.

ADDRESS
2600 Blairstone Rd.

CITY | STATE | ZIP CODE (REQUIRED)
Tallahassee | FL | 32301

ATTN. (NAME/DEPT.) | PHONE
Bill Thomas Chief Engr.

BILLING REFERENCE INFORMATION TO APPEAR ON INVOICE

RECEIVER'S AIRBORNE EXPRESS ACCOUNT NO.

TYPE OF PACKAGING
- ☐ EXPRESS/AD PACK ENVELOPE
- ☒ LETTER EXPRESS (UP TO 8 OZ.)
- ☐ EXPRESS PACK BOX/TUBE
- ☐ MAG TAPE PACK

DESCRIPTION OF CONTENTS

NO. OF PACKAGES	WEIGHT (LBS.)

SENDER'S C.O.D. $

ROUTING

TLH

3-B

BILL CHARGES TO (ASSUMED SENDER UNLESS OTHERWISE SPECIFIED)
- ☐ SENDER
- ☐ RECEIVER
- ☐ 3RD PARTY _____ AIRBORNE EXPRESS ACCOUNT NO.
- ☐ PAID IN ADVANCE $ _____
- CHECK NUMBER _____

TYPE OF SPECIAL SERVICE (EXTRA CHARGES MAY APPLY)
- ☐ SPECIAL PICKUP
- ☐ SATURDAY DELIVERY
- ☐ SPECIAL DELIVERY _____ : _____ TIME
- ☐ HOLD AT AIRBORNE FOR PICKUP (NO CHARGE)
- ☐

AIRBORNE SIGNATURE | DATE RECEIVED

Copies to:
Mike
Clair
Bob
Jack Preece

P 274 007 723

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED
NOT FOR INTERNATIONAL MAIL
(See Reverse)

Sent to Sue Cummings, Oper. Mgr. Exxon Company, USA	
Street and No. Post Office Box 61707	
P.O., State and ZIP Code New Orleans, LA 70161-1707	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt showing to whom and Date Delivered	
Return Receipt showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$
Postmark or Date Mailed: 07/28/87 Permit: AC 57-131370	

PS Form 3800, June 1985 ★ U.S.G.P.O. 1985-480-794

PS Form 3811, July 1983 447-845

SENDER: Complete items 1, 2, 3 and 4.

Put your address in the "RETURN TO" space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for service(s) requested.

1. ☒ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to: Ms. Sue Cummings
Exxon Company, USA
Post Office Box 61707
New Orleans, LA 70161-1707

4. Type of Service:
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail

Article Number: P 274 007 723

Always obtain signature of addressee or agent and **DATE DELIVERED.**

5. Signature – Addressee
X

6. Signature – Agent
X

7. Date of Delivery JUL 31 1987

8. Addressee's Address *(ONLY if requested and paid)*

DOMESTIC RETURN RECEIPT

File

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

July 27, 1987

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Ms. Sue Cummings
Operations Manager
Eastern Division
Exxon Company, USA
Post Office Box 61707
New Orleans, LA 70161-1707

Dear Ms. Cummings:

Attached is one copy of the Technical Evaluation and Preliminary Determination and proposed permit to install four production wells (McLellan Field), with associated equipment and control systems, to be located near Munson, Santa Rosa County, Florida.

Please submit, in writing, any comments which you wish to have considered concerning the Department's proposed action to Mr. Bill Thomas of the Bureau of Air Quality Management.

Sincerely,

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality
Management

CHF/bm

Attachments

cc: E. Middleswart, NW Dist.
R.L. Bruce, Jr., P.E.
A. Broussard- Hand Delivered 7/28/87 mr
C. Martin

Copied M. Harley - 7/28/87 mr

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

In the Matter of
Application for Permit by:

Exxon Company, USA
Eastern Division
Post Office Box 61707
New Orleans, LA 70161-1707

DER File No. AC 57-131370

INTENT TO ISSUE

The Department of Environmental Regulation hereby gives notice of its intent to issue a permit (copy attached) for the proposed project as detailed in the application specified above. The Department is issuing this Intent to Issue for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The applicant, Exxon Company, USA, applied on March 5, 1987, to the Department of Environmental Regulation for a permit to install four production wells (McLellan Field). Other equipment proposed for that site are one heater treater, 2 separators, 6 engines and stock tanks. The pollutant emissions from the equipment installed will be controlled through various strategies, such as a flame arrestor, stack flare, vapor recovery unit, fuel gas scrubber and flare gas scrubber.

The Department has permitting jurisdiction under Chapter 403, Florida Statutes and Florida Administrative Code Rules 17-2 and 17-4. The project is not exempt from permitting procedures. The Department has determined that an air construction permit was needed for the proposed work.

Pursuant to Section 403.815, F.S. and DER Rule 17-103.150, FAC, you (the applicant) are required to publish at your own expense the enclosed Notice of Proposed Agency Action on permit application. The notice must be published one time only in a section of a major local newspaper of general circulation in the county in which the project is located and within thirty (30) days from receipt of this intent. Proof of publication must be provided to Department within seven days of publication of

the notice. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

The Department will issue the permit with the attached conditions unless petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S. A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. Petitions must comply with the requirement of Florida Administrative Code Rules 17-103.155 and 28-5.201 (copies enclosed) and be filed with (received by) the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of this intent. Petitions filed by other persons must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this intent, whichever first occurs. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes, concerning the subject permit application. Petitions which are not filed in accordance with the above provisions will be dismissed.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality
Management

Copies furnished to:

E. Middleswart, NW Dist.
R. L. Bruce, Jr., P.E.
A. Broussard
C. Martin

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this NOTICE OF INTENT TO ISSUE and all copies were mailed before the close of business on July 28, 1987.

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to §120.52(9), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Margaret H. Jones
Clerk

7/28/87
Date

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

State of Florida
Department of Environmental Regulation
Notice of Intent

The Department gives notice of its intent to issue a permit to Exxon Company, USA, to handle four production wells (McLellan Field) to be located along State Road 4 and Reedy Creek, near Munson, in Santa Rosa County, Florida. Other equipment proposed for that site are one heater treater, 2 separators, 6 engines and stock tanks. The pollutant emissions from the equipment installed will be controlled through various strategies, such as a flame arrestor, stack flare, vapor recovery unit, fuel gas scrubber and flare gas scrubber.

Persons whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative determination (hearing) in accordance with Section 120.57, Florida Statutes. The petition must conform to the requirements of Chapters 17-103 and 28-5, Florida Administrative Code, and must be filed (received) in the Department's Office of General Counsel, 2600 Blair Stone Road, Twin Towers Office Building, Tallahassee, Florida 32399-2400, within fourteen (14) days of publication of this notice. Failure to file a petition within this time period constitutes a waiver of any right such person has to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the proposed agency action. Therefore, persons who may not wish to file a petition may wish to intervene in the proceeding. A petition for intervention must be filed pursuant to Rule 28-5.207, Florida Administrative Code, at least five (5) days before the final hearing and be filed with the hearing officer if one has been assigned at the Division of Administrative Hearings, Department of Administration, 2009, Apalachee Parkway, Tallahassee, Florida 32301. If no hearing officer has been assigned, the petition is to be filed with the Department's Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Failure to petition to intervene within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, Florida Statutes.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dept. of Environmental Regulation
Northwest District
160 Governmental Center
Pensacola, Florida 32501

Any person may send written comments on the proposed action to Mr. Bill Thomas at the Department's Tallahassee address. All comments mailed within 14 days of the publication of this notice will be considered in the Department's final determination.

RULES OF THE ADMINISTRATIVE COMMISSION
MODEL RULES OF PROCEDURE
CHAPTER 28-5
DECISIONS DETERMINING SUBSTANTIAL INTERESTS

28-5.15 Requests for Formal and Informal Proceedings

(1) Requests for proceedings shall be made by petition to the agency involved. Each petition shall be printed, typewritten or otherwise duplicated in legible form on white paper of standard legal size. Unless printed, the impression shall be on one side of the paper only and lines shall be double spaced and indented.

(2) All petitions filed under these rules should contain:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name and address of the petitioner or petitioners;

(c) All disputed issues of material fact. If there are none, the petition must so indicate;

(d) A concise statement of the ultimate facts alleged, and the rules, regulations and constitutional provisions which entitle the petitioner to relief;

(e) A statement summarizing any informal action taken to resolve the issues, and the results of that action;

(f) A demand for the relief to which the petitioner deems himself entitled; and

(g) Such other information which the petitioner contends is material.

Technical Evaluation
and
Preliminary Determination

Exxon Company, USA
Santa Rosa County

Crude Oil Production Installation

Permit Number
AC 57-131370

Florida Department of Environmental Regulation
Bureau of Air Quality Management
Central Air Permitting

July 24, 1987

I. Project Description

A. Applicant

Exxon Company, USA
Eastern Division
P. O. Box 61707
New Orleans, Louisiana 70161-1707

B. Project and Location

The applicant's proposed project entails the drilling of four crude oil production wells with the capacity to produce 18,824 pounds per hour of crude oil (1600 barrels per day) and 2,370 pounds per hour of saturated fuel gas. The applicant also proposes to install: four separators; one heater treater with a maximum heat input capacity of 500,000 Btu per hour; two crude oil storage vessels--each with a capacity of 1,000 barrels; two saltwater storage vessels--each with a capacity of 400 barrels; one slop oil tank with a capacity of 250 barrels; four 120 brake horsepower engines; one 100 brake horsepower engine; one 50 brake horsepower engine; one vapor recovery unit; one T-bar flare; and, one sump. The four crude oil production wells and associated equipment will be located at the McLellan Field, State Road 4 and Reedy Creek, Munson, Florida in Santa Rosa County (Section 33, Township 6 North, Range 26 West). The universal transverse mercator (UTM) coordinates of the sources are Zone 16, 515.29 km East, and 3427.83 km North.

The application was received March 5, 1987 and deemed complete on June 10, 1987.

C. Project Description and Controls

The McLellan Field is a new installation that will enable the Exxon Company, USA, to remove 18,824 pounds per hour of crude oil (1600 barrels per day) and 2,370 pounds per hour of saturated gas (804,800 standard cubic feet per day at 60°F and 14.65 psia) from a subterranean facility. The product produced by the installation will be crude oil.

The crude oil and gas is removed from the subterranean facility through four wells. Each well is equipped with a pump that is powered by a 120 brake horsepower engine.

The well streams are fed to four three-phase separators where the gas, oil, and water are separated. The saturated gas from the separators is vented to a fuel gas scrubber which removes any entrained liquids from the saturated gas. A portion of the scrubbed gas is used as fuel for the engines, heater treater and flare pilot. The remaining saturated gas is vented to the flare. The water from the separators is piped to one of

the two 400 barrel capacity saltwater storage vessels. The liquid from the fuel gas scrubber is pumped to the 250 barrel capacity slop oil tank.

The crude oil from the four three-phase separators is fed to a heater treater with a maximum heat input capacity of 500,000 Btu per hour. The heater treater is used to remove residual gas and water from the crude oil through the addition of heat. The saturated gas from the heater treater is vented to the flare scrubber. The separated water is piped to the saltwater storage vessel.

The crude oil is piped to one of two 1,000 barrel storage vessels where it is stored prior to custody transfer. At the time of custody transfer the crude oil is loaded into trucks that are equipped with vapor balance systems. These systems prevent the release of hydrocarbons during loading by transferring truck tank vapors into the 1,000 barrel storage vessels.

The slop oil storage vessel receives liquids containing crude oil and water from the heater treater, the fuel gas scrubber, the flare gas scrubber, and storage vessels when they are manually drained. The crude oil and water are allowed to separate in the slop oil storage vessel. Any separated crude oil is pumped through an upper outlet to the crude oil storage vessels and, any separated water is pumped through a lower outlet to the saltwater storage vessels. If necessary, the contents of the slop oil storage vessel may be recirculated to the heater treater for remedial treatment.

The two saltwater storage vessels receive water from the four three-phase separators and the heater treater. Rainwater that is collected within diked walls surrounding the storage vessels is also pumped to the saltwater storage vessels. A 50 brake horsepower engine is used to operate a saltwater disposal pump.

A 100 brake horsepower engine is located at the battery of storage vessels. The engine is used to power a generator.

The saturated gas from the storage vessels is vented to a vapor recovery compressor. The vapor recovery compressor elevates the gas pressure to 29.65 psia.

The saturated gas from the vapor recovery compressor is vented to the flare gas scrubber where it is combined with the saturated gas from the heater treater. The flare gas scrubber removes any entrained liquid from the gas stream. The recovered liquid is piped to the slop oil storage vessel.

The saturated gas from the flare gas scrubber is combined with the saturated gas from the fuel gas scrubber. The combined saturated gas is vented to a horizontal bar (T-bar) flare.

II. Rule Applicability

The McLellan Field and the associated subterranean crude oil and gas reservoir is a major facility for emissions of volatile organic compounds pursuant to Rule 17-2.100(110), FAC.

The proposed project is located in an area classified as attainment for all criteria pollutants according to Rule 17-2.420, FAC.

The proposed project is exempt from the requirements of Rule 17-2.500, FAC, Prevention of Significant Deterioration. This determination is based on Rule 17-2.500(2)(d)1., FAC, and Rule 17-2.500(2)(d)2., FAC. The facility does not belong to any of the major facility categories listed in Table 500-1. An examination of Table 500-2 indicates that volatile organic compound emissions are to be broken into two categories--those which are photochemically reactive and those which are not photochemically reactive. The proposed project will not result in either photochemically reactive or photochemically unreactive emissions of more than 250 tons per year.

The Standard Industrial Classification (SIC) code for the proposed project is 1311.

III. Summary of Emissions and Air Quality Analysis

A. Summary of Emissions

The pollutants emitted by the six engines, the heater treater firebox, and the flare will be nitrogen oxides, carbon monoxide, sulfur dioxide, and volatile organic compounds. Minor amounts of particulate matter will also be emitted by the heater treater firebox. The hydrogen sulfide emissions from these combustion sources will be negligible. The fugitive emissions from the installation will consist of volatile organic compounds and negligible quantities of hydrogen sulfide.

The installation is to operate continuously 8,760 hours per year. The emissions for the purpose of determining the applicability of Rule 17-2.500, FAC, Prevention of Significant Deterioration are:

Equipment	Maximum Emissions Tons/Year NOx	CO	C_3+(1)	C_1&C_2(2)
1-Heater Treater	Trace	Trace	Trace	Trace
5-Storage Vessels	--	--	--	--
4-120 bhp Engines	50	7	7	12
1-100 bhp Engine	11	1	1	2
1-50 bhp Engine	5	1	1	1
1-Flare (3)	19	19	82	112
Fugitive Emissions	--	--	35	--
Total Emissions	85	28	126	127

(1) Volatile organic compounds that are photochemically reactive.

(2) Volatile organic compounds that are not photochemically reactive.

(3) The maximum possible emission rate from the flare.

Particulate matter, sulfur dioxide, and hydrogen sulfide are emitted in trace amounts.

The emissions of volatile organic compounds from the installation are to be controlled by employing the following measures:

(1) Welding all connections.

(2) Equipping all skid mounted equipment with drip pans to collect contaminated fluids. The contaminated fluids are to be piped to a central sump.

(3) Installing a central sump to collect fluids from the skid drip pans and storage vessels. These fluids are to be pumped to the saltwater storage vessels.

(4) Development of a spill prevention and countermeasure plan.

(5) Using some of the gas from the three-phase separator as fuel in the six engines and heater treater.

(6) Equipping tank trucks with vapor balance systems to pipe the volatile organic compound vapors, displaced during custody transfer of oil, into the crude oil storage vessels.

(7) Installation of a vapor recovery compressor to recover vapors from all storage vessels.

(8) Installation of a 98% efficient smokeless T-bar flare equipped with an automatic reignition system. The flare

will burn all volatile organic compounds from the storage vessels, heater treater, and three-phase separators (not used as fuel). The flare will comply with all applicable requirements of 40 CFR 60.18(c) through (f). These include no visible emissions--except for five minutes in any consecutive two-hour period, an exit velocity equal to or greater than 60 feet per second and less than 400 feet per second, a gas net heating value greater than 1,000 Btu per standard cubic foot, and the presence of a flare pilot flame at all times.

The applicant has proposed these measures for control of volatile organic compound emissions and the Department accepts them as necessary. Since the visible emissions from sources burning gaseous fuels is a surrogate measure of combustion efficiency, the heater treater firebox and the six engines will each be assigned a visible emissions limit of 5% opacity (no visible emissions). Pursuant to Rule 17-2.620(1), FAC, these controls are deemed necessary and ordered by the Department.

The proposed combustion sources are not subject to specific emission limiting standards for nitrogen oxides, carbon monoxide, particulate matter, and sulfur dioxide. But Rule 17-2.250(4), FAC, requires these sources to be properly operated and maintained so that excess emissions will be minimized. The absence of visible emissions from the combustion sources is evidence of the proper operation and maintenance of these sources to minimize emissions of nitrogen oxides, carbon monoxide and particulate matter. Operation of the flare within certain velocity limits and above certain net gas heating values also ensures that these pollutant emissions will be minimized. The most effective way to minimize emissions of sulfur dioxide is to limit the quantity of gas burned. The quantity of gas to be burned is controlled by the rate that the crude oil is removed from the subterranean facility because the gas is dissolved in the crude oil. Pursuant to Rule 17-2.250(5), FAC, the following emissions limitations will be applied:

(1) Visible emissions from each of the six engines and the heater treater firebox are not to exceed 5% opacity (no visible emissions) except for 20% during one six-minute period in any hour.

(2) There are not to be any visible emissions from the flare, except for a total period of not more than a total of five cumulative minutes in any consecutive two-hour period.

(3) The exit gas velocity of the T-bar flare is to be equal to or greater than 60 feet per second and less than 400 feet per second.

(4) The net heating value of the gas burned in the T-bar flare is not to be less than 1000 Btu per standard cubic foot.

(5) A flare pilot flame is to be present at all times.

(6) The flow of crude oil from the four crude oil production wells, four three-phase separators, and heater treater is not to exceed 18,824 pounds per hour (1600 barrels per day).

Since the installation will not be attended 24 hours per day, the Department feels the following measures are reasonable pursuant to Rule 17-2.250(5), FAC. Each source is to be inspected by the applicant during the daylight working hours of each day. The applicant is to maintain a permanent log of inspections, and comply with the applicable provisions of Rules 17-2.250 and 17-4.130, FAC, immediately upon discovery of any excess emissions or operation problem.

The installation will release trace amounts of reduced sulfur compounds primarily hydrogen sulfide. Reduced sulfur compounds can produce objectionable odors. Rule 17-2.620(2), FAC, requires that no objectionable odors be emitted by the installation. Therefore, reduced sulfur emissions are limited to those concentrations that will not produce objectionable odors.

B. Air Quality Analysis

Since the project is exempt from the requirements of Rule 17-2.500, FAC, Prevention of Significant Deterioration, an ambient air quality analysis is not required.

IV. Conclusion

The emission limitations to be imposed have been determined to be in compliance with all applicable requirements of Chapter 17-2, FAC. The permitted maximum allowable emissions should not cause any violation of Florida's ambient air quality standards.

The General and Specific Conditions listed in the proposed permit (attached) will assure compliance with all applicable requirements of Chapter 17-2, FAC.

APIS Numbers: 10PEN5700 3201
thru
10PEN5700 3208

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

PERMITTEE:
Exxon Company, USA
Eastern Division
P. O. Box 61707
New Orleans, LA 70161-1707

Permit Number: AC 57-131370
Expiration Date: March 31, 1988
County: Santa Rosa
Latitude/Longitude: 30° 59' 08" N
86° 50' 24" W
Project: McLellan Permanent
Production Installation

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rule(s) 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the construction of the McLellan permanent crude oil production installation consisting of 4 crude oil production wells; 4 three-phase separators; a heater treater with a 500,000 Btu per hour heat input capacity; a slop oil storage vessel with a capacity of 250 barrels; 2 saltwater storage vessels--each with a capacity of 400 barrels; 2 crude oil storage vessels--each with a capacity of 1,000 barrels; 4 120 brake horsepower engines; a 100 brake horsepower engine; a 50 brake horsepower engine; a complete vapor recovery system; a vapor recovery compressor; a flare with horizontal (T-bar) flare tip; a fuel gas scrubber; a flare gas scrubber; and a sump. The maximum production capacity of the installation is 18,824 lbs/hr (1600 barrels/day) of crude oil. The project is located at the McLellan Field, Section 33, Township 6 North, Range 26 West, Munson, Santa Rosa County, Florida.

The construction and operation shall be in accordance with the attached permit applications, plans, documents, and drawings except as noted in the Specific Conditions of this permit.

Attachments:

1. Application to Construct an Air Pollution Source, DER Form 17-1.202(1), received March 5, 1987.
2. C. H. Fancy's letter dated April 3, 1987.
3. Exxon's letter with attached revised Application to Construct an Air Pollution Source, DER Form 17-1.202(1), received June 10, 1987.
4. Technical Evaluation and Preliminary Determination dated July 24, 1987.

PERMITTEE:
Exxon Company, USA

Permit Number: AC 57-131370
Expiration Date: March 31, 1988

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the state. Only the Trustees of the Internal Improvement Trust Fund may express state opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

GENERAL CONDITIONS:

6. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

a. Having access to and copying any records that must be kept under the conditions of the permit;

b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately notify and provide the Department with the following information:

a. a description of and cause of non-compliance; and

b. the period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance.

GENERAL CONDITIONS:

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source, which are submitted to the Department, may be used by the Department as evidence in any enforcement case arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Compliance with New Source Performance Standards.

14. The permittee shall comply with the following monitoring and record keeping requirements:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the department, during the course of any unresolved enforcement action.

GENERAL CONDITIONS:

b. The permittee shall retain at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be at least three years from the date of the sample, measurement, report or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the date(s) analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be submitted or corrected promptly.

SPECIFIC CONDITIONS:

1. The flow of crude oil from the four crude oil production wells shall not exceed 18,824 pounds per hour as measured at the heater treater crude oil outlet.

2. A calibrated device to continuously monitor and record the crude oil flow from the heater treater outlet shall be installed as close to the heater treater oil outlet as reasonably possible. The crude oil flow is to be measured in pounds per hour and the device is to be recalibrated at least annually.

SPECIFIC CONDITIONS:

3. Each of the engines, the heater treater, and the flare pilot shall be fueled only by gas generated in the three-phase separators.

4. Visible emissions from each of the engines and the heater treater shall not exceed 5% opacity as a 6-minute average, except an average of 20% opacity during one 6-minute period in any hour shall be allowed. EPA Method 9 shall be used for the compliance determinations.

5. A 98% efficient smokeless flare of the type shown in Illustration VIII of the application shall be installed and equipped with an automatic reignition system. All volatile organic compounds from the 3-phase separators (except those used as fuel), the heater treater, and storage vessels shall be burned by the flare.

6. Pursuant to 40 CFR 60.18, General Control Device Requirements, revised as of July 1, 1986, the flare shall be subject to the following requirements:

a. No visible emissions, except for periods not to exceed a total of 5 minutes during any consecutive 2 hours. EPA Method 22 and the requirements of 40 CFR 60.18(f)(1) shall be used to determine compliance.

b. The flare shall be designed for and operated with an exit velocity equal to or greater than 60 feet per second and less than 400 feet per second. Compliance shall be determined using the procedure in 40 CFR 60.18(f)(4), and either EPA Method 2, 2A, 2C, or 2D (as appropriate).

c. The net heating value of gas combusted by the flare shall be greater than 1,000 Btu per standard cubic foot. Compliance shall be determined pursuant to 40 CFR 60.18(f)(3).

d. The flare shall be operated at all times that the installation is operated. The presence of a flare pilot flame shall be continuously monitored and recorded using a thermocouple or other equivalent device to detect the presence of a flame.

e. EPA Method 15 shall be used to determine whether reduced sulfur concentrations in the gas stream to be flared exceed 11 ppm at dry standard conditions (14.7 psia and 68°F).

7. Pursuant to Rule 17-2.600(2), FAC, Objectionable Odor Prohibited, the installation shall not emit any objectionable odors.

SPECIFIC CONDITIONS:

8. Each tanker truck shall be equipped with a vapor balance system which shall be properly connected so that all displaced vapors will be vented to the crude oil storage vessels during custody transfer of crude oil. The system shall be properly operated and maintained.

9. A spill prevention control and countermeasure plan acceptable to the Department shall be developed by the applicant. This plan shall be submitted with the application for an operation permit. If approved, the plan shall become a condition of the operation permit.

10. Since personnel will not be present at the installation 24 hours per day--each source of emissions shall be inspected each day during daylight hours. Pursuant to Rule 17-2.250(5), FAC--the applicable requirements of Rules 17-2.250 and 17-4.130, FAC, shall be immediately complied with upon discovery of excess emissions.

11. The permitted sources shall be tested for compliance with Specific Conditions 4 and 6.a. through d. annually. The test required by Specific Condition 6.e. shall also be conducted annually. The installation and each affected source is to be operated at 90% to 100% of permitted capacity during compliance testing.

12. All source sampling shall be performed and test results shall be submitted in accordance with the applicable provisions Rule 17-2.700, FAC, Stationary Point Source Emissions Test Procedures, which includes 15 days advance notification of any compliance test to the Department's NW District office--Air Programs and the submission of test reports to the Department's NW District office--Air Programs within 45 days after testing is completed.

13. An operations report for this installation shall be submitted each calendar year pursuant to Rule 17-4.140, FAC, Reports. The report shall be for the preceding calendar year.

14. All compliance test reports and other reports shall identify each source and include the assigned APIS number. The assigned APIS numbers are:

PERMITTEE:
Exxon Company, USA

Permit Number: AC 57-131370
Expiration Date: March 31, 1988

SPECIFIC CONDITIONS:

Emission Source	APIS Number
120 bhp Engine at well 33-1	10 PEN 5700 3201
120 bhp Engine at well 34-2	10 PEN 5700 3202
120 bhp Engine at well 34-3	10 PEN 5700 3203
120 bhp Engine at well 28-4	10 PEN 5700 3204
100 bhp Engine	10 PEN 5700 3205
50 bhp Engine	10 PEN 5700 3206
Heater Treater	10 PEN 5700 3207
Flare	10 PEN 5700 3208

Refer to Illustration V in the application for the well numbers.

15. After satisfactory completion of the initial compliance test and prior to 90 days before the expiration date of this permit, a complete application for an operation permit shall be submitted to the NW District office. The permittee shall continue to operate in compliance with the terms of this construction permit until its expiration date or until the issuance of an operation permit.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION

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Dale Twachtmann, Secretary

06/10/87 List of Attendees

Name	Company	Address	Phone
Michael J Lamore	Exxon Co., U.S.A.	N.O., LA	(504) 561-4660
Lee Bruce	Exxon Co. USA	New Orleans	504 561-3904
Ashley Broussard	"	"	(504) 561-4226
Mike Harley	DER	Tallahassee	(904) 488-1344
Bill Thomas	DER	"	"

These estimates compace the differences in emissions for determining PSD applicability. The applicant estimated total emissions based on the engine and heater treater consuming a portion of the separator gas as fuel. The applicant also assumed in the same estimate that the flare would consume 100% of the separator gas. Since the purpose of the PSD applicability is to assess the maximum potential of the installation to emit this comparison is necessary. It is also necessary to estimate the maximum H_2S emissions.

The estimates of H_2S emissions are based on the following assumptions:

- H_2S emissions are proportional to reactive hydrocarbon (C_3+) emissions
- H_2S in Separator gas @ 9 ppm = 8.0779 EE-07 $\frac{lb}{ft^3}$
- H_2S in Heater Treater gas @ 16 ppm = 1.4345 EE-06 $\frac{lb}{ft^3}$
- H_2S in Stock Tank gas @ 19 ppm = 1.7053 EE-06 $\frac{lb}{ft^3}$

Separator Gas H_2S = $(675{,}200 \frac{SCF}{day})(8.0779\,EE\text{-}07 \frac{lb}{ft^3})(\frac{day}{24\,hr}) = 0.023 \frac{lb}{hr}$

Heater Treater Gas H_2S = $(75{,}200 \frac{SCF}{day})(1.4345\,EE\text{-}06 \frac{lb}{ft^3})(\frac{day}{24\,hr}) = 0.004 \frac{lb}{hr}$

Stock Tank Gas H_2S = $(54{,}400 \frac{SCF}{day})(1.7053\,EE\text{-}06 \frac{lb}{ft^3})(\frac{day}{24\,hr}) = 0.004 \frac{lb}{hr}$

$0.031 \frac{lb}{hr}$

Separator Gas C_3+ = $(675{,}200 \frac{SCF}{day})(\frac{mole}{380.68\,SCF})(\frac{28.97\,lb}{mole})(0.8270)(0.2729)(\frac{day}{24\,hr}) = 483.191 \frac{lb}{hr}$

Heater Treater Gas C_3+ = $(75{,}200 \frac{SCF}{day})(\frac{mole}{380.68\,SCF})(\frac{28.97\,lb}{mole})(1.3177)(0.6762)(\frac{day}{24\,hr}) = 21.465 \frac{lb}{hr}$

Stock Tank Gas C_3+ = $(54{,}400 \frac{SCF}{day})(\frac{mole}{380.68\,SCF})(\frac{28.97\,lb}{mole})(1.6531)(0.8484)(\frac{day}{24\,hr}) = 241.922 \frac{lb}{hr}$

$937.578 \frac{lb}{hr}$

Max Engine & Heater Treater H_2S

Ratio Separator $H_2S : C_3+ = \frac{0.023 \frac{lb}{hr}}{483.191 \frac{lb}{hr}} = 0.00005 \frac{lb\,H_2S}{lb\,C_3+}$

Engine & Heater Treater $C_3+ = 0.0009 \frac{lb}{hr} + 1.5470 \frac{lb}{hr} + 0.3222 \frac{lb}{hr} + 0.1612 \frac{lb}{hr} = 2.0313 \frac{lb}{hr}$

Engine & Heater Treater $H_2S = (2.0313 \frac{lb\ C_3+}{hr})(0.00005 \frac{lb\ H_2S}{lb\ C_3+}) = 0.00010 \frac{lb}{hr}\ H_2S$

Max Flare H_2S

Ratio $H_2S : C_3+ = \frac{0.031 \frac{lb}{hr}}{937.578 \frac{lb}{hr}} = 0.00003 \frac{lb\ H_2S}{lb\ C_3+}$

Flare $C_3+ = 18.7515 \frac{lb}{hr}$

Flare $H_2S = (18.7515 \frac{lb}{hr})(0.00003 \frac{lb\ H_2S}{lb\ C_3+}) = 0.00056 \frac{lb}{hr}$

Max Fugitive H_2S

Ratio $H_2S : C_3+ = \frac{0.031 \frac{lb}{hr}}{937.578 \frac{lb}{hr}} = 0.00003 \frac{lb\ H_2S}{lb\ C_3+}$

Fugitive $C_3+ = 7.8796 \frac{lb}{hr}$

Fugitive $H_2S = (7.8796 \frac{lb}{hr} X 0.00003 \frac{lb\ H_2S}{lb\ C_3+}) = 0.00024 \frac{lb}{hr}$

The comparison of emissions for PSD applicability is based on two assumptions

- Heater Treater, Engines, & Flare Operating
- Engines & Flare Operating

Fuel Consumed by Engines: $2941.23 \frac{SCF}{hr} + 612.76 \frac{SCF}{hr} + 306.38 \frac{SCF}{hr} = 3,860.37 \frac{SCF}{hr}$

Fuel Consumed by Heater Treater: $408.50 \frac{SCF}{hr}$

Flare Fuel Consumption Engines & Heater Treater Running:

$(675,200 \frac{SCF}{day}) - (3,860.37 \frac{SCF}{hr} + 408.50 \frac{SCF}{hr} X 24 \frac{hr}{day}) = 572,747.12 \frac{SCF}{day}$

Flare Fuel Consumption Engines Running:

$(675,200 \frac{SCF}{day}) - (3,860.37 \frac{SCF}{hr} X 24 \frac{hr}{day}) = 582,551.12 \frac{SCF}{day}$

Gas Btu with Engines & Heater Treater

				Total Btu
Separator	$572,747 \frac{SCF}{day}$	81.55%	$1,112.4 \frac{Btu}{SCF}$	907.16
Heater Treater	$75,200 \frac{SCF}{day}$	10.71%	$1,945.76 \frac{Btu}{SCF}$	208.39
Stock Tank	$54,400 \frac{SCF}{day}$	7.74%	$2,463.66 \frac{Btu}{SCF}$	190.69
	$702,347 \frac{SCF}{day}$	100.00%		$1,306.24 \frac{Btu}{SCF}$

Gas Btu with Engines

				Total Btu
Separator	582,551 SCF/day	81.80%	1,112.4 Btu/SCF	909.94
Heater Treater	75,200 SCF/day	10.56%	1,945.76 Btu/SCF	205.47
Stock Tank	54,400 SCF/day	7.64%	2,463.66 Btu/SCF	188.22
	712,151 SCF/day	100.00%		1,303.63 Btu/SCF

SO_2

Sep. w/Eng. & Heater = $(572,747 \frac{SCF}{day} \times \frac{9 SCF}{1E6 SCF} \times \frac{mole}{380.68 SCF} \times \frac{64 lb}{mole} \times \frac{1 day}{24 hr}) = 0.0361 \frac{lb}{hr}$

Flare SO_2 w/Engines & Heater:

$0.0361 \frac{lb}{hr} + 0.0082 \frac{lb}{hr} + 0.0072 \frac{lb}{hr} = 0.0515 \frac{lb}{hr}$ or 0.226 T/Y

Sep. w/Eng. = $(582,551 \frac{SCF}{day} \times \frac{9 SCF}{1E6 SCF} \times \frac{mole}{380.68 SCF} \times \frac{64 lb}{mole} \times \frac{1 day}{24 hr}) = 0.0367 \frac{lb}{hr}$

Flare SO_2 w/Engines:

$0.0367 \frac{lb}{hr} + 0.0082 \frac{lb}{hr} + 0.0072 \frac{lb}{hr} = 0.0521 \frac{lb}{hr}$ or 0.228 T/Y

Separator/Flare SO_2:

$0.058 \frac{lb}{hr}$ or 0.254 T/Y

NO_x

Flare NO_x w/Engines & Heater:

$(\frac{0.1 lbs\ NO_x}{MMBtu} \times \frac{1306.24 Btu}{SCF} \times \frac{1 MMBtu}{1E6 Btu} \times 702,347 \frac{SCF}{day} \times \frac{1 day}{24 hr}) = 3.82 \frac{lb}{hr}$ or 16.73 T/Y

Flare NO_x w/Engines:

$(\frac{0.1 lb\ NO_x}{MM Btu} \times \frac{1303.63 Btu}{SCF} \times \frac{1 MM Btu}{1E6 Btu} \times 712,151 \frac{SCF}{day} \times \frac{1 day}{24 hr}) = 3.87 \frac{lb}{hr}$ or 16.95 T/Y

Separator/Flare NO_x

$4.30 \frac{lb}{hr}$ or 18.82 T/Y

CO

Sep. CO_2 w/Engines & Heater:

$(\frac{16.1778 lbs\ C}{mole} \times \frac{mole}{380.68 SCF} \times 572,747 \frac{SCF}{day} \times \frac{mole}{12.011216} \times 0.98) = 1,985.92 \frac{moles\ C}{day}$

Sep. CO w/Engines & Heater:

$\frac{8}{7000} = \frac{CO}{1,985.92}$

$CO = (2.27 \frac{mole}{day} \times 28.010 \frac{lb}{mole} \times \frac{1 day}{24 hr}) = 2.65 \frac{lb}{hr}$

Flare CO w/Engines & Heater:

$2.65 \frac{lb}{hr} + 0.65 \frac{lb}{hr} + 0.60 \frac{lb}{hr} = 3.90 \frac{lb}{hr}$ or 17.08 T/Y

Sep. CO_2 w/Engines

$(\frac{16.1778 lbs\ C}{mole} \times \frac{mole}{380.68 SCF} \times 582,551 \frac{SCF}{day} \times \frac{mole}{12.011216} \times 0.98) = 2,019.91 \frac{moles\ C}{day}$

Sep. CO w/Engines

$\frac{8}{7000} = \frac{CO}{2,019.91}$

$CO = (2.31 \frac{mole}{day})(28.010 \frac{lb}{mole})(\frac{day}{24 hr}) = 2.70 \frac{lb}{hr}$

Flare CO w/Engines:

$2.70 \frac{lb}{hr} + 0.65 \frac{lb}{hr} + 0.60 \frac{lb}{hr} = 3.95 \frac{lb}{hr}$ or 17.30 T/Y

Separator/Flare CO

$4.38 \frac{lb}{hr}$ or 19.18 T/Y

C_3+

Separator C_3+ w/Engines & Heater:

$(572,747 \frac{SCF}{day})(\frac{mole}{380.68 SCF})(\frac{28.97 lb}{mole})(0.8270)(0.2729)(\frac{day}{24 hr})(0.02) = 8.20 \frac{lb}{hr}$

Flare C_3+ w/Engines & Heater:

$8.20 \frac{lb}{hr} + 4.25 \frac{lb}{hr} + 4.84 \frac{lb}{hr} = 17.29 \frac{lb}{hr}$ or 75.73 T/Y

Separator C_3+ w/Engines:

$(582,551 \frac{SCF}{day})(\frac{mole}{380.68 SCF})(\frac{28.97 lb}{mole})(0.8270)(0.2729)(\frac{day}{24 hr})(0.02) = 8.34 \frac{lb}{hr}$

Flare C_3+ w/Engines:

$8.34 \frac{lb}{hr} + 4.25 \frac{lb}{hr} + 4.84 \frac{lb}{hr} = 17.43 \frac{lb}{hr}$ or 76.34 T/Y

Separator/Flare C_3+:

$18.75 \frac{lb}{hr}$ or 82.12 T/Y

$C_2=$

Separator $C_2=$ w/Engines & Heater:

$(572,747 \frac{SCF}{day})(\frac{SCF}{380.68})(\frac{28.97 lb}{mole})(0.8270)(0.59)(\frac{day}{24 hr})(0.02) = 17.72 \frac{lb}{hr}$

Flare $C_2=$ w/Engines & Heater:

$17.72 \frac{lb}{hr} + 2.97 \frac{lb}{hr} + 1.62 \frac{lb}{hr} = 22.31 \frac{lb}{hr}$ or 97.72 T/Y

Separator $C_2=$ w/Engines:

$(582,551 \frac{SCF}{day})(\frac{mole}{380.68 SCF})(\frac{28.97 lb}{mole})(0.8270)(0.59)(\frac{day}{24 hr})(0.02) = 18.02 \frac{lb}{hr}$

Flare $C_2=$ w/Engines:

$18.02 \frac{lb}{hr} + 2.97 \frac{lb}{hr} + 1.62 \frac{lb}{hr} = 22.61 \frac{lb}{hr}$ or 99.03 T/Y

Separator/Flare $C_2=$:

$25.49 \frac{lb}{hr}$ or 111.65 T/Y

H_2S

Flare w/Engines & Heater $H_2S = (17.29 \frac{lb}{hr})(0.00003 \frac{lb}{lb}) = 0.00052 \frac{lb}{hr}$ or 0.00228 T/Y

Flare w/Engines $H_2S = (17.43 \frac{lb}{hr})(0.00003 \frac{lb}{lb}) = 0.00052 \frac{lb}{hr}$ or 0.00229 T/Y

Separator/Flare $H_2S = (18.75 \frac{lb}{hr})(0.00003 \frac{lb}{lb}) = 0.00056 \frac{lb}{hr}$ or 0.00246 T/Y

Flare, Engines & Heater Treater

Maximum Emissions Tons/Year

Equipment	NO_x	CO	SO_2	C_3+	PM	C_2-	H_2S
1-H. Treater	0.18	0.04	<0.01	<0.01	0.01	0.01	<0.01
5-S. Vessels	--	--	--	--	--	--	--
4-120 bhp Eng	50.46	6.52	0.02	6.78	--	12.03	<0.01
1-100 bhp Eng	10.51	1.36	<0.01	1.41	--	2.51	<0.01
1-50 bhp Eng	5.26	0.68	<0.01	0.70	--	1.25	<0.01
1-Flare	16.73	17.08	0.23	75.73	--	97.72	<0.01
Fug. Emiss.	--	--	--	34.51	--	--	<0.01
Total	83.14	25.68	0.25	119.13	0.01	113.52	T

Flare & Engines

Maximum Emissions Tons/Year

Equipment	NO_x	CO	SO_2	C_3+	PM	C_2-	H_2S
1-H. Treater	--	--	--	--	--	--	--
5-S. Vessels	--	--	--	--	--	--	--
4-120 bhp Eng	50.46	6.52	0.02	6.78	--	12.03	<0.01
1-100 bhp Eng	10.51	1.36	<0.01	1.41	--	2.51	<0.01
1-50 bhp Eng	5.26	0.68	<0.01	0.70	--	1.25	<0.01
1-Flare	16.95	17.30	0.23	76.34	--	99.03	<0.01
Fug. Emiss.	--	--	--	34.51	--	--	<0.01
Total	83.18	25.86	0.25	119.74	--	114.82	T

Flare

Maximum Emissions Tons/Year

Equipment	NO_x	CCO	SO_2	C_3+	PM	C_2-	H_2S
1-H. Treater	--	--	--	--	--	--	--
5-S. Vessels	--	--	--	--	--	--	--
4-120 bhp Eng	--	--	--	--	--	--	--
1-100 bhp Eng	--	--	--	--	--	--	--
1-50 bhp Eng	--	--	--	--	--	--	--
1-Flare	18.82	19.18	0.25	82.12	--	111.65	<0.01
Fug. Emiss.	--	--	--	34.51	--	--	<0.01
Total	18.82	19.18	0.25	116.63	--	111.65	T

The correction of H_2S concentration based on saturated conditions at 60°F & 14.65 psia to dry conditions at 68°F & 14.70 psia was accomplished in the following way

Based on Kent Volume I p. 2-76

$$V_{std\ (sat)} = \frac{V \times (459.6+68)}{459.6+t} \times \frac{H-A}{29.920-0.692}$$

From Steam Tables Kent Volume I p. 4-34

70°F = 0.7392

68°F = X

65°F = 0.6222

$$\frac{3}{5} = \frac{X-0.6222}{0.1170}$$

$$X = 0.6924$$

$$V_{std\ (sat)} = \left[\frac{(1ft^3)(459.6+68)}{459.6+60}\right]\left[\frac{(14.65)(2.036)-0.522}{29.920-0.692}\right] = 1.018\ ft^3$$

From Perry's 5th Ed p. 12-7

$V_a = 13.298\ ft^3/lb$ ..... $V_s = 13.613\ ft^3/lb$

$$V_d = 1.018\ ft^3\left(\frac{13.298\ ft^3/lb}{13.613\ ft^3/lb}\right) = 0.994\ ft^3$$

Flare H_2S with Engines & Heater Treater

Separator	9 ppm	X	81.55%	÷ 0.994 =	7.384 ppm
Heater Treater	15.5 ppm	X	10.71%	÷ 0.994 =	1.670 ppm
Stock Tank	19.0 ppm	X	7.74%	÷ 0.994 =	1.479 ppm
					10.533 ppm

Flare H_2S with Engines

Separator	9 ppm	X	81.80%	÷ 0.994 =	7.406 ppm
Heater Treater	15.5 ppm	X	10.56%	÷ 0.994 =	1.647 ppm
Stock Tank	19.0 ppm	X	7.64%	÷ 0.994 =	1.460 ppm
					10.513 ppm

Flare

Separator	9 ppm	X	83.90%	÷ 0.994 =	7.596
Heater Treater	15.5 ppm	X	9.34%	÷ 0.994 =	1.456
Stock Tank	19.0 ppm	X	6.76%	÷ 0.994 =	1.292
					10.344 ppm

Page 1 of 12

○ coordinates Corrected

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○ Note: 4 separators are now included instead of 2. Description no longer states that gas from heater treater and excess gas will be flared. Need to check Exhibit VII

○ Note: Vapor recovery system has been added.

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○ Note: 8760 hrs requested

○ This is a new source: NA area rules are not applicable. BACT does not apply. PSD does not apply. NSPS does not apply. NESHAPs does not apply. RACT does not apply. Check

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○ Note: Oil from separators is metered before going to heater treater (See Exhibit VII) b. Fuel gas is burned in flare pilot, heater treater, and engines. The heater treater gas is burned in the flare. Excess fuel gas is burned in the flare. A thermocouple senses when the flare goes out and automatically reactivates. Tank vapors compressed to 2 atm. absolute

○ Gas

	Fuel Gas / 100 Moles				Heater Treater Gas/100 Moles			
	Comp	Lb	Ft³	Btu	Comp	Lb	Ft³	Btu
CO_2	1.03	45.33	387.48	—	1.32	58.09	496.55	—
N_2	10.08	282.40	3,796.30	—	1.41	39.50	531.00	—
H_2S								
CH_4	62.47	1,002.08	23,614.02	23,945,861.2	25.35	406.64	9,582.47	9,710,156.6
C_2H_6	13.71	412.22	5,134.20	9,200,750.4	24.16	726.42	9,047.56	16,213,694.4
C_3H_8	7.79	343.48	1,873.21	7,440,420.3	24.88	1,097.01	9,176.49	23,262,333.6
$I-C_4H_{10}$	1.37	79.62	503.28	1,692,482.3	5.30	308.02	1,946.99	6,547,581.1
$N-C_4H_{10}$	2.22	129.02	815.54	2,749,158.2	10.23	594.55	3,758.15	12,668,671.4
$I-C_5H_{12}$	0.55	39.68	208.40	835,343.4	1.24	89.46	469.84	1,833,311.9
$N-C_5H_{12}$	0.46	33.19	174.31	700,010.3	4.03	290.74	1,526.97	6,131,997.3
C_6H_{14}	0.22	18.96	83.39	397,022.4	1.29	111.16	488.88	2,327,690.4
C_7H_{16}	0.10	10.02	37.86	208,365.9	0.79	79.16	299.14	1,646,132.2
	100.00	2,396.00	37,627.99	47,169,114.4	100.00	3,800.75	37,324.04	80,841,568.9

Stock Tank Gas/100 moles

Comp	Lb	Ft^3	Btu
CO_2	0.72	31.69	270.89	—
N_2	0.11	3.08	41.40	—
H_2S				
CH_4	5.62	90.15	2,124.38	2,152,691.8
C_2H_6	19.71	592.62	7,381.08	13,227,278.4
C_3H_8	35.68	1,573.20	13,159.82	34,077,085.2
$I-C_4H_{10}$	8.72	506.79	3,203.42	10,772,835.0
$N-C_4H_{10}$	17.41	1,011.83	6,395.78	21,560,073.6
$I-C_5H_{12}$	2.11	152.22	799.46	3,204,535.4
$N-C_5H_{12}$	6.81	491.30	2,580.31	10,362,608.3
C_6H_{14}	2.03	174.92	769.30	3,662,824.8
C_7H_{16}	1.08	108.21	408.92	2,250,227.0
	100.00	4,736.01	37,134.76	101,269,559.5

Fuel Gas

$$\text{Density} = \frac{2,396.00\ lb/100\ moles}{37,627.99\ ft^3/100\ moles} = 0.0637\ lb/ft^3$$

$$\text{Btu} = \frac{47,169,114.4\ Btu/100\ moles}{37,627.99\ ft^3/100\ moles} = 1,254\ Btu/ft^3$$

$$= \frac{47,169,114.4\ Btu/100\ moles}{2,396.00\ lb/100\ moles} = 19,687\ Btu/lb$$

$$\text{Sp. gr.} = (13.14\ \tfrac{ft^3}{lb} \times 0.0637\ \tfrac{lb}{ft^3}) = 0.837$$

Heater Treater Gas

$$\text{Density} = \frac{3,800.75\ lb/100\ moles}{37,324.04\ ft^3/100\ moles} = 0.1018\ lb/ft^3$$

$$\text{Btu} = \frac{80,841,568.9\ Btu/100\ moles}{37,324.04\ ft^3/100\ moles} = 2,166\ Btu/ft^3$$

$$= \frac{80,841,568.9\ Btu/100\ moles}{3,800.75\ ft^3/100\ moles} = 21,270\ Btu/lb$$

$$\text{Sp. gr.} = (13.14\ \tfrac{ft^3}{lb} \times 0.1018\ \tfrac{lb}{ft^3}) = 1.338$$

Stock Tank Gas

$$\text{Density} = \frac{4,736.01\ lb/100\ moles}{37,134.76\ ft^3/100\ moles} = 0.1275\ lb/ft^3$$

$$\text{Btu} = \frac{101,269,559.5\ Btu/100\ moles}{37,134.76\ ft^3/100\ moles} = 2,727\ Btu/ft^3$$

$$= \frac{101,269,559.5\ Btu/100\ moles}{4,736.01\ lb/100\ moles} = 21,383\ Btu/lb$$

10:

$$\text{Sp. gr.} = (13.14\ \tfrac{ft^3}{lb} \times 0.1275\ \tfrac{lb}{ft^3}) = 1.675$$

$$V = \frac{RT}{(MW)(P)} = \frac{(0.7302)(520°R)}{(29)\left(\frac{14.65}{14.7}\right)} = 13.14\ \tfrac{ft^3}{lb}$$ air @ 60°F & 14.65

BHC

Fuel Gas = $\frac{653.97}{2396} = 0.2729$ BHC $\frac{lb}{lb}$

Heater Treater Gas = $\frac{2570.10}{3800.75}$ = 0.6762 RHC $\frac{lb}{lb}$

Stock Tank Gas = $\frac{4017.75}{4735.22}$ = 0.8485 RHC $\frac{lb}{lb}$

H_2S

If: Sepacator and stock tank concentrations are @ 60°F and 14.65 psia

then:

$$\text{Separator} = \left[\frac{(M.W.)(P)}{\frac{RT}{1EE06}}\right] ppm = \left[\frac{(34.08)(1)}{\frac{(0.7302)(520)}{1EE06}}\right] 9 = 8.0779\ EE\text{-}07\ \frac{lb}{ft^3}$$

$$\text{Stock Tank} = \left[\frac{(M.W.)(P)}{\frac{RT}{1EE06}}\right] ppm = \left[\frac{(34.08)(1)}{\frac{(0.7302)(520)}{1EE06}}\right] 19 = 1.7053\ EE\text{-}06\ \frac{lb}{ft^3}$$

	$\frac{P}{T}$	lb	$\frac{lb}{ft^3}$
Separator	$\frac{(6.80)}{523} = 1.3002\ EE\text{-}02$		$8.0779\ EE\text{-}07\ \frac{lb}{ft^3}$
Heater Treater	$\frac{(3.05)}{590} = 5.1695\ EE\text{-}03$		x
Stock Tanks	$\frac{1}{560} = 1.7857\ EE\text{-}03$		$1.7053\ EE\text{-}06\ \frac{lb}{ft^3}$
	$\frac{3.3838\ EE\text{-}03}{1.12163\ EE\text{-}02}$	=	$\frac{x - 1.7053\ EE\text{-}06}{-8.97510\ EE\text{-}07}$

$$(3.0169\ EE\text{-}01)(-8.97511\ EE\text{-}07) + 1.7053\ EE\text{-}06 = X$$

$$X = 1.4345\ EE\text{-}06\ \frac{lb}{ft^3}$$

$$\text{Heater Treater} = (1.4345\ EE\text{-}06\ \tfrac{lb}{ft^3}) \div \left[\frac{(34.08)(1)}{\frac{(0.7302)(520)}{1EE06}}\right] = 15.98\ ppm$$

O Note: Exhibit I and Appendix I calculations sufficiently close

But: RHC was actually calculated as

$$RHC = \frac{\text{Reactive } C_xH_y}{\text{Total gas mass}} \quad \& \text{ Not } RHC = \frac{\text{Reactive } C_xH_y}{\text{Total } C_xH_y}$$

* Input = 18,824 lb/hr crude oil + 1,771 lb/hr separator gas + 313 lb/hr heater treater gas + 282 lb/hr stock tank gas = 21,190 lb/hr + 25,514 lb H_2O (sale)/bbl = 46,704 lb/hr

O Note: The process input is at least 595 lb/hr low. No water is included either in input or gas. Yet gas is assumed to be saturated. Q: Is H_2S concentration dry standard conditions? Does company wish to live with lower process input?

* O Note: Heater Treater calculations assume 100% DE for H_2S probably should be est. 98% – No change SO_2 but H_2S would be 1.2423 EE-05 lb/hr or 0.0001 T/y

$C_3H_8 = (0.0033)(0.3168) = 0.0010\ \frac{lb}{hr}$ or 0.0044 T/Y $C_6H_6 = 0.0023\ \frac{lb}{hr}$ or 0.0101 T/y

Otherwise Heater Treater Emissions OK

o Note: Because of vapor recovery for all tanks & trucks -- Fixed roof tank emissions are OK

o Note: The correct AP-42 reference for Gas fired engines is 3.2-1.1 gr/100 scf = 16 ppm estimate is found on p. 9.2-3

K Comp.	Mole Frac	C_xH_y	C (lb/lb mole)	C_xH_y (lb/lb mole)
CH_4	62.47	0.7487	7.5033	10.0221
C_2H_6	13.71	0.7989	3.2935	4.1226
C_3H_8	7.79	0.8171	2.8069	3.4352
$I\text{-}C_4H_{10}$	1.37	0.8266	0.6582	0.7963
$N\text{-}C_4H_{10}$	2.22	0.8266	1.0666	1.2903
$I\text{-}C_5H_{10}$	0.55	0.8324	0.3303	0.3968
$N\text{-}C_5H_{10}$	0.46	0.8324	0.2763	0.3319
C_6H_{12}	0.22	0.8363	0.1585	0.1896
C_7H_{14}	0.10	0.8391	0.0841	0.1002
			16.1777	20.6850

As C RHC = $\frac{5.3809}{16.1777} = 0.3326$ As C_xH_y RHC = $\frac{6.5403}{20.6850} = 0.3162$

RHC of Gas = $\frac{6.5403}{23.9620} = 0.2729$

Total VOC = $(0.0097)\left(\frac{20.6850}{16.1777}\right)(120)(4) = 5.9532 \frac{lb}{hr}$

$C_3+ = (5.9532 \frac{lb}{hr})(0.3326) = 1.9800 \frac{lb}{hr}$

C_1 & C_2 = $3.9732 \frac{lb}{hr}$

Exxon should have an additional 3.846 T/Y RH emissions *

o Note: C_1 & C_2 emissions should be $3.9732 \frac{lb}{hr}$ or 17.4026 T/Y For 120 HP Engines

C_3+ emissions should be $1.9800 \frac{lb}{hr}$ or 8.6724 T/Y

Total VOC = $(0.0097)\left(\frac{20.6850}{16.1777}\right)(100) = 1.2402 \frac{lb}{hr}$

$C_3+ = (1.2402 \frac{lb}{hr})(0.3326) = 0.4125 \frac{lb}{hr}$

C_1 & C_2 = $0.8277 \frac{lb}{hr}$

* o Note: C_1 & C_2 emissions should be $0.8277 \frac{lb}{hr}$ or 3.6253 T/Y For 100 HP Engines

C_3+ emissions should be $0.4125 \frac{lb}{hr}$ or 1.8068 T/Y

Total VOC = $(0.0097)\left(\frac{20.6850}{16.1777}\right)(50) = 0.6201 \frac{lb}{hr}$

$C_3+ = (0.6201)(0.3326) = 0.2062 \frac{lb}{hr}$

C_1 & C_2 = $0.4139 \frac{lb}{hr}$

* o Note: C_1 & C_2 emissions should be $0.4139 \frac{lb}{hr}$ or 1.8129 T/Y For 50 HP Eng

C_3+ emissions should be $0.2062 \frac{lb}{hr}$ or 0.9032 T/Y

For Flare emissions

A. Separator Gas

CO emission should be 75.07 lb/day or 3.13 lb/hr or 13.71 T/Y

Heater Treater Gas

Comp.	Mole Frac	C/CxHx	C (lb/lb mole)	CxHy (lb/lb mole)
CH_4	25.35	0.7487	3.0449	4.0669
C_2H_6	24.16	0.7989	5.8039	7.2649
C_3H_8	24.88	0.8171	8.9646	10.9713
$I\text{-}C_4H_{10}$	5.30	0.8266	2.5463	3.0805
$N\text{-}C_4H_{10}$	10.23	0.8266	4.9150	5.9460
$I\text{-}C_5H_{12}$	1.24	0.8324	0.7447	0.8947
$N\text{-}C_5H_{12}$	4.03	0.8324	2.4203	2.9076
C_6H_{14}	1.29	0.8363	0.9297	1.1117
C_7H_{16}	0.79	0.8391	0.6642	0.7916
			30.0336	37.0352

As C RHC = $\frac{21.1848}{30.0336} = 0.7154$ As CxHy RHC = $\frac{25.7034}{37.0352} = 0.6940$

RHC of Gas = $\frac{25.7034}{37.0352 + 0.5809 + 0.3950} = \frac{25.7034}{38.0111} = 0.6762$

CO emission should be 15.49 lb/day or 0.65 lb/hr or 2.85 T/Y

Stock Tank Gas

Comp	Mole Frac	C/CxHy	C (lb/lb mole)	CxHy (lb/lb mole)
CH_4	5.62	0.7487	0.6750	0.9016
C_2H_6	19.71	0.7989	4.7349	5.9268
C_3H_8	35.68	0.8171	12.8561	15.7338
$I\text{-}C_4H_{10}$	8.72	0.8266	4.1895	5.0683
$N\text{-}C_4H_{10}$	17.41	0.8266	8.3645	10.1192
$I\text{-}C_5H_{12}$	2.11	0.8324	1.2672	1.5224
$N\text{-}C_5H_{12}$	6.81	0.8324	4.0899	4.9134
C_6H_{14}	2.03	0.8363	1.4630	1.7494
C_7H_{16}	1.08	0.8394	0.9084	1.0822
			38.5485	47.0171

As C RHC = $\frac{33.1386}{38.5485} = 0.8597$ As CxHy RHC = $\frac{40.1887}{47.0171} = 0.8548$

RHC of Gas = $\frac{40.1887}{47.0171 + 0.0308 + 0.3167} = \frac{40.1887}{47.3648} = 0.8485$

CO emission should be 14.40 lb/day or 0.60 lb/hr or 2.63 T/Y

- Note: Total CO emission should be 4.38 lb/hr or 19.19 T/Y
- Note: C_3H_8 emissions should be 82.1316 T/Y. These emissions calculate correctly but a carbon balance based on the

assumption for the CO calculations indicates that emissions of C_3+ & C_1 & C_2 should be ≈ 77.4450 T/Y

Separator Gas

2388.94 moles C total/day

- 2341.16 moles C → CO_2 / day

- 2.68 moles C → CO / day

45.10 moles C → C_xH_y / day

$$VOC = \left(45.10 \frac{\text{moles C}}{\text{day}}\right)\left(\frac{12.0112 \text{ lbs C}}{\text{mole C}}\right)\left(\frac{\text{moles gas}}{16.1778 \text{ lbs C}}\right)\left(\frac{20.6850 \text{ lb } C_xH_y}{\text{mole gas}}\right)\left(\frac{\text{day}}{24 \text{ hr}}\right) = 28.8594 \frac{\text{lb}}{\text{hr}}$$

$C_3+ = (28.8594 \frac{\text{lb}}{\text{hr}})(0.3162) = 9.1253 \frac{\text{lb}}{\text{hr}}$

C_1 & $C_2 = (28.8594 \frac{\text{lb}}{\text{hr}}) - 9.1253 \frac{\text{lb}}{\text{hr}} = 19.7351 \frac{\text{lb}}{\text{hr}}$

Heater Treater Gas

493.91 moles C total/day

- 484.03 moles C → CO_2 / day

- 0.553 moles C → CO / day

9.327 moles C → C_xH_y / day

$$VOC = \left(\frac{9.327 \text{ moles C}}{\text{day}}\right)\left(\frac{12.0112 \text{ lbs C}}{\text{mole C}}\right)\left(\frac{\text{moles gas}}{130.0336 \text{ lbs C}}\right)\left(\frac{37.0352 \text{ lb } C_xH_y}{\text{mole gas}}\right)\left(\frac{\text{day}}{24 \text{ hr}}\right) = 5.7560 \frac{\text{lb}}{\text{hr}}$$

$C_3+ = (5.7560 \frac{\text{lb}}{\text{hr}})(0.6940) = 3.9947 \frac{\text{lb}}{\text{hr}}$

C_1 & $C_2 = 5.7560 \frac{\text{lb}}{\text{hr}} - 3.9947 \frac{\text{lb}}{\text{hr}} = 1.7613 \frac{\text{lb}}{\text{hr}}$

Stock Tank Gas

458.55 moles C total/day

- 449.38 moles C → CO_2 / day

- 0.514 moles C → CO / day

8.656 moles C → C_xH_y

$$VOC = \left(\frac{8.656 \text{ moles C}}{\text{day}}\right)\left(\frac{12.0112 \text{ lbs C}}{\text{mole C}}\right)\left(\frac{\text{moles gas}}{38.5485 \text{ lbs C}}\right)\left(\frac{47.0171 \text{ lb } C_xH_y}{\text{mole gas}}\right)\left(\frac{\text{day}}{24 \text{ hr}}\right) = 5.2837 \frac{\text{lb}}{\text{hr}}$$

$C_3+ = (5.2837 \frac{\text{lb}}{\text{hr}})(0.8548) = 4.5165 \frac{\text{lb}}{\text{hr}}$

C_1 & $C_2 = 5.2837 \frac{\text{lb}}{\text{hr}} - 4.5165 \frac{\text{lb}}{\text{hr}} = 0.7672 \frac{\text{lb}}{\text{hr}}$

Total $C_3+ = 9.1253 \frac{\text{lb}}{\text{hr}} + 3.9947 \frac{\text{lb}}{\text{hr}} + 4.5615 \frac{\text{lb}}{\text{hr}} = 17.6815 \frac{\text{lb}}{\text{hr}}$ or 77.4450 T/Y

Total C_1 & $C_2 = 19.7351 \frac{\text{lb}}{\text{hr}} + 1.7613 \frac{\text{lb}}{\text{hr}} + 0.7672 \frac{\text{lb}}{\text{hr}} = 22.2636 \frac{\text{lb}}{\text{hr}}$ or 97.5146 T/Y

- Note: SO_2 emissions are OK
- Note: NOx emissions could be as high as $4.69 \frac{\text{lb}}{\text{hr}}$ or 20.54 T/Y based

on an emission factor of 0.1 lbs NO_x/MBtu. But emissions based on Exxon's value of 0.076 lbs NO_x/MBtu should be 3.69 $\frac{lb}{hr}$ or 16.16 T/Y

Fugitive Emissions

Component	Gas	Other
Valve	(5.81EE-02)(6.1EE-02) = 3.5441EE-03	(7.00EE-04)(7.9EE-02) = 5.53EE-05
Connection	(2.94EE-02)(5.2EE-01) = 1.5288EE-02	(7.00EE-04)(2.91EE-01) = 2.037EE-04
Hatch	(5.16EE-02)(1.0EE-03) = 5.16EE-05	(1.47EE-02)(1EE-03) = 1.47EE-05
Seal Packing	(4.985EE-01)(5.0EE-03) = 2.4925EE-03	(1.30EE-03)(2EE-03) = 2.6EE-06
Diaphcam	(1.495EE-01)(1.0EE-02) = 1.495EE-03	(7.44EE-01)(0) = 0
Seal/Mechanism	(7.38EE-02)(1.3EE-02) = 9.594EE-04	(3.10EE-03)(1.7EE-02) = 5.27EE-05
	2.038306EE-02	3.29EE-04

Total = 0.0242

VOC = (0.0242)(6521.0303) = 157.8089 $\frac{lb}{day}$ or 6.57541 $\frac{lb}{hr}$ or 28.8003 T/Y

$\left(\frac{675,200\ SCF}{day}\right)\left(\frac{moles}{380.68\ SCF}\right)\left(\frac{28.97\ lb\ air}{mole}\right)(0.8270\ sp.gr)\left(\frac{day}{24\ hr}\right) = 1,770.58\ \frac{lb}{hr}$

$\left(\frac{75,200\ SCF}{day}\right)\left(\frac{moles}{380.68\ SCF}\right)\left(\frac{28.97\ lb\ air}{mole}\right)(1.3177\ sp.gr)\left(\frac{day}{24\ hr}\right) = 314.20\ \frac{lb}{hr}$

$\left(\frac{54,400\ SCF}{day}\right)\left(\frac{moles}{380.68\ SCF}\right)\left(\frac{28.97\ lb\ air}{mole}\right)(1.6531\ sp.gr)\left(\frac{day}{24\ hr}\right) = 285.15\ \frac{lb}{hr}$

2,369.93 $\frac{lb}{hr}$

VOC lb/gas	C_3+ lb/gas
$(1,770.58\ \frac{lb}{hr})(\frac{20.6850}{23.9620}) = 1,528.44\ \frac{lb}{hr}$	$(1770.58\ \frac{lb}{hr})(0.2729) = 483.19\ \frac{lb}{hr}$
$(314.20\ \frac{lb}{hr})(\frac{37.0352}{38.0111}) = 306.13\ \frac{lb}{hr}$	$(314.20\ \frac{lb}{hr})(0.6762) = 212.46\ \frac{lb}{hr}$
$(285.15\ \frac{lb}{hr})(\frac{47.0171}{47.3648}) = 283.06\ \frac{lb}{hr}$	$(285.15\ \frac{lb}{hr})(0.8485) = 241.95\ \frac{lb}{hr}$
2,117.63 $\frac{lb}{hr}$	937.60 $\frac{lb}{hr}$

C_1 & C_2 = 2,117.63 $\frac{lb}{hr}$ − 937.60 $\frac{lb}{hr}$ = 1,180.03 $\frac{lb}{hr}$

C_1-C_2/VOC = $\frac{1,180.03}{2117.63}$ = 0.5572 C_3+/VOC = $\frac{937.60}{2,117.63}$ = 0.4428

C_3+ = (6.5754 $\frac{lb}{hr}$)(0.4428) = 2.9116 $\frac{lb}{hr}$ or 12.7528/

C_1 & C_2 = 6.5754 $\frac{lb}{hr}$ − 2.9116 $\frac{lb}{hr}$ = 3.6638 $\frac{lb}{hr}$ or 16.0474 T/Y

Note: It is not clear whether the VOC is all C_3+ or could be calcied on the basis of mix. Emission factor is too high.

$\left(\frac{675,200\ SCF}{day}\right)\left(8.0779\ EE-07\ \frac{lb}{ft^3}\right)\left(\frac{day}{24\ hr}\right) = 0.0227\ \frac{lb}{hr}$

$\left(\frac{75,200\ SCF}{day}\right)\left(1.4345\ EE-06\ \frac{lb}{ft^3}\right)\left(\frac{day}{24\ hr}\right) = 0.0045\ \frac{lb}{hr}$

$\left(\frac{54,400\ SCF}{day}\right)\left(1.7053\ EE-06\ \frac{lb}{ft^3}\right)\left(\frac{day}{24\ hr}\right) = 0.0039\ \frac{lb}{hr}$

$0.0311\ \frac{lb}{hr}$

$H_2S/VOC = \frac{0.0311\ \frac{lb}{hr}}{2,117.63\ \frac{lb}{hr}} = 1.4686\ EE-05\ \frac{lb\ H_2S}{lb\ VOC}$

$H_2S = \left(6.5754\ \frac{lb}{hr}\right)\left(1.4686\ EE-05\ \frac{lb\ H_2S}{lb\ VOC}\right) = 9.6566\ EE-05\ \frac{lb}{hr}$ or $4.2296\ EE-04\ T/N$

lbs/hr

	NO_x	CO	SO_2	C_3+	PM	C_1-C_2	H_2S
Heater Treater	0.0409	0.0082	0.0006	0.0010	0.0020	0.0023	Neg
Tanks	—	—	—	—	—	—	—
4-120 HP Eng.	11.5200	1.4880	0.0054	1.9800	—	3.9732	—
1-100 HP Eng.	2.4000	0.3100	0.001125	0.4125	—	0.8277	—
1-50 HP Eng.	1.2000	0.1550	0.000560	0.2062	—	0.4139	—
Flare	4.6900	4.3800	0.058	17.6815	—	22.2636	—
Fug. Emiss.	—	—	—	2.9116	—	3.6638	—
	19.8509	6.3412	0.0656850	23.1928	0.0020	31.1445	
				(26.8566 If all reactive from fugitive		(27.4801 If all reactive from fugitive	

ONote: Exxon est.

18.7409	6.3412	0.0657	28.2997	0.0020	29.0980	

Tons/Year

	NO_x	CO	SO_2	C_3+	PM	C_1-C_2	H_2S
Heater Treater	0.1789	0.0358	0.0027	0.0044	0.0089	0.0101	Neg
Tanks	—	—	—	—	—	—	—
4-120 HP Eng	50.4576	6.5174	0.0237	8.6724	—	17.4026	—
1-100 HP Eng	10.5120	1.3578	0.0049	1.8068	—	3.6253	—
1-50 HP Eng	5.2560	0.6789	0.0025	0.9032	—	1.8129	—
Flare	20.5400	19.1900	0.2540	77.4450	—	97.5416	—
Fug. Emiss	—	—	—	12.7528	—	16.0474	—
	86.9535	27.7799	0.2878	101.5846	0.0089	136.4399	
				(117.6321 If all reactive from fugitive		(120.3925 If all reactive from fugitive	

ONote: Exxon est.

82.0945	27.7699	0.2878	123.9524	0.0089	127.4493	

ONote: Exhibits II & III appear to contain some rather high values.

Page 3 of 12

ONote: Fuel Calculations & Exhibits IV & V OK

Page 4 of 12

ONote: Flare velocity should be 337.4 ft/sec

air = $\left(\frac{\text{mole}}{28.97\text{ lb}}\right)(15\text{ lb}) = 0.5178$ mole air

Fuel = $\left(\frac{\text{mole}}{23.962\text{ lb}}\right)(1\text{ lb}) = 0.0417$ mole fuel

Based on assumption that maximum fuel consumption occurs at 15:1 (by weight) air : fuel ratio

$\frac{0.5178\text{ mole air}}{0.0417\text{ mole fuel}} = \frac{\text{mole air}}{1\text{ mole fuel}}$

Air = 12.4172 Moles Air/Mole Fuel

		O_2	N_2
CH_4	0.6247	x 2 = 1.2494	x 7.53 = 4.7040
C_2H_6	0.1371	x 3.5 = 0.4798	x 13.18 = 1.8070
C_3H_8	0.0779	x 5.0 = 0.3895	x 18.82 = 1.4661
$I\text{-}C_4H_{10}$	0.0137	x 6.5 = 0.0890	x 24.47 = 0.3352
$N\text{-}C_4H_{10}$	0.0222	x 6.5 = 0.1443	x 24.47 = 0.5432
$I\text{-}C_5H_{12}$	0.0055	x 8.0 = 0.0440	x 30.11 = 0.1656
$N\text{-}C_5H_{12}$	0.0046	x 8.0 = 0.0368	x 30.11 = 0.1385
C_6H_{14}	0.0022	x 9.5 = 0.0209	x 35.76 = 0.0787
C_7H_{16}	0.0010	x 11.0 = 0.0110	x 41.50 = 0.0415
		2.4647	9.2798

Air = $O_2 + N_2$ = 2.4647 + 9.2798 = 11.7445 Moles Air/Mole Fuel

		CO_2	H_2O	N_2
CH_4	0.6247	x 1 = 0.6247	x 2 = 1.2494	x 7.53 = 4.7040
C_2H_6	0.1371	x 2 = 0.2742	x 3 = 0.4113	x 13.18 = 1.8070
C_3H_8	0.0779	x 3 = 0.2337	x 4 = 0.3116	x 18.82 = 1.4661
$I\text{-}C_4H_{10}$	0.0137	x 4 = 0.0548	x 5 = 0.0685	x 24.47 = 0.3352
$N\text{-}C_4H_{10}$	0.0222	x 4 = 0.0888	x 5 = 0.1110	x 24.47 = 0.5432
$I\text{-}C_5H_{12}$	0.0055	x 5 = 0.0275	x 6 = 0.0330	x 30.11 = 0.1656
$N\text{-}C_5H_{12}$	0.0046	x 5 = 0.0230	x 6 = 0.0276	x 30.11 = 0.1385
C_6H_{14}	0.0022	x 6 = 0.0132	x 7 = 0.0154	x 35.76 = 0.0787
C_7H_{16}	0.0010	x 7 = 0.0070	x 8 = 0.0080	x 41.50 = 0.0415
		1.34690	2.2358	9.2798

Flue Gas = 1.34690 + 2.2358 + 9.2798 + 0.0103 + 0.1008 = 12.9736

= 12.9736 Moles Flue Gas/Mole Fuel

with 15:1 (by weight) air : fuel =

Flue Gas = 12.9736 + (12.4172 − 11.7445) = 13.6463 Moles Flue Gas/Mole Fuel

	C_3+	C_1 & C_2	Total
Heater Treater	0.0009	0.0019	0.0028
Engines			
4-120 HP	1.2706	2.7470	4.0176
1-100 HP	0.2647	0.5723	0.8370
1- 50 HP	0.1324	0.2862	0.4186
Flare	18.7515	25.4906	44.24210

Pages 5 of 12 & 6 of 12

Calculations substantially OK

Page 7 of 12

Ok

Pages 8 of 12 through 12 of 12

Ok

Exhibit VI

○ Note: The emission calculations for gas volumes did not consider the C_1 & C_2, but did not differ substantially from those given.

5/27/87

Mr. Mitchell,

Attached is a copy of the McClellan Field application for an Air Permit. The original has been sent to C. C. Fancy of your Tallahassee office. We neglected to include additional copies in the original package.

Thank you,
Ashlee Broussard

EXXON COMPANY, U.S.A.
POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
EASTERN DIVISION

May 22, 1987

McLellan Field
Common Tank Battery
Section 33, T6N, R26W
Santa Rosa County, Florida

Mr. C. H. Fancy, Bureau Chief
Bureau of Air Quality Management
Twin Towers Office Building
Tallahassee, Florida 32301

Dear Mr. Fancy:

Attached, in quadruplicate, is the revised application for the air permit to construct the oil production facility captioned above. We have addressed all areas of incompleteness noted in your letter dated April 3, 1987.

A vapor recovery unit will be installed at our tank battery to control emissions from the two crude oil storage tanks, two saltwater storage tanks, and slop oil tank. All of the pollutants listed in Table 500-2 of FAC Rule 17-2.500 that may be emitted have been included, with methane and ethane emissions quantified separately as requested. Data and calculations have been refined to provide the most accurate information available, with all procedures and assumptions documented. A copy of the appropriate section of API Publication #4322 has been provided for fugitive emission calculations.

Our responses to other items of incompleteness are as follows:

INCOMPLETENESS	RESPONSE
1. UTM coordinates incorrect	1. Corrected UTM coordinates found on page 1 of 1 of application
2. Will auxiliary fuels be used	2. No auxiliary fuels will be used
3. Heater treater operation and design capacity clarification	3. See Appendix II(a)(1) and Exhibit VII
4. Smokeless flare operation and efficiency clarification	4. See Appendix II(d) and Exhibit VII
5. Details of engine design	5. See Exhibit VII
6. Process input/output rates as maximums instead of average maximums	6. All rates shown in calculations are maximums

EXXON COMPANY, U.S.A.
POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
EASTERN DIVISION

DER

JUN 10 1987

BAQM

May 22, 1987

Changes from submission rcv'd on May 26 are marked here

McLellan Field
Common Tank Battery
Section 33, T6N, R26W
Santa Rosa County, Florida

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1. UTM coordinates incorrect	1. Corrected UTM coordinates found on page 1 of 1 of application
2. Will auxiliary fuels be used	2. No auxiliary fuels will be used
3. Heater treater operation and design capacity clarification	3. See Appendix II(a)(1) and Exhibit VII
4. Smokeless flare operation and efficiency clarification	4. See Appendix II(d) and Exhibit VII
5. Details of engine design	5. See Exhibit VII
6. Process input/output rates as maximums instead of average maximums	6. All rates shown in calculations are maximums

INCOMPLETENESS	RESPONSE
7. Document the gas physical properties information in Appendix I. Include sulfur content, reduced sulfur content and hydrogen sulfide content.	7. See Appendix I
8. Describe the design and operation of separators, scrubbers and slop oil tank.	8. See Exhibit VII
9. Include all sources and pollutants with justifications of assumptions and documentation of procedures.	9. All sources and pollutants have been included with all assumptions justified and procedures documented
10. Provide information about instrumentation and test procedures for monitoring emissions.	10. See Exhibit VI

We would like to meet with you or your staff at your earliest convenience to review the revised permit application and answer any questions that you might have. Please contact Ms. Ashlyn Broussard at (504) 561-4226 to arrange a meeting. Your timely review of this application would be appreciated.

Sincerely,

EXXON CORPORATION

By: 

Charles A. Martin
Permit/Surveillance Supervisor
Eastern Division
Exxon Company, U.S.A.
(a division of Exxon Corporation)

AAB:fab[2]
Attachments

Mike Harley recd copy from Exxon 5/26/87 eam

cc:
Jack Preece 5/26/87 eam

FEDERAL EXPRESS

QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL NUMBER 331536846 4

69 70230N

DATE 5/22/87

AIRBILL NUMBER 331536846 4

From (Your Name)	Your Phone Number (Very Important)	To (Recipient's Name)	Recipient's Phone Number (Very Important)
1 R. L. BRUCE	(504 561-3904	2 C H FANCY, BUREAU CHIEF	( )
Company	**Department/Floor No.**	**Company**	**Department/Floor No.**
EXXON USA/MAILROOM		BUREAU OF AIR QUALITY MANAGEMENT	
Street Address		**Exact Street Address** *(Use of P.O. Boxes or P.O. ® Zip Codes Will Delay Delivery And Result in Extra Charge.)*	
1555 POYDRAS RM 62C		TWIN TOWERS OFFICE BUILDING	
City / **State**	**ZIP Required For Correct Invoicing**	**City** / **State**	**ZIP Street Address Zip Required**
NEW ORLEANS LA	7 0 1 1 2	TALLAHASSEE FL	32301

3 **YOUR BILLING REFERENCE INFORMATION (FIRST 24 CHARACTERS WILL APPEAR ON INVOICE.)**
37400

PAYMENT ☑ Bill Sender ☐ Bill Recipient's FedEx Acct. No. ☐ Bill 3rd Party FedEx Acct. No. ☐ Bill Credit Card ☐ Cash

H **HOLD FOR PICK-UP AT THIS FEDERAL EXPRESS LOCATION:**
Street Address (See Service Guide or Call 800-238-5355)

City / State

ZIP ® Zip Code of Street Address Required

Emp. No. / Date

☐ Cash Received
☐ Return Shipment
☐ Third Party ☐ Chg. To Del. ☐ Chg. To Hold

Street Address

City / State / Zip

Received By: X

Date/Time Received / FedEx Employee Number

Federal Express Use

Base Charges

Declared Value Charge

Origin Agent Charge

Other

Total Charges

4 **SERVICES CHECK ONLY ONE BOX**

1 ☐ **PRIORITY 1** Overnight Delivery Using Your Packaging
6 ☐ **OVERNIGHT LETTER*** (Our Packaging) 9½"x12½"

OVERNIGHT DELIVERY USING OUR PACKAGING

2 ☑ Courier-Pak Overnight Envelope* 12"x 15½"
3 ☐ Overnight Box 12½"x 17½"x 3" A ☐
4 ☐ Overnight Tube 38"x 6"x 6"x 6" B ☐
*Declared Value Limit $100.

5 ☐ **STANDARD AIR** Delivery not later than second business day

SERVICE COMMITMENT

PRIORITY 1 - Delivery is scheduled early next business morning in most locations. It may take two or more business days if the destination is outside our primary service areas.
STANDARD AIR - Delivery is generally next business day or not later than second business day. It may take three or more business days if the destination is outside our primary service areas.

DELIVERY AND SPECIAL HANDLING CHECK SERVICES REQUIRED

1 ☐ **HOLD FOR PICK-UP** (Fill in Section H at right)
2 ☑ **DELIVER WEEKDAY**
3 ☐ **DELIVER SATURDAY** (Extra charge) ☐
4 ☐ **DANGEROUS GOODS** (P-1 and Standard Air Packages only. Extra charge)
5 ☐ **CONSTANT SURVEILLANCE SERVICE (CSS)** (Extra charge) (Do Not Complete Section 5)
6 ☐ **DRY ICE** _____ Lbs.
7 ☐ **OTHER SPECIAL SERVICE** _____
8 ☐
9 ☐ **SATURDAY PICK-UP** (Extra charge)
10 ☐

PACKAGES	WEIGHT	YOUR DECLARED VALUE	OVER SIZE
1	LBS		
	LBS		
	LBS		
	LBS		
Total 1	Total	Total	

Received At
1 ☐ Regular Stop
2 ☐ On-Call Stop
3 ☐ Drop Box 4 ☐ B.S.C. 5 ☐ Station

Federal Express Corp. Employee No.

Date/Time For Federal Express Use
5/22 1736

5 Sender authorizes Federal Express to deliver this shipment without obtaining a delivery signature and shall indemnify and hold harmless Federal Express from any claims resulting therefrom.
Release Signature:

PART #106001
FEC-S-751-1000
REVISION DATE 10/86
PRINTED U.S.A. GBFE

RECIPIENT'S COPY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHWEST DISTRICT
160 GOVERNMENTAL CENTER
PENSACOLA, FLORIDA 32501

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Air Pollution [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: Exxon Company, U.S.A. (a division of Exxon Corp.) COUNTY: Santa Rosa

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) McLellan Field Tanks, Flare Stack, Heater Treater, Engines

SOURCE LOCATION: Street Highway 4 City Munson, Florid

UTM: East (16) 515.29 KM E North (16) 3427.83 KM N

Latitude 30 ° 59 ' 8.1 "N Longitude 86 ° 50 ' 23.6 "W

APPLICANT NAME AND TITLE: Sue Cummings, Operations Manager

APPLICANT ADDRESS: Exxon Company, U.S.A., Eastern Division, Post Office Box 61707, New Orleans, LA 70161-1707

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Exxon Corporation

I certify that the statements made in this application for a Construction permit are true, correct and complete to the best of my knowledge and belief. Furthe I agree to maintain and operate the pollution control source and pollution contr facilities in such a manner as to comply with the provision of Chapter 403, Flori Statutes, and all the rules and regulations of the department and revisions thereof. also understand that a permit, if granted by the department, will be non-transferab and I will promptly notify the department upon sale or legal transfer of the permitt establishment.

*Attach letter of authorization

Signed: Sue Cummings

Sue Cummings, Operations Manager
Name and Title (Please Type)

Date: 5-22-87 Telephone No. 504-561-4039

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project hav been designed/examined by me and found to be in conformity with modern engineerin principles applicable to the treatment and disposal of pollutants characterized in t permit application. There is reasonable assurance, in my professional judgment, tha

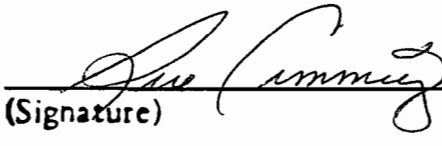
[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

CERTIFICATION

APPLICATIONS, REPORTS AND OTHER REQUESTED INFORMATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

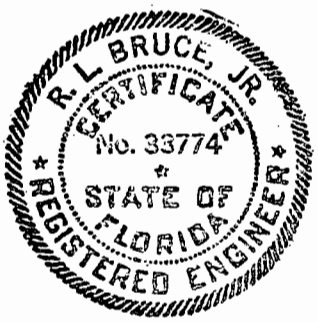
Sue Cummings
(Name)


(Signature)

Operations Manager
(Title) Production Department
Exxon Company, U.S.A.

5-22-87
(Date)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.



Signed RLBruce

R. L. Bruce

Name (Please Type)

Exxon Company, U.S.A.

Company Name (Please Type)

P. O. Box 61707, New Orleans LA 70161-1707

Mailing Address (Please Type)

Florida Registration No. 33774 Date: May 22, 1987 Telephone No. (504) 561-3904

SECTION II: GENERAL PROJECT INFORMATION

1. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

The McLellan permanent production facility will handle 4 production wells. Proposed equipment will include one heater treater , 4 separators, 6 engines , 2 saltwater storage tanks, 2 oil storage tanks, and 1 slop oil tank. The facility is described in detail in Exhibit VII. The proposed production facility will comply with all applicable State and Federal air pollution source rules and regulations.

2. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction July, 1987 Completion of Construction August, 1987

3. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

Flare System: $15k installed

Vapor Recovery Unit: $30k installed

4. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Approval to test State of Florida Lease 33-1 was given on March 17, 1986 for a 60-day test and on August 12, 1986 for a 90-day test. Robert Kriegal, District Manager, and Norman L. Richards, Asst. District Manager, granted these approvals. We are currently testing the State of Florida Lease 34-2. Approval for a 90-day production test was received on February 2, 1987 by Norman L. Richards.

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52 ;

If power plant, hrs/yr -- ; if seasonal, describe: N/A

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? No

   a. If yes, has "offset" been applied? N/A

   b. If yes, has "Lowest Achievable Emission Rate" been applied? N/A

   c. If yes, list non-attainment pollutants. N/A

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. No

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. No

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? No

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

G. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? No

   a. If yes, for what pollutants? N/A

   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
43.3° API Gravity				
Crude Oil	None	None	18824 lbs/hr	(see Illustration I)
Associated Gas	H_2S	9-19 ppm	1771 lbs/hr	(see Illustration I)

B. Process Rate, if applicable: (See Section V, Item 1) (see Exhibit I)

1. Total Process Input Rate (lbs/hr): 20595 lbs/hr Crude Oil & Gas

2. Product Weight (lbs/hr): 18824 lbs/hr Crude Oil

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/yr	T/yr	
(see Exhibits II and III)							

[1]See Section V, Item 2.

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated without control (See Section V, Item 3).

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
43.3° API Gravity				
Crude Oil	None	None	18824 lbs/hr	(see Illustration I)
Associated Gas	H_2S	9-19 ppm	2370 lbs/hr *	(see Illustration I)

B. Process Rate, if applicable: (See Section V, Item 1) (see Exhibit I)

1. Total Process Input Rate (lbs/hr): 21194 lbs/hr Crude Oil & Gas *

2. Product Weight (lbs/hr): 18824 lbs/hr Crude Oil

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/yr	T/yr	
(see Exhibits II and III)							

[1]See Section V, Item 2.

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated without control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 6)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
McGill Flare Tip BFI-3 or equivalent	H_2S & Hydrocarbon Gases	98%	N/A	Appendix II(d)
Hybon Vapor Recovery Unit, HB 50 A or equivalent	H_2S & Hydrocarbon Gases	100%	N/A	Appendix II(b)

E. Fuels (see Exhibit IV)

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Produced Fuel Gas	.0043 MMcf/hr	.0043 MMcf/hr	5.2862 MMBTU/hr

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: (see Exhibit V)

Percent Sulfur: .0009% Percent Ash: 0

Density: N/A lbs/gal Typical Percent Nitrogen: 10.08%

Heat Capacity: 19448 BTU/lb 1224 BTU/SCF BTU/gal

Other Fuel Contaminants (which may cause air pollution): None

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average N/A Maximum N/A

G. Indicate liquid or solid wastes generated and method of disposal.

All saltwater produced will be trucked away and disposed of at a permitted saltwater disposal well; eventually, if warranted, a saltwater disposal well may be drilled and saltwater disposed by a natural gas fired engine driven pump (emissions from this 50 horsepower engine have been included).

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: (see Exhibit VIII) ft. Stack Diameter: _____ ft.

Gas Flow Rate: _____ ACFM _____ DSCFM Gas Exit Temperature: _____ °F.

Water Vapor Content: _____ % Velocity: _____ FPS

SECTION IV: INCINERATOR INFORMATION

(Not Applicable)

Type of Waste	Type 0 (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste _____

Total Weight Incinerated (lbs/hr) _____ Design Capacity (lbs/hr) _____

Approximate Number of Hours of Operation per day _____ day/wk _____ wks/yr. _____

Manufacturer _____

Date Constructed _____ Model No. _____

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: _____ ft. Stack Diameter: _____ Stack Temp. _____

Gas Flow Rate: _____ ACFM _____ DSCFM* Velocity: _____ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic feet dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) _____

Brief description of operating characteristics of control devices: _____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)] (Exhibit I)
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. (Appendix II & Exhibit VI)
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.) (Illustration VIII & Illustration XI)
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). (see Appendix IId)
6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained. (Illustration I)
7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map). (Illustration IV and Illustration V)
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram. (Illustration II)

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[ ] Yes [ ] No

Contaminant	Rate or Concentration

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[ ] Yes [ ] No

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration

D. Describe the existing control and treatment technology (if any).

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter: ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Costs:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data

1. _____ no. sites _____ TSP _____ ( ) SO_2* _____ Wind spd/dir

Period of Monitoring ____/____/____ to ____/____/____
month day year month day year

Other data recorded _____

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling

1. _____ Year(s) of data from ____/____/____ to ____/____/____
month day year month day year

2. Surface data obtained from (location)_____

3. Upper air (mixing height) data obtained from (location)_____

4. Stability wind rose (STAR) data obtained from (location)_____

C. Computer Models Used

1. _____ Modified? If yes, attach description.

2. _____ Modified? If yes, attach description.

3. _____ Modified? If yes, attach description.

4. _____ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data

Pollutant	Emission Rate
TSP	_____ grams/sec
SO^2	_____ grams/sec

E. Emission Data Used in Modeling

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review.

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources.

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology.

UTILIZATION RATE Lbs/Hr

1) **OIL**

Maximum oil throughput from 4 producing wells (BOPDm) = 1600 $\frac{\text{barrels}}{\text{day}}$

API Gravity = 43.3° API (field tested using API Standard: 2544/ASTM designation D 287-67)

S. G. of oil = .81

$$1600 \frac{\text{barrels}}{\text{day}} \times 42 \frac{\text{gal}}{\text{barrel}} \times 8.3 \frac{\text{lb H2O}}{\text{gal}} \times .81 \frac{\text{lb oil}}{\text{lb H2O}}$$

$$= 4.52 \times 10^5 \text{ lbs/day}$$

$$= 18824 \text{ lbs/hr}$$

2) **GAS***

Gas/Oil Ratio (GOR) = 422 SCF/Bbl (see Gas Physical Properties, Appendix I)
BOPDm = 1600 (Maximum oil throughput expected)

$$1600 \frac{\text{barrels}}{\text{day}} \times 422 \frac{\text{SCF}}{\text{barrel}} \times \frac{\text{LB-MOL}}{380.68 \text{ SCF}} = 1.77 \times 10^3 \frac{\text{LB-MOL}}{\text{day}}$$

	Gas MOL %		LB-MOL DAY		M. W. (LB/LB-MOL)		
Nitrogen	10.08	x	(1.77×10^3)	x	28.013	=	5.01×10^3
Carbon Dioxide	1.03	x	(1.77×10^3)	x	44.010	=	8.04×10^2
Methane	62.47	x	(1.77×10^3)	x	16.043	=	1.78×10^4
Ethane	13.71	x	(1.77×10^3)	x	30.070	=	7.31×10^3
Propane	7.79	x	(1.77×10^3)	x	44.097	=	6.09×10^3
I-Butane	1.37	x	(1.77×10^3)	x	58.123	=	1.41×10^3
N-Butane	2.22	x	(1.77×10^3)	x	58.123	=	2.29×10^3
I-Pentane	.55	x	(1.77×10^3)	x	72.150	=	7.04×10^2
N-Pentane	.46	x	(1.77×10^3)	x	72.150	=	5.89×10^2
Hexane	.22	x	(1.77×10^3)	x	86.177	=	3.36×10^2
Heptane	.10	x	(1.77×10^3)	x	100.204	=	1.78×10^2
	100%					=	4.25×10^4 lbs/day

= 1771 lbs/hr

3) **TOTAL INLET** (Oil + Gas)

$$18824 \frac{\text{lbs}}{\text{hr}} + 1771 \frac{\text{lbs}}{\text{hr}} = 20595 \frac{\text{lbs}}{\text{hr}}$$

4) **TOTAL PRODUCT** (Oil)

$$18824 \frac{\text{lbs}}{\text{hr}}$$

* All process gas calculations are based on a standard temperature of 60°F. All gas discharge rates to the atmosphere are based on a standard temperature of 68°F). Standard pressure is 14.65 psia.

EXHIBIT I

UTILIZATION RATE Lbs/Hr

1) **OIL**

Maximum oil throughput from 4 producing wells (BOPDm) = 1600 $\frac{\text{barrels}}{\text{day}}$

API Gravity = 43.3° API (field tested using API Standard: 2544/ASTM designation D 287-67)

S. G. of oil = .81

$$1600 \frac{\text{barrels}}{\text{day}} \times 42 \frac{\text{gal}}{\text{barrel}} \times 8.3 \frac{\text{lb H2O}}{\text{gal}} \times .81 \frac{\text{lb oil}}{\text{lb H2O}}$$

$= 4.52 \times 10^5$ lbs/day

= 18824 lbs/hr

2) **GAS***

- Gas From Separator

Gas/Oil Ratio (GOR) = 422 SCF/Bbl (see Gas Physical Properties, Appendix I)
BOPDm = 1600 (Maximum oil throughput expected)

$$1600 \frac{\text{barrels}}{\text{day}} \times 422 \frac{\text{SCF}}{\text{barrel}} \times \frac{\text{LB-MOL}}{380.68 \text{ SCF}} = 1.77 \times 10^3 \frac{\text{LB-MOL}}{\text{day}}$$

	Gas MOL %		LB-MOL DAY		M. W. (LB/LB-MOL)		
Nitrogen	10.08	x	(1.77×10^3)	x	28.013	=	5.01×10^3
Carbon Dioxide	1.03	x	(1.77×10^3)	x	44.010	=	8.04×10^2
Methane	62.47	x	(1.77×10^3)	x	16.043	=	1.78×10^4
Ethane	13.71	x	(1.77×10^3)	x	30.070	=	7.31×10^3
Propane	7.79	x	(1.77×10^3)	x	44.097	=	6.09×10^3
I-Butane	1.37	x	(1.77×10^3)	x	58.123	=	1.41×10^3
N-Butane	2.22	x	(1.77×10^3)	x	58.123	=	2.29×10^3
I-Pentane	.55	x	(1.77×10^3)	x	72.150	=	7.04×10^2
N-Pentane	.46	x	(1.77×10^3)	x	72.150	=	5.89×10^2
Hexane	.22	x	(1.77×10^3)	x	86.177	=	3.36×10^2
Heptane	.10	x	(1.77×10^3)	x	100.204	=	1.78×10^2
	100%					=	4.25×10^4 lbs/day

= 1771 lbs/hr

- Gas From Heater Treater (See Appendix I) *

$$1600 \frac{\text{barrels}}{\text{day}} \times 47 \frac{\text{SCF}}{\text{barrel}} \times 1.3177 \frac{\text{LBS GAS}}{\text{lb air}} \times 28.97 \frac{\text{LBS AIR}}{1 \text{ lb-mol}} \times \frac{1 \text{ LB-MOL}}{380.68 \text{ SCF}}$$

$$\times \frac{1 \text{ DAY}}{24 \text{ hr}} = 314 \frac{\text{LBS}}{\text{hr}}$$

- Gas From Stock Tanks (See Appendix I) *

$$1600 \frac{\text{barrels}}{\text{day}} \times 34 \frac{\text{SCF}}{\text{barrel}} \times 1.6531 \frac{\text{LBS GAS}}{\text{lb air}} \times 28.97 \frac{\text{LBS AIR}}{1 \text{ lb-mol}} \times \frac{1 \text{ LB-MOL}}{380.68 \text{ SCF}}$$

$$\times \frac{1 \text{ DAY}}{24 \text{ hr}} = 285 \frac{\text{LBS}}{\text{hr}}$$

- Total Gas = 1771 + 314 + 285 = 2370 lbs/hr *

3) TOTAL INLET (Oil + Gas)

$$18824 \frac{\text{lbs}}{\text{hr}} + 2370 \frac{\text{lbs}}{\text{hr}} = 21194 \frac{\text{lbs}}{\text{hr}} *$$

4) TOTAL PRODUCT (Oil)

$$18824 \frac{\text{lbs}}{\text{hr}}$$

* All process gas calculations are based on a standard temperature of 60°F. All gas discharge rates to the atmosphere are based on a standard temperature of 68°F). Standard pressure is 14.65 psia.

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

DESCRIPTION OF EQUIPMENT	NUMBER OF UNITS	MAXIMUM EMISSIONS LBS/HR					
		NO_X	CO	SO_2	VOC	PM	$C_1 + C_2$(6)
Heater Treater Firebox	1	.0409	.0082	.0006	.0009	.0020	.0019
Tanks	5	--	--	--	---	---	---
Engines:							
120 H.P. Natural Gas	4	11.5200	1.4880	.0054	1.2706	---	2.7470
100 H.P. Natural Gas	1	2.4000	.3100	.0011	.2647	---	.5723
50 H.P. Natural Gas	1	1.2000	.1550	.0006	.1324	---	.2862
Flare	1	3.5800	4.3800	.0580	18.7515	---	25.4906
Fugitive Emissions		--	--	--	7.8796	---	---
		18.7409	6.3412	.0657	28.2997	.0020	29.0980

NOTES:
1) 1600 BOPD production rate assumed
2) See Appendix I for gas physical properties
3) See Appendix II for all design calculations
4) VOC emissions include non-methane/non-ethane hydrocarbon emissions
5) The above emission estimates include all pollutants from Table 500-2 of FAC Rule 17-2.500 that may be emitted. If a pollutant is not shown, it is assumed to be negligible.
6) See Appendix II(f) for methane (C_1) / ethane (C_2) calculations

AAB[8]

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

DESCRIPTION OF EQUIPMENT	NUMBER OF UNITS	MAXIMUM EMISSIONS LBS/HR					
		NO_X	CO	SO_2	VOC	PM	$C_1 + C_2$(6)
Heater Treater Firebox	1	.0409	.0082	.0006	.0009	.0020	.0019
Tanks	5	--	--	--	---	---	---
Engines:							
120 H.P. Natural Gas	4	11.5200	1.4880	.0054	1.5470 *	---	2.7470
100 H.P. Natural Gas	1	2.4000	.3100	.0011	.3222 *	---	.5723
50 H.P. Natural Gas	1	1.2000	.1550	.0006	.1612 *	---	.2862
Flare	1	4.3000 *	4.3800	.0580	18.7515	---	25.4906
Fugitive Emissions		--	--	--	7.8796	---	---
		19.4609 *	6.3412	.0657	28.6624 *	.0020	29.0980

NOTES:
1) 1600 BOPD production rate assumed
2) See Appendix I for gas physical properties
3) See Appendix II for all design calculations
4) VOC emissions include non-methane/non-ethane hydrocarbon emissions
5) The above emission estimates include all pollutants from Table 500-2 of FAC Rule 17-2.500 that may be emitted. If a pollutant is not shown, it is assumed to be negligible.
6) See Appendix II(f) for methane (C_1) / ethane (C_2) calculations

AAB[8]

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

DESCRIPTION OF EQUIPMENT	NUMBER OF UNITS	MAXIMUM EMISSIONS TONS/YR NO_x	CO	SO_2	VOC	PM	$C_1 + C_2$(6)
Heater Treater Firebox	1	.1789	.0358	.0027	.0039	.0089	.0083
Tanks	5	--	--	--	---	---	---
Engines:							
120 H.P. Natural Gas	4	50.4576	6.5174	.0237	5.5653	---	12.0319
100 H.P. Natural Gas	1	10.5120	1.3578	.0049	1.1594	---	2.5067
50 H.P. Natural Gas	1	5.2560	.6789	.00250	.5797	---	1.2536
Flare	1	15.6900	19.1800	.2540	82.1315	---	111.6488
Fugitive Emissions		--	--	--	34.5126	---	---
		82.0945	27.7699	.2878	123.9524	.0089	127.4493

NOTES:
1) 1600 BOPD production rate assumed
2) See Appendix I for gas physical properties
3) See Appendix II for all design calculations
4) VOC emissions include non-methane/non-ethane hydrocarbon emissions
5) The above emission estimates include all pollutants from Table 500-2 of FAC Rule 17-2.500 that may be emitted. If a pollutant is not shown, it is assumed to be negligible.
6) See Appendix II(f) for methane (C_1) / ethane (C_2) calculations

AAB[9]

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

DESCRIPTION OF EQUIPMENT	NUMBER OF UNITS	MAXIMUM EMISSIONS TONS/YR NO_x	CO	SO_2	VOC	PM	$C_1 + C_2$(6)
Heater Treater Firebox	1	.1789	.0358	.0027	.0039	.0089	.0083
Tanks	5	--	--	--	---	---	---
Engines:							
120 H.P. Natural Gas	4	50.4576	6.5174	.0237	6.7750 *	---	12.0319
100 H.P. Natural Gas	1	10.5120	1.3578	.0049	1.4114 *	---	2.5067
50 H.P. Natural Gas	1	5.2560	.6789	.00250	.7057 *	---	1.2536
Flare	1	18.8200 *	19.1800	.2540	82.1315	---	111.6488
Fugitive Emissions		--	--	--	34.5126	---	---
		85.2245 *	27.7699	.2878	125.5401	.0089	127.4493

NOTES:
1) 1600 BOPD production rate assumed
2) See Appendix I for gas physical properties
3) See Appendix II for all design calculations
4) VOC emissions include non-methane/non-ethane hydrocarbon emissions
5) The above emission estimates include all pollutants from Table 500-2 of FAC Rule 17-2.500 that may be emitted. If a pollutant is not shown, it is assumed to be negligible.
6) See Appendix II(f) for methane (C_1) / ethane (C_2) calculations

AAB[9]

FUEL CALCULATION

Note: See Appendix I for Gas Analysis

TREATER

- ASSUMPTIONS
  - $.5 \times 10^6$ BTU/hr is manufacturer's recommended maximum use rate (see Illustration III)
  - Runtime for heater treater is 24 hours/day
  - Fuel gas BTU content = 1223.978 $\frac{BTU}{SCF}$ (see Appendix I)

$$\text{Maximum} = .5 \times 10^6 \frac{BTU}{hr} \times \frac{1\ SCF}{1223.978\ BTU} = 408.50 \frac{SCF}{hr}$$

$$\text{Average} = 408.50 \frac{SCF}{hr} \times 1.0\ (\text{runtime}) = 408.50 \frac{SCF}{hr}$$

ENGINES

- ASSUMPTIONS
  - Average fuel consumption of 7500 $\frac{BTU}{Hp \cdot Hr}$ assumed (AP-42, Table 3.3.2-1)
  - Fuel gas BTU content = 1223.978 $\frac{BTU}{SCF}$ (see Appendix I)
  - All engines natural gas fired, internal combustion engines

Four 120 HP Engines:

$$\text{Maximum} = 4 \times 120\ HP \times \frac{7500\ BTU}{HP \cdot Hr} \times \frac{1\ SCF}{1223.978\ BTU} = 2941.23 \frac{SCF}{hr}$$

$$\text{Average} = 2941.23 \times 1.0\ (\text{runtime}) = 2941.23 \frac{SCF}{hr}$$

One 100 HP Engine:

$$\text{Maximum} = 100\ HP \times \frac{7500\ BTU}{HP \cdot Hr} \times \frac{1\ SCF}{1223.978\ BTU} = 612.76 \frac{SCF}{hr}$$

$$\text{Average} = 612.76 \times 1.0\ (\text{runtime}) = 612.76 \frac{SCF}{hr}$$

One 50 HP Engine:

$$\text{Maximum} = 50\ HP \times \frac{7500\ BTU}{HP \cdot Hr} \times \frac{1\ SCF}{1223.978\ BTU} = 306.38 \frac{SCF}{hr}$$

$$\text{Average} = 306.38 \times 1.0\ (\text{runtime}) = 306.38 \frac{SCF}{hr}$$

PILOT GAS

- ASSUMPTIONS
  - Maximum fuel consumption = 50 $\frac{SCF}{hr}$ (manufacturer's recommendation)
  - Fuel gas will be supplied to pilot continuously

    Maximum = 50 $\frac{SCF}{hr}$

    Average = 50 $\frac{SCF}{hr}$ x 1.0 (runtime) = 50 $\frac{SCF}{hr}$

INSTRUMENT GAS

Negligible

TOTAL FUEL CONSUMED:

Average = Maximum = 408.50 + 2941.23 + 612.76 + 306.38 + 50 = 4318.87 $\frac{SCF}{hr}$

MAXIMUM HEAT INPUT

- BTU Content = 1223.978 $\frac{BTU}{SCF}$ (see Gas Physical Properties, Appendix I)

$4318.87 \frac{SCF}{hr} \times 1223.978 \frac{BTU}{SCF} = 5.2862 \times 10^6 \frac{BTU}{hr} = 5.2862 \frac{MMBTU}{hr}$

FUEL ANALYSIS:

- See Appendix I for Gas Analysis

% Sulfur = $\frac{9}{1 \times 10^6}$ mol fraction = .000009 = .0009%

% Ash = 0

N_2 = 10.08%

Heat Capacity:

1) $\frac{1223.978 \text{ BTU}}{\text{SCF}} \times \frac{380.68 \text{ scf}}{\text{lb mol}} \times \frac{1 \text{ lb mol}}{28.97 \text{ lbs air}} \times \frac{1 \text{ lb air}}{.8270 \text{ lb gas}}$

= 19448 BTU/lb

2) 1224 BTU/SCF

PROPOSED METHODS OF ENSURING COMPLIANCE

Minimizing Spill Potential:

1) Connections are welded.

2) Skids are equipped with drip pans to ensure oil does not drip onto the ground. Any contaminated fluid is collected and piped to the sump.

3) The sump system collects fluid from the skid drip pans and diked area around the tanks and pumps it to the saltwater tanks.

4) A Spill Prevention Control & Countermeasure (SPCC) plan will be developed for the field.

Minimizing Air Emissions:

1) A smokeless flare burns excess gas produced.

2) Tank vapors will be recovered and routed to the flare.

3) The flare has an automatic re-ignition system to minimize downtime.

4) Tank trucks are equipped with vapor recovery units, which pipe recovered vapors back into the stock tanks, to prevent the escape of hydrocarbons during oil loading operations.

Monitoring Emissions:*

1) The fuel for the heater treater firebox and engines will be analyzed annually to determine the percentage by weight of reactive hydrocarbons. VOC emissions from the heater treater firebox and all engines will be calculated using this percentage to ensure compliance with permit conditions.

2) The flow rate and composition of the gas going to flare will be determined annually. VOC, NO_x, CO and SO_2 emissions will be calculated using this data to ensure compliance with permit conditions.

3) The fuel rate to the heater treater firebox will be measured annually and emissions from the firebox will be calculated to ensure compliance with permit conditions.

4) Equipment will be properly maintained to minimize emissions due to equipment malfunctions.

MJL/AAB[55]

5) Immediate action will be taken to correct equipment malfunctions which cause excess emissions. The Florida Department of Environmental Resources (FDER) will be notified within 24 hours after discovering excess emissions due to an equipment malfunction. Notification will include the cause of the malfunction, action taken to correct the problem, and steps taken to prevent recurrance of this problem. A follow-up written response will be submitted to the FDER if requested.

6) Immediate action will be taken to correct visible smoke emissions from the flare stack. The Florida Department of Environmental Resources (FDER) will be notified within 24 hours after discovering visible smoke emissions. Notification will include the cause of visible smoke emissions, action taken to correct the problem, and action taken to prevent recurrence. A follow-up written response will be submitted to the FDER if requested.

7) Good operational practices will be adhered to during start-ups and shut-downs to minimize air emissions.

* These permit conditions will substitute for Sections 17-4.13 and 17-2.250 of the Florida Department of Environmental Regulations.

PROCESS DESCRIPTION*

Separation

As the full well stream is produced from the reservoir, it enters a three phase separator where the gas, oil, and water are separated (see Illustration IX). Gas is used as fuel, with excess going to the flare. Oil is routed to the heater treater for further treating while the water is sent to the saltwater tanks for storage.

Gas Handling

The gas off of the separator is routed to a fuel gas scrubber (see Illustration X). The scrubber removes any entrained fluids from the gas. These fluids are routed to the slop oil tank. The heater treater, six engines, and flare pilot use the scrubbed fuel gas.

Oil Treating

The oil from the separator is metered, then sent to the heater treater. The heater treater removes any residual gas in the oil and, by adding heat, separates any entrained water from the oil stream (see Illustration III). The gas is routed to the flare where it is burned. The oil and water are piped to the oil and water storage tanks, respectively.

Flare Operation

Any excess gas that is not used as fuel is sent through a flare scrubber which removes any entrained liquids. These liquids are piped to the slop oil tank. The scrubbed gas is sent to the flare. The pilot of the flare is supplied from the fuel gas line. A thermocouple at the top of the flare stack senses when the pilot goes out and the air-aspirated reignition system relights the pilot automatically.

Tank Operation

Two 1000 barrel cylindrical steel shell tanks with fixed roofs will store the produced oil. Oil may be produced into or sold from either tank. An equalizing line connects the two tanks.

The slop oil tank receives oil and water from the heater treater and scrubbers when the vessels are manually drained. After the oil and the water separate in the tank, the oil is pumped from an upper outlet on the tank to the oil storage tanks. The water is pumped from a lower outlet to the salt water storage tanks. If necessary, the slop oil tank can be recirculated to the heater treater for remedial treating.

Two saltwater tanks receive water that has been separated from the oil in the inlet separator and heater treater. Also, rainwater collected in the sump inside the tank dike walls is pumped to the saltwater tanks.

Vapor Recovery Compressor

The vapors from the oil, saltwater and slop oil tanks are collected and sent to an electric vapor recovery unit (see Illustration XI). The tank vapors are compressed from approximately 14.65 PSIA to 29.65 PSIA and are sent to the flare stack.

Engines

Six natural gas fired, internal combustion engines will be used: four 120 horsepower engines will be located at the wellhead to run pumping units, one 100 horsepower engine will be located at the tank battery to run a generator, and one 50 horsepower engine will be used to run a saltwater disposal pump. Final specifications on engines have not yet been determined.

* For clarity, the process description refers to only one well. For actual design see Illustration I.

EMISSION STACK GEOMETRY & FLOW CHARACTERISTICS

	STACK DIMENSIONS		GAS FLOW RATE		GAS EXIT		Water Vapor
	Height	Diameter	ACFM	DSCFM	Temp °F	Velocities(Ft/S)	%
1 - Heater Treater	25'	8-3/8"	300	80	1200	13.1	16.2
1 - 100 HP Engine	9'	3-1/2"	370	120	900	92.3	16.2
4 - 120 HP Engines	10'	3-1/2"	480	144	1010	119.7	16.2
1 - 50 HP Engine	7'	3-1/2"	167	60	770	41.7	16.2
1 - Flare Stack	40'	2-1/4"	559	N/A	1300	336.1*	N/A

* Gas velocity leaving flare before combustion

AAB[1]

$$\text{Volume } \frac{ft^3}{min} = 0.247 \times 380.68 \times (1200 + 460)/520 = 300 \text{ (ACFM)} = 80 \text{ (DSCFM)}$$

$$\text{Velocity } \frac{ft}{sec} = \frac{4 \times 300}{\pi \ (8.375/12)^2 \times 60} = 13.1$$

100 HP ENGINE

- ASSUMPTIONS

  - Maximum exhaust stack temperature will be approximately 900°F (historical data) with 16.2% moisture
  - Height of exhaust stack exit point will be approximately 9' (typical)
  - Internal diameter of exhaust stack exit point will be approximately 3.5" (typical)

$$\text{Total } \frac{\text{lb Mol}}{\text{Mols}} \text{ min} = \frac{\frac{2.4}{46} + \frac{.31}{28} + \frac{.2647}{51} + \frac{.001125}{64} + 13.81 \times 612.76 \times \frac{1}{380.68}}{60 \frac{\text{Mins}}{\text{hr}}}$$

$$= 0.372$$

$$\text{Volume } \frac{ft^3}{min} = 0.372 \times 380.68 \times (900 + 460)/520 = 370 \text{ (ACFM)} = 120 \text{ (DSCFM)}$$

$$\text{Velocity } \frac{ft}{sec} = \frac{4 \times 370}{\pi \ (3.5/12)^2 \times 60} = 92.3$$

120 HP ENGINE

- ASSUMPTIONS

  - Maximum exhaust stack temperature will be approximately 1010°F (historical data)
  - Height of exhaust stack exit point will be approximately 10' (typical)
  - Internal diameter of exhaust stack exit point will be approximately 3.5" (typical)

$$\text{Total } \frac{\text{lb Mol}}{\text{Mols}} \text{ min} = \frac{\frac{2.88}{46} + \frac{.372}{28} + \frac{.3177}{51} + \frac{.0014}{64} + 13.81 \times 735.30 \times \frac{1}{380.68}}{60 \frac{\text{Mins}}{\text{hr}}}$$

$$= 0.446$$

EXHAUST TEMPERATURE, VOLUME, AND VELOCITY AT STACK EXIT POINT

NATURAL GAS FIRED ENGINES & FIREBOXES:

$$\text{Total } \frac{\text{lb Mol}}{\text{Mols}} \quad \frac{\text{min}}{} = \frac{\frac{\text{Max NOx}}{46} + \frac{\text{Max CO}}{28} + \frac{\text{Max VOC}}{51^{(1)}} + \frac{\text{Max SO2}}{64} \quad \frac{\text{lbs/hr}}{\text{lbs/lb-mol}} + 13.81^{(2)} \times \text{Max. Fuel Rate } \frac{\text{SCF}}{\text{hr}} \times \frac{1}{380.68} \frac{\text{lb mol}}{\text{SCF}}}{60 \frac{\text{Mins}}{\text{hr}}}$$

$$\text{Volume } \frac{\text{ft}^3}{\text{min}} = \text{Total Mols } \frac{\text{lb mol}}{\text{min}} \times 380.68 \frac{\text{SCF}}{\text{lb mol}} \text{ Temp.°R (°F + 460)/Std Temp (60° + 460°)}$$

$$\text{Velocity } \frac{\text{ft}}{\text{sec}} = \frac{4 \times \text{Volume } \frac{\text{ft}^3}{\text{min}}}{\pi \times \text{Stack Exit Diameter (ft)}^2 \times 60 \frac{\text{sec}}{\text{min}}}$$

(1) Average molecular weight of reactive hydrocarbons in fuel gas

(2) Based on fuel gas composition:

$$12.81 \frac{\text{Mols Combustion Air}}{\text{Mol Fuel Gas}} + 1 \frac{\text{Mol Fuel Gas}}{\text{Mol Fuel Gas}} = 13.81 \frac{\text{Mols Combustion Products}}{\text{Mol Fuel Gas}}$$

HEATER TREATER

- ASSUMPTIONS
  - Maximum exhaust stack temperature will be approximately 1200°F (manufacturer's information) with 16.2% moisture
  - Height of exhaust stack exit point will be approximately 25' (manufacturer's information)
  - Internal diameter of exhaust stack exit point will be approximately 8-3/8" (manufacturer's information)

$$\text{Total } \frac{\text{lb Mol}}{\text{Mols}} \quad \frac{\text{min}}{} = \frac{\frac{.0409}{46} + \frac{.0082}{28} + \frac{.0009}{51} + \frac{.0006}{64} + 13.81 \times 408.5 \times \frac{1}{380.68}}{60 \frac{\text{Mins}}{\text{hr}}}$$

$$= 0.247$$

MJL/AAB[30b]

$$\text{Volume } \frac{ft^3}{min} = 0.446 \times 380.68 \times (1010 + 460)/520 = 480 \text{ (ACFM)} = 144 \text{ (DSCFM)}$$

$$\text{Velocity } \frac{ft}{sec} = \frac{4 \times 480}{\pi \ (3.5/12)^2 \times 60} = 119.7$$

50 HP ENGINE

- ASSUMPTIONS
  - Maximum exhaust stack temperature will be approximately 770°F (historical data)
  - Height of exhaust stack exit point will be approximately 7' (typical)
  - Internal diameter of exhaust stack exit point will be approximately 3.5" (typical)

$$\text{Total Mols } \frac{\text{lb Mol}}{\text{min}} = \frac{\frac{1.2}{46} + \frac{.155}{28} + \frac{.1342}{51} + \frac{.00056}{64} + 13.81 \times 306.38 \times \frac{1}{380.68}}{60 \frac{\text{Mins}}{\text{hr}}}$$

$$= 0.186$$

$$\text{Volume } \frac{ft^3}{min} = 0.186 \times 380.68 \times (770 + 460)/520 = 167 \text{ (ACFM)} = 60 \text{ (DSCFM)}$$

$$\text{Velocity } \frac{ft}{sec} = \frac{4 \times 167}{\pi \ (3.5/12)^2 \times 60} = 41.7$$

FLARE STACK

- ASSUMPTIONS
  - Gas temperature in flare stack will be approximately 70°F
  - Height of flare stack exit point will be approximately 40' (actual condition)
  - Internal diameter of flare stack exit point will be approximately 2.25" (actual condition)
  - Temperature of combusted gas is approximately 1300°F (typical)

Maximum volume to flare = 804,800 $\frac{ft^3}{day}$ at 60°F

. Separator gas: 675,200 $\frac{SCF}{day}$ at 63°F

. Heater treater gas: 75,200 $\frac{SCF}{day}$ at 130°F

MJL/AAB[30b]

. Tank vapors: 54,400 $\frac{SCF}{day}$

Gas Exit Velocity at Flare Tip (ft/sec):

$$\frac{\text{Volume } \frac{SCF}{day} \times \frac{144 \text{ in}^2}{1 \text{ ft}^2} \times \frac{1 \text{ Day}}{24 \text{ hrs}} \times \frac{1 \text{ hr}}{3600 \text{ sec}} \times \frac{\text{Exit } ^\circ R}{\text{Standard } ^\circ R}}{\frac{\pi (d_{tip})^2}{4}}$$

$$= \frac{(804{,}800) \times (144) \times \frac{1}{24} \times \frac{1}{3600} \times \frac{528}{530}}{\pi \frac{(2.25)^2}{4}}$$

$$= 336.1 \frac{ft}{sec}$$

MJL/AAB[30b]

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN COMMON TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

GAS PHYSICAL PROPERTIES

- ASSUMPTIONS:
  - All process gas calculations are based on a standard temperature of 60°F. All gas discharge rates to the atmosphere are based on a standard temperature of 68°F). Standard pressure is 14.65 psia.
  - All gas fully saturated with water
  - GPA Standard 2172-86 used in BTU and specific gravity determination
  - 40 CFR 60, App. A, Method 15 used to determine total sulfur, reduced sulfur, and hydrogen sulfide contents

COMPOSITION	FUEL GAS MOL %(1)	HEATER TREATER(2) GAS MOL %	STOCK TANK(2) GAS MOL %
Carbon Dioxide	1.03	1.32	0.72
Nitrogen	10.08	1.41	.11
Hydrogen Sulfide	Trace (see below)	Trace(5)	Trace (see below)
Methane	62.47	25.35	5.62
Ethane	13.71	24.16	19.71
Propane	7.79	24.88	35.68
Iso Butane	1.37	5.30	8.72
N Butane	2.22	10.23	17.41
Iso Pentane	0.55	1.24	2.11
N Pentane	0.46	4.03	6.81
Hexane	0.22	1.29	2.03
Heptanes Plus	0.10	.79	1.08
	100%	100%	100%
Gas/Oil Ratio (SCF/bbl)	422(3)	47(2)	34(2)
Specific Gravity	.8270	1.3177	1.6531
Reactive Hydrocarbons Correction (RHC)	.2729(4)	.6762	.8484
BTU Content (BTU/Ft^3)	1223.978	2120.428	2676.549

AAB[10]

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN COMMON TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

GAS PHYSICAL PROPERTIES

- ASSUMPTIONS:
  - All process gas calculations are based on a standard temperature of 60°F. All gas discharge rates to the atmosphere are based on a standard temperature of 68°F). Standard pressure is 14.65 psia.
  - All gas fully saturated with water
  - GPA Standard 2172-86 used in BTU and specific gravity determination
  - 40 CFR 60, App. A, Method 15 used to determine total sulfur, reduced sulfur, and hydrogen sulfide contents

COMPOSITION	FUEL GAS MOL %(1)	HEATER TREATER(2) GAS MOL %	STOCK TANK(2) GAS MOL %
Carbon Dioxide	1.03	1.32	0.72
Nitrogen	10.08	1.41	.11
Hydrogen Sulfide	Trace (see below)	Trace(5)	Trace (see below)
Methane	62.47	25.35	5.62
Ethane	13.71	24.16	19.71
Propane	7.79	24.88	35.68
Iso Butane	1.37	5.30	8.72
N Butane	2.22	10.23	17.41
Iso Pentane	0.55	1.24	2.11
N Pentane	0.46	4.03	6.81
Hexane	0.22	1.29	2.03
Heptanes Plus	0.10	.79	1.08
	100%	100%	100%
Gas/Oil Ratio (SCF/bbl)	422(3)	47(2)	34(2)
Specific Gravity	.8270	1.3177	1.6531
Reactive Hydrocarbons Correction (RHC)	.2729(4)	.6762	.8484
* Gross BTU Content (BTU/Ft^3)	1223.978	2120.428	2676.549
AAB[10]	$C_{3+} = 0.2729$ $C_{2+} = 0.4450$ $C_{1+} = 0.8632$	$C_{3+} = 0.6762$ $C_{2+} = 0.8673$ $C_{1+} = 0.9743$	$C_{3+} = 0.8484$ $C_{2+} = 0.9936$ $C_{1+} = 0.9927$

- SULFUR COMPOUNDS:

COMPOUND	SEPARATOR GAS(1)	STOCK TANK GAS(1)
Carbonyl Sulfide, COS	BMDL(6)	BMDL
Sulfur Dioxide	BMDL	BMDL
Carbon Disulfide	BMDL	BMDL
Methyl Mercaptan	BMDL	BMDL
Ethyl Mercaptan	BMDL	BMDL
Propyl Mercaptan	BMDL	BMDL
Butyl Mercaptan	BMDL	BMDL
Hydrogen Sulfide	9.0 ppm	19.0 ppm

(1) Obtained during most recent production test on the State of Florida 34-2 production test (April 14, 1987).

(2) Derived from computer simulation of processes using Benedict, Webb, Rubin, Starling (BWRS) equation found in: Lin, C. J., Kwok, Y. C., and Starling, K. E., paper presented at 68th National AIChE Meeting, Houston (1971); Lin, C. J., Natural Gas Memo 71002, February 24, 1971.

Assumptions used in computer simulation:

- Bottomhole compositional analysis from the State of Florida 33-1 used as a representative reservoir sample
- Separator operates at 99.65 PSIA, 63°F
- Heater treater operates at 44.65 PSIA, 130°F
- Stock tanks operate at 14.65 PSIA, 100°F

(3) Average gas/oil ratio (GOR) based on a ninety-day production test of State of Florida 33-1 and thirty-seven production test days of State of Florida 34-2

(4) $\frac{\text{Tons Reactive Hydrocarbon}}{\text{Tons Total Hydrocarbon}}$, for calculation see Appendix II(c)

(5) Heater treater H_2S mol fraction = 15.5 ppm

Estimated based on interpolation of absolute pressures between vessels and associated H_2S fractions since actual analysis not available:

	Absolute Pressure (PSIA)	H_2S Mol Fraction
Separator	99.65	9.0 ppm(1)
Stock Tank	14.65	19.0 ppm(1)
Heater Treater	44.65	15.5 ppm (interpolated)

(6) Below Minimal Detectable Level = 0.1 ppm (BMDL)

HEATER TREATER EMISSIONS

- OPERATION (see Illustration III)

The oil from the separator is metered, then sent to the heater treater. The heater treater removes any residual gas in the oil and separates any entrained water from the oil stream by adding heat. Fuel gas is supplied to the heater treater firebox. The only heater treater emissions result from burning fuel gas in the firebox which vents through a stack. All gas off the heater treater is collected and sent to the flare. Emissions from this gas are included in the flare emission calculations.

- ASSUMPTIONS

See Appendix II(a)(2)

- FIREBOX EMISSIONS

Maximum Emissions (lbs/hr)

Max. Design Fuel Rate $\frac{10^6 \text{ SCF}}{\text{hr}}$ x Emission Factor $\frac{\text{lbs}}{10^6 \text{ SCF}}$

Maximum Design Fuel Rate

= .5 x 10^6 BTU/hr (see heater treater design parameters illustration #III)

= .5 x 10^6 BTU/hr x $\frac{1 \text{ SCF}}{1223.978 \text{ BTU}}$ = 408.5041 SCF/hr

= .00041 x 10^6 SCF/hr

VOC EMISSIONS

Emissions Factors = 5.3 (non-Methane); 2.7 (Methane) (AP-42, Table 1.4-1)

Maximum Non-Methane Hydrocarbon Emissions = .00041 x 5.3 = .0022 $\frac{\text{lbs}}{\text{hr}}$

Maximum Methane Emissions = .00041 x 2.7 = 0.0011 $\frac{\text{lbs}}{\text{hr}}$

Total Hydrocarbon Emissions = 0.0033 $\frac{\text{lbs}}{\text{hr}}$

Maximum VOC Emissions = .0033 x 0.2729 = 0.0009 $\frac{\text{lbs}}{\text{hr}}$

Maximum Emissions = .0009 $\frac{\text{lbs}}{\text{hr}}$ x $\frac{24 \times 365}{2000}$ = .0039 $\frac{\text{tons}}{\text{yr}}$

AAB/MJL[37]

NOx EMISSIONS

Emissions Factor = 100 (AP-42, Table 1.4-1)

Maximum Emissions = .00041 x 100

= .0409 lbs/hr

Maximum Emissions = $.0409 \frac{\text{lbs}}{\text{hr}} \times \frac{24 \times 365}{2000}$

= .1789 T/yr

CO EMISSIONS

Emissions Factor = 20 (AP-42, Table 1.4-1)

Maximum Emissions = .00041 x 20

= .0082 lbs/hr

Maximum Emissions = $.0082 \frac{\text{lbs}}{\text{hr}} \times \frac{24 \times 365}{2000}$

= .0358 T/yr

PM EMISSIONS

Emissions Factor = 5 (AP-42, Table 1.4-1)

Maximum Emissions = .00041 x 5

= $.0020 \frac{\text{lbs}}{\text{hr}}$

Maximum Emissions = $.0020 \frac{\text{lbs}}{\text{hr}} \times \frac{24 \times 365}{2000}$

= $.0089 \frac{\text{tons}}{\text{yr}}$

SO_2 EMISSIONS

H_2S Mol Fraction = $9/(1 \times 10^6)$ (see Gas Physical Properties, Appendix I)

Maximum Emissions = $408.5041 \frac{\text{SCF}}{\text{hr}} \times \frac{9}{1 \times 10^6} \times \frac{1}{380.68} \frac{\text{lb mol}}{\text{scf}}$

$\times 64 \frac{\text{lbs } SO_2}{\text{lb mol}}$

= $.0006 \frac{\text{lbs}}{\text{hr}}$

Maximum Emissions = $.0006 \frac{\text{lbs}}{\text{hr}} \times \frac{24 \times 365}{2000}$

= $.0027 \frac{\text{tons}}{\text{yr}}$

AAB/MJL[37]

Heater Treater Capacity Clarifications

- Manufacturer's data is as follows:

Capacity *		Total Fluid Capacity
Oil (Bbls/Hr)	Water (Bbls/Day)	(Bbls/Hr)
10 - 50	550 - 4000	33 - 217

- Estimated maximum throughput:

Oil (Bbls/Hr)	Water (Bbls/Day)	Total Fluid (Bbls/Hr)
67	< 100	71

- The produced, oil and water and gas are primarily separated before reaching the heater treater. The oil stream, with any entrained water, is routed to the heater treater where the water is removed. Total fluid handling capacity of the heater treater varies as shown above. The total fluid throughput is within capacity limits; therefore, a higher oil throughput can be handled by the unit.

- Firebox lit 24 hrs/day.

* See Illustration III.

FIXED ROOF TANK EMISSIONS

- OPERATION

Two 1000 barrel cylindrical steel shell tanks with fixed roofs will store the produced oil. Oil may be produced into or sold from either tank. An equalizing line connects the two tanks.

The slop oil tank receives oil and water from the heater treater and scrubbers when the vessels are manually drained. After the oil and the water separate in the tank, the oil is pumped from an upper outlet on the tank to the oil storage tanks. The water is pumped from a lower outlet to the salt water storage tanks. If necessary, the slop oil tank can be recirculated to the heater treater for remedial treating.

The saltwater tanks receive water that has been separated from the oil in the inlet separator and heater treater. Also, rainwater collected in the sump inside the tank dike walls is pumped to the saltwater tanks.

- ASSUMPTIONS

  - Tanks operate at approximately atmospheric pressure.

  - Maximum production of 1600 barrels of oil includes all produced hydrocarbons stored in the oil tanks and the slop oil tank.

  - The flash loss calculation is a conservative empirical calculation which determines venting of natural gas from a tank as a result of a pressure drop from an upstream vessel to the atmospheric tank. All gases from the oil tanks, the slop oil tank, and the saltwater tanks are collected by a continuously operating vapor recovery system and sent to the flare (Illustration XI); therefore, no flash losses result from these tanks [see Flare Emissions, Appendix II(d)].

  - Working and breathing losses which are included in the flash loss are also collected from all the tanks.

  - Excess emissions resulting from failure of the vapor recovery system will be subject to the requirements of Exhibit VI, Monitoring Emissions.

FOUR 120 HP ENGINES

- ASSUMPTIONS
  - These engines will be used at the four wells to run pumping units.
  - Assume 100% loaded, 100% runtime; therefore, maximum emissions equal average emissions.

NATURAL GAS FIRED INTERNAL COMBUSTION ENGINES

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .00001125 (see next page for calculation)

NO_x (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097

NOx, SO_2, CO Emission Rates

Maximum Emissions

$$\text{Emission Factor } \frac{\text{lbs}}{\text{hp·hr}} \times \text{Rated hp}$$

Average Emissions

$$\text{Max. Emissions } \frac{\text{lbs}}{\text{hr}} \times \text{Runtime (fraction)} \times \text{Loading (fraction)}$$

Maximum Emissions (Lbs/hr)

NOx = .024 x 120 hp = 2.88 lb/hr x 4 engines = 11.52 lb/hr

CO = .0031 x 120 hp = .372 lb/hr x 4 engines = 1.488 lb/hr

SO_2 = .00001125 x 120 hp = .00135 lb/hr x 4 engines = .0054 lb/hr

PM = N/A

Maximum Emissions (T/yr)

$$\text{NOx} = 11.52 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 50.4576 \text{ T/yr}$$

$$\text{CO} = 1.488 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 6.5174 \text{ T/yr}$$

$$SO_2 = .0054 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = .0237 \text{ T/yr}$$

PM = N/A

FOUR 120 HP ENGINES

- ASSUMPTIONS
  - These engines will be used at the four wells to run pumping units.
  - Assume 100% loaded, 100% runtime; therefore, maximum emissions equal average emissions.

NATURAL GAS FIRED INTERNAL COMBUSTION ENGINES

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .00001125 (see next page for calculation)

NO_x (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097 (as carbon) *

NOx, SO_2, CO Emission Rates

Maximum Emissions

$$\text{Emission Factor } \frac{\text{lbs}}{\text{hp·hr}} \times \text{Rated hp}$$

Average Emissions

$$\text{Max. Emissions } \frac{\text{lbs}}{\text{hr}} \times \text{Runtime (fraction)} \times \text{Loading (fraction)}$$

Maximum Emissions (Lbs/hr)

NOx = .024 x 120 hp = 2.88 lb/hr x 4 engines = 11.52 lb/hr

CO = .0031 x 120 hp = .372 lb/hr x 4 engines = 1.488 lb/hr

SO_2 = .00001125 x 120 hp = .00135 lb/hr x 4 engines = .0054 lb/hr

PM = N/A

Maximum Emissions (T/yr)

$$\text{NOx} = 11.52 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 50.4576 \text{ T/yr}$$

$$\text{CO} = 1.488 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 6.5174 \text{ T/yr}$$

$$SO_2 = .0054 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = .0237 \text{ T/yr}$$

PM = N/A

SO_2 EMISSION FACTOR DETERMINATION

$\frac{1 \text{ grain}}{100 \text{ SCF}}$ = 16 ppm H_2S (estimate)

$\frac{.2 \text{ grains}}{100 \text{ SCF}}$ = 3.2 ppm H_2S = .000004 $\frac{\text{lbs}}{\text{hp·hr}}$ (AP-42, Table 3.3.2-1)

therefore,

9 ppm (see Appendix I) = .00001125 $\frac{\text{lbs}}{\text{hp·hr}}$

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ x hp x RHC Correction

= .0097 x 120 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 100%

RHC Correction (Note: Fuel gas lines will supply engines with natural gas)

	Mol Fraction %	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	10.08		28.013		2.8238	N
CO_2 =	1.03		44.010		.4533	N
C_1 =	62.47		16.043		10.0221	N
C_2 =	13.71		30.070		4.1226	N
C_3 =	7.79		44.097		3.4352	Y
iC_4 =	1.37		58.123		.7963	Y
nC_4 =	2.22		58.123		1.2903	Y
iC_5 =	0.55		72.150		.3968	Y
nC_5 =	0.46		72.150		.3319	Y
C_6 =	0.22		86.177		.1896	Y
C_7 =	0.10		100.204		.1002	Y
	100				23.9620	

RHC Correction = $\frac{3.4352 + .7963 + 1.2903 + .3968 + .3319 + .1896 + .1002}{23.9620}$

RHC Correction = .2729

MAXIMUM EMISSIONS RATE (Lbs/hr)

.0097 x 120 x .2729 = .3177 $\frac{\text{lb}}{\text{hr}}$ x 4 = 1.2706 $\frac{\text{lb}}{\text{hr}}$

AAB[44]

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ x hp x RHC Correction

= .0097 x 120 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 100%

RHC Correction (Note: Fuel gas lines will supply engines with natural gas)

	Mol Fraction %	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	10.08		28.013		2.8238	N
CO_2 =	1.03		44.010		.4533	N
C_1 =	62.47		16.043		10.0221	N
C_2 =	13.71		30.070		4.1226	N
C_3 =	7.79		44.097		3.4352	Y
iC_4 =	1.37		58.123		.7963	Y
nC_4 =	2.22		58.123		1.2903	Y
iC_5 =	0.55		72.150		.3968	Y
nC_5 =	0.46		72.150		.3319	Y
C_6 =	0.22		86.177		.1896	Y
C_7 =	0.10		100.204		.1002	Y
	100				23.9620	

RHC Correction = $\frac{3.4352 + .7963 + 1.2903 + .3968 + .3319 + .1896 + .1002}{23.9620}$

RHC Correction = .2729

MAXIMUM EMISSIONS RATE (Lbs/hr)

.0097 x 1.217 $\frac{\text{lbs RHC}}{\text{LB Carbon RHC}}$ x 120 x .2729 = .3868 $\frac{\text{lb}}{\text{hr}}$ x 4 = 1.5470 $\frac{\text{lb}}{\text{hr}}$ *

AAB[44]

MAXIMUM EMISSIONS RATE (T/yr)

$$1.2706 \frac{\text{lbs}}{\text{hr}} \times \frac{24 \times 365}{2000} = 5.5653 \frac{\text{tons}}{\text{yr}}$$

AAB[44]

MAXIMUM EMISSIONS RATE (T/yr)

$$1.5470 \frac{\text{lbs}}{\text{hr}} \times \frac{24 \times 365}{2000} = 6.7750 \frac{\text{tons}}{\text{yr}} \ *$$

ONE 100 HP ENGINE

- ASSUMPTIONS
  - This engine will be used at the facility to run lights, pumps, etc.
  - Assume 100% loaded, 100% runtime; therefore, maximum emissions equal average emissions.

NATURAL GAS FIRED INTERNAL COMBUSTION ENGINE

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .00001125 (see next page for calculation)

NO_X (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097

NOx, SO_2, CO Emission Rates

Maximum Emissions

$$\text{Emission Factor } \frac{\text{lbs}}{\text{hp hr}} \times \text{Rated hp}$$

Average Emissions

$$\text{Max. Emissions } \frac{\text{lbs}}{\text{hr}} \times \text{Runtime (fraction)} \times \text{Loading (fraction)}$$

Maximum Emissions (Lbs/hr)

NOx = .024 x 100 hp = 2.4 lb/hr

CO = .0031 x 100 hp = .31 lb/hr

SO_2 = .00001125 x 100 hp = .001125 lb/hr

PM = N/A

Maximum Emissions (T/hr)

$$NO_x = 2.4 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 10.5120 \text{ T/yr}$$

$$CO = .31 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 1.3578 \text{ T/yr}$$

$$SO_2 = .001125 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = .0049 \text{ T/yr}$$

PM = N/A

AAB[21B]

ONE 100 HP ENGINE

- ASSUMPTIONS
  - This engine will be used at the facility to run lights, pumps, etc.
  - Assume 100% loaded, 100% runtime; therefore, maximum emissions equal average emissions.

NATURAL GAS FIRED INTERNAL COMBUSTION ENGINE

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .00001125 (see next page for calculation)

NO_x (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097 (as carbon) *

NOx, SO_2, CO Emission Rates

Maximum Emissions

$$\text{Emission Factor } \frac{\text{lbs}}{\text{hp hr}} \times \text{Rated hp}$$

Average Emissions

$$\text{Max. Emissions } \frac{\text{lbs}}{\text{hr}} \times \text{Runtime (fraction)} \times \text{Loading (fraction)}$$

Maximum Emissions (Lbs/hr)

NOx = .024 x 100 hp = 2.4 lb/hr

CO = .0031 x 100 hp = .31 lb/hr

SO_2 = .00001125 x 100 hp = .001125 lb/hr

PM = N/A

Maximum Emissions (T/hr)

$$NO_x = 2.4 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 10.5120 \text{ T/yr}$$

$$CO = .31 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 1.3578 \text{ T/yr}$$

$$SO_2 = .001125 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = .0049 \text{ T/yr}$$

PM = N/A

AAB[21B]

SO_2 EMISSION FACTOR DETERMINATION

$\frac{1 \text{ grain}}{100 \text{ SCF}}$ = 16 ppm H_2S (estimate)

$\frac{.2 \text{ grains}}{100 \text{ SCF}}$ = 3.2 ppm H_2S = .000004 $\frac{\text{lbs}}{\text{hp·hr}}$ (AP-42, Table 3.3.2-1)

therefore,

9 ppm (see Appendix I) = .00001125 $\frac{\text{lbs}}{\text{hp·hr}}$

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ x hp x RHC Correction

= .0097 x 100 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 100%

RHC Correction

	Mol Fraction %	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	10.08		28.013		2.8238	N
CO_2 =	1.03		44.010		.4533	N
C_1 =	62.47		16.043		10.0221	N
C_2 =	13.71		30.070		4.1226	N
C_3 =	7.79		44.097		3.4352	Y
iC_4 =	1.37		58.123		.7963	Y
nC_4 =	2.22		58.123		1.2903	Y
iC_5 =	0.55		72.150		.3968	Y
nC_5 =	0.46		72.150		.3319	Y
C_6 =	0.22		86.177		.1896	Y
C_7 =	0.10		100.204		.1002	Y
	100				23.9620	

RHC Correction = .2729

MAXIMUM EMISSIONS RATE (Lbs/hr)

.0097 x 100 x .2729 = .2647 $\frac{\text{lb}}{\text{hr}}$

MAXIMUM EMISSIONS RATE (T/yr)

.2647 $\frac{\text{lbs}}{\text{hr}}$ x $\frac{24 \times 365}{2000}$ = 1.1594 $\frac{\text{tons}}{\text{yr}}$

AAB[21B]

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ x hp x RHC Correction

= .0097 x 100 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 100%

RHC Correction

	Mol Fraction %	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	10.08		28.013		2.8238	N
CO_2 =	1.03		44.010		.4533	N
C_1 =	62.47		16.043		10.0221	N
C_2 =	13.71		30.070		4.1226	N
C_3 =	7.79		44.097		3.4352	Y
iC_4 =	1.37		58.123		.7963	Y
nC_4 =	2.22		58.123		1.2903	Y
iC_5 =	0.55		72.150		.3968	Y
nC_5 =	0.46		72.150		.3319	Y
C_6 =	0.22		86.177		.1896	Y
C_7 =	0.10		100.204		.1002	Y
	100				23.9620	

RHC Correction = .2729

MAXIMUM EMISSIONS RATE (Lbs/hr)

.0097 x 1.217 $\frac{\text{LBS RHC}}{\text{LB CARBON RHC}}$ x 100 x .2729 = .3222 $\frac{\text{lb}}{\text{hr}}$ *

MAXIMUM EMISSIONS RATE (T/yr)

.3222 $\frac{\text{lbs}}{\text{hr}}$ x $\frac{24 \times 365}{2000}$ = 1.4114 $\frac{\text{tons}}{\text{yr}}$

VOC corr for APTS C_2^+

$\frac{10.6629}{23.9620} = 0.4450$

AAB[21B]

ONE 50 HP ENGINE

- ASSUMPTIONS
  - This engine will be used to run a saltwater disposal pump. This engine may not be installed, depending on the amount of water produced by the field.
  - Assume 100% loaded, 100% runtime; therefore, maximum emissions equal average emissions.

NATURAL GAS FIRED INTERNAL COMBUSTION ENGINES

$$BHP = \frac{GPM \times \Delta P}{1714 \times Eo}$$

Eo = Efficiency = 50%
ΔP = 1600 psi
GPM = 15

$$BHP = \frac{15 \times 1600}{1714 \times .50} = 28 \text{ BHP}$$

Therefore, use 50 BHP maximum

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .00001125 (see SO_2 Emission Factor Determination)

NO_x (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097

NOx, SO_2, CO Emission Rates

Maximum Emissions

Emission Factor $\frac{lbs}{hp\ hr}$ x Rated hp

Average Emissions

Max. Emissions $\frac{lbs}{hr}$ x Runtime (fraction) x Loading (fraction)

Maximum Emissions (Lbs/hr)

NOx = .024 x 50 hp = 1.2 lb/hr

CO = .0031 x 50 hp = .155 lb/hr

SO_2 = .00001125 x 50 hp = .00056 lb/hr

PM = N/A

AAB[20b]

ONE 50 HP ENGINE

- ASSUMPTIONS
  - This engine will be used to run a saltwater disposal pump. This engine may not be installed, depending on the amount of water produced by the field.
  - Assume 100% loaded, 100% runtime; therefore, maximum emissions equal average emissions.

NATURAL GAS FIRED INTERNAL COMBUSTION ENGINES

$$BHP = \frac{GPM \times \Delta P}{1714 \times Eo}$$

Eo = Efficiency = 50%
ΔP = 1600 psi
GPM = 15

$$BHP = \frac{15 \times 1600}{1714 \times .50} = 28 \text{ BHP}$$

Therefore, use 50 BHP maximum

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .00001125 (see SO_2 Emission Factor Determination)

NO_x (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097 (as carbon) *

NOx, SO_2, CO Emission Rates

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp hr}}$ x Rated hp

Average Emissions

Max. Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime (fraction) x Loading (fraction)

Maximum Emissions (Lbs/hr)

NOx = .024 x 50 hp = 1.2 lb/hr

CO = .0031 x 50 hp = .155 lb/hr

SO_2 = .00001125 x 50 hp = .00056 lb/hr

PM = N/A

AAB[20b]

Maximum Emissions (T/yr)

$NOx = 1.2 \frac{lb}{hr} \times \frac{365 \times 24}{2000} = 5.2560$ T/yr

$CO = .155 \frac{lb}{hr} \times \frac{365 \times 24}{2000} = .6789$ T/yr

$SO_2 = .00056 \frac{lb}{hr} \times \frac{365 \times 24}{2000} = .0025$ T/yr

PM = N/A

SO_2 EMISSION FACTOR DETERMINATION

$\frac{1 \text{ grain}}{100 \text{ SCF}}$ = 16 ppm H_2S (estimate)

$\frac{.2 \text{ grains}}{100 \text{ SCF}}$ = 3.2 ppm H_2S = .000004 $\frac{\text{lbs}}{\text{hp·hr}}$ (AP-42, Table 3.3.2-1)

therefore,

9 ppm (see Appendix I) = .00001125 $\frac{\text{lbs}}{\text{hp·hr}}$

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp·hr}}$ x hp x RHC Correction

= .0097 x 50 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 100%

RHC Correction

	Mol Fraction %	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	10.08		28.013		2.8238	N
CO_2 =	1.03		44.010		.4533	N
C_1 =	62.47		16.043		10.0221	N
C_2 =	13.71		30.070		4.1226	N
C_3 =	7.79		44.097		3.4352	Y
iC_4 =	1.37		58.123		.7963	Y
nC_4 =	2.22		58.123		1.2903	Y
iC_5 =	0.55		72.150		.3968	Y
nC_5 =	0.46		72.150		.3319	Y
C_6 =	0.22		86.177		.1896	Y
C_7 =	0.10		100.204		.1002	Y
	100				23.9620	

RHC Correction = .2729

MAXIMUM EMISSIONS RATE (Lbs/hr)

.0097 x 50 x .2729 = .1324 $\frac{\text{lb}}{\text{hr}}$

MAXIMUM EMISSIONS RATE (T/yr)

.1324 $\frac{\text{lbs}}{\text{hr}}$ x $\frac{24 \times 365}{2000}$ = .5797 $\frac{\text{tons}}{\text{yr}}$

AAB[20b]

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp·hr}}$ x hp x RHC Correction

= .0097 x 50 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 100%

RHC Correction

	Mol Fraction %	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	10.08		28.013		2.8238	N
CO_2 =	1.03		44.010		.4533	N
C_1 =	62.47		16.043		10.0221	N
C_2 =	13.71		30.070		4.1226	N
C_3 =	7.79		44.097		3.4352	Y
iC_4 =	1.37		58.123		.7963	Y
nC_4 =	2.22		58.123		1.2903	Y
iC_5 =	0.55		72.150		.3968	Y
nC_5 =	0.46		72.150		.3319	Y
C_6 =	0.22		86.177		.1896	Y
C_7 =	0.10		100.204		.1002	Y
	100				23.9620	

RHC Correction = .2729

MAXIMUM EMISSIONS RATE (Lbs/hr)

.0097 x 1.217 $\frac{\text{LBS RHC}}{\text{LBS CARBON RHC}}$ x 50 x .2729 = .1612 $\frac{\text{lb}}{\text{hr}}$ *

MAXIMUM EMISSIONS RATE (T/yr)

.1612 $\frac{\text{lbs}}{\text{hr}}$ x $\frac{24 \times 365}{2000}$ = .7057 $\frac{\text{tons}}{\text{yr}}$ *

AAB[20b]

FLARE EMISSIONS

- OPERATION

  - Flare is a non-assisted, smokeless, self-aspirating flare. An automatic re-ignition system insures that under normal operating conditions, the flare is continuously lit.

  - Excess gases from the separator, heater treater, and tanks are collected and sent to the flare where they are burned.

- ASSUMPTIONS

  - 98% combustion efficiency is assumed since the flare complies with all criteria set forth in Section 60.622 of

    Environmental Protection Agency (EPA), 40 CFR Part 60 Standards of Performance for New Stationary Sources VOC Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Unit Operations, [AD-FRL-2280-31, 48 FR 57538, December 30, 1983].

    and the amended requirements for control devises which apply to the above reference (Federal Register/Vol. 51, No. 13/Tuesday, January 21, 1986/Rules and Regulations/Part 60-Amended).

    These criteria for non-assisted flares are:

	BTU	Velocity
EPA Accepted	> 1000 BTU/SCF	< 400 ft/sec
Proposed Flare	1405.90 BTU/SCF(1)	336.1 ft/sec(2)

(1) Composite BTU calculated as follows:

COMPOSITION CONTENT (see Gas Physical Properties, Appendix I)

Gas to Flare	BTU/SCF	Rate (SCF/Day)	% Rate	Total BTU
Separator (fuel gas)	1223.978	675,200	83.90%	1026.92
Heater Treater	2120.428	75,200	9.34%	198.05
Stock Tank	2676.549	54,400	6.76%	180.93
		804,800	100%	1405.90

(2) See Exhibit VIII.

Les Evans with the Environmental Protection Agency, Research Triangle Park, North Carolina, has advised that the above are the best available guidelines regarding flare efficiency and are used in various applications including the petroleum industry. It should be noted that a 98% combustion efficiency assumption is a conservative estimate according to Mr. Evans.

- NO_x and CO emission estimates determined from the Environmental Protection Agency Flare Efficiency Study, EPA-600/2-83-052, July 1983.

MJL/AAB[19b]

FLARE EMISSIONS

- OPERATION

  - Flare is a non-assisted, smokeless, self-aspirating flare. An automatic re-ignition system insures that under normal operating conditions, the flare is continuously lit.

  - Excess gases from the separator, heater treater, and tanks are collected and sent to the flare where they are burned.

- ASSUMPTIONS

  - 98% combustion efficiency is assumed since the flare complies with all criteria set forth in Section 60.622 of

    Environmental Protection Agency (EPA), 40 CFR Part 60 Standards of Performance for New Stationary Sources VOC Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Unit Operations, [AD-FRL-2280-31, 48 FR 57538, December 30, 1983].

    and the amended requirements for control devises which apply to the above reference (Federal Register/Vol. 51, No. 13/Tuesday, January 21, 1986/Rules and Regulations/Part 60-Amended).

    These criteria for non-assisted flares are:

	Net BTU	Velocity
EPA Accepted	> 1000 BTU/SCF	< 400 ft/sec
Proposed Flare	1281.57 BTU/SCF(1) *	336.1 ft/sec(2)

(1) Composite BTU calculated as follows:

COMPOSITION CONTENT (see Gas Physical Properties, Appendix I)

Gas to Flare	Net BTU/SCF*	Rate (SCF/Day)	% Rate	Total BTU *
Separator (fuel gas)	1112.40	675,200	83.90%	933.30
Heater Treater	1945.76	75,200	9.34%	181.73
Stock Tank	2463.66	54,400	6.76%	166.54
		804,800	100%	1281.57

* Net BTU calculated in accordance with GPA Standard 2172-86 and GPSA Engineering Data Book, 1987.

(2) See Exhibit VIII.

Les Evans with the Environmental Protection Agency, Research Triangle Park, North Carolina, has advised that the above are the best available guidelines regarding flare efficiency and are used in various applications including the petroleum industry. It should be noted that a 98% combustion efficiency assumption is a conservative estimate according to Mr. Evans.

MJL/AAB[19b]

- Excess emissions resulting from failure of the flare system will comply with the requirements of Exhibit VI, Monitoring Emissions.
- Maximum production = 4 wells x 400 $\frac{bbl}{well}$ = 1600 $\frac{bbl}{day}$
- No fuel gas using equipment operating for maximum possible emissions calculations
- Pure $CO_2 + N_2$ in gas stream are inert.
- Pilot gas included in total flare throughput.
- Natural gas burns clean; therefore, particulate matter is negligible.

SO_2 EMISSIONS

$$SO_2 \text{ (lbs/hr)} = \text{Flare Rate } \frac{SCF}{day} \times H_2S \frac{Mol}{Fraction} \times \frac{1}{380.68} \frac{lb \cdot mol}{SCF}$$

$$\times 64 \frac{\text{lbs } SO_2}{SCF} \times \frac{1}{24} \frac{Day}{hr}$$

MAXIMUM EMISSIONS

- Maximum Gas Off of Separators (see Gas Physical Properties, Appendix I)

  GOR = 422 $\frac{SCF}{bbl}$

  Gas Rate = 422 $\frac{SCF}{bbl}$ x 1600 $\frac{bbl}{day}$ = 675,200 $\frac{SCF}{day}$

  H_2S mol fraction = $9/1 \times 10^6$

- Maximum Gas Off of Heater Treater (see Gas Physical Properties, Appendix I)

  GOR = 47 $\frac{SCF}{day}$

  Gas Rate = 47 $\frac{SCF}{bbl}$ x 1600 $\frac{bbl}{day}$ = 75,200 $\frac{SCF}{day}$

  H_2S mol fraction = $15.5/1 \times 10^6$

- Maximum Gas Off Tanks (see Gas Physical Properties, Appendix I)

  GOR = 34 $\frac{SCF}{day}$

- NO_x and CO emission estimates determined from the Environmental Protection Agency Flare Efficiency Study, EPA-600/2-83-052, July 1983.
- Excess emissions resulting from failure of the flare system will comply with the requirements of Exhibit VI, Monitoring Emissions.
- Maximum production = 4 wells x 400 $\frac{bbl}{well}$ = 1600 $\frac{bbl}{day}$
- No fuel gas using equipment operating for maximum possible emissions calculations
- Pure $CO_2 + N_2$ in gas stream are inert.
- Pilot gas included in total flare throughput.
- Natural gas burns clean; therefore, particulate matter is negligible.

SO_2 EMISSIONS

$$SO_2 \text{ (lbs/hr)} = \text{Flare Rate } \frac{SCF}{day} \times H_2S \frac{Mol}{Fraction} \times \frac{1}{380.68} \frac{lb \cdot mol}{SCF}$$

$$\times 64 \frac{\text{lbs } SO_2}{SCF} \times \frac{1}{24} \frac{Day}{hr}$$

MAXIMUM EMISSIONS

- Maximum Gas Off of Separators (see Gas Physical Properties, Appendix I)

  GOR = 422 $\frac{SCF}{bbl}$

  Gas Rate = 422 $\frac{SCF}{bbl}$ x 1600 $\frac{bbl}{day}$ = 675,200 $\frac{SCF}{day}$

  H_2S mol fraction = $9/1 \times 10^6$

- Maximum Gas Off of Heater Treater (see Gas Physical Properties, Appendix I)

  GOR = 47 $\frac{SCF}{day}$

  Gas Rate = 47 $\frac{SCF}{bbl}$ x 1600 $\frac{bbl}{day}$ = 75,200 $\frac{SCF}{day}$

  H_2S mol fraction = $15.5/1 \times 10^6$

- Maximum Gas Off Tanks (see Gas Physical Properties, Appendix I)

  GOR = 34 $\frac{SCF}{day}$

MJL/AAB[19b]

Gas Rate = 36 $\frac{SCF}{bbl}$ x 1600 $\frac{bbl}{day}$ = 54,400 $\frac{SCF}{day}$

H_2S mol fraction = 19/1 x 10^6

- Maximum SO_2 Emissions

Separator Gas = 675,200 $\frac{SCF}{day}$ x $\frac{9}{1 \times 10^6}$ x $\frac{1}{380.68}$ $\frac{lb \cdot mol}{SCF}$

x 64 $\frac{lbs\ SO_2}{SCF}$ x $\frac{1}{24}$ $\frac{Days}{hr}$

= .0426 lbs/hr

Heater Treater Gas = 75,200 $\frac{SCF}{day}$ x $\frac{15.5}{1 \times 10^6}$ x $\frac{1}{380.68}$ $\frac{lb \cdot mol}{SCF}$

x 64 $\frac{lbs\ SO_2}{SCF}$ x $\frac{1}{24}$ $\frac{Days}{hr}$

= .0082 lbs/hr

Tank Gas = 54,400 $\frac{SCF}{day}$ x $\frac{19}{1 \times 10^6}$ x $\frac{1}{380.68}$ $\frac{lb \cdot mol}{SCF}$

x 64 $\frac{lbs\ SO_2}{SCF}$ x $\frac{1}{24}$ $\frac{Days}{hr}$

= .0072 lbs/hr

Total SO_2 Emissions = .0426 + .0082 + .0072
= .058 lbs/hr
= .2540 tons/yr

NOx EMISSIONS (EPA-600/2-83-052, July 1983, pg. 40)

4 flares with high BTU contents studied with NOx emissions as follows:

1. $\frac{.132\ lbs\ NOx}{MMBTU}$ (air assisted)
2. $\frac{.076\ lbs\ NOx}{MMBTU}$ (non assisted)
3. $\frac{.208\ lbs\ NOx}{MMBTU}$ (air assisted)
4. $\frac{.136\ lbs\ NOx}{MMBTU}$ (air assisted)

Non assisted estimate chosen since this case most closely models actual flare stack conditions.

Gas Rate = 36 $\frac{SCF}{bbl}$ x 1600 $\frac{bbl}{day}$ = 54,400 $\frac{SCF}{day}$

H_2S mol fraction = 19/1 x 10^6

- Maximum SO_2 Emissions

Separator Gas = 675,200 $\frac{SCF}{day}$ x $\frac{9}{1 \times 10^6}$ x $\frac{1}{380.68}$ $\frac{lb \cdot mol}{SCF}$

x 64 $\frac{lbs\ SO_2}{SCF}$ x $\frac{1}{24}$ $\frac{Days}{hr}$

= .0426 lbs/hr

Heater Treater Gas = 75,200 $\frac{SCF}{day}$ x $\frac{15.5}{1 \times 10^6}$ x $\frac{1}{380.68}$ $\frac{lb \cdot mol}{SCF}$

x 64 $\frac{lbs\ SO_2}{SCF}$ x $\frac{1}{24}$ $\frac{Days}{hr}$

= .0082 lbs/hr

Tank Gas = 54,400 $\frac{SCF}{day}$ x $\frac{19}{1 \times 10^6}$ x $\frac{1}{380.68}$ $\frac{lb \cdot mol}{SCF}$

x 64 $\frac{lbs\ SO_2}{SCF}$ x $\frac{1}{24}$ $\frac{Days}{hr}$

= .0072 lbs/hr

Total SO_2 Emissions = .0426 + .0082 + .0072
= .058 lbs/hr
= .2540 tons/yr

NOx EMISSIONS (EPA-600/2-83-052, July 1983, pg. 40 & EPA-600/2-85-106)

- EPA-600/2-83-052

4 flares with high BTU contents studied with NOx emissions as follows:

1. $\frac{.132\ lbs\ NOx}{MMBTU}$ (air assisted)
2. $\frac{.076\ lbs\ NOx}{MMBTU}$ (non assisted)
3. $\frac{.208\ lbs\ NOx}{MMBTU}$ (air assisted)
4. $\frac{.136\ lbs\ NOx}{MMBTU}$ (air assisted)

- EPA-600/2-85-106 *

NOx emissions are generally found to be less than $\frac{.1\ lbs\ NOx}{MMBTU}$.

Based on these two references, emission factor of $\frac{.1\ lbs\ NOx}{MMBTU}$ was selected.

MJL/AAB[19b]

$$\text{MAXIMUM NOx EMISSIONS} = \frac{.076 \text{ lbs NOx}}{\text{MMBTU}} \times \frac{1405.90 \text{ BTU}}{\text{SCF}} \times \frac{1 \text{ MMBTU}}{1 \times 10^6 \text{ BTU}}$$

$$= .00011 \frac{\text{lbs NOx}}{\text{SCF}} \times \frac{804{,}800 \text{ SCF}}{\text{Day}}$$

$$= 85.99 \frac{\text{lbs NOx}}{\text{Day}}$$

$$= 3.58 \frac{\text{lbs NOx}}{\text{Hr}}$$

$$= 15.69 \frac{\text{Tons NOx}}{\text{Yr}}$$

CO EMISSIONS (EPA-600/12-83-052, July 1983, Pg. 58)

The ratio below is given by the EPA:

$$\frac{CO}{CO_2} = \frac{8}{7000} \text{ (PPM Vol)}$$

Assuming a 98% combustion efficiency, 98% of all carbon is combusted to CO_2 in the flare.

1) SEPARATOR GAS

- Carbon from Hydrocarbons:

FORMULA	MOL %	M. W. (Lbs/Lb Mol)	CARBON (Lbs/Lb Mol)	MOL % x LBS C
C_1	62.47	16.043	12.0112	7.5034
C_2	13.71	30.070	24.0223	3.2935
C_3	7.79	44.097	36.0334	2.8070
iC_4	1.37	58.123	48.0435	0.6582
nC_4	2.22	58.123	48.0435	1.0666
iC_5	0.55	72.150	60.0546	0.3303
nC_5	0.46	72.150	60.0546	0.2763
C_6	0.22	86.177	72.0657	0.1585
C_7	0.10	100.204	84.0768	0.0841
				16.1778

- Carbon to Flare = $\frac{16.1778 \text{ lbs}}{\text{lb·mol gas}} \times \frac{\text{lb mol}}{380.68 \text{ SCF}} \times \frac{675{,}200 \text{ SCF}}{\text{day}}$

$$= 28694.05 \frac{\text{lbs}}{\text{day}}$$

$$= \frac{28694.05 \text{ lbs/day}}{12.0112 \text{ lbs/lb·mol}}$$

$$= 2388.94 \frac{\text{mol}}{\text{day}}$$

MJL/AAB[19b]

$$\text{MAXIMUM NOx EMISSIONS} = \frac{.1 \text{ lbs NOx}}{\text{MMBTU}} \times \frac{1281.57 \text{ BTU}}{\text{SCF}} \times \frac{1 \text{ MMBTU}}{1 \times 10^6 \text{ BTU}}$$

$$= .00013 \frac{\text{lbs NOx}}{\text{SCF}} \times \frac{804{,}800 \text{ SCF}}{\text{Day}}$$

$$= 103.14 \frac{\text{lbs NOx}}{\text{Day}}$$

$$= 4.30 \frac{\text{lbs NOx}}{\text{Hr}}$$

$$= 18.82 \frac{\text{Tons NOx}}{\text{Yr}} \quad *$$

CO EMISSIONS (EPA-600/12-83-052, July 1983, Pg. 58)

The ratio below is given by the EPA:

$$\frac{CO}{CO_2} = \frac{8}{7000} \text{ (PPM Vol)}$$

Assuming a 98% combustion efficiency, 98% of all carbon is combusted to CO_2 in the flare.

1) SEPARATOR GAS

- Carbon from Hydrocarbons:

FORMULA	MOL %	M. W. (Lbs/Lb Mol)	CARBON (Lbs/Lb Mol)	MOL % x LBS C
C_1	62.47	16.043	12.0112	7.5034
C_2	13.71	30.070	24.0223	3.2935
C_3	7.79	44.097	36.0334	2.8070
iC_4	1.37	58.123	48.0435	0.6582
nC_4	2.22	58.123	48.0435	1.0666
iC_5	0.55	72.150	60.0546	0.3303
nC_5	0.46	72.150	60.0546	0.2763
C_6	0.22	86.177	72.0657	0.1585
C_7	0.10	100.204	84.0768	0.0841
				16.1778

- Carbon to Flare = $\frac{16.1778 \text{ lbs}}{\text{lb·mol gas}} \times \frac{\text{lb mol}}{380.68 \text{ SCF}} \times \frac{675{,}200 \text{ SCF}}{\text{day}}$

$$= 28694.05 \frac{\text{lbs}}{\text{day}}$$

$$= \frac{28694.05 \text{ lbs/day}}{12.0112 \text{ lbs/lb·mol}}$$

$$= 2388.94 \frac{\text{mol}}{\text{day}}$$

98% of carbon combusted to CO_2 = .98 (2388.94 mol/day)

= 2341.16 $\frac{mol}{day}$

- CO Emissions:

$$\frac{8}{7000} = \frac{CO}{2341.16}$$

$$CO = 2.68 \frac{mol}{day} \times 28.010 \frac{lbs}{lb \cdot mol}$$

$$= 79.94 \frac{lbs}{day}$$

$$= 3.13 \frac{lbs}{hr}$$

$$= 13.68 \frac{tons}{yr}$$

2) HEATER TREATER GAS

- Carbon from Hydrocarbons:

FORMULA	MOL %	M. W. (Lbs/Lb Mol)	CARBON (Lbs/Lb Mol)	MOL % x LBS C
C_1	25.35	16.043	12.0112	3.0452
C_2	24.16	30.070	24.0223	5.8031
C_3	24.88	44.097	36.0334	8.9655
iC_4	5.30	58.123	48.0435	2.5468
nC_4	10.23	58.123	48.0435	4.9129
iC_5	1.24	72.150	60.0546	0.7429
nC_5	4.03	72.150	60.0546	2.4190
C_6	1.29	86.177	72.0657	0.9325
C_7	0.79	100.204	84.0768	0.6634
				30.0312

- Carbon to Flare = $\frac{30.0312 \text{ lbs}}{\text{lb·mol gas}} \times \frac{\text{lb mol}}{380.68 \text{ SCF}} \times \frac{75{,}200 \text{ SCF}}{\text{day}}$

$$= 5932.40 \frac{lbs}{day}$$

$$= \frac{5932.40 \text{ lbs/day}}{12.0112 \text{ lbs/lb·mol}}$$

$$= 493.91 \frac{mol}{day}$$

98% of carbon combusted to CO_2 = .98 (493.91 mol/day)

= 484.03 $\frac{mol}{day}$

- CO Emissions:

$$\frac{8}{7000} = \frac{CO}{484.03}$$

$$CO = .553 \frac{mol}{day} \times 28.010 \frac{lbs}{lb \cdot mol}$$

$$= 15.49 \frac{lbs}{day}$$

$$= .65 \frac{lbs}{hr}$$

$$= 2.83 \frac{tons}{yr}$$

3) STOCK TANK GAS

- Carbon from Hydrocarbons:

FORMULA	MOL %	M. W. (Lbs/Lb Mol)	CARBON (Lbs/Lb Mol)	MOL % x LBS C
C_1	5.62	16.043	12.0112	0.6749
C_2	19.71	30.070	24.0223	4.7355
C_3	35.68	44.097	36.0334	12.8564
iC_4	8.72	58.123	48.0435	4.1884
nC_4	17.41	58.123	48.0435	8.3620
iC_5	2.11	72.150	60.0546	1.2684
nC_5	6.81	72.150	60.0546	4.0873
C_6	2.03	86.177	72.0657	1.4622
C_7	1.08	100.204	84.0768	0.9072
				38.5423

- Carbon to Flare = $\frac{38.5423 \text{ lbs}}{\text{lb·mol gas}} \times \frac{\text{lb mol}}{380.68 \text{ SCF}} \times \frac{54{,}400 \text{ SCF}}{\text{day}}$

$$= 5507.78 \frac{lbs}{day}$$

$$= \frac{5507.78 \text{ lbs/day}}{12.0112 \text{ lbs/lb·mol}}$$

$$= 458.55 \frac{mol}{day}$$

98% of carbon combusted to CO_2 = .98 (458.55 mol/day)

$$= 449.38 \frac{mol}{day}$$

- CO Emissions:

$$\frac{8}{7000} = \frac{CO}{449.38}$$

MJL/AAB[19b]

$$CO = .514 \frac{mol}{day} \times 28.010 \frac{lbs}{lb \cdot mol}$$

$$= 14.38 \frac{lbs}{day}$$

$$= .60 \frac{lbs}{hr}$$

$$= 2.63 \frac{tons}{yr}$$

Total CO Emissions (lbs/hr) = 3.13 + .65 + .60
= 4.38 lbs/hr
= 19.18 tons/yr

VOC EMISSIONS

. Separator Gas Stream

- Maximum Flow Rate to Flare = 675,200 SCF/day
- Specific Gravity of Gas = 0.8270
- RHC Correction = 0.2729

. Heater Treater Gas

- Maximum Flow Rate to Flare = 75,200 SCF/day
- Specific Gravity of Gas = 1.3177
- RHC Correction = 0.6762

. Tank Vapors

- Maximum Flow Rate to Flare = 54,400 SCF/day
- Specific Gravity of Gas = 1.6531
- RHC Correction = 0.8484

$$\text{VOC Emissions} = \frac{SCF}{day} \times (\text{Gas S.G.}) \times (\text{RHC Correction}) \times \frac{1}{380.68} \frac{lb \cdot mol}{SCF} \times 28.97 \frac{lb \cdot air}{lb \cdot mol} \times \frac{1}{24} \frac{Day}{hr} \times 0.02 \text{ Flare Combustion Inefficiency}$$

VOC Emissions (Separator Gas Stream)

$$= 675{,}200 \frac{SCF}{Day} \times (0.8270) \times (0.2729) \times \frac{1}{380.68} \times (28.97) \times \frac{1}{24} \times (0.02)$$

$$= 9.6638 \frac{lbs}{hr}$$

VOC Emissions (Heater Treater Gas)

$$= 75{,}200 \frac{SCF}{Day} \times (1.3177) \times (.6762) \times \frac{1}{380.68} \times (28.97) \times \frac{1}{24} \times (0.02)$$

$$= 4.2493 \frac{lbs}{hr}$$

MJL/AAB[19b]

VOC Emissions (Stock Tank Vapors)

$$= 54{,}400 \frac{SCF}{Day} \times (1.6531) \times (.8484) \times \frac{1}{380.68} \times (28.97) \times \frac{1}{24} \times (0.02)$$

$$= 4.8384 \frac{lbs}{hr}$$

Total VOC Emissions (Flare Stack)

$$= 9.6638 + 4.8384 + 4.2493 = 18.7515 \frac{lbs}{hr} = 82.1315 \frac{tons}{yr}$$

FUGITIVE EMISSIONS

- ASSUMPTIONS:

The calculation was taken from API Publication No. 4322. Although the equation was developed for offshore production facilities, using the equation to estimate fugitive hydrocarbon emissions from a proposed onshore production facility has been accepted by other agencies based on the following reasons:

1. There is no equation available for estimating fugitive hydrocarbon emissions from a proposed onshore production facility.

2. Until the entire facility is constructed, there is no way to accurately count valves, connections, seals, hatches, etc. needed to perform the fugitive hydrocarbon calculation technique currently available.

1) $\text{Components per Well} = \dfrac{1}{(2.69 \times 10^{-4}) + [(8.61 \times 10^{-5}) \times \text{Number of Wells}]}$

Number of Wells = 4

$$\text{Components per Well} = \frac{1}{(2.69 \times 10^{-4}) + [(8.61 \times 10^{-5}) \times 4]}$$

$$= 1630.2576$$

2) Total Components at the Facility = Components per Well x Number of Wells

$$= 1630.2576 \times 4$$

$$= 6521.0303$$

3) $\text{VOC Emissions} \ \frac{\text{lbs}}{\text{hr}} = \text{Total Components} \times \text{Emission Factor} \ \frac{\text{lbs/day}}{\text{component}} \times \frac{1}{24} \ \frac{\text{day}}{\text{hr}}$

Emission Factor = .0290 (Based on a logical distribution of valves, connections, hatches and sealing mechanisms as shown in API 4322).

$$\text{VOC Emissions} = 6521.0303 \times .0290 \ \frac{\text{lbs/day}}{\text{component}} \times \frac{1}{24} \ \frac{\text{day}}{\text{hr}}$$

$$= 7.8796 \ \frac{\text{lbs}}{\text{hr}}$$

$$= 34.5126 \ \frac{\text{tons}}{\text{yr}}$$

MJL/AAB[60]

METHANE & ETHANE EMISSIONS

FUEL GAS ANALYSIS:	COMPOSITION	MOL %
	Carbon Dioxide	1.03
	Nitrogen	10.08
	Methane	62.47
	Ethane	13.71
	Propane	7.79
	Iso Butane	1.37
	N Butane	2.22
	Iso Pentane	0.55
	N Pentane	0.46
	Hexane	0.22
	Heptanes Plus	0.10
		100%

Specific Gravity of Gas = .8270
% by Weight of C_1 and C_2 = 0.590

Heater Treater Firebox

Non-Methane Hydrocarbon Emissions = 0.00041 x 5.3 = 0.0022 $\frac{lbs}{hr}$

Methane Hydrocarbon Emissions = 0.00041 x 2.7 = 0.0011 $\frac{lbs}{hr}$

Total Hydrocarbon Emissions = 0.0033 $\frac{lbs}{hr}$

$C_1 + C_2$ Emissions = .0033 x .590 = 0.0019 $\frac{lbs}{hr}$

50 HP Engine

$C_1 + C_2$ Emissions = 0.0097 x 50 x 0.590 = 0.2862 $\frac{lbs}{hr}$

100 HP Engine

$C_1 + C_2$ Emissions = 0.0097 x 100 x 0.590 = 0.5723 $\frac{lbs}{hr}$

4-120 HP Engines

$C_1 + C_2$ Emissions = 4 x (0.0097 x 120 x 0.590) = 2.7470 $\frac{lbs}{hr}$

MJL/AAB[31b]

Flare Stack

Gas Streams Going to Flare
(see Gas Physical Properties, Appendix I)

Composition	Separator Gas	Heater Treater Gas	Stock Tank Vapors
Carbon Dioxide	1.03	1.32	0.72
Nitrogen	10.08	1.41	0.11
Hydrogen Sulfide	(Trace)	--	(Trace)
Methane	62.47	25.35	5625
Ethane	13.71	24.16	19.71
Propane	7.79	24.88	35.68
Iso Butane	1.37	5.30	8.72
N Butane	2.22	10.23	17.41
Iso Pentane	0.55	1.24	2.11
N Pentane	0.46	4.03	6.81
Hexane	0.22	1.29	2.03
Heptanes Plus	0.10	0.79	1.08

Specific Gravity of Separator Gas = 0.8270
Specific Gravity of Heater Treater Gas = 1.3177
Specific Gravity of Stock Tank Vapors = 1.6531

% by Weight of $C_1 + C_2$ (Separator Gas) = 0.590
% by Weight of $C_1 + C_2$ (Heater Treater Gas) = 0.473
% by Weight of $C_1 + C_2$ (Stock Tank Vapors) = 0.285

Flowrate to Flare (Separator Gas) = 675,200 SCF/Day
Flowrate to Flare (Heater Treater Gas) = 75,200 SCF/Day
Flowrate to Flare (Stock Tank Vapors) = 54,400 SCF/Day

$$C_1 + C_2 \text{ Emissions} = \text{Flow Rate } \frac{SCF}{day} \times (\text{Gas S.G.}) \times (C_1 + C_2 \text{ Percentage}) \times \frac{1}{380.68} \frac{lb\cdot mol}{SCF} \times 28.97 \frac{lb\cdot air}{lb\cdot mol} \times \frac{1}{24} \frac{Day}{hr} \times 0.02 \text{ Flare Combustion Inefficiency}$$

$C_1 + C_2$ Emissions (Separator)

$$= 675{,}200 \frac{SCF}{Day} \times (0.8270) \times (0.59) \times \frac{1}{380.68} \times (28.97) \times \frac{1}{24} \times (0.02)$$

$$= 20.8928 \frac{lbs}{hr}$$

$C_1 + C_2$ Emissions (Heater Treater Gas)

$$= 75{,}200 \frac{SCF}{Day} \times (1.3177) \times (.473) \times \frac{1}{380.68} \times (28.97) \times \frac{1}{24} \times (0.02)$$

$$= 2.9724 \frac{lbs}{hr}$$

MJL/AAB[31b]

$C_1 + C_2$ Emissions (Stock Tank Vapors)

$$= 54{,}400 \frac{SCF}{Day} \times (1.6531) \times (.285) \times \frac{1}{380.68} \times (28.97) \times \frac{1}{24} \times (0.02)$$

$$= 1.6254 \frac{lbs}{hr}$$

Total $C_1 + C_2$ Emissions from Flare Combustion Inefficiency = 25.4906 $\frac{lbs}{hr}$

Total Methane and Ethane Emissions:*

$$C_1 + C_2 = .0019 + .2862 + .5723 + 2.7470 + 25.4906$$

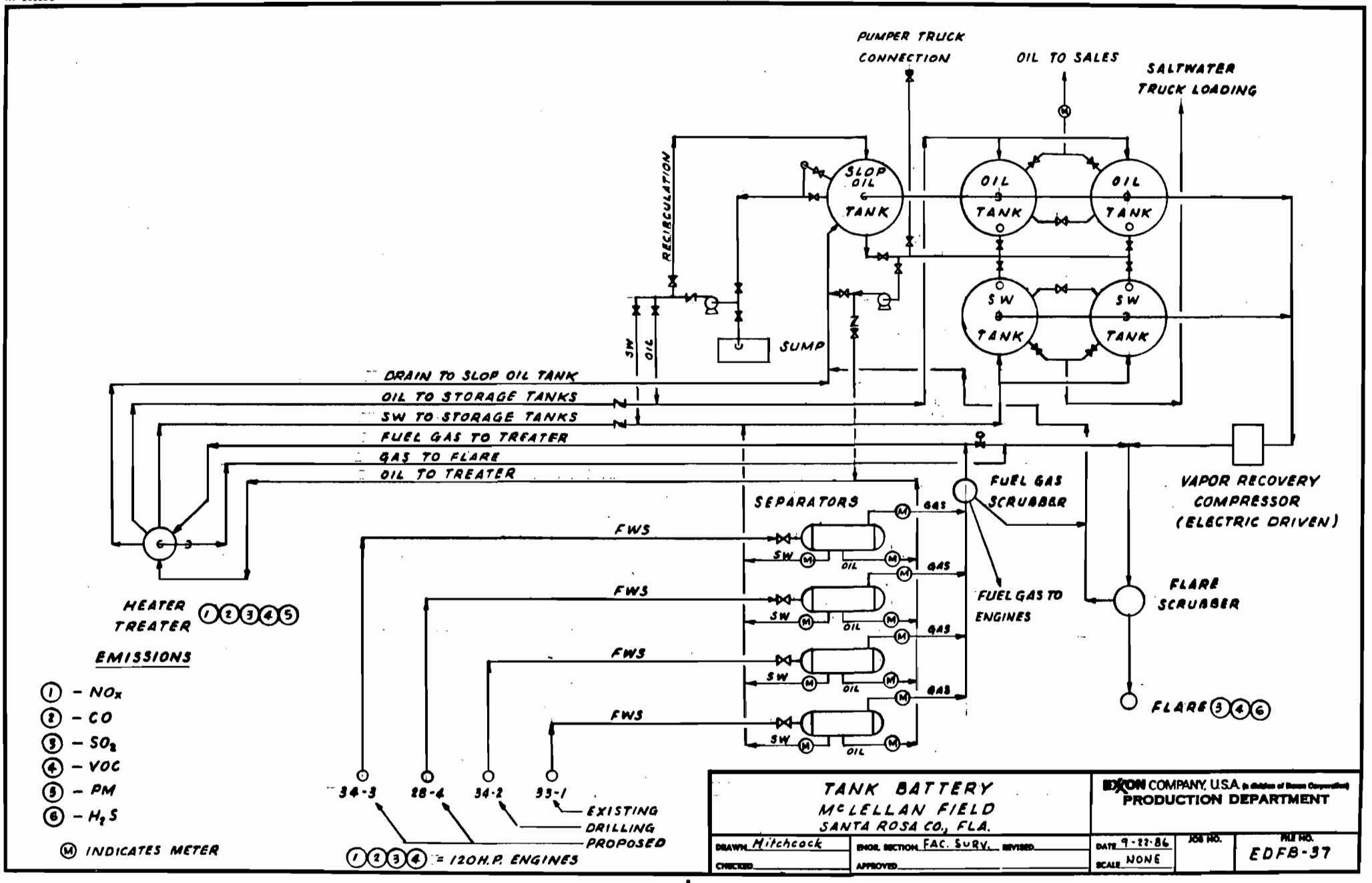
$$= 29.0980 \frac{lbs}{hr}$$

$$= 127.4492 \frac{tons}{yr}$$

* $C_1 + C_2$ fugitive emissions are not included because no emission factors are available.

MJL/AAB[31b]

ILLUSTRATION I



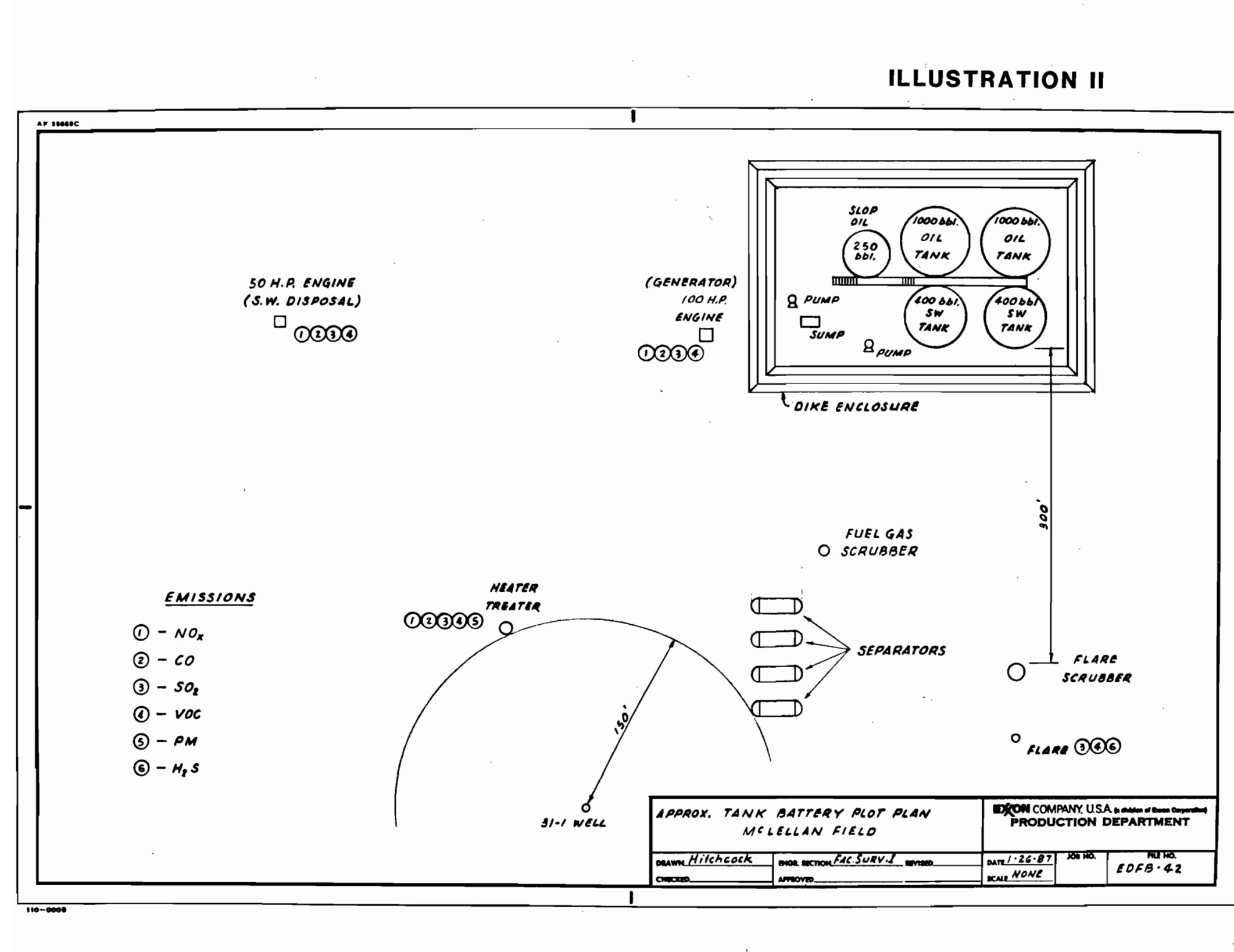
TANK BATTERY
McLELLAN FIELD
SANTA ROSA CO., FLA.

EXXON COMPANY, U.S.A. (a division of Exxon Corporation)
PRODUCTION DEPARTMENT

DRAWN Hitchcock	ENGR. SECTION FAC. SURV.	REVISED	DATE 9-22-86	JOB NO.	FILE NO.
CHECKED	APPROVED		SCALE NONE		EDFB-37

ILLUSTRATION II

AF 35668C



APPROX. TANK BATTERY PLOT PLAN
McLELLAN FIELD

EXXON COMPANY, U.S.A. (a division of Exxon Corporation)
PRODUCTION DEPARTMENT

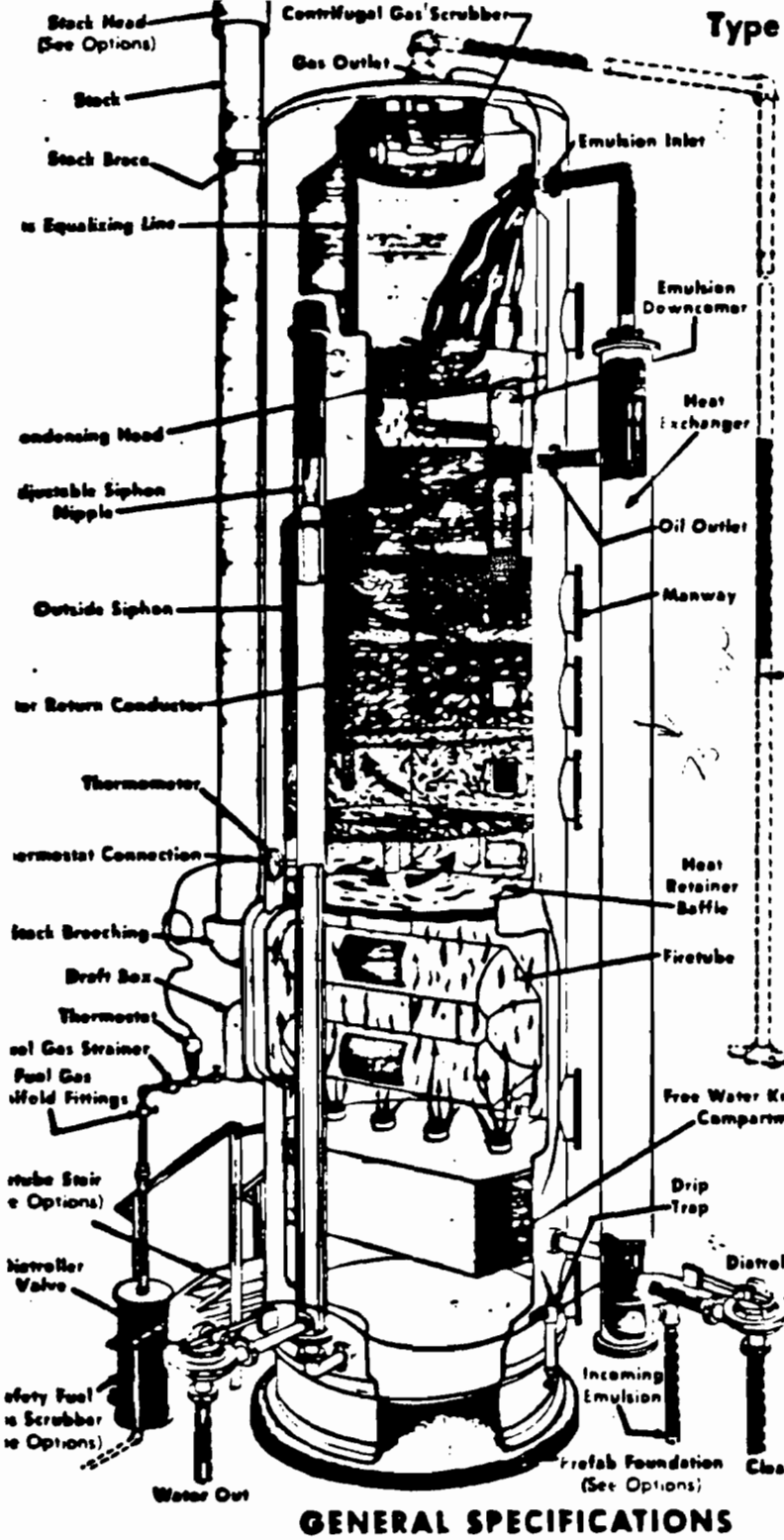
DRAWN Hitchcock	ENGR. SECTION FAC. SURV. I	REVISED	DATE 1-26-87	JOB NO.	FILE NO. EDFB-42
CHECKED	APPROVED		SCALE NONE		

110-0008

Type "ICP" Treaters

ILLUSTRATION III

BEST AVAILABLE COPY



LEGEND

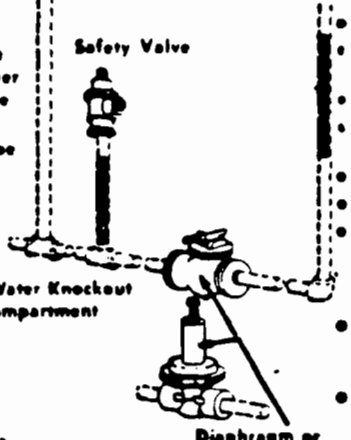
- RAW EMULSION
- CLEAN OIL
- WATER
- GAS
- HEAT AND FIRE

OPTIONAL EXTRA PRICE ITEMS COMMONLY ORDERED WITH UNIT

- Flame Arrestor
- Siphon Isolation Valves
- Gas Back-Pressure Valve
- Fuel Gas Scrubber With Safety Level Shut-off
- Fuel Gas Manifold By-Pass Fittings
- Field Piping And Installation
- Prefab Foundation
- Stack Head
- Heat Exchanger
- OCF Baffles
- Firetube Stair

OTHER EQUIPMENT FURNISHED (Not Shown)

- Ladder
- Gauge Cock And Glass
- Pressure Gauge
- Drip Trap
- Safety Railing



PLUS VALUES OF THE "ICP" TREATER

- Engineered for safety; performance and automatic operation.
- Field Proven.
- Complete flexibility throughout capacity range.
- Easy one-man start up.
- Full-size centrifugal type gas scrubbing element — nothing to plug up.
- Multi-orifice cross-flow baffles.
- Extra heat retaining cross-flow baffle.
- Exclusive free water knockout compartment with oil retaining and good-oil skimming feature. (Reduces heat load — increases treating capacity.)
- Tripple excelsior section with equally disposed multi-orifice cross-flow baffles, having water return conductors.
- Large diameter, reversible single "U" Tube self-descaling firetube design with low thermally stressed welds. Large diameter permits 100% welding of joints inside, as well as outside.
- Manways are pressed steel, one-piece.
- Shell and head joints are double-welded butt welded.
- All baffles and inside heads are continuous seal-welded to shell — no skip welding.
- Skirt is continuous-welded to shell.
- Condensing inside head originated by National.
- Provides its own fuel source.
- Needs no auxiliary power.
- Available with all controls and valves manufactured by National; one supplier — one source.
- Competent field engineers available in all areas for your convenience. These men live and work in your locality.
- Wherever you may transfer National Units, National parts and service are already there.

GENERAL SPECIFICATIONS

SIZE: Diameter x Height	Working Pressure Psig (1)	Recommended Maximum Btu/Hr. Use Rate	Shipping Weight Lbs.	CAPACITY		GAS (4) Gas/Oil Ratio
				OIL (2) Bbls./Hr.	FREE WATER (3) Bbls./Day	
4' x 27½'	50	350,000	10,000#	5 — 30	250-1800	1000:1
6' x 27½'	50	500,000	14,900#	10 — 50	550-4000	1000:1
8' x 27½'	25	1,000,000	20,900#	20 — 100	1000-7000	1000:1
10' x 27½'	25	1,350,000	28,900#	35 — 150	1500-10000	1000:1

NOTES:

(1) Units are available manufactured to non-code or ASME Sec. VIII Code in the standard pressures as well as higher pressures. Shipping weights will be higher for higher pressure units.

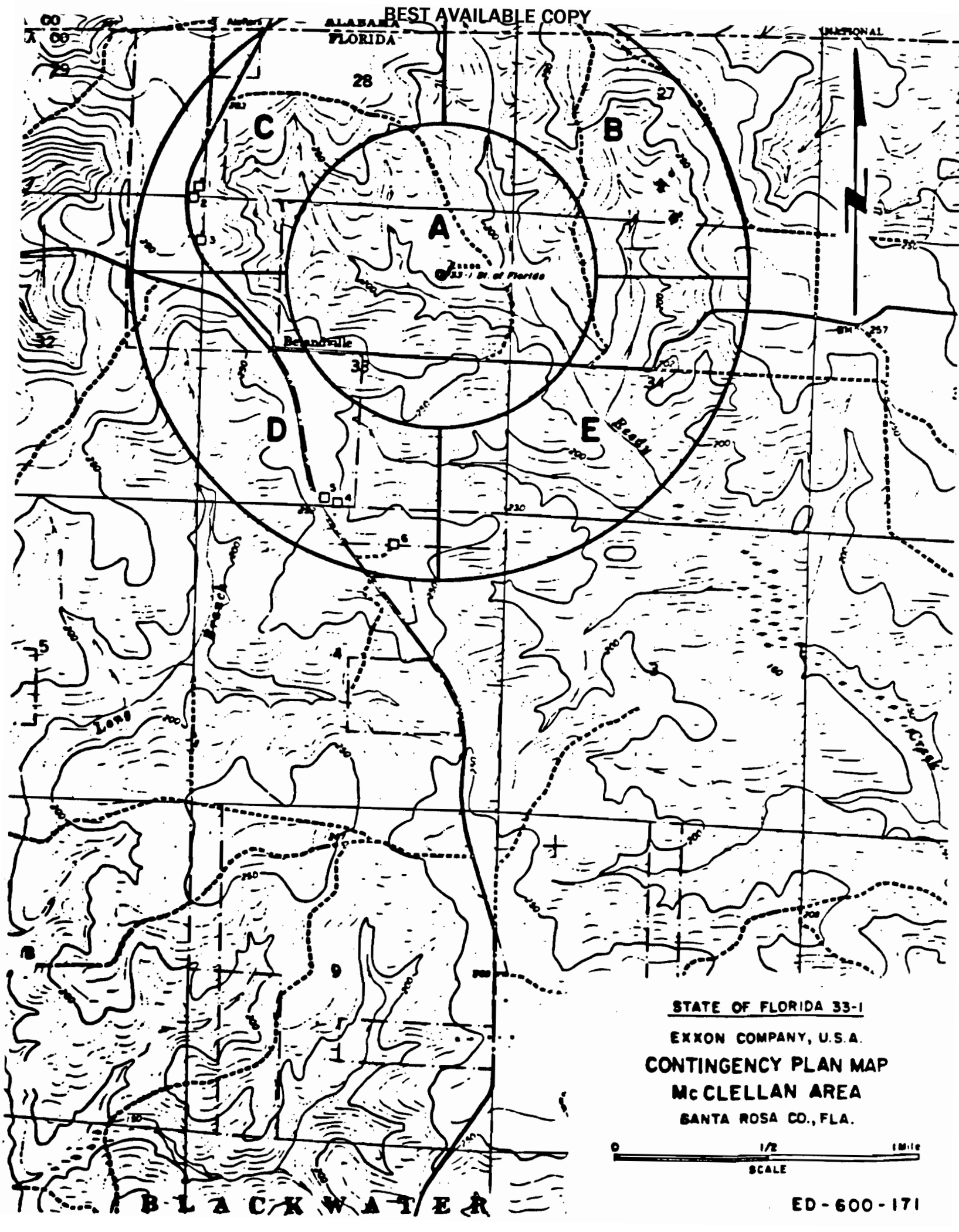
(2) OIL CAPACITIES are quite variable, depending upon viscosity of crude relative densities of oil and water, heating and settling requirements, and other variables. Contact the nearest National Tank Company Representative for recommendations on specific applications.

(3) WATER CAPACITIES are for free water, i.e. will settle without further heat within a few minutes.

(4) GAS CAPACITIES of standard units are designed for peak performance for GOR of 1000 : 1 or less. If higher GOR's are encountered at treating conditions, please advise at time of order.

Catalog No. 1201

DECEMBER 1962



STATE OF FLORIDA 33-1

EXXON COMPANY, U.S.A.

CONTINGENCY PLAN MAP

McCLELLAN AREA

SANTA ROSA CO., FLA.

0 1/2 1 Mile

SCALE

ED-600-171

BEST AVAILABLE COPY

McLellan Wells

ILLUSTRATION V

STATE

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

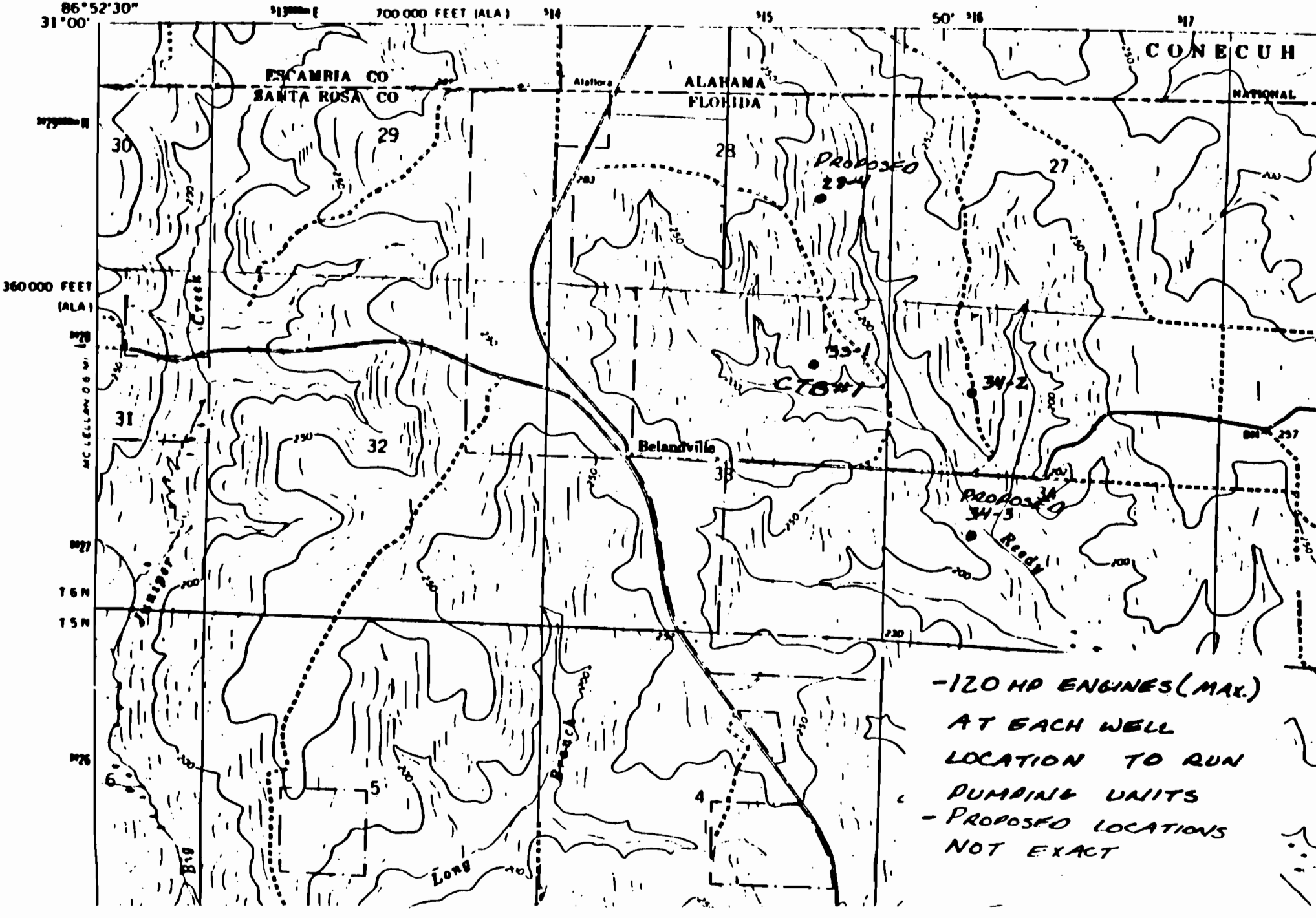


ILLUSTRATION VI

BEST AVAILABLE COPY

T 5 N - R 26 W

Road / Culvert Ex. 2

28

Exxon
J.G. Morris

Exxon
J.P. Wiseman, et al

Exxon
P.I. Overstreet

Exxon, et al

Exxon
Texaco

1101'

99-1

1186'

299'

℄ of NE/4

NE/4
160 Ac. ±

32

33

34

Exxon

State of Florida
U.S.A.

W.N. Jones

State of Florida
USA

Exxon
A.O. Thompson

4

T 5 N - R 26 W

ROBERT E. LEE
CERTIFICATE
NO. 2277
STATE OF
FLORIDA
REGISTERED LAND SURVEYOR

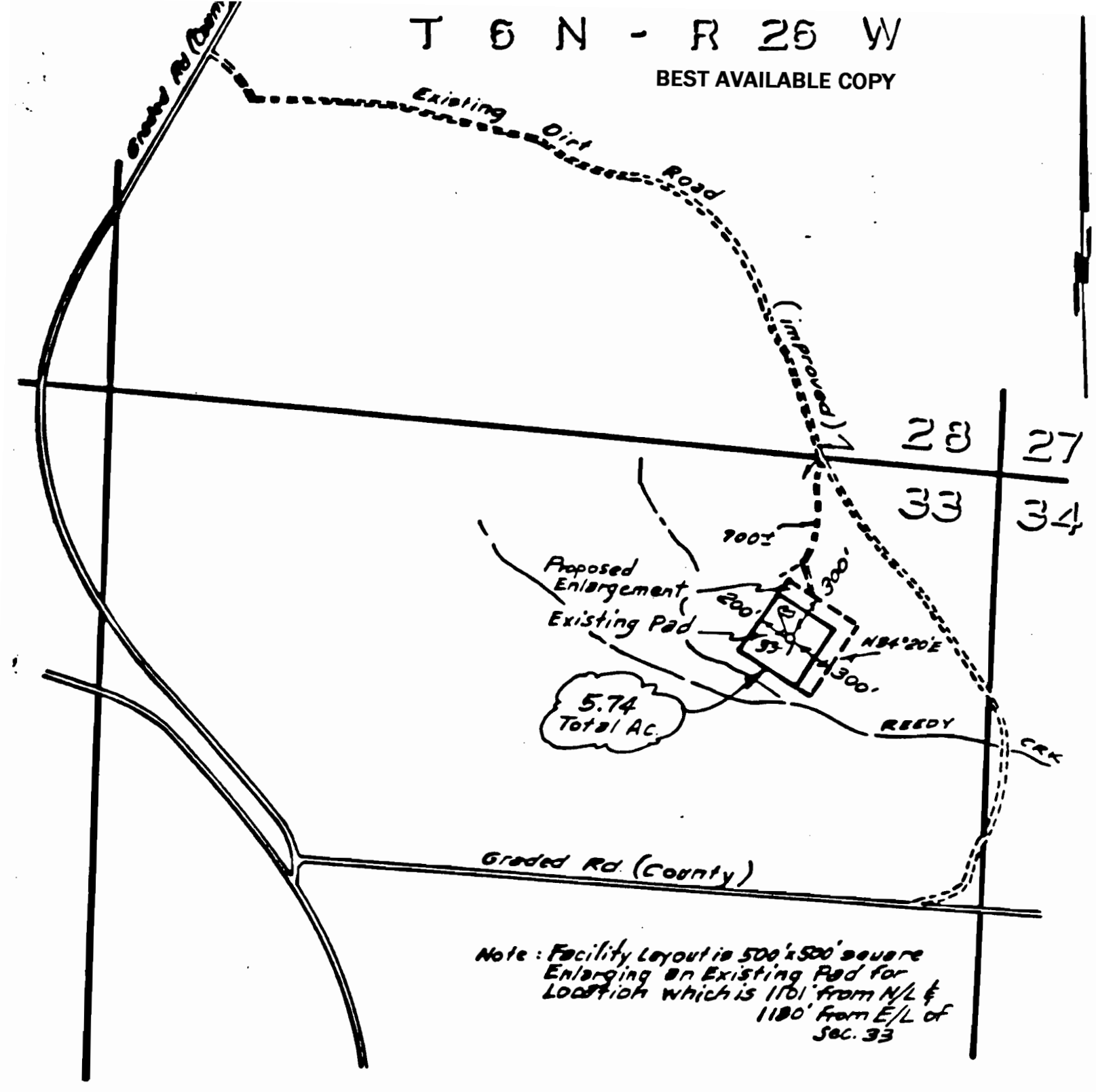
DEPOSITED
5710931
STATE OF FLORIDA

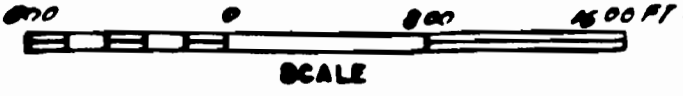
Prepared by Robert E. Lee
Fla. Reg Land Surveyor No 2277

1000 0 1000 2000 FT.
SCALE

STATE OF FLORIDA McCLELLAN AREA SANTA ROSA CO., FLORIDA	Exxon Company, U.S.A. (A DIVISION OF EXXON CORPORATION) PRODUCTION DEPARTMENT NEW ORLEANS

DRAWN R.A. Gutierrez	ENGR SECTION	REVISED	SCALE 1" = 1000'	JOB NO.	FILE NO.
CHECKED	APPROVED RAL		DATE 7/26/85		EA-6244





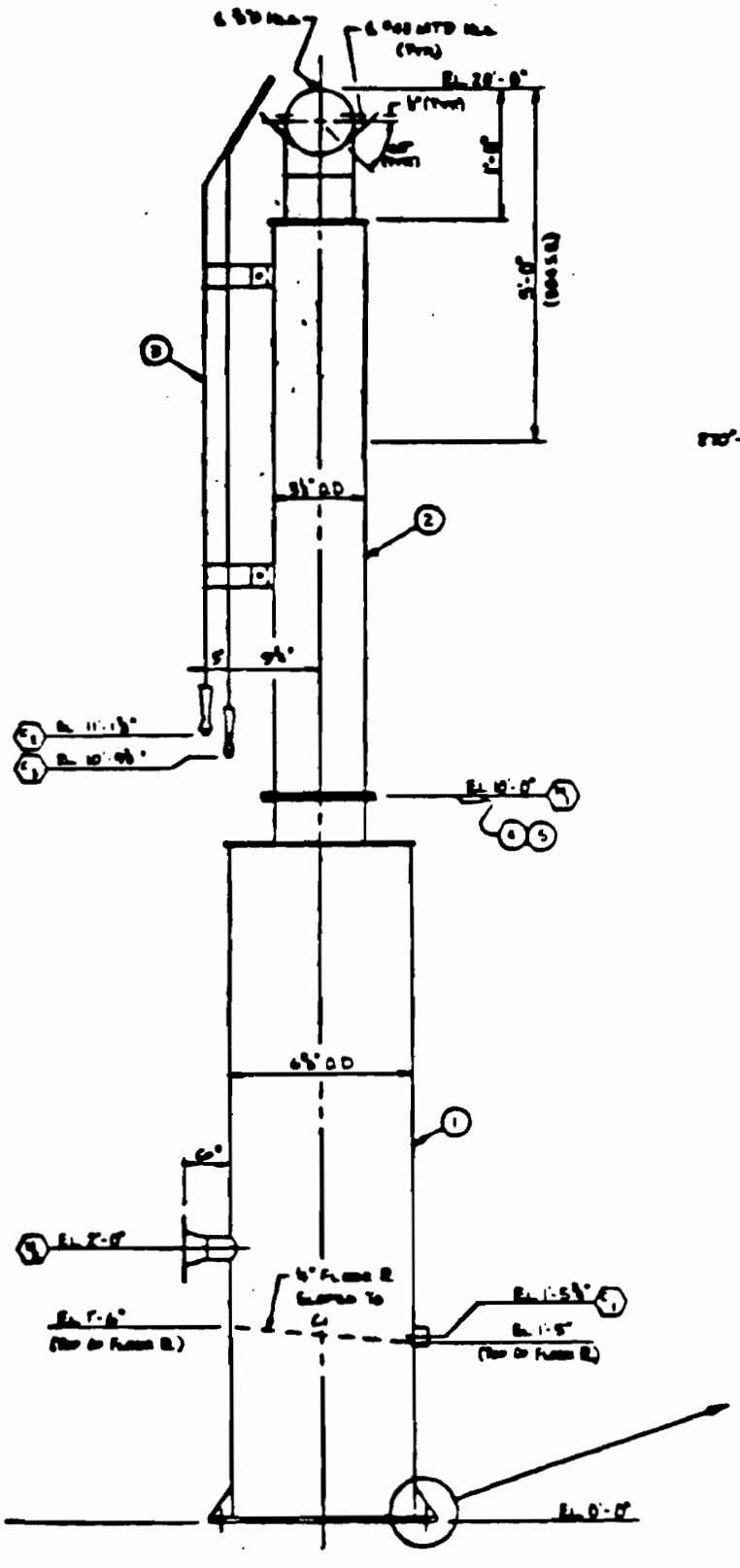
PROPOSED PRODUCTION FACILITY
to Serve STATE OF FLORIDA No 33-1
McCLELLAN AREA SANTA ROSA Co, FLA.

Exxon Company, U.S.A.
(DIVISION OF EXXON CORPORATION)
PRODUCTION DEPARTMENT
NEW ORLEANS

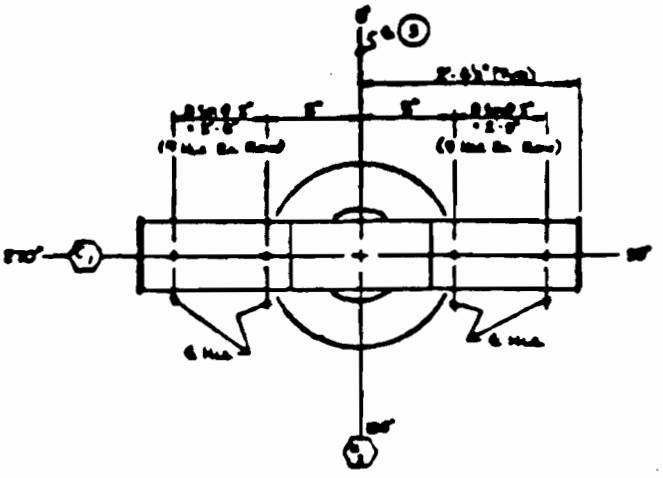
DRAWN R.A. Gutierrez	ENGR. SECTION	REVISED 9-23-80	SCALE 1" = 600'	JOB NO.
CHECKED	APPROVED R.C. Lamb	JKM	DATE 8-1-80	FILE NO. EA-6245

ILLUSTRATION VIII

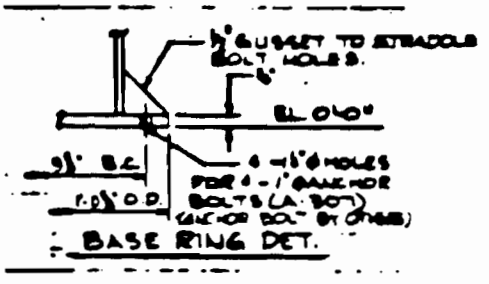
BEST AVAILABLE COPY



Side Elevation



Plan View

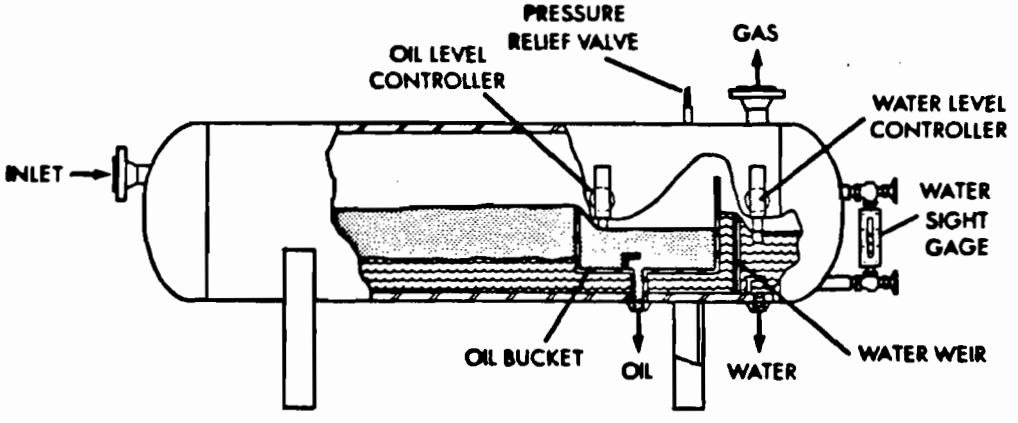


REPRESENTATIVE DESIGN:
FLARE STACK W/ AUTO RELIGHT
(DIMENSIONS NOT CORRECT)

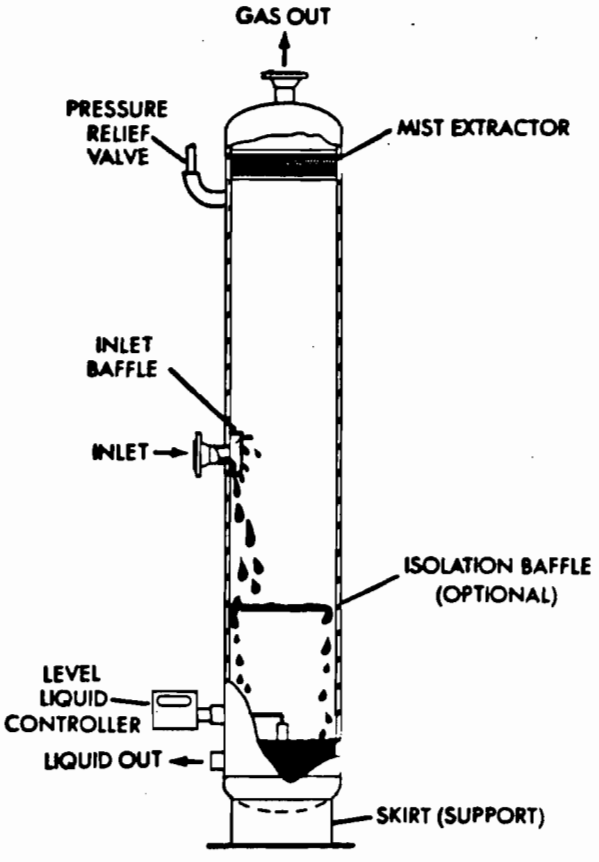
EXXON COMPANY, U.S.A.
A DIVISION OF EXXON CORPORATION
PRODUCTION DEPARTMENT

DRAWN	BRDR SECTION	REVISED	SCALE	JOB NO / FILE NO
CHECKED	APPROVED		DATE	

110-0004 1A

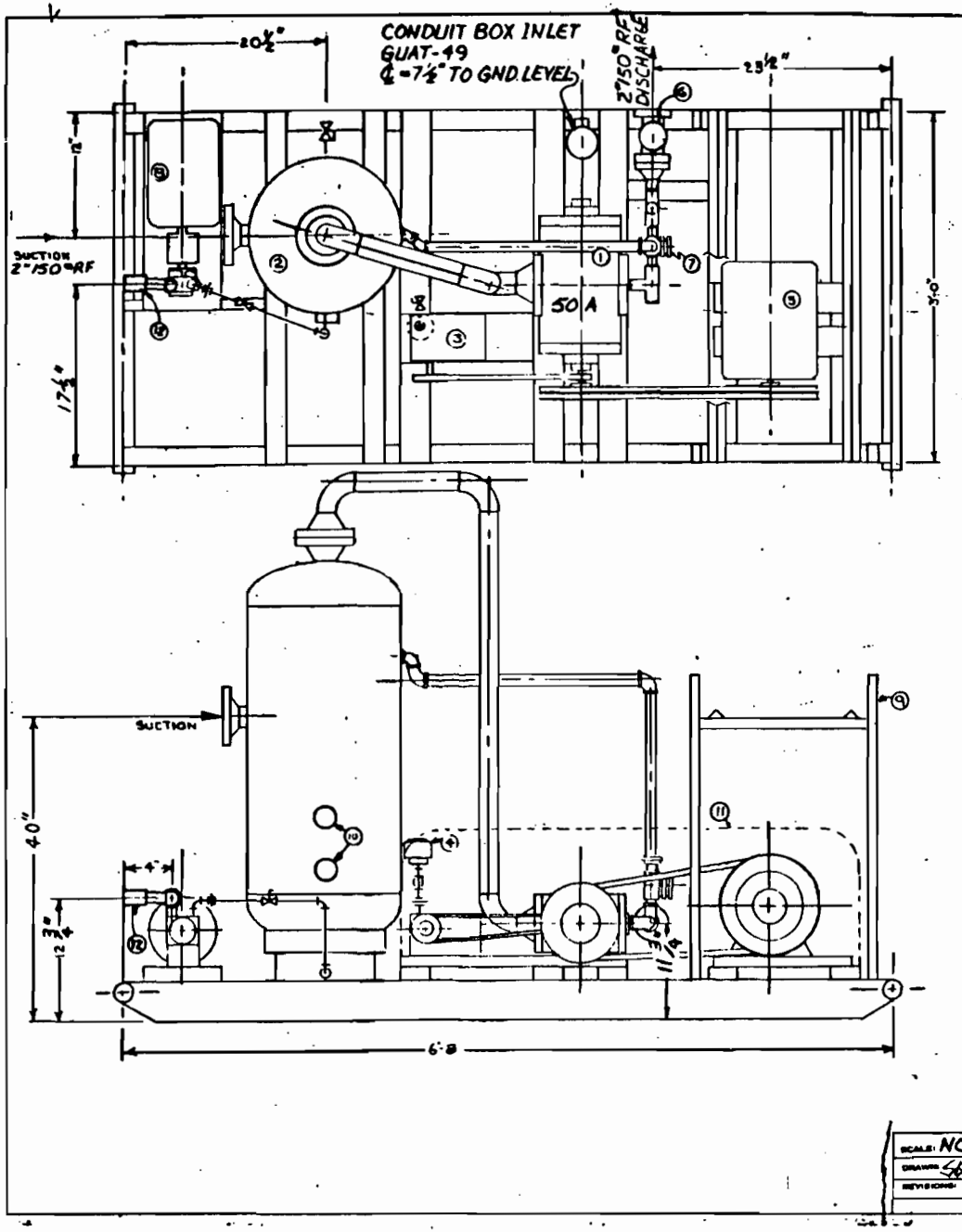


Cutaway Horizontal Three-Phase Separator (Courtesy Smith Industries, Inc.)



Cutaway Vertical Two-Phase Separator (Courtesy Smith Industries, Inc. Internals may vary among manufacturers.)

ILLUSTRATION XI



LEGEND	
ITEM	DESCRIPTION
1	HB50A ROTARY GAS COMPRESSOR
2	16" OD SUCTION SURGE VESSEL
3	MEGA SINGLE FEED LUBRICATOR
4	LOW LUBE LEVEL SHUTIN SWITCH
5	ELECTRIC MOTOR 220-3-60 7.5hp
6	DISCHARGE CHECK VALVE
7	COMPRESSOR BY-PASS VALVE
8	LIQUID PUMP MOTOR 115-1-60 (ELECTRIC)
9	LUBE DRUM RACK
10	LIQUID LEVEL SWITCH
11	BELT DRIVE GUARD
12	LIQUID CHECK VALVE

NOTE:
ALL ELECTRIC MOTORS:.
NO EMISSIONS RESULT.

SCALE: NONE DATE: 5-'85 DRAWN: SBD APPROVED: REVISIONS:	HB 50 A VAPOR RECOVERY UNIT OR EQUIVALENT	WT- APPROX.- HY-BON ENGINEERING CO, INC. MIDLAND, TEXAS DRWG. NO.

API PUBLICATION #4322

FUGITIVE HYDROCARBON EMISSIONS FROM PETROLEUM PRODUCTION OPERATIONS

MARCH 1980

APPENDIX N

GENERALIZED PREDICTION METHOD FOR OFFSHORE PRODUCING FACILITIES

INTRODUCTION

Future site hydrocarbon predictions require a complete component inventory. In order to assist in the estimation of the number of components at an offshore site, a correlation has been made with the number of wells at the site.

COMPONENT CORRELATIONS

This correlation has limited use. At best the number of wells could be used to predict the total number of components (over all types and styles combined). We have found considerable differences exist between the emissions from different component types and styles carrying different products. Therefore, it must be expected that attempts to predict emissions from the total number of components alone will result in considerably lower precision than the inventory-based predictions.

The offshore sites tested are listed in Table N-1 along with the corresponding numbers of components and wells. Every wellhead on a platform, flowing or non-flowing, was counted. Dual completion wells were counted as two wells. Except for wells not flowing at the time of testing, all components were included in the inventory. In the case of Site 5, the associated onshore treatment facility inventory was included because those systems are typically found on offshore producing platforms.

The number of components per well was calculated for each site (Table N-1). A linear regression analysis was performed on the number of wells versus the number of components per well data. A hyperbolic curve best fit the data and resulted in a correlation coefficient of .98 (where 1.0 indicates a perfect fit).

TABLE N-1

OFFSHORE WELL AND COMPONENT COUNTS

Site		Component Count	Well Count	Components Per Well*
	WEST COAST			
4, 5	Light Crude	9,243	32	289
6	Light Crude	10,792	42	257
	GULF COAST			
12	Natural Gas	12,580	30	419
13	Light Crude	17,593	Uncharacteristic Platform	
14	Light Crude	7,980	6	1,330
15	Condensate	8,204	6	1,367
16	Natural Gas	9,223	6	1,537
17	Condensate	5,248	5	1,050

*Rounded to nearest component, plotted at +, Figure N-1.

The hyperbolic equation

$$1/y = (2.69 \times 10^{-4}) + (8.61 \times 10^{-5})X$$

where y = the number of components per well
x = the number of wells at the site

is plotted in Figure N-1. Table N-2 was generated from the equation in Figure N-1. As the table indicates, the number of components per well varies substantially but above a certain number of wells, approximately fifteen (15), the total number of components is relatively constant.

TABLE N-2

COMPONENT TOTALS CALCULATED FROM OFFSHORE WELL COUNTS

NUMBER OF WELLS	ESTIMATED COMPONENTS PER WELL (FROM GRAPH)	CALCULATED TOTAL NUMBER OF COMPONENTS
5	1430	7150
10	885	8850
15	641	9615
20	502	10040
25	413	10325
30	351	10530
35	305	10675
40	270	10800
45	241	10845
50	219	10950

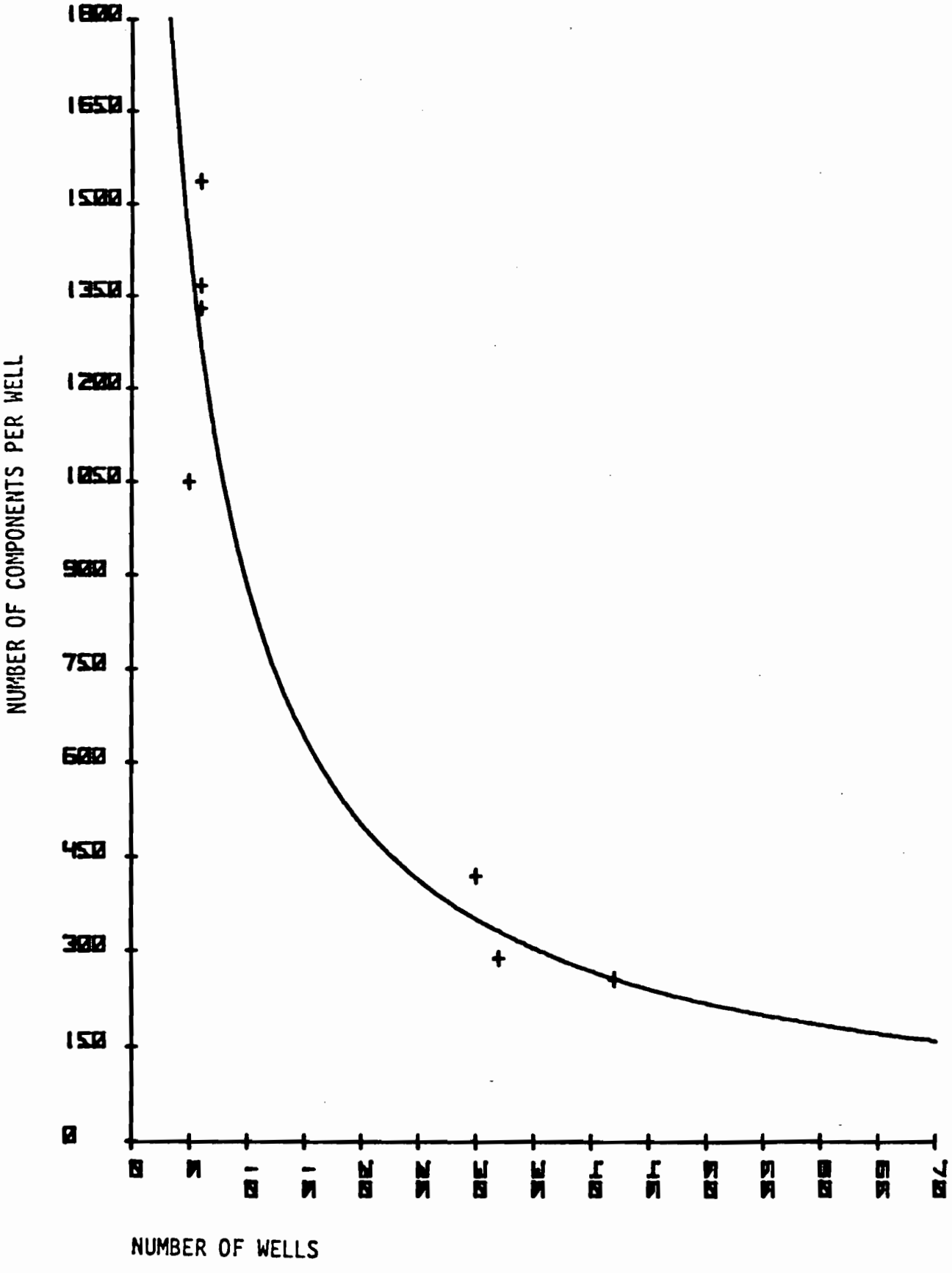


Figure N-1. Offshore Components Prediction

Discussion

Prediction of emissions from offshore platforms cannot be calculated from the component count, Figure N-1, without a means of establishing the associated component types and styles. Two attempts were made to establish such a correlation, but to no avail. An average distribution of component types were developed from the inventories of the seven offshore platforms included within the study, Table N-3. The products handled by the components located on these platforms were light crude oil, gas and condensate, Table N-1. These products have different predicted emission factors for the same component, Appendix M. Thus, an average distribution of component types in these three services is suspect. Obtaining an average component type distribution by individual service (oil, gas and condensate) would be statistically inaccurate because only 3 light crude oil, 2 natural gas and 2 condensate platforms were tested, Table N-1. Such a sample is too small to be statistically meaningful. Accordingly, the average distribution of component types was retained and used in the following analysis, Table N-3.

Component styles must be established to provide a base for emission predictions. The first assumption of style distribution was based on an equal distribution of styles, Table N-4. These values of prediction factors resulted in grossly varying predictions of emissions from the seven offshore platforms. Thus equal distribution of styles was abandoned.

Next, the component style distribution was based on an intuitive selection by an experienced engineer, Table N-5. The resulting predictions of total hydrocarbon emissions were improved, Table N-6. However both over-and underpredictions resulted when compared with the calculated values for the platforms, Table 3-8. In general, the predicted emissions from oil platforms were over estimated (Platforms 4, 5, and 6), Table N-6. Platform 14, another oil platform was underpredicted.

The gas platform emissions (Platforms 12 and 16) were substantially underpredicted, Table N-6. On the other hand the condensate platform emissions

TABLE N-3

AVERAGE PERCENTAGE OF COMPONENT TYPES
BY SERVICE FOR AN OFFSHORE PLATFORM

	Gas	Other
Valve (VL)	6.1	7.9
Connection (CN)	52.0	29.1
Hatch (HA)	0.1	0.1
Seal Packing (SP)	0.5	0.2
Diaphragm (DI)	1.0	0.0
Seal Mechanism	1.3	1.7
Total	61.0	39.0

TABLE N-4

AVERAGE EMISSION FACTOR FOR
OFFSHORE OPERATIONS BASED
ON EQUAL COMPONENT STYLE DISTRIBUTION

Total Hydrocarbon Prediction Factor

	Gas #/Day	Other #/Day
Valve (VL)	0.132	0.0017
Connection (CN)	0.030	0.0008
Hatch (HA)	0.052	0.015
Seal Packing (SP)	0.534	0.0012
Diaphragm (DI)	0.150	0.744
Seal Mechanism (SM)	0.633	0.0247

TABLE N-5

EMISSION FACTORS FOR OFFSHORE OPERATIONS
BASED ON AN ASSUMMED LOGICAL
DISTRIBUTION OF COMPONENT STYLES

	Total Hydrocarbon Prediction Factors	
	Gas #/Day	Other #/Day
Valves (VL)[a]	0.0581	0.0007
Connection (CN)[b]	0.0294	0.0007
Hatch (HA)[c]	0.0516	0.0147
Seal Packing[d]	0.4985	0.0013
Diaphragm[e]	0.1495	0.744
Seal Mechanism[a]	0.0738	0.0031

[a] Plug valves

[b] equal distribution of FLFF, GRVD & TUBE

[c] equal distribution of FLFF, & FLGA

[d] equal distribution of RERO, ROSH, & MESL

[e] equal distribution of VLOP & DPRS

Table N-6
Comparison of Emission Predictions
Predicted Emissions Based on Tables N-2, 3 & 5

Site	Wells	Description: Total No.	Description: Type	Service: Gas No.	Service: Other No.	Total Hydrocarbon Prediction Factors: Gas #/day	Total Hydrocarbon Prediction Factors: Other #/day	Total Hydrocarbon Emissions: Gas #/day	Total Hydrocarbon Emissions: Other #/day	Total Hydrocarbon Emissions: Total #/day	Calculated Emissions (Table 3-8): Total #/day
4 & 5 (oil)	32	10592	Valve	646	837	0.0581	0.0007	37.5	0.6	38.1	
			Connection	5507	3082	0.0294	0.0007	161.9	2.2	164.1	
			Hatch	11	11	0.0516	0.0147	0.6	0.2	0.8	
			Seal Packing	53	21	0.4985	0.0013	26.4	0.0	26.4	
			Diaphragm	106	0	0.1495	0.744	15.8	0.0	15.8	
			Seal Mechanism	138	180	0.0738	0.0031	10.2	0.6	10.8	
								252.4	3.6	256	105
6 (oil)	42	10794	Valve	658	853	0.0581	0.0007	38.2	0.6	38.8	
			Connection	5613	3141	0.0294	0.0007	165.0	2.2	167.2	
			Hatch	11	11	0.0516	0.0147	0.6	0.2	0.8	
			Seal Packing	54	22	0.4985	0.0013	26.9	0.0	26.9	
			Diaphragm	108	0	0.1495	0.744	16.1	0.0	16.1	
			Seal Mechanism	140	183	0.0738	0.0031	10.3	0.6	10.9	
								257.1	3.6	260.7	91.1
12(gas), 14(oil), 15(cond) &16(gas)	30	10530	Valve	642	832	0.0581	0.0007	37.3	0.6	37.9	
			Connection	5476	3064	0.0294	0.0007	161.	2.1	163.1	
			Hatch	11	11	0.0516	0.0147	0.6	0.2	0.8	
			Seal Packing	53	21	0.4985	0.0013	26.4	0.0	26.4	
			Diaphragm	105	0	0.1495	0.744	15.7	0.0	15.7	
			Seal Mechanism	137	179	0.0738	0.0031	10.1	0.6	10.7	
								251.1	3.5	254.6	548
(oil)(cond) 14,15 & 16 (gas)	6	7758	Valve	473	613	0.0581	0.0007	27.5	0.4	27.9	
			Connection	4034	2258	0.0294	0.0007	118.6	1.2	120.2	
			Hatch	7	7	0.0516	0.0147	0.4	0.1	0.4	
			Seal Packing	39	16	0.4985	0.0013	19.4	0.0	19.4	
			Diaphragm	78	0	0.1495	0.744	11.7	0.0	11.7	
			Seal Mechanism	101	132	0.0738	0.0031	7.5	0.4	7.9	
								185.1	2.1	187.5	#14-310; #15-141; #16-353
17 (cond)	5	7150	Valve	436	565	0.0581	0.0007	25.3	0.4	25.7	
			Connection	3718	2080	0.0294	0.0007	109.3	1.5	110.8	
			Hatch	7	7	0.0516	0.0147	0.4	0.1	0.4	
			Seal Packing	36	14	0.4985	0.0013	17.9	0.0	17.9	
			Diaphragm	72	0	0.1495	0.744	10.8	0.0	10.8	
			Seal Mechanism	93	122	0.0738	0.0031	6.9	0.4	7.3	
								170.6	2.4	179.9	155

(Platforms 15 and 17) were reasonably well predicted by the correlation technique, Table N-6.

It is concluded from this analysis the correlation technique provides erratic results. Accordingly, the use of an accurate inventory of component types and styles is essential in providing a reasonable prediction of emissions both on- and offshore.

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

FOR ROUTING TO OTHER THAN THE ADDRESSEE

To: _____ Loctn: _____
To: _____ Loctn: _____
To: _____ Loctn: _____
From: _____ Date: _____

TO: Clair H. Fancy

THROUGH: Ed K. Middleswart Ed M 4/17

FROM: Jack Preece Jack

DATE: April 17, 1987

DER
APR 28 1987
BAQM

SUBJECT: AC57-131370 (Emon Co, USA, McClellan Field)

The subject facility has been entered into APIS (Screen AIR020) with identification number 10PEN570032.

Whenever this permit is issued, please place the I.D. Number 10PEN570032/01-XX (with all point numbers) at the top right corner of the first page. Also, include as a permit condition the following:

The permanent source identification numbers for the permitted point sources are:

10PEN57003201	Description #1
10PEN57003202	Description #2
ect.	ect.

Please cite the appropriate number on all test reports and other correspondence specific to one of the permitted point sources.

JP/jpl

cc: Mike Harley 4-29-87

P 408 531 577

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED—
NOT FOR INTERNATIONAL MAIL

(See Reverse)

Sent to Sue Cummings	
Exxon Company, USA P.O. Box 61707	
P.O., State and ZIP Code New Orleans, LA. 70161-1707	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to whom and Date Delivered	
Return Receipt Showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$
Postmark or Date 4/3/87 AC 57-131370	

PS Form 3800, Feb. 1982

PS Form 3811, July 1983 447-845

SENDER: Complete items 1, 2, 3 and 4.

Put your address in the "RETURN TO" space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for service(s) requested.

1. ☒ Show to whom, [redacted] delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:
Sue Cummings
Operations Manager
Exxon Company, USA
P.O. Box 61707
New Orleans, LA 70161-1707

4. Type of Service:
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail

Article Number
P 408 531 577

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X

6. Signature – Agent
X

7. Date of Delivery
APR 8 1987

8. Addressee's Address *(ONLY if requested and fee paid)*

DOMESTIC RETURN RECEIPT

File Copy

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

April 3, 1987

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Sue Cummings
Operations Manager
Eastern Division
Exxon Company, USA
P. O. Box 61707
New Orleans, Louisiana 70161-1707

Dear Ms. Cummings:

The department has reviewed your application for a permit (File No. AC 57-131370) to construct air pollution sources consisting of four crude oil production wells and associated equipment. This application was received on March 5, 1987. We have reviewed your application and find it to be incomplete.

The application includes five proposed vessels, two for the storage of crude oil, two for saltwater storage and one for "slop" oil, that appear to be sources of VOC, reduced sulfur, and hydrogen sulfide emissions. We note that you do not propose to control the emissions from these vessels. These vessels are subject to the requirements of FAC Rule 17-2.620--General Pollutant Emission Limiting Standards. The proposed sources are to be located in an attainment area and may be subject to review pursuant to FAC Rule 17-2.500--Prevention of Significant Deterioration. All of the pollutants listed in Table 500-2 of FAC Rule 17-2.500 that may be emitted are to be included in the application. The emissions of methane and ethane are to be separately quantified and included in the application. We have also noted several apparent errors and inconsistencies in your calculations. Please check all of your calculations and revise where necessary, justifying all assumptions, and document your procedures. If the procedures used to calculate the emissions are different from those specified in AP-42, then copies must be provided. Other items of incompleteness include:

1. The UTM coordinates on page 1 of 1 of the application appear to be incorrect. Please confirm or correct.

2. Will auxiliary fuels be used in any of the proposed unit operations? If so, please provide details.

3. Please describe the operation of the proposed heater treater and the associated emission point(s). The emission estimates assume that the proposed heater treater (capacity 50 bbls/hr) will operate 12 hours per day while the pumps continuously supply oil at the rate of 60-67 bbls/hr. Explain how operation at rates exceeding the manufacturer's rated nominal design capacity is to be achieved. Provide all particulars.

4. Describe in detail the operation of the proposed smokeless flare and provide all of the information requested by Sections III.D., III.H., and V. of the application. Also, provide the information necessary to amend the application to include any external sources needed to operate the proposed flare. Please justify and document all assumptions related to normal flare operation and efficiency. Excess emissions resulting from failure of the proposed flare will be subject to the requirements of FAC Rule 17-2.250, Excess Emissions, and FAC Rule 17-4.070, Plant Operations-Problems. Estimates of excess emissions resulting from unexpected failure of the proposed flare are not to be included as normal emissions. Please be advised that a surrogate standard of 5% opacity will be assigned to the proposed flare in order to ensure proper operation and maintenance.

5. Please provide details about each of the proposed engines that are to be installed.

6. The process input and output rates in your application are expressed as average maximums. Please provide the maximum rates and revise your emission estimates accordingly. Be sure to justify all assumptions.

7. It will be necessary for you to document the information in Appendix I of your application. Please provide measurements of the sulfur content, reduced sulfur content, and hydrogen sulfide content of the fuel and stock tank gases based on applicable federal reference methods. You will need to furnish all particulars.

8. Please describe the design and operation of the separators, fuel gas scrubbers, and "slop" oil tank. Provide all particulars.

9. The emission estimates do not appear to include all sources and pollutants. Please recalculate and justify all assumptions and document procedures.

10. Please provide information about the instrumentation and test procedures that you propose to use to monitor the process and show proof of compliance with any emission limits.

We will resume the processing of your application upon receipt of the requested information. If you have any questions or wish to meet with us, please call Mike Harley at (904)488-1344 or write to me at the above address.

Sincerely,

C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality
Management

CHF/MH/s

cc: E. Middleswart
R. L. Bruce, Jr.
A. Broussard
C. Martin

Exxon Meeting

Permit Application — April 1, 1986

1. Annual average for potential to emit can be applied on the basis of the 30 Day rolling average.
2. Heater treater operation rate is determined by 24 hrs/day 365 day/yr.
3. Explain capacity difference in wording.
4. 20% —
   Assume 95% to be demonstrated — Louisiana requires 98.5%
   Provide us with citation on efficiency and clarify in the assumptions
   5% V.E. Places reference. copy of concluding page.
5. Engines 100% load — 100% Industry.
6. Heater treater specific gravity
7. ~~Specif~~ Explain assumptions on item 10.
8. ~~ER~~ Your application will include C_1 & C_2 hydrocarbons
9. Flare emissions downtime can be excluded.
10. Test methods and non
11.

April 1, 1986
DER/Exxon Meeting

	Name	Company	Address	Phone
1.	Mike Lamore	Exxon	1555 Poydras St., N.O., LA 70127	(504) 561-4660
2.	Lee Bruce	"	"	561-3904
3.	Ashlyn Broussard	"	"	561-4226
4	Bill Thomas	DER/BAQN	2600 Blairstone Talla.	488-1344
	Mike Harley	"	"	"

Meeting

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

APRIL 1, 1987

ISSUES:

1) Heater Treater Firing Time
2) Heater Treater Capacity
3) Flare Operation
4) Exclusion of NO_x, VOC, CO and PM in Flare Emissions
5) Basis for 95% Loading of Engines
6) Engine Emission Factors
7) Fuel Consumption Estimate
8) BTU Content of Fuel Gas
9) Heater Treater Specific Gravity Estimate
10) Fugitive Emission Calculation Method
11) SO_2 Emission Factor for Engines
12) Exclusion of Methane and Ethane from Emission Calculations

AAB[6b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #1

Heater Treater Firing Time

REPLY

- Minimum amount of freewater produced (500 barrels/day = maximum) Total field 4 wells
- Required heating temperature is low due to higher ambient temperature — Temperature sensor controlled.
- Inlet emulsion heat exchanger increases heating efficiency
- Turbulator deflects heat from flame to walls of firetube, which increases efficiency 8-10%
- Most heater treaters in our operations are fired a maximum of 12 hrs/day

CONCLUSION

- 12 hours/day runtime for the heater treater is a good estimate

AAB[7b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #2

Heater Treater Capacity

REPLY

- Rates quoted on manufacturer's data are general guidelines
- Since low levels of water will be produced (500 barrels/day maximum), more oil can be treated effectively
- If heater treater does not function effectively, separator will be converted to a three-phase separator

CONCLUSION

- Heater treater selected in facility design is satisfactory

AAB[8b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #3

Flare Operation

REPLY

- No steam goes to flare
- Flare is smokeless, self-aspirating

CONCLUSION

- Opacity limit (20%) will be met under normal operating conditions

AAB[9b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #4

Exclusion of NO_X, VOC, CO and PM in Flare Emissions

REPLY

- Flare efficiency assumed to be approximately 100% with a gas heat value of at least 1000 BTU/FT^3
- NO_X*: Formation of NO_X is insignificant in a temperature range of 1000°F to 1600°F
- VOC: VOC emissions are negligible, with 100% combustion efficiency
- CO*: At combustion efficiencies greater than 98%, CO emissions are negligible
- PM*: Natural gas burns very clean, and particulate emissions are negligible

*There is no method to calculate NO_X, CO and PM emissions for flares

cite research & provide concluding page

CONCLUSION

- NO_X, VOC, CO and PM emissions can be excluded from flare emission calculations

AAB[10b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #5

Basis for 95% Loading of Engines

REPLY

- Larger horsepower engines than are actually needed have been selected
- 95% loading reduces operating costs and maintenance costs

CONCLUSION

- 95% loading on all engines is a conservative assumption

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #6

Engine Emission Factors

REPLY

- Engine emission factors represent total hydrocarbons (see Footnote AP-42; Table 3.3.2-1)

CONCLUSION

- Emission factors used for engines are correct

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #7

Fuel Consumption Estimate

REPLY

- 7500 BTU/hp·hr is an estimate of average fuel consumption assuming approximately 30% efficiency

CONCLUSION

- 7500 BTU/hp·hr is a conservative estimate for the average fuel consumption of an engine

AAB[13b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #8

BTU Content of Fuel Gas

REPLY

- BTU content given in the application was from an analysis run during the first 33-1 production test (4/18/86)
- The latest gas analysis composition (10/9/86) is given in the application
- The wet BTU content of the latest analysis = 1006.53 BTU/FT^3

CONCLUSION

- The BTU content in the application can be changed from 1161.98 BTU/FT^3 to 1006.53 BTU/FT^3

AAB[14b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #9

Heater Treater Specific Gravity Estimate

REPLY

- Heater treater specific gravity = .95 is a representative value calculated from field data
- Stock tank specific = 1.1465 and separator specific gravity = .7854; .95 is an estimate of heater treater specific gravity

CONCLUSION

- Use .95 as heater treater specific gravity until gas analysis can be obtained after construction of facility

AAB[15b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #10

Fugitive Emission Calculation Method

REPLY

- Approximate method of calculating fugitive emissions from API #4322 was used since no other method was available
- Onshore facility emission factors are estimates derived from individual equipment factors

CONCLUSION

- Use approximate fugitive emission calculation for construction application

AAB[16b]

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #11

SO_2 Emission Factor for Engines

REPLY

- Calculations of SO_2 emission factor for engines are one decimal place off

CONCLUSION

- Change SO_2 emission factor for engines from .000125 to .0000125 (LB/hp·hr)

McLELLAN FIELD DEVELOPMENT
FLORIDA DER AIR PERMIT REVIEW

FLORIDA DER ISSUE #12

Exclusion of Methane and Ethane from Emission Calculations

REPLY

- Federal Register, Volume 42, July 1977 states that methane and ethane have negligible photochemical reactivity in forming oxidants and, therefore, should not be inventoried or controlled by state implementation plans
- Preconstruction review requirements (FDER Regulations) require the owner/operator of a new facility to demonstrate that federally enforceable allowable emissions will not violate any ambient air quality standard. Methane and ethane are not federally enforceable emissions
- Under Table 500-2 (FDER Regulations), ozone is defined as a "regulated air pollutant". Methane and ethane do not form ozone (according to the EPA) and, therefore, should not be regulated
- Previous air permits approved by the FDER did not include methane and ethane emissions. New FDER regulations stating methane and ethane emissions will now be inventoried have not been sent to us

CONCLUSION

It is not necessary to include methane and ethane emissions in the permit application

6

7

8

Points of Interest

When seeking diversion close to home or en route, look on the map for these red number symbols ❶ . Corresponding numbers below describe these attractions. Admission free unless noted and frequently reduced for children. Facts were up-to-date at publication but are subject to change.

Other points of interest are located by ■ or ● and principal public recreation areas by ‡ (see chart for facilities).

❶ **PENSACOLA** (C-6). Self-guided tours of **U.S. Naval Air Station** daily 9-5. On grounds is Naval Aviation Museum. Near tip of Santa Rosa Island is **Fort Pickens**, a coastal defense relic (1834), part of **Gulf Islands Nat. Seashore**, which preserves strip of coastal islands. Auto fee $1. In city center a marked auto route passes sites in two Historical Districts.

❷ **GULFARIUM** (D-6). Porpoise, sea lion and "living sea" shows, marine life exhibits. Daily 9-dusk. $3.

❸ **GULF WORLD** (F-6). Native Gulf sea life and a coral reef with tropical fish can be observed in windowed tanks. Underwater shows, trained porpoise and sea lion acts. Daily March-Oct. Fee.

❹ **FLORIDA CAVERNS STATE PARK** (B-1). Guided tours of underground caverns are

❶❺ **CITRUS TOWER** (J-6). Offers panoramic view of citrus-growing area from top. Elevator. Daily. $1.50.

❶❻ **WALT DISNEY WORLD** (J-6). Highlighted by "Magic Kingdom" entertainment complex which includes six theme lands: Main Street, U.S.A., Adventureland, Frontierland, Liberty Square, Fantasyland and Tomorrowland; Space Mountain. Daily 9-7, to 1 a.m. in summer. Fee.

❶❼ **ORLANDO** (K-5). Family entertainment centered around performing dolphin, penguin, whale and seal shows at **Sea World of Florida**; Japanese village, marine life exhibits, animal petting areas. Daily 9-6, to 8 in summer. $5.50.

About 180 re-created performers in 100 memorable movie and TV scenes in **Stars Hall of Fame** nearby. Open daily. $3.95.

MYAKKA RIVER STATE PARK (H-8). Extensive preserve with appearance of African veldt is a wildlife sanctuary where wild birds and animals roam free. Daily. 25c. Tours (fee) by trackless train and boat available.

HAPPINESS TOWER (K-8). Panoramic view from top. Elevator. Daily 8-6. $1.

ELLIOTT MUSEUM (M-8). Contains collection of antique horse-drawn and automotive vehicles; old-time shops, old country store, art gallery. Daily 1-5. $1. **House of Refuge Museum**, restored 1875 life-saving station; turtle aquarium. Daily 1-5. 50c.

PALMDALE (K-9). Cypress Knee Museum, first cypress knee factory, has catwalk into cypress swamp. Daily 8-dusk. $1.

SEMINOLE INDIANS. Reservations are

Principal Public Recreation Areas

RED symbols on the map shown thus ‡ locate principal recreation areas that are listed below. Facts were up-to-date at publication but are subject to change.

☐ Available
‡ Trailers permitted
○ Trailer hookups available
■ Boats for hire
▲ Boat ramps
△ Historic interest
● Reservations required

FLORIDA	Index	Bathing	Boating	Camping	Fishing	Lodging	Picnicking
Alfred B. Maclay Gardens	D 1		▲				
Anastasia	K 3			‡○			
Bahia Honda	K 13		■▲	‡○			
Basin Bayou	E 6			‡○			
Bill Baggs (Cape Florida) △	M-11						
Blackwater River	D 5			‡○			
Blackwater River St. For	D 5			‡○			
Blue Springs	K 5		▲	‡○			

FLORIDA	Index	Bathing	Boating	Camping	Fishing	Lodging	Picnicking
Lake Griffin	I-5		▲	‡○			
Little Talbot Island	K-2			‡○			
Long Key	L-13			‡○			
Manatee Springs	G-4		■▲	‡○			
Mike Roess (Gold Head Branch)	J-3		■▲	‡○		●	
Myakka River	H-8		■▲	‡○		●	
Natural Bridge Battlefield △	D-2						
Ochlockonee River	C-2		▲	‡○			

BEST AVAILABLE COPY

McLELLAN WELLS

ILLUSTRATION V

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

STATE C

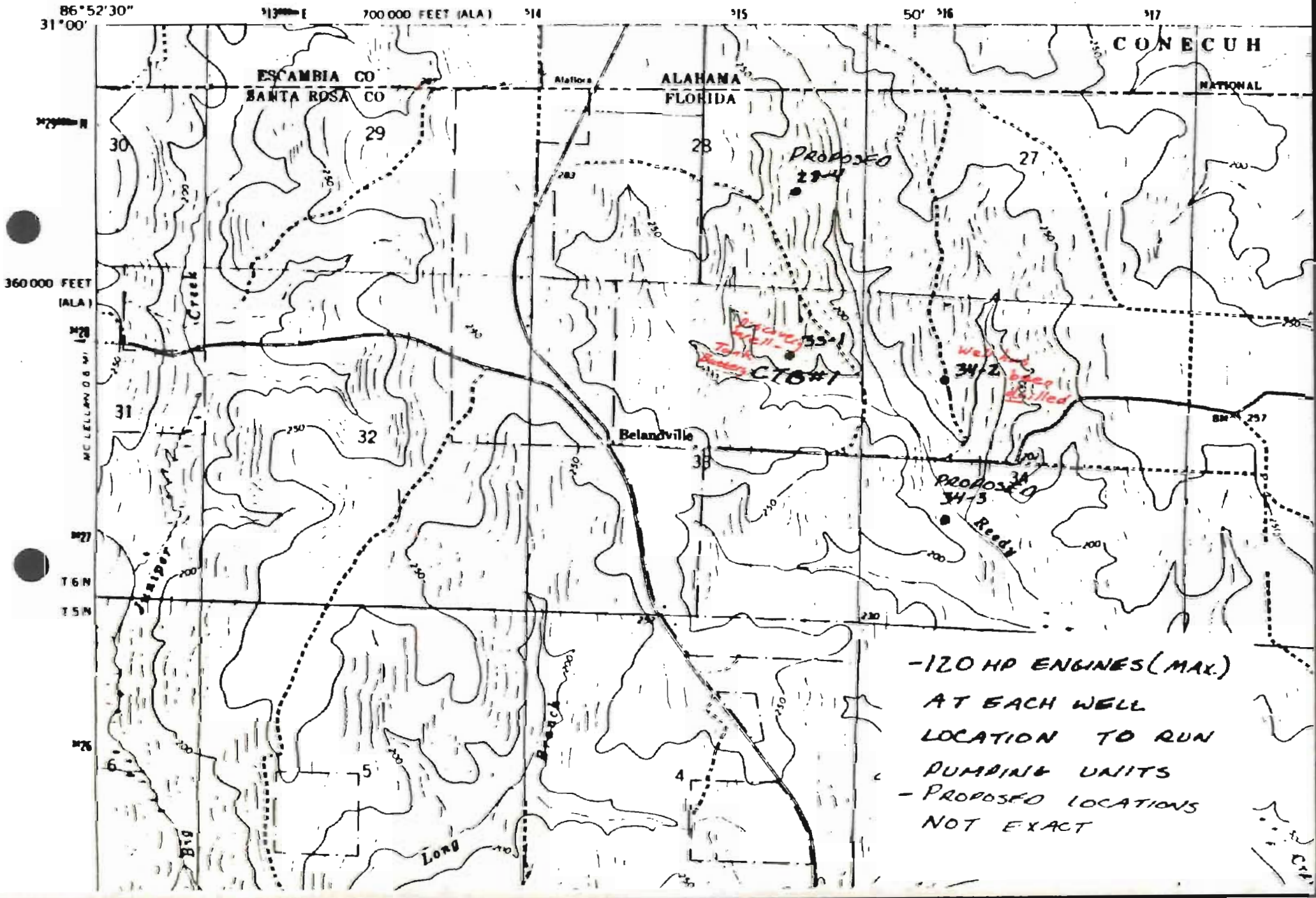
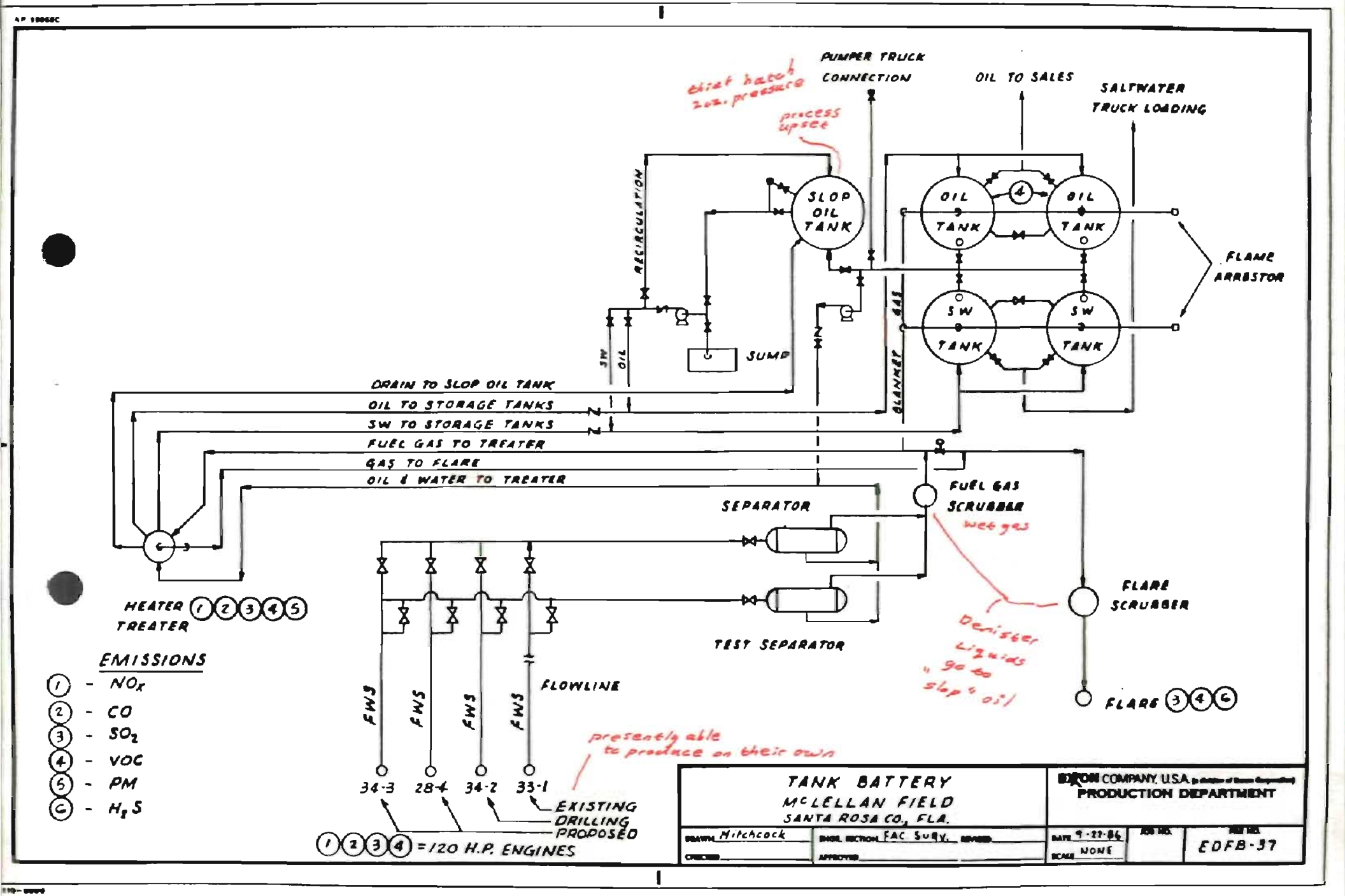


ILLUSTRATION I



Page 1 of 12

New Source

O UTM's may not be coccect E. 515.29 N. 3427.83

O No leteer of authocization

Page 2 of 12

4 wells, 1 heater treater, 2 separators, 6 engines, — stock tanks, flare

O How many stock tanks?

O What is the capacity of the stock tanks?

O Where will the stock tanks be vented?

O What are abaocmal conditions & what happens to excess gas ducing abnocmal conditions?

O Is the flare the only aic pollution contcol component?

Page 3 of 12

The soucce will not be located in a nonattainment acea.

O The two 1,000 bacce/ storage tanks appear to be subject to Ka. We will need the tcue vapoc pcessuce of the ccude oil?

PSD does not apply.

BACT does not apply.

NESHAPs does not apply.

RACT does not apply.

8760 hours per yeac of opecat ion is cequested.

Pages 4 of 12 and 5 of 12

O See Next Page:

4.0 Will auxiliary fuel(s) be used to start or operate the proposed engines, heater treater, or flare at any time? If so, please provide the type, quantity, and analyses of the auxiliary fuel(s) to be used in each of the proposed sources? Please quantify the maximum hourly and potential emissions associated with the storage and use of the auxiliary fuel(s) in each of the proposed sources.

6.0 Please describe the operation of the proposed smokeless flare. If steam is to be supplied to the proposed flare, then provide the information necessary to amend the permit application to include the steam generator. You will need to provide the maximum hourly and potential emissions of VOC, NO_x, CO, and particulate that are expected to result from the operation of the flare. The specific emission factors used to estimate these emissions will need to be provided and supported by derivations, test data, the manufacturer's guarantee or other information acceptable to the Department. You will need to explain why the proposed flare is assumed to be out of service 1% of the time (88 hours per year). The maximum hourly emissions expected when the flare is out-of-service are not to be spread out over the 8,760 hours per year unless they are the result of brief flame-outs lasting only a few minutes. Depending on the reasons for the out-of-service time estimate -- these may need to be recalculated. In addition you will need to supply the effective stack diameter, combustion gas flow rate (ACFM and DSCFM @ 68°F and 14.7 psia), combustion gas temperature (°F), water vapor content (% by volume), and combustion gas velocity (FPS) for the flare. We will also need the estimated opacity of any visible emissions that are expected.

50.0 Please describe the operation of the proposed heater treater. The emission estimates assume the heater treater (capacity 50 bbl/hr) will operate 12 hours per day while the pumps provide oil at the rate of 60-67 bbl/hr 24 hours per day. From the application it appears that the heater treater is expected to process oil at rates that exceed the maximum design capacity by 34% to 168%. You will need to explain how this is to be accomplished, how the oil is to be stored prior to processing, and the emissions associated with the storage prior to processing. Will the design maximum fuel input rate of 500,000 Btu/hr be exceeded. If so, what will be the actual heat input rate and the associated quantity of maximum hourly and potential emissions of each pollutant? The proposed heater treater is designed for a working pressure of 50 psig -- while your calculations assume a working pressure of 30 psig. Explain how this pressure difference will affect the operation rate of the proposed

heater treater. Your calculations indicate that the gas from the proposed heater treater will have a specific gravity of 0.95 and a reactive hydrocarbon content of 40% on the basis of AP-42. We are unable to locate this information in AP-42 or understand why the gas released in the heater treater differs from the fuel gas. Please provide the specific AP-42 page numbers and explain why the characteristics of the gas released in the heater treater is different from the fuel gas released in the separators.

11 ff 0 The proposed sources include two fixed roof vessels for the storage of oil. Your application indicates that the emissions from these tanks will not be controlled. A review of the Code of Federal Regulations, revised as of July 1, 1985, indicates that these vessels are subject to the requirements of 40 CFR 60 Subpart Ka. Therefore, the Department cannot approve your application unless the required control equipment is installed. Your application will need to be revised accordingly. Also, a procedure different from that described Section of AP-42 was used to estimate the emissions from these vessels. You will either need to estimate these emissions using the appropriate AP-42 procedure or fully justify your calculations.

ff 0 The proposed sources include two fixed roof vessels for the storage of saltwater. Since these proposed vessels are to be blanketed with fuel gas -- it appears that the saltwater contains compounds which may be emitted as VOC. Your application indicates that the emissions from these vessels will not be controlled. The emissions from the proposed saltwater storage vessels do not appear to be included in the emission estimates. The emissions from these tanks must be quantified and included in the application. If a procedure different from that used in Section of AP-42 is used -- then the calculations must be fully justified. Based on your application these vessels will be subject to the requirements of FAC Rule 17-2.620 -- General Pollutant Emission Limiting Standards. You will need to revise the application to include controls for these vessels before our review of the application can proceed. The controls will need to be consistent with those for the oil storage vessels.

ff 0 The pilot plan includes a proposed fixed roof vessel for the storage of "slop" oil. Please explain the purpose of this vessel and identify any emission points associated with this vessel. Any emissions associated with the production

and storage of the "slop" oil are to be identified and quantified - since these emissions do not appear to be included in the emission estimates. All calculations need to be justified. If the proposed "slop" oil storage vessel is a source of VOC emissions -- then it will be subject to the requirements of FAC Rule 17-2.620 -- General Pollutant Emission Limiting Standards. You will need to revise your application to include controls for this vessel before our review of your application can proceed if it is a source of emissions.

3. O What is the name of the geological formation from which the raw material is to be withdrawn? Is the raw material being withdrawn from this geological formation at any other geographical point(s)? If so, please identify each of the proposed sources associated with the withdrawal, recovery, and storage of the raw material from this geological formation. The name, location, permit number, actual and maximum operation rates are to be provided for each of the sources. You will also need to identify and quantify the maximum actual, allowable, and potential emissions of each pollutant to be emitted by each source.

8. O The calculations of process input rate and product output rate indicate that the the maximum values included in your application are average values. These estimates will need to be revised to reflect the actual instantaneous maximum rates unless the company is willing to restrict operation rates to these limits. The The response to Section III. A. of your application needs to reflect the correct specific gravity of the crude oil, and the fractions of saltwater, gas, and oil contained in the raw material inputs. The derivation of utilization rates in Exhibit I contains several apparent inconsistencies. The molecular weights of the fuel gas components are not the same as those found in the 5th edition of Perry's Chemical Engineers' Handbook. One factors for the conversion of the API gravity to specific gravity provide a different results. It is not clear what reference conditions have been used to define standard conditions for the volumetric determinations in your calculations. It is also not clear whether the standard conditions referred to in the calculations are dry or wet.

15. O The gas analyses in Appendix I contain some apparent inconsistencies. The data must be supported with copies of the laboratory results. The specific gravity and heat contents of the fuel gas appear to be questionable. The hydro-

gen sulfide content of the fuel gas was determined with Draegur™ Tubes. This procedure is unacceptable. The company needs to determine the hydrogen sulfide (using EPA 11) and total sulfur content of the fuel gas using ASTM D 1137-53(1975), ASTM D 1945-64 (1976), or ASTM D 1946-77. You will need to supply copies of the test reports and a set of revised emission estimates that reflect the test results and other corrections. Also, you will need to document the estimated gas/oil ratios, and provide documented saltwater/oil ratios.

7. O The estimates of fuel use in Exhibit IV do not include any data to support the specific fuel consumption estimates for the proposed engines. The basis for assuming that the engines will be operated 95% of the time needs to be justified as does the basis for assuming that the proposed heater treater will be operated only 12 hours/day. It appears that the proposed engines are to be piston engines -- but you will need to confirm this. We will also need the make, model number, and displacement of each engine.

8. O The emission estimates for each of the proposed engines -- Appendix II -- assume that the engines will be operated 100% of the time at 95% of the rated loading. This assumption is inconsistent with that used in the fuel use calculations -- Exhibit IV -- which assume that the engines will be operated 95% of the time at 100% of the rated load. The emission estimates also do not account for the projected efficiency differentials between the proposed engines and those used to establish the AP-42 emission factor estimates. The AP-42 emission factor estimates assume 7500 Btu/HP-Hr and 1050 Btu/ft³ of natural gas. The calculation of SO_2 emissions appears to contain a decimal point error. Additionally the calculation of SO_2 emissions is based on an assumption that 16 ppm H_2S is equivalent to 1 grain/SCF. This approximation does not necessarily hold. The SO_2 emissions need to be determined on the basis of the total sulfur in the fuel. The VOC emissions are expressed as total carbon in AP-42. VOC emissions are to be expressed as VOC emissions not carbon. Please, recalculate the emission estimates and justify all assumptions.

11. O The estimate of fugitive emissions appears to include only the wells and not those fugitive emission points associated with the handling (separation, scrubbing, storage, and burning of crude oil, saltwater, and gas. The procedures used to calculate the fugitive emissions are not clear and the assumptions

are not clear. The company will either need to clearly explain all calculations, justify all assumptions, and provide a copy of the appropriate references, or use the procedures in section ___ of AP-42. We will also need to know what medium is to be used in the fuel gas scrubbers, what it is to remove, how it will be stored and disposed of, and you will need to quantify the emissions that are expected to result.

10. Please explain the function of the separators, whether these separators are to be sealed, and what will happen to any saltwater removed in the separators. The resulting emissions will have to be quantified and justified.

The fuel use estimates do not include the quantity of fuel gas to be burned by the flare. These must be included by the company. The fuel analysis in the application would be more appropriate if it were expressed in terms of specific gravity at a specified reference temperature.

11. The proposed sources are to be located in an attainment area. The company has excluded those compounds that are exempted pursuant to FAC Rules 17-2.500 - Nonattainment Area New Source Review -- and 17-2.650(1) -- Reasonably Available Control Technology - Volatile Organic Compounds. The proposed sources are subject to review pursuant to FAC Rule 17-2.500 -- Prevention of Significant Deterioration which does not provide any exemptions for VOC compounds. As a result the company will need to recalculate the VOC emissions from the proposed sources.

12. Based on the map provided pursuant to Section V of the application it appears that the proposed sources are to be located within 10 Km of a National Forest. The company will need to confirm whether this is a federal Class I area. Also, we will need a list of all federal Class I areas within 50 km of the proposed sources and the distance to each federal Class I area.

11. The emissions from the "slop" oil and saltwater storage vessels do not appear to be included in the emission estimates. The company will need to amend the application to include these emissions.

Fuel Gas

	Moles/100 Moles	Mole Wt	Lb/100 Moles	Ft³/Lb	Ft³/100 Moles
CO_2	0.56	44.01	24.6456	8.548	210.67
N_2	15.90	28.016	445.4544	13.443	5,988.24
CH_4	67.081	16.041	1,076.7402	23.565	25,632.60
C_2H_6	9.97	30.067	299.7680	12.455	3,733.61
C_3H_8	3.74	44.092	164.9041	8.365	1,379.42
$I\text{-}C_4H_{10}$	0.81	58.118	47.0756	6.321	297.56
$N\text{-}C_4H_{10}$	0.87	58.118	50.5627	6.321	319.61
$I\text{-}C_5H_{12}$	0.17	72.144	12.2645	5.252	64.41
$N\text{-}C_5H_{12}$	0.13	72.144	9.3787	5.252	49.26
C_6H_{14}	0.04	86.169	3.4468	4.398	15.16
	100.00		2,145.2406 lb/100 Moles		37,690.54 ft³/100 Moles
			21.45 lb/Mole		376.90 ft³/Mole

$SG = \frac{21.45}{28.90} = 0.7422$

$RHC = \frac{287.6324\ lb/100\ Moles}{2,145.2406\ lb/100\ Moles} = 0.1341$ $\rho = \frac{21.45\ lb/Mole}{376.90\ ft^3/Mole} = 0.0569\ \frac{lb}{ft^3}$ @ 60F

$VOC = \frac{1,675.1406\ lb/100\ Moles}{2,145.2406\ lb/100\ Moles} = 0.7809$ Fuel Gas $VOC = \frac{1695.6222\ lb/100\ Moles}{3303.6633\ lb/100\ Moles} = 0.5133$ Stock Tank Gas

Stock Tank Gas

	Moles/100 Moles	Mole Wt	Lb/100 Moles	Ft³/Lb	Ft³/100 Moles
CO_2	0.349	44.01	15.3595	8.548	131.29
N_2	56.849	28.016	1,592.6816	13.443	21,410.42
CH_4	7.967	16.041	127.7986	23.565	3,011.58
C_2H_6	11.588	30.067	348.4164	12.455	4,339.53
C_3H_8	13.139	44.092	579.3248	8.365	4,846.05
$I\text{-}C_4H_{10}$	2.812	58.118	163.4278	6.321	1,033.03
$N\text{-}C_4H_{10}$	4.544	58.118	264.0882	6.321	1,669.30
$I\text{-}C_5H_{12}$	1.137	72.144	82.0277	5.252	430.81
$N\text{-}C_5H_{12}$	0.897	72.144	64.7132	5.252	339.87
C_6H_{14}	0.436	86.169	37.5697	4.398	165.23
C_7H_{16}	0.282	100.198	28.2558	3.779	106.78
	100.000		3,303.6633 lb/100 Mole		37,483.89 ft³/100 Moles
			33.04 lb/Mole		374.84 ft³/Mole

$SG = \frac{33.04}{28.90} = 1.1432$

$RHC = \frac{1,219.4072\ lb/100\ Moles}{3,303.6633\ lb/100\ Moles} = 0.3691$ $\rho = \frac{33.04\ lb/Mole}{374.84\ lb/Mole} = 0.0881\ \frac{lb}{ft^3}$ @ 60 F

Fuel Gas

	Lb/100 Moles	Btu/Lb	Btu/100 Moles
CO_2	24.6456	--	--
N_2	445.4544	--	--
CH_4	1087.7402	23,879	25,974,148.24
C_2H_6	299.7680	22,320	6,690,821.76
C_3H_8	164.9041	21,661	3,571,987.71
$I\text{-}C_4H_{10}$	47.0756	21,257	1,000,686.03
$N\text{-}C_4H_{10}$	50.5627	21,308	1,077,390.01
$I\text{-}C_5H_{12}$	12.2645	21,052	258,192.25
$N\text{-}C_5H_{12}$	9.3787	21,091	197,806.16
C_6H_{14}	3.4468	20,940	72,175.99
	2,145.2406 lb/100 Moles		38,843,208.15 Btu/100 Moles

$Btu/lb = \frac{38,843,208.15}{2,145.2406} = 18,106.69$ Btu/lb

$Btu/ft^3 = (18,106.69\ Btu/lb \times 0.0569\ lb/ft^3) = 1,030\ Btu/ft^3$

10ppm H_2S adds $(8.98EE\text{-}08\ lb/ft^3/ppm) \times (10\ ppm) \times (7100\ Btu/ft^3) = 0.00638\ Btu/ft^3$ if considered

$$\begin{array}{l} 0.815 = 42.12 \\ X = 43.00 \\ 0.810 = 43.19 \\ \frac{x-0.810}{.005} = \frac{-.019}{-1.070} \\ x = 0.81089 \end{array}$$ — Specific Gravity of Crude Oil

Stock Tank Gas

	LB/100 Moles	Btu/LB	Btu/100 Moles
CO_2	15.3595	--	--
N_2	1,592.6816	--	--
CH_4	127.7986	23,879	3,051,702.77
C_2H_6	348.4164	22,320	7,776,654.05
C_3H_8	579.3248	21,661	12,548,754.49
$I\text{-}C_4H_{10}$	163.4278	21,257	3,473,984.74
$N\text{-}C_4H_{10}$	264.0882	21,308	5,627,191.37
$I\text{-}C_5H_{12}$	82.0277	21,052	1,726,847.14
$N\text{-}C_5H_{12}$	64.7132	21,091	1,364,866.10
C_6H_{14}	32.5697	20,940	786,709.52
C_7H_{16}	28.2558	20,795	587,579.36
	3,303.6633 lb/100 Moles		36,944,289.54 Btu/100 Moles

Btu/lb = $\frac{36,944,289.54 \text{ Btu}/100 \text{ Moles}}{3,303.6633 \text{ lb}/100 \text{ Moles}}$ = 11,182.82 Btu/lb

Btu/ft³ = (11,182.82 Btu/lb)(0.08816 lb/ft³) = 985 Btu/ft³

Emissions

	VOC		NOx		CO		PM	
	Actual	Potential	Actual	Potential	Actual	Potential	Actual	Potential
Heater Treater ①	0.0039	0.0171	0.0490	0.2146	0.0098	0.0429	0.0024	0.0105
Tanks	63.3104	277.2995	—	—	—	—	—	—
4 120HP Engines	6.1622	26.9906	11.7437	51.4374	1.5169	6.6440	—	—
1 100HP Engine	1.2838	5.6230	2.4466	10.7161	0.3160	1.3841	—	—
1 50HP Engine	0.6419	2.8115	1.2233	5.3580	0.1580	0.6920	—	—
Flare	0.0533	0.1979	1.2600	4.6777	0.2867	1.0644	—	—
Dehydrator ②	1570.7961	68.8009					[illegible]	
Fugitive	4.4990	19.7055	—	—	—	—	—	—
	75.9545	401.446	16.7226	72.4038	2.2874	9.8274		

① Assumes 8760 -- company says 4380 which does not fit because the heater treater is sized for 50 bbls/hr & daily max production is 67 Bbls/hr & daily avg production is 60 Bbl/hr. 12-hr per operation would require 120-134 bbls/hr. Max production of 1600 bbls/hr is also assumed. At 1450 Bbls/hr potential emissions should be 91%. 1030 Btu/SCF of gas @ 60F. See sulfur calculations next page

② Assumes 1600 bbls/hr for actual & potential. Also all VOC included

③ Assumes 1030 Btu/SCF

Emissions

	SO_2		H_2S	
	Actual	Potential	Actual	Potential
Heater Treater ①	0.0008	0.0035		
Tanks	—	—	0.0013	0.0055
4 120 HP Engines	0.0059	0.0258	—	—
1 100 HP Engine	0.0012	0.0053	—	—
1 50 HP Engine	0.0006	0.0026	—	—
Flare	0.0597	0.2216		
Dehydrator*	[illegible]		0.0318	0.0014
Fugitive	[illegible]		?	
	0.06820	0.25880	0.0013	0.00690

① @ 60F & 30 in Hg

$$H_2S = \frac{(P)(m_{H_2S})(PPm)}{1EE06\ R\ T} = \frac{(\frac{30}{29.92})(34.076)(10)}{(1EE06)(0.7302)(519.67)} = 9.0041EE\text{-}07\ \frac{lb}{ft^3}\ \text{or}\ 0.90041\ lb/MCF\ \text{or}\ 6303\ gr/MCF$$

$$S = \frac{(P)(m_{S_2})(m_{H_2S})(PPm)}{1EE06(m_{H_2S})(R)(T)} = \frac{(\frac{30}{29.92})(32.06)(34.076)(10)}{(1EE06)(34.076)(0.7302)(519.67)} = 8.4714EE\text{-}07\ \frac{lb}{ft^3}\ \text{or}\ 0.84711\ lb/MCF$$

$$SO_2 = \frac{(P)(m_{SO_2})(m_{H_2S})(PPm)}{(1EE06)(m_{H_2S})(R)(T)} = \frac{(\frac{30}{29.92})(64.06)(34.076)(10)}{(1EE06)(34.076)(0.7302)(519.67)} = 1.6927EE\text{-}06\ \frac{lb}{ft^3}\ \text{or}\ 1.6927\ lb/MCF$$

or 5,930 gr/MCF

or 11,849 gr/MCF

Heater Treater

$\left(\frac{500{,}000\ Btu/hr}{1030\ Btu/SCF}\right) = 485.44\ \frac{SCF}{hr}$ or $0.00049\ \frac{MCF}{Hr}$

$VOC = (0.00049\ MCF/Hr)(8116\ lb/MCF) = 0.0039\ \frac{lb}{hr}$ $T/Y = (0.0039\ lb/hr)(4.38) = 0.0171\ T/Y$

$NO_x = (0.00049\ MCF/Hr)(100\ lb/MCF) = 0.0490\ \frac{lb}{hr}$ $T/Y = (0.049\ lb/hr)(4.38) = 0.2146\ T/Y$

$CO = (0.00049\ MCF/Hr)(20\ lb/MCF) = 0.0098\ \frac{lb}{hr}$ $T/Y = (0.0098\ lb/hr)(4.38) = 0.0429\ T/Y$

$PM = (0.00049\ MCF/Hr)(5\ lb/MCF) = 0.0024\ \frac{lb}{hr}$ $T/Y = (0.0024\ \frac{lb}{hr})(4.38) = 0.0105\ T/Y$

$SO_2 = (0.00049\ MCF/Hr)(1.6927\ lb/MCF) = 0.0008\ \frac{lb}{hr}$ $T/Y = (0.0008\ \frac{lb}{hr})(4.38) = 0.0035\ T/Y$

* Tanks

$\left(\frac{1600\ bbl/day}{24\ hr/day}\right)(21\ ft^3/bbl)(0.0881\ lb/ft^3)(0.5133\ lb\ VOC/lb\ Gas) = 63.3104\ lb/hr$

$T/Y = (63.3104\ lb/hr)(4.38) = 277.30\ T/Y$

4-120 HP Engines

$SO_2\ factor = \left(\frac{7500\ Btu/hp\text{-}hr}{1030\ Btu/ft^3}\right)(1.6927 EE-06\ lb\ SO_2/ft^3) = 1.233 EE-05\ lb\ SO_2/HP\text{-}Hr$

$HP\text{-}Hr = (4\ engines)(120\ HP\text{-}Hr) = 480\ HP\text{-}Hr$

$VOC_{as\ C} = (0.480\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/lb}\right)(9.7\ lb/EE03\ HP\text{-}Hr) = 4.7464\ lb/Hr$ $T/Y = (4.7464\ lb/hr)(4.38) = 20.7892\ T/Y$

$NO_x = (0.480\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/lb}\right)(24\ lb/EE03\ HP\text{-}Hr) = 11.7437\ lb/Hr$ $T/Y = (11.7437\ lb/hr)(4.38) = 51.4374\ T/Y$

$CO = (0.480\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/lb}\right)(3.1\ lb/EE03\ HP\text{-}Hr) = 1.5169\ lb/Hr$ $T/Y = (1.5169\ lb/hr)(4.38) = 6.6440\ T/Y$

$PM = NA$

$SO_2 = (480\ HP\text{-}Hr)(1.233 EE-05\ lb\ SO_2/HP\text{-}Hr) = 0.0059\ lb/hr$ $T/Y = (0.0059\ lb/hr)(4.38) = 0.0258\ T/Y$

	Lb VOC/100 Moles	Mole Wt Ratio	Lb VOC as C/100 Moles
CH_4	1087.7402	0.7487	814.0391
C_2H_6	299.7680	0.7989	239.4847
C_3H_8	164.9041	0.8172	134.7596
$I\text{-}C_4H_{10}$	47.0756	0.8266	38.9127
$N\text{-}C_4H_{10}$	50.5627	0.8266	41.7951
$I\text{-}C_5H_{12}$	12.2645	0.8324	10.2090
$N\text{-}C_5H_{12}$	9.3787	0.8324	7.8068
C_6H_{14}	3.4468	0.8363	2.8826
	1,675.1406 lb VOC/100 Moles		1,290.2416 lb VOC as C/100 Moles

$VOC_{corr} = \frac{1{,}675.1406\ lb\ VOC/100\ Moles}{1{,}290.2416\ lb\ C\ (VOC)/100\ Moles} = 1.2983\ lb\ VOC/lb\ C$

$VOC = (4.7464)(1.2983) = 6.1622\ \frac{lb}{hr}$ $T/Y = (20.7892)(1.2983) = 26.9906\ T/Y$

* H_2S from Tanks $= 0.0013\ \frac{lb}{hr}$ $0.0055\ T/Y$

1 - 100 HP Engine

$VOC = (0.100\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/ft^3}\right)(9.71\ lb/EE03\ HP\text{-}Hr)(1.2983) = 1.2838\ \frac{lb}{hr}$ $T/Y = (1.2838\ lb/hr)(4.38) = 5.6230\ T/Y$

$NO_x = (0.100\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/ft^3}\right)(24\ lb/EE03\ HP\text{-}Hr) = 2.4466\ \frac{lb}{hr}$ $T/Y = (2.4466\ lb/hr)(4.38) = 10.7161\ T/Y$

$CO = (0.100\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/ft^3}\right)(3.1\ lb/EE03\ HP\text{-}Hr) = 0.3160\ \frac{lb}{hr}$ $T/Y = (0.3160\ lb/hr)(4.38) = 1.3841\ T/Y$

$PM = NA$

$SO_2 = (100\ HP\text{-}Hr)(1.233\ EE\text{-}05\ lb\ SO_2/HP\text{-}Hr) = 0.0042\ \frac{lb}{hr}$ $T/Y = (0.0012\ \frac{lb}{hr})(4.38) = 0.0053\ T/Y$

1 - 50 HP Engine

$VOC = (0.050\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/ft^3}\right)(9.71\ lb/EE03\ HP\text{-}Hr)(1.2983) = 0.6419\ \frac{lb}{hr}$ $T/Y = (0.6419\ lb/hr)(4.38) = 2.8115$

$NO_x = (0.050\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/ft^3}\right)(24\ lb/EE03\ HP\text{-}Hr) = 1.2233\ \frac{lb}{hr}$ $T/Y = (1.2233\ lb/hr)(4.38) = 5.3580\ T/Y$

$CO = (0.050\ EE03\ HP\text{-}Hr)\left(\frac{1050\ Btu/ft^3}{1030\ Btu/ft^3}\right)(3.1\ lb/EE03\ HP\text{-}Hr) = 0.1580\ \frac{lb}{hr}$ $T/Y = (0.1580\ lb/hr)(4.38) = 0.6920\ T/Y$

$PM = NA$

$SO_2 = (150\ HP\text{-}Hr)(1.233\ EE\text{-}05\ lb\ SO_2/HP\text{-}Hr) = 0.0006\ \frac{lb}{hr}$ $T/Y = (0.0006\ \frac{lb}{hr})(4.38) = 0.0026\ T/Y$

Flare

$VOC = (1.600\ EE03\ bbls/day)\left(\frac{1}{24\ hr/day}\right)(0.8\ lb/EE03\ bbls) = 0.0533\ \frac{lb}{hr}$

$NO_x = (1.600\ EE03\ bbls/day)\left(\frac{1}{24\ hr/day}\right)(18.9\ lb/EE03\ bbls) = 1.2600\ \frac{lb}{hr}$

$CO = (1.600\ EE03\ bbls/day)\left(\frac{1}{24\ hr/day}\right)(4.3\ lb/EE03\ bbls) = 0.2867\ \frac{lb}{hr}$

$PM = Neg$

$SO_2 = (1600\ bbls/day)(457\ ft^3/bbl + 72\ ft^3/bbl)\left(\frac{1}{24\ hrs/day}\right)(1.6927\ EE\text{-}06\ lb/ft^3) = 0.0597\ \frac{lb}{hr}$

Gas used $= (630\ HP\text{-}Hr)\left(\frac{7500\ Btu/hr}{1030\ Btu/ft^3}\right) + \left(\frac{500,000\ Btu/hr}{1030\ Btu/ft^3}\right) = 5,072,081.553\ ft^3/hr$ Engines + Heater Treater

Gas Produced $= \left(\frac{1600\ bbl/day}{24\ hr/day}\right)(457\ ft^3/bbl + 72\ ft^3/bbl) = 35,266.6667\ ft^3/hr$

Gas Produced - Gas Used = Total Gas Burned

$35,266.6667\ ft^3/hr - 5,072,081.553\ ft^3/hr = 30,193.85121\ ft^3/hr$

$VOC = (0.0533\ \frac{lb}{hr})\left(\frac{30,193.85121\ ft^3/hr}{35,266.6667\ ft^3/hr}\right)(4.38)(0.99) = 0.1979\ T/Y$

$NO_x = (1.2600\ \frac{lb}{hr})\left(\frac{30,193.85121\ ft^3/hr}{35,266.6667\ ft^3/hr}\right)(4.38)(0.99) = 4.6777\ T/Y$

$CO = (0.2867\ \frac{lb}{hr})\left(\frac{30,193.85121\ ft^3/hr}{35,266.6667\ ft^3/hr}\right)(4.38)(0.99) = 1.0644\ T/Y$

$PM = Neg$

$SO_2 = (0.0597\ \frac{lb}{hr})\left(\frac{30,193.85121\ ft^3/hr}{35,266.6667\ ft^3/hr}\right)(4.38)(0.99) =$

Downtime

$VOC = \left(\frac{1600\ bbl/day}{24\ hr/day}\right)(457\ \frac{ft^3}{bbl})(0.0569\ \frac{lb}{ft^3})(0.7809\ \frac{lb\ VOC}{lb}) + \left(\frac{1600\ bbl/day}{24\ hr/day}\right)(72\ \frac{ft^3}{bbl})(0.0881\ \frac{lb}{ft^3})(0.5133\ \frac{lb\ VOC}{lb})$

$= 1,570.7961\ lb/hr$ $(4.38)(0.01)(1,373.7318\ lb/hr) = 68.8009\ T/Yr$

$H_2S = (35,266.6667\ \frac{ft^3}{hr})(9.0041\ EE\text{-}07\ \frac{lb}{ft^3}) = 0.03175\ \frac{lb}{hr}$ $(4.38)(0.01)(0.03175\ \frac{lb}{hr}) = 0.0014\ T/Y$

Department of Environmental Regulation

Daily Cash Listing # 3

Date Received 03-09-87

Dep # 1731

Bureau of Accounting & Budgeting (Revenue Section)

Date Bureau of AIR QUALITY Received 3-9-87

Lister's Signature Lil Sweeney

Signature of Receiver RRM

REMITTED BY	CHECK NUMBER	AMOUNT	RECEIPT NUMBER	REVENUE CODE	FILE NUMBER
Exxon Company U.S.A.	34039	$ 1,000.00	76151	001031	AC 57-131370
Total this Page		$1,000.00			

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

Nº 76151

RECEIPT FOR APPLICATION FEES AND MISCELLANEOUS REVENUE

Received from Exxon Company U.S.A Date March 5, 1989

Address P.O. Box 61707 New Orleans LA 70161-1707 Dollars $ 1000.00

Applicant Name & Address Same as above

Source of Revenue

Revenue Code 001031 Application Number AC 57-131570

By Patricia G. Adams

(153)

14-2
650

EXXON COMPANY, U.S.A.

A DIVISION OF EXXON CORPORATION

NEW ORLEANS, LOUISIANA FEBRUARY 27, 1987

CHECK NUMBER 34039

PAY EXXON COMPANY USA 1000265 $ 1,000.00

TO THE ORDER OF
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
2600 BLAIR STONE RD
TALLAHASSEE, FLA 32301

EASTERN DIVISION

THE FIRST NATIONAL BANK OF COMMERCE
IN NEW ORLEANS, LOUISIANA

[redacted]

1031

Attached, in quadruplicate, is an application for an Air Permit to construct the oil production facility captioned above. Also included is an Exxon Company, U.S.A. check in the amount of $1,000.00 to cover the permit fee.

The estimated production from a proposed four well development is considered in the emissions calculations for this application. The production facility will have emission sources including a heater treater, stock tanks, engines, and a flare. This application reflects the actual produced gas and stock tank gas analyses obtained from recent production tests of the one completed drillwell.

The second of the four proposed wells begins a 90-day production test within the next month. Afterwards, we plan to convert and expand our testing facility to the permanent production facility described in this application. Initially, only two of the four proposed wells will be producing into the facility, resulting in emission rates substantially lower than the permitted rates.

Immediately after construction is complete we will apply for an operating permit. At that time we will perform necessary tests and calculate emissions using approved methods to ensure that we are below the emissions levels stated in our construction permit and will report our results to you. When future wells start to produce into our facility, we will re-evaluate emissions to ensure our permitted rates are not exceeded.

Should you need additional information, please contact Ms. Ashlyn Broussard at 504-561-4226. Your timely review of this application would be appreciated.

Very truly yours,

EXXON CORPORATION

Charles A. Martin
Permits/Surveillance Supervisor
Operations Accounting
Exxon Company, U.S.A.
(a division of Exxon Corporation)

1987 MAR -5 PM 1:57

RECEIVED
DER - MAIL ROOM

AAB:fab[53]
Attachments

RECEIVED BWIM

MAR 0 8 1987

EXXON COMPANY, U.S.A.
POST OFFICE BOX 61707 • NEW ORLEANS, LOUISIANA 70161-1707

PRODUCTION DEPARTMENT
EASTERN DIVISION

March 2, 1987

McLellan Field
Common Tank Battery
Section 33, T6N, R26W
Santa Rosa County, Florida

Mr. C. H. Fancy, Bureau Chief
Bureau of Air Quality Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

Dear Mr. Fancy:

1031

Attached, in quadruplicate, is an application for an Air Permit to construct the oil production facility captioned above. Also included is an Exxon Company, U.S.A. check in the amount of $1,000.00 to cover the permit fee.

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EXXON CORPORATION

Charles A. Martin
Permits/Surveillance Supervisor
Operations Accounting
Exxon Company, U.S.A.
(a division of Exxon Corporation)

AAB:fab[53]
Attachments

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION)	Initial / Date
Bill	
2.	Initial / Date
3.	Initial / Date
4.	Initial / Date

REMARKS:

New Application
$1000 paid
Dist. sent a copy
File — Mike has copy
BT

INFORMATION	
	Review & Return
	Review & File
	Initial & Forward

DISPOSITION	
	Review & Respond
	Prepare Response
	For My Signature
	For Your Signature
	Let's Discuss
	Set Up Meeting
	Investigate & Report
	Initial & Forward
	Distribute
	Concurrence
	For Processing
	Initial & Return

FROM:
Patty

DATE 3/5/87

PHONE 8-1341

AC 57 - 131370

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHWEST DISTRICT
160 GOVERNMENTAL CENTER
PENSACOLA, FLORIDA 32501

DER

MAR 5 1987

BAQM

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Air Pollution [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: Exxon Company, U.S.A. (a division of Exxon Corp.) COUNTY: Santa Rosa

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) McLellan Field Flare Stack, Heater Treater, Engines

SOURCE LOCATION: Street Highway 4 City Munson, Florida

UTM: East 1186' North 1101'

Latitude 30 ° 59 ' 8.1 "N Longitude 86 ° 50 ' 23.6 "W

APPLICANT NAME AND TITLE: Sue Cummings, Operations Manager

APPLICANT ADDRESS: Exxon Company, U.S.A., Eastern Division, Post Office Box 61707, New Orleans, LA 70161-1707

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Exxon Corporation

I certify that the statements made in this application for a Construction permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Sue Cummings

Sue Cummings, Operations Manager
Name and Title (Please Type)

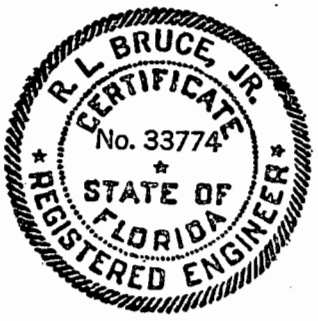
Date: 2-27-87 Telephone No. 504-561-4039

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.



Signed R. L. Bruce Jr.

R. L. Bruce
Name (Please Type)

Exxon Company, U.S.A.
Company Name (Please Type)

P. O. Box 61707, New Orleans LA 70161-1707
Mailing Address (Please Type)

Florida Registration No. 33774 Date: 2/23/87 Telephone No. (504) 561-3904

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

The McLellan permanent production facility will handle 4 production wells. Proposed equipment will include one heater treater , 2 separators, 6 engines and stock tanks. A flame arrestor will be installed on the tanks and the gas will be vented off of the tanks through the flame arrestor. The gas off the heater treater will be collected whereby, under normal operating conditions, all excess gas will be burned at the flare stack (see illustration I). The proposed production facility will comply with all applicable State and Federal air pollution source rules and regulations.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction May , 1987 Completion of Construction June , 1987

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

Flare System: $15k installed

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Approval to test State of Florida Lease 33-1 was given on March 17, 1986 for a 60-day test and on August 12, 1986 for a 90-day test. Robert Kriegal, District Manager, and Norman L. Richards, Asst. District Manager, granted these approvals. We are currently seeking approval to test the State of Florida Lease 34-2 for 90 days beginning approximately February 16, 1987.

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52 ;

if power plant, hrs/yr -- ; if seasonal, describe: N/A

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? No

   a. If yes, has "offset" been applied? N/A

   b. If yes, has "Lowest Achievable Emission Rate" been applied? N/A

   c. If yes, list non-attainment pollutants. N/A

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. No

3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. No

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? No

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

M. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? No

   a. If yes, for what pollutants? N/A

   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
43° API Gravity	---	---	19077 lbs/hr	(see Illustration I)
Crude Oil &				
Associated Gas				

B. Process Rate, if applicable: (See Section V, Item 1) By sample analysis (see Exhibit I)

1. **Total Process Input Rate (lbs/hr):** 19077 lbs/hr
2. **Product Weight (lbs/hr):** 17542 lbs/hr

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) See Exhibits II and III

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
NO_x	15.1630/	63.0086	N/A	15.1630	15.1630/	66.4139	Illus. I&II ①
CO	1.9616/	8.1453	N/A	1.9619	1.9616/	8.5918	Illus. I&II ②
SO_2	.1386/	.5530	N/A	.1388	.1388/	.6079	Illus. I&II ③
VOC	54.2360/	217.1091	N/A	54.2360	54.2360/	237.5539	Illus. I&II ④
PM	.0022/	.0047	N/A	.0022	.0022/	.0096	Illus. I&II ⑤
H_2S	.0003/	.0009	N/A	.0003	.0003/	.0013	Illus. I&II ⑥

[1] See Section V, Item 2.

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated with control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminent	Efficiency (Downtime Related)	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
McGill Flare Tip BFI-3 or equivalent	SO_2 and VOC	99%		

E. Fuels (see Exhibit IV)

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Produced Fuel Gas	1567.76 SCF/HR	1854.10 SCF/HR	2.1544 MMBTU/HR
(10 ppm H_2S)			

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: (see Exhibit V)

Percent Sulfur: .001% Percent Ash: 0

Density: .4471 lbs/gal Typical Percent Nitrogen: 15.90%

Heat Capacity: 19441.0373 BTU/lb 155.3342 BTU/gal

Other Fuel Contaminants (which may cause air pollution): ---

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average _____ Maximum _____

G. Indicate liquid or solid wastes generated and method of disposal.

All saltwater produced will be trucked away and disposed of at a permitted saltwater disposal well; eventually, if warranted, a saltwater disposal well may be drilled and saltwater disposed by a natural gas fired engine driven pump (emissions from this engine have been included).

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: 40 ft. Stack Diameter: .1666* ft.

Gas Flow Rate: -- ACFM -- DSCFM Gas Exit Temperature: -- °F.

Water Vapor Content: -- % Velocity: -- FPS

*Approximate stack diameter at exit point (see Illustration VIII).

SECTION IV: INCINERATOR INFORMATION

Type of Waste	Type 0 (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste _____

Total Weight Incinerated (lbs/hr) _____ Design Capacity (lbs/hr) _____

Approximate Number of Hours of Operation per day _____ day/wk _____ wks/yr. _____

Manufacturer _____

Date Constructed _____ Model No. _____

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: _____ ft. Stack Diameter: _____ Stack Temp. _____

Gas Flow Rate: _____ ACFM _____ DSCFM* Velocity: _____ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) _____

Brief description of operating characteristics of control devices: _____

_____

_____

_____

_____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

_____

_____

_____

_____

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)] (Exhibit I)
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. (Appendix II & Exhibit VI)
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test). (Exhibit VI)
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.) (Illustration VIII)
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). Conservative Estimate
6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained. (Illustration I)
7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map). (Illustration IV and Illustration V)
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram. (Illustration II)

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[ ] Yes [ ] No

Contaminant	Rate or Concentration

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[ ] Yes [ ] No

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration

D. Describe the existing control and treatment technology (if any).

1. Control Device/Syetem:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft. b. Diameter: ft.

c. Flow Rate: ACFM d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1.

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Cost:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Cost:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Costs:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data

1. _____ no. sites _____ TSP _____ ( ) SO^2* _____ Wind spd/dir

Period of Monitoring ___/___/___ to ___/___/___
month day year month day year

Other data recorded _____

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling

1. _____ Year(s) of data from ____/____/____ to ____/____/____
month day year month day year

2. Surface data obtained from (location)_____

3. Upper air (mixing height) data obtained from (location)_____

4. Stability wind rose (STAR) data obtained from (location)_____

C. Computer Models Used

1. _____ Modified? If yes, attach description.

2. _____ Modified? If yes, attach description.

3. _____ Modified? If yes, attach description.

4. _____ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data

Pollutant	Emission Rate
TSP	_____ grams/sec
SO^2	_____ grams/sec

E. Emission Data Used in Modeling

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review.

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources.

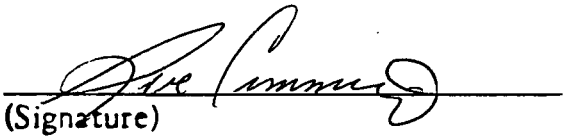
H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology.

CERTIFICATION

APPLICATIONS, REPORTS AND OTHER REQUESTED INFORMATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Sue Cummings
(Name)


(Signature)

Operations Manager
(Title) Production Department
Exxon Company, U.S.A.

7-27-87
(Date)

UTILIZATION RATE Lbs/Hr

1) OIL

S. G. of FWS properties = .8323

$$1600 \frac{\text{barrels}}{\text{day}} \times 42 \frac{\text{gal}}{\text{barrel}} \times 8.3 \frac{\text{lb H2O}}{\text{gal}} \times .8323 \frac{\text{lb oil}}{\text{lb H2O}}$$

$$= 4.64 \times 10^5 \text{ lbs/day}$$

2) GAS

GOR = 457 SCF/Bbl (see Gas Analysis, Appendix I)
BOPDm = 1600 (Maximum oil throughput expected)
BOPDa = 1450 (Average oil throughput expected)

$$1600 \frac{\text{barrels}}{\text{day}} \times 457 \frac{\text{SCF}}{\text{barrel}} \times \frac{\text{LB-MOL}}{380.68 \text{ SCF}} = 1.92 \times 10^3 \frac{\text{LB-MOL}}{\text{day}}$$

	Gas Mole %		LB-MOL DAY		M. W. (LB/LB-MOL)		
N_2	15.90	x	(1.92×10^3)	x	28.013	=	8.56×10^3
CO_2	.56	x	(1.92×10^3)	x	44.010	=	4.73×10^2
H_2S	---	x	(1.92×10^3)	x	---	=	- - -
Methane	67.81	x	(1.92×10^3)	x	16.043	=	2.09×10^4
Ethane	9.97	x	(1.92×10^3)	x	30.070	=	5.76×10^3
Propane	3.74	x	(1.92×10^3)	x	44.097	=	3.17×10^3
I-Butane	.81	x	(1.92×10^3)	x	58.124	=	9.04×10^2
N-Butane	.87	x	(1.92×10^3)	x	58.124	=	9.71×10^2
I-Pentane	.17	x	(1.92×10^3)	x	72.151	=	2.36×10^2
N-Pentane	.13	x	(1.92×10^3)	x	72.151	=	1.80×10^2
Hexane	.04	x	(1.92×10^3)	x	86.178	=	6.62×10^1
	100%						4.12×10^4 lbs/day

3) TOTAL INLET

$$4.64 \times 10^5 \frac{\text{lbs}}{\text{day}} + 4.12 \times 10^4 \frac{\text{lbs}}{\text{day}} = 5.05 \times 10^5 \frac{\text{lbs}}{\text{day}}$$

4) AVERAGE INLET

$$\frac{1450}{1600} (5.05 \times 10^5) = 4.58 \times 10^5 \frac{\text{lbs}}{\text{day}} = 19077 \frac{\text{lbs}}{\text{hr}}$$

5) AVERAGE PRODUCT

$$\frac{1450}{1600} (4.64 \times 10^5) = 4.21 \times 10^5 \frac{\text{lbs}}{\text{day}} = 17542 \frac{\text{lbs}}{\text{hr}}$$

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

DESCRIPTION OF EQUIPMENT	NUMBER OF UNITS	MAXIMUM THEORETICAL EMISSIONS LBS/HR					
		NO_x	CO	SO_2	VOC	PM	H_2S
Heater Treater	1	.0430	.0086	.0007	.0023	.0022	---
Tanks (1000 bbl, oil)	2	--	--	--	45.0852	---	---
Engines:							
120 H.P. Natural Gas	4	11.5200	1.4880	.0600	.6244	---	---
100 H.P. Natural Gas	1	2.4000	.3100	.0125	.1301	---	---
50 H.P. Natural Gas	1	1.2000	.1550	.0063	.0650	---	---
Flare	1	--	--	.0593	3.8300	---	.0003
Fugitive Emissions		--	--	--	4.4990	---	---
		15.1630	1.9616	.1388	54.2360	.0022	.0003

NOTES: 1) 1600 BOPD production rate with 1% downtime of flare stack system assumed
2) See Appendix I for gas analysis
3) See Appendix II for all design calculations

AAB[8]

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

DESCRIPTION OF EQUIPMENT	NUMBER OF UNITS	ACTUAL EMISSIONS TONS/YR					
		NO_x	CO	SO_2	VOC	PM	H_2S
Heater Treater	1	.0942	.0188	.0016	.0050	.0047	---
Tanks (1000 bbl, oil)	2	--	--	--	178.9602	---	---
Engines:							
120 H.P. Natural Gas	4	47.9348	6.1916	.2496	2.5980	---	---
100 H.P. Natural Gas	1	9.9864	1.2899	.0520	.5413	---	---
50 H.P. Natural Gas	1	4.9932	.6450	.0260	.2706	---	---
Flare	1	--	--	.2238	15.0285	---	.0008
Fugitive Emissions		--	--	--	19.7055	---	---
		63.0086	8.1453	.5530	217.1091	.0047	.0008

NOTES: 1) 1450 BOPD production rate with 1% downtime of flare stack system assumed
2) See Appendix I for gas analysis
3) See Appendix II for all design calculations

AAB[9]

FUEL CALCULATION

Note: See Appendix I for Gas Analysis

TREATER

$$\text{Maximum} = .5 \times 10^6 \frac{\text{BTU}}{\text{hr}} \times \frac{1 \text{ SCF}}{1161.9803 \text{ BTU}} = 430.30 \frac{\text{SCF}}{\text{hr}}$$

$$\text{Average} = 430.3 \frac{\text{SCF}}{\text{hr}} \times \frac{12 \text{ hrs}}{\text{day}} \times \frac{1 \text{ day}}{24 \text{ hrs}} = 215.15 \frac{\text{SCF}}{\text{hr}}$$

ENGINES

Four 120 HP Engines:

$$\text{Maximum} = 4 \times 120 \text{ HP} \times \frac{2.26 \text{ SCF gas}}{\text{HP} \cdot \text{Hr}} = 1084.80 \frac{\text{SCF}}{\text{hr}}$$

$$\text{Average} = 1084.80 \times .95 \text{ (runtime)} = 1030.56 \frac{\text{SCF}}{\text{hr}}$$

One 100 HP Engine:

$$\text{Maximum} = 100 \text{ HP} \times \frac{2.26 \text{ SCF gas}}{\text{HP} \cdot \text{Hr}} = 226.00 \frac{\text{SCF}}{\text{hr}}$$

$$\text{Average} = 226.00 \times .95 \text{ (runtime)} = 214.70 \frac{\text{SCF}}{\text{hr}}$$

One 50 HP Engine:

$$\text{Maximum} = 50 \text{ HP} \times \frac{2.26 \text{ SCF gas}}{\text{HP} \cdot \text{Hr}} = 113.00 \frac{\text{SCF}}{\text{hr}}$$

$$\text{Average} = 113.00 \times .95 \text{ (runtime)} = 107.35 \frac{\text{SCF}}{\text{hr}}$$

INSTRUMENT GAS

Negligible

TOTAL FUEL CONSUMED:

$$\text{Maximum} = 430.30 + 1084.80 + 226.00 + 113.00 = 1854.10 \frac{\text{SCF}}{\text{hr}}$$

$$\text{Average} = 215.15 + 1030.56 + 214.70 + 107.35 = 1567.76 \frac{\text{SCF}}{\text{hr}}$$

MAXIMUM HEAT INPUT

- BTU Content = 1161.9803 $\frac{\text{BTU}}{\text{SCF}}$ (see Appendix I)

$$1854.10 \frac{\text{SCF}}{\text{hr}} \times 1161.9803 \frac{\text{BTU}}{\text{SCF}} = 2.1544 \times 10^6 \frac{\text{BTU}}{\text{hr}} = 2.1544 \frac{\text{MMBTU}}{\text{hr}}$$

AAB[39]

FUEL ANALYSIS:

- See Appendix I for Gas Analysis

$$\% \text{ Sulfur} = \frac{10}{1 \times 10^6} \text{ mol fraction} = .00001 = .001\%$$

% Ash = 0

$$\text{Density (lbs/gal)} = \frac{.7854 \text{ lb gas}}{\text{lb air}} \times \frac{28.97 \text{ lbs air}}{\text{lb mol}} \times \frac{1 \text{ lb mol}}{380.68 \text{ scf}} \times \frac{7.480519 \text{ scf}}{1 \text{ gal}}$$

$$= \frac{.4471 \text{ lbs gas}}{\text{gal}}$$

N_2 = 15.90%

Heat Capacity:

1) $$\frac{1161.9803 \text{ BTU}}{\text{SCF}} \times \frac{380.68 \text{ scf}}{\text{lb mol}} \times \frac{1 \text{ lb mol}}{28.97 \text{ lbs air}} \times \frac{1 \text{ lb air}}{.7854 \text{ lb gas}}$$

= 19441.0373 BTU/lb

2) $$\frac{1161.9803 \text{ BTU}}{\text{SCF}} \times \frac{1 \text{ SCF}}{7.480519 \text{ gal}} = \frac{155.3342 \text{ BTU}}{\text{gal}}$$

PROPOSED METHODS OF ENSURING COMPLIANCE

Minimizing Spill Potential:

1) All connections are welded.

2) Skids are equipped with drip pans to ensure oil does not drip on ground. This fluid is collected and piped to the sump.

3) A sump system collects fluid from skid drip pans and diked area and pumps it to a slop oil tank to allow for the proper disposition of fluids.

4) A Spill Prevention Control & Countermeasure (SPCC) plan will be developed for the field. This plan will be implemented as needed.

Minimizing Air Emissions:

1) A smokeless flare burns all excess gas produced.

2) Flare has an automatic relight to ensure flare downtime is minimized.

EXXON COMPANY, U.S.A.
EASTERN DIVISION
McLELLAN COMMON TANK BATTERY NO. 1
SANTA ROSA COUNTY, FLORIDA

GAS PHYSICAL PROPERTIES

COMPOSITION	FUEL GAS MOL %	STOCK TANK GAS MOL %
Carbon Dioxide	.56	0.349
Nitrogen	15.90	56.849
Methane	67.81	7.967
Ethane	9.97	11.588
Propane	3.74	13.139
Iso Butane	.81	2.812
N Butane	.87	4.544
Iso Pentane	.17	1.137
N Pentane	.13	.897
Hexane	.04	.436
Heptane	--	.282
	100%	100%
Gas/oil ratio (SCF/bbl)	457	21
Specific Gravity	.7854	1.1465
RHC Correction (1)	.1341	.3691
BTU Content (BTU/Ft^3)	1161.9803	984.0
H_2S Content (from field Dragger Tube)	10 ppm	---

(1) $\frac{\text{Tons VOC}}{\text{Tons THC}}$

AAB[10]

HEATER TREATER EMISSIONS

TWO COMPONENTS

- Flash loss from venting
- Emissions from combustion in firebox

- Flash loss is N/A since all gas is collected and sent to flare system
- Gas off of heater treater is included in flare emissions

Firebox Emissions

Maximum Emissions (lbs/hr)

Max. Design Fuel Rate $\frac{10^6 \text{ SCF}}{\text{hr}}$ x Emission Factor $\frac{\text{lbs}}{10^6 \text{ SCF}}$

Average Emissions (lbs/hr)

Max. Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime $\frac{\text{hr}}{\text{day}}$ x $\frac{1}{24}$ $\frac{\text{day}}{\text{hr}}$

Maximum Design Fuel Rate

= .5 x 10^6 BTU/hr (see heater treater design parameters illustration #III)

= .5 x 10^6 BTU/hr x $\frac{1 \text{ SCF}}{1161.9803 \text{ BTU}}$ = 430.30 SCF/hr

= .00043 x 10^6 SCF/hr

Note: Assume firebox lit 12 hours/day (maximum)

VOC EMISSIONS

Emissions Factor = 5.3 (AP-42, Table 1.4-1)

Maximum Emissions = .00043 x 5.3 = .0023

= .0023 lbs/hr

Average Emissions = .0023 lbs/hr x $\frac{12 \text{ hrs}}{\text{day}}$ x $\frac{365 \text{ days}}{\text{year}}$ x $\frac{1 \text{ ton}}{2000 \text{ lbs}}$

= .0050 tons/yr

NOx EMISSIONS

Emissions Factor = 100 (AP-42, Table 1.4-1)

Maximum Emissions = .00043 x 100

= .043 lbs/hr

Average Emissions = $.043 \frac{\text{lbs}}{\text{hr}} \times \frac{12 \times 365}{2000}$

= .0942 T/yr

CO EMISSIONS

Emissions Factor = 20 (AP-42, Table 1.4-1)

Maximum Emissions = .00043 x 20

= .0086 lbs/hr

Average Emissions = $.0086 \frac{\text{lbs}}{\text{hr}} \times \frac{12 \times 365}{2000}$

= .0188 T/yr

PM EMISSIONS

Emissions Factor = 5 (AP-42, Table 1.4-1)

Maximum Emissions = .00043 x 5

= $.0022 \frac{\text{lbs}}{\text{hr}}$

Average Emissions = $.0022 \frac{\text{lbs}}{\text{hr}} \times \frac{12 \times 365}{2000}$

= $.0047 \frac{\text{tons}}{\text{yr}}$

SO_2 EMISSIONS

H_2S Mol Fraction = $10/(1 \times 10^6)$ (from Dragger Tube)

Maximum Emissions = $430.30 \frac{\text{SCF}}{\text{hr}} \times \frac{10}{1 \times 10^6} \frac{\text{lb mol}}{\text{SCF}} \times \frac{1}{380.68} \frac{\text{lbs } SO_2}{\text{lb mol}} \times 64$

= $.0007 \frac{\text{lbs}}{\text{hr}}$

Average Emissions = $.0007 \frac{\text{lbs}}{\text{hr}} \times \frac{12 \times 365}{2000}$

= $.0016 \frac{\text{tons}}{\text{yr}}$

FIXED ROOF TANK EMISSIONS

FLASH LOSS CALCULATION - VOC EMITTED

- NOTE: Working and breathing losses are included in the flash loss calculations

$$\text{FLASH LOSS } \frac{\text{lbs}}{\text{hr}} = \text{Throughput } \frac{\text{bbls}}{\text{day}} \times \text{GOR } \frac{\text{SCF}}{\text{Bbl}} \times \text{S.G. of gas} \times \text{RHC Correction} \times \frac{1}{380.68} \frac{\text{lb mol}}{\text{SCF}} \times 28.97 \frac{\text{lbs air}}{\text{lb mol}} \times \frac{1}{24} \frac{\text{day}}{\text{hr}}$$

Maximum Throughput = $4 \times 400 = 1600 \frac{\text{bbls}}{\text{day}}$

Average Throughput = $300 + 450 + 400 + 300 = 1450 \frac{\text{bbls}}{\text{day}}$

GOR (Stock Tank)

API Gravity = 43.2
Heater Treater Pressure = 30 psig (approximate maximum)
Stock Tank GOR = 21 SCF/bbl (estimate)

Gas

Specific Gravity = 1.1465 (see analysis: Appendix I)

RHC Correction = .3691 (see next page for calculation)

MAXIMUM FLASH LOSS

$1600 \times 21 \times 1.1465 \times .3691 \times 1/380.68 \times 28.97 \times 1/24 = 45.0852$ lbs/hr

AVERAGE FLASH LOSS

$\frac{1450}{1600} \times 45.0852 = 40.8585$ lbs/hr

AVERAGE FLASH LOSS

178.9602 tons/year

AAB[35]

	Mol Fraction	x	M. W.	=	Product of Mol Fraction & M. W.	RHC
N_2 =	.56849		28.013		15.9251	N
CO_2 =	.00349		44.010		.1536	N
C_1 =	.07967		16.043		1.2781	N
C_2 =	.11588		30.070		3.4845	N
C_3 =	.13139		44.097		5.7939	Y
iC_4 =	.02812		58.124		1.6344	Y
nC_4 =	.04544		58.124		2.6412	Y
iC_5 =	.01137		72.151		.8204	Y
nC_5 =	.00897		72.151		.6472	Y
C_6 =	.00436		86.178		.3757	Y
C_7 =	.00282		100.205		.2826	Y
	1.0				33.0367	

$$RHC = \frac{5.7939 + 1.6344 + 2.6412 + .8204 + .6472 + .3757 + .2862}{33.0367}$$

$$RHC = \frac{12.194}{33.0367} = .3691$$

Note: Gas analysis found in Appendix I.

FOUR 120 HP ENGINES

(Maximum Values; Actual Engine HP May be Less)

Note: These engines will be used at four planned drillwells to run pumping units. Actual engine horsepower may be less.

Natural Gas Fired

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .000125 (see next page for calculation)

NO_x (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097

NOx, SO_2, CO Emission Rates

Maximum Emissions

$$\text{Emission Factor } \frac{\text{lbs}}{\text{hp·hr}} \times \text{Rated hp}$$

Average Emissions

$$\text{Max. Emissions } \frac{\text{lbs}}{\text{hr}} \times \text{Runtime (fraction)} \times \text{Loading (fraction)}$$

Assume 95% loaded, 100% runtime

Maximum Emissions

NOx = .024 x 120 hp = 2.88 lb/hr x 4 engines = 11.52 lb/hr

CO = .0031 x 120 hp = .372 lb/hr x 4 engines = 1.488 lb/hr

SO_2 = .000125 x 120 hp = .015 lb/hr x 4 engines = .06 lb/hr

PM = N/A

Average Emissions

NOx = $2.88 \times 1.0 \times .95 = 2.736 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 11.9837$ T/yr x 4 = 47.9348 T/yr

CO = $.372 \times 1.0 \times .95 = .3534 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = 1.5479$ T/yr x 4 = 6.1916 T/yr

SO_2 = $.015 \times 1.0 \times .95 = .0143 \frac{\text{lb}}{\text{hr}} \times \frac{365 \times 24}{2000} = .0624$ T/yr x 4 = .2496 T/yr

PM = N/A

AAB[44]

SO_2 EMISSION FACTOR DETERMINATION

$\frac{1 \text{ grain}}{100 \text{ SCF}}$ = 16 ppm H_2S (estimate)

$\frac{.2 \text{ grains}}{100 \text{ SCF}}$ = 3.2 ppm H_2S = .00004 $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ (AP-42, Table 3.3.2-1)

therefore,

10 ppm (max. obtained from Dragger Tube) = .000125 $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ x hp x RHC Correction

= .0097 x 120 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 95%

RHC Correction (Note: Fuel gas lines will supply engines with natural gas)

	Mol Fraction	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	.1590		28.013		4.4541	N
CO_2 =	.0056		44.010		.2465	N
C_1 =	.6781		16.043		10.8788	N
C_2 =	.0997		30.070		2.9980	N
C_3 =	.0374		44.097		1.6492	Y
iC_4 =	.0081		58.124		.4708	Y
nC_4 =	.0087		58.124		.5057	Y
iC_5 =	.0017		72.151		.1227	Y
nC_5 =	.0013		72.151		.0938	Y
C_6 =	.0004		86.178		.0345	Y
	1.0				21.4539	

RHC Correction = $\frac{1.6492 + .4708 + .5057 + .1227 + .0938 + .0345}{21.4539}$

RHC Correction = .1341

MAXIMUM EMISSIONS RATE

.0097 x 120 x .1341 = .1561 $\frac{\text{lb}}{\text{hr}}$ x 4 = .6244 $\frac{\text{lb}}{\text{hr}}$

AVERAGE EMISSIONS RATE

.1561 x .95 x 1.0 = .1483 $\frac{\text{lbs}}{\text{hr}}$ x $\frac{24 \times 365}{2000}$ = .6495 $\frac{\text{tons}}{\text{yr}}$ x 4 = 2.598 $\frac{\text{tons}}{\text{yr}}$

ONE 100 HP ENGINE

(Maximum Values; Actual Engine HP May be Less)

Note: This engine will be used at the facility to run lights, pumps, etc. Actual horsepower may be less.

Natural Gas Fired

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .000125 (see next page for calculation)

NO_x (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097

NOx, SO_2, CO Emission Rates

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp hr}}$ x Rated hp

Average Emissions

Max. Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime (fraction) x Loading (fraction)

Assume 95% loaded, 100% runtime

Maximum Emissions

NOx = .024 x 100 hp = 2.4 lb/hr

CO = .0031 x 100 hp = .31 lb/hr

SO_2 = .000125 x 100 hp = .0125 lb/hr

PM = N/A

Average Emissions

NOx = 2.4 x 1.0 x .95 = 2.28 $\frac{\text{lb}}{\text{hr}}$ x $\frac{365 \times 24}{2000}$ = 9.9864 T/yr

CO = .31 x 1.0 x .95 = .2945 $\frac{\text{lb}}{\text{hr}}$ x $\frac{365 \times 24}{2000}$ = 1.2899 T/yr

SO_2 = .0125 x 1.0 x .95 = .01188 $\frac{\text{lb}}{\text{hr}}$ x $\frac{365 \times 24}{2000}$ = .0520 T/yr

PM = N/A

AAB[36]

SO_2 EMISSION FACTOR DETERMINATION

$\frac{1 \text{ grain}}{100 \text{ SCF}}$ = 16 ppm H_2S (estimate)

$\frac{.2 \text{ grains}}{100 \text{ SCF}}$ = 3.2 ppm H_2S = .00004 $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ (AP-42, Table 3.3.2.1)

therefore,

10 ppm (max. obtained from Dragger Tube) = .000125 $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp·hr}}$ x hp x RHC Correction

= .0097 x 100 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 95%

RHC Correction

	Mol Fraction	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	.1590		28.013		4.4541	N
CO_2 =	.0056		44.010		.2465	N
C_1 =	.6781		16.043		10.8788	N
C_2 =	.0997		30.070		2.9980	N
C_3 =	.0374		44.097		1.6492	Y
iC_4 =	.0081		58.124		.4708	Y
nC_4 =	.0087		58.124		.5057	Y
iC_5 =	.0017		72.151		.1227	Y
nC_5 =	.0013		72.151		.0938	Y
C_6 =	.0004		86.178		.0345	Y
	1.0				21.4539	

RHC Correction = $\frac{1.6492 + .4708 + .5057 + .1227 + .0938 + .0345}{21.4539}$

RHC Correction = .1341

MAXIMUM EMISSIONS RATE

.0097 x 100 x .1341 = .1301 $\frac{\text{lb}}{\text{hr}}$

AVERAGE EMISSIONS RATE

.1301 x .95 x 1.0 = .1236 $\frac{\text{lbs}}{\text{hr}}$ x $\frac{24 \times 365}{2000}$ = .5413 $\frac{\text{tons}}{\text{yr}}$

AAB[36]

ONE 50 HP ENGINE

(Maximum Values; Actual Engine HP May be Less)

Note: This engine will be used to run a saltwater disposal pump. This engine may not be installed, depending on the amount of water produced by the field.

Natural Gas Fired

$$BHP = \frac{GPM \times \Delta P}{1714 \times Eo}$$

Eo = Efficiency = 50%
ΔP = 1600 psi
GPM = 15

$$BHP = \frac{15 \times 1600}{1714 \times .50} = 28 \text{ BHP}$$

Therefore, use 50 BHP maximum

Emission Factors: (AP-42, Table 3.3.2-1)

SO_2 (lb/hp·hr) = .000125 (see SO_2 Emission Factor Determination)

NO_X (lb/hp·hr) = .024

CO (lb/hp·hr) = .0031

H.C. (lb/hp·hr) = .0097

NOx, SO_2, CO Emission Rates

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp hr}}$ x Rated hp

Average Emissions

Max. Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime (fraction) x Loading (fraction)

Assume 95% loaded, 100% runtime

Maximum Emissions

NOx = .024 x 50 hp = 1.2 lb/hr

CO = .0031 x 50 hp = .155 lb/hr

SO_2 = .000125 x 50 hp = .0063 lb/hr

PM = N/A

AAB[43]

Average Emissions

NOx = 1.2 x 1.0 x .95 = 1.14 $\frac{lb}{hr}$ x $\frac{365 \times 24}{2000}$ = 4.9932 T/yr

CO = .155 x 1.0 x .95 = .1473 $\frac{lb}{hr}$ x $\frac{365 \times 24}{2000}$ = .6450 T/yr

SO_2 = .0063 x 1.0 x .95 = .0060 $\frac{lb}{hr}$ x $\frac{365 \times 24}{2000}$ = .0260 T/yr

PM = N/A

SO_2 EMISSION FACTOR DETERMINATION

$\frac{1 \text{ grain}}{100 \text{ SCF}}$ = 16 ppm H_2S (estimate)

$\frac{.2 \text{ grains}}{100 \text{ SCF}}$ = 3.2 ppm H_2S = .00004 $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ (AP-42, Table 3.3.2-1)

therefore,

10 ppm (max. obtained from Dragger Tube) = .000125 $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$

Hydrocarbon Emission Rates: Reactive Hydrocarbons

Maximum Emissions

Emission Factor $\frac{\text{lbs}}{\text{hp}\cdot\text{hr}}$ x hp x RHC Correction

= .0097 x 50 hp x RHC Correction

Average Emissions: Maximum Emissions $\frac{\text{lbs}}{\text{hr}}$ x Runtime x Loading

Assume: Runtime = 100% Loading = 95%

RHC Correction

	Mol Fraction	x	M. W. (lbs/lb Mol)	=	Product of Mol Fraction & M. W.	RHC
N_2 =	.1590		28.013		4.4541	N
CO_2 =	.0056		44.010		.2465	N
C_1 =	.6781		16.043		10.8788	N
C_2 =	.0997		30.070		2.9980	N
C_3 =	.0374		44.097		1.6492	Y
iC_4 =	.0081		58.124		.4708	Y
nC_4 =	.0087		58.124		.5057	Y
iC_5 =	.0017		72.151		.1227	Y
nC_5 =	.0013		72.151		.0938	Y
C_6 =	.0004		86.178		.0345	Y
	1.0				21.4539	

RHC Correction = $\frac{1.6492 + .4708 + .5057 + .1227 + .0938 + .0345}{21.4539}$

RHC Correction = .1341

MAXIMUM EMISSIONS RATE

.0097 x 50 x .1341 = .0650 $\frac{\text{lb}}{\text{hr}}$

AVERAGE EMISSIONS RATE

.0650 x .95 x 1.0 = .0618 $\frac{\text{lbs}}{\text{hr}}$ x $\frac{24 \times 365}{2000}$ = .2706 $\frac{\text{tons}}{\text{yr}}$

AAB[43]

FLARE EMISSIONS

Flare emissions result from:

- SO_2 emissions from burning gas
- Flare downtime

SO_2 EMISSIONS

$$SO_2 \text{ (lbs/hr)} = \text{Flare Rate } \frac{SCF}{day} \times H_2S \frac{Mol}{Fraction} \times \frac{1}{380.68} \frac{lb \cdot mol}{SCF}$$

$$\times 64 \frac{\text{lbs } SO_2}{SCF} \times \frac{1}{24} \frac{Day}{hr}$$

$$\text{\# of Wells} = 4$$

MAXIMUM EMISSIONS

- Assume maximum production = 4 wells x 400 $\frac{bbl}{well}$ = 1600 $\frac{bbl}{day}$
- Assume no fuel gas using equipment running

Maximum Gas Off of Separators

GOR = 457 $\frac{SCF}{bbl}$ (see Gas Analysis, Appendix I)

Gas Rate = 457 $\frac{SCF}{bbl}$ x 1600 $\frac{bbl}{day}$ = 731,200 $\frac{SCF}{day}$

Maximum Gas Off of Heater Treater

GOR = 72 $\frac{SCF}{day}$ (Estimate: assuming 100 psi pressure drop and 43.2° API gravity)

Gas Rate = 72 $\frac{SCF}{bbl}$ x 1600 $\frac{bbl}{day}$ = 115,200 $\frac{SCF}{day}$

Total Gas Rate = 731,200 + 115,200 = 846,400 $\frac{SCF}{day}$

H_2S mol fraction = $10/1 \times 10^6$

$$\text{Maximum } SO_2 \text{ Emissions} = 846{,}400 \frac{SCF}{day} \times \frac{10}{1 \times 10^6} \times \frac{1}{380.68} \frac{lb \cdot mol}{SCF}$$

$$\times 64 \frac{\text{lbs } SO_2}{SCF} \times \frac{1}{24} \frac{Days}{hr}$$

$$= .0593 \text{ lbs/hr}$$

AVERAGE EMISSIONS

- Assume average production = 1450 $\frac{bbl}{day}$ (estimate)
- Assume all equipment using fuel gas is running
- Assume instrument gas is negligible

Average Gas Off of Separator

GOR = 457 $\frac{SCF}{bbl}$ (see Gas Analysis, Appendix I)

Gas Rate = 457 $\frac{SCF}{bbl}$ x 1450 $\frac{bbl}{day}$ = 662,650 $\frac{SCF}{day}$

Maximum Gas Off of Heater Treater

GOR = 72 $\frac{SCF}{bbl}$ (Estimate: assuming 100 psi pressure drop and 43.2° API gravity)

Gas Rate = 72 $\frac{SCF}{bbl}$ x 1450 $\frac{bbl}{day}$ = 104,400 $\frac{SCF}{day}$

Total Gas Supplied = 662,650 + 104,400 = 767,050 $\frac{SCF}{day}$

Total Gas Used:

(See Fuel Calculation, Exhibit IV)

Average Fuel Used = 1567.76 $\frac{SCF}{hr}$ x 24 $\frac{hr}{day}$ = 37,626.24 $\frac{SCF}{day}$

Total Gas Sent to Flare = Total Gas Supplied - Total Gas Used

= 767,050 - 37,626.24 = 729,423.76 $\frac{SCF}{day}$

Average SO_2 Emissions = 729,423.76 $\frac{SCF}{day}$ x $\frac{10}{1 \times 10^6}$ x $\frac{1}{380.68}$ x 64 x $\frac{1}{24}$

= .0511 $\frac{lbs}{hr}$

= .2238 $\frac{tons}{yr}$

VOC EMISSIONS FROM FLARE DOWNTIME

- Assume 1% downtime

VOC $\frac{\text{Tons}}{\text{yr}}$ = Gas vented during downtime $\frac{\text{SCF}}{\text{yr}}$ x S.G. Gas

x RHC Correction x $\frac{1}{380.68}$ $\frac{\text{LB Mol}}{\text{SCF}}$

x 28.97 $\frac{\text{lbs air}}{\text{lb Mol}}$ x $\frac{1}{2000}$ $\frac{\text{Tons}}{\text{lbs}}$

SEPARATOR GAS

Specific Gravity = .7854

RHC Correction = .1341 [see Appendix II(c)(1) for calculation]

NOTE: For gas rates, see flare SO_2 emission section

Maximum Emissions

Maximum Gas Vented During Downtime = 731,200 $\frac{\text{SCF}}{\text{day}}$ x .01 (downtime)

= 7,312 $\frac{\text{SCF}}{\text{day}}$

Maximum VOC Emissions = 7,312 $\frac{\text{SCF}}{\text{day}}$ x $\frac{365 \text{ days}}{\text{yr}}$ x .7854

x .1341 x $\frac{1}{380.68}$ x 28.97 x $\frac{1}{2000}$

= 10.6956 $\frac{\text{Tons}}{\text{yr}}$

= 2.4419 $\frac{\text{Lbs}}{\text{hr}}$

Average Emissions

Average Gas Vented During Downtime = 662,650 $\frac{\text{SCF}}{\text{day}}$ x .01 = 6,626.50 $\frac{\text{SCF}}{\text{day}}$

Average VOC Emissions = 6,626.50 $\frac{\text{SCF}}{\text{day}}$ x $\frac{365 \text{ days}}{\text{yr}}$ x .7854 x .1341

x $\frac{1}{380.68}$ x 28.97 x $\frac{1}{2000}$

= 9.6929 $\frac{\text{Tons}}{\text{yr}}$

HEATER TREATER GAS

Specific Gravity = .95 (AP-42)

RHC Correction = .4 (AP-42)

NOTE: For gas rates, see flare SO_2 emission section

Maximum Emissions

Maximum Gas Vented During Downtime = 115,200 $\frac{SCF}{day}$ x .01 (downtime)

= 1,152 $\frac{SCF}{day}$

Maximum VOC Emissions = 1,152 $\frac{SCF}{day}$ x $\frac{365\ days}{yr}$ x .95

x .4 x $\frac{1}{380.68}$ x 28.97 x $\frac{1}{2000}$

= 6.0798 $\frac{Tons}{yr}$

= 1.3881 $\frac{Lbs}{hr}$

Average Emissions

Average Gas Vented During Downtime = 104,400 $\frac{SCF}{day}$ x .01 = 1,044 $\frac{SCF}{day}$

Average VOC Emissions = 1,044 $\frac{SCF}{day}$ x $\frac{365\ days}{yr}$ x .95 x .4

x $\frac{1}{380.68}$ x 28.97 x $\frac{1}{2000}$

= 5.3356 $\frac{Tons}{yr}$

TOTAL VOC EMISSIONS FROM FLARE DOWNTIME

Maximum Emissions = 2.4419 $\frac{lbs}{hr}$ + 1.3881 $\frac{lbs}{hr}$

= 3.83 $\frac{lbs}{hr}$

Average Emissions = 9.6929 $\frac{Tons}{yr}$ + 5.3356 $\frac{Tons}{yr}$

= 15.0285 $\frac{Tons}{yr}$

H_2S EMISSIONS FROM FLARE DOWNTIME

Separator Gas

Maximum Emissions = 7,312 $\frac{SCF}{day}$ x $\frac{365\ days}{yr}$ x .7854

x $\frac{10}{1 \times 10^6}$ (H_2S Mol Fraction) x $\frac{1}{380.68}$ $\frac{Lb \cdot Mol}{SCF}$

x 28.97 $\frac{Lbs\ Air}{Lb\ Mol}$ x $\frac{1}{2000}$ $\frac{Tons}{Lbs}$

= .0008 $\frac{Tons}{yr}$

= .0002 $\frac{Lbs}{hr}$

Average Emissions = 6,626.50 $\frac{SCF}{day}$ x $\frac{365\ days}{yr}$ x $\frac{10}{1 \times 10^6}$

x .7854 x $\frac{1}{380.68}$ x 28.97 x $\frac{1}{2000}$

= .0007 $\frac{Tons}{yr}$

Heater Treater Gas

Maximum Emissions = 1,152 $\frac{SCF}{day}$ x $\frac{365\ days}{yr}$ x .95

x $\frac{10}{1 \times 10^6}$ (H_2S Mol Fraction) x $\frac{1}{380.68}$ $\frac{Lb \cdot Mol}{SCF}$

x 28.97 $\frac{Lbs\ Air}{Lb\ Mol}$ x $\frac{1}{2000}$ $\frac{Tons}{Lbs}$

= .0002 $\frac{Tons}{yr}$

= .0001 $\frac{Lbs}{hr}$

Average Emissions = 1,044 $\frac{SCF}{day}$ x $\frac{365\ days}{yr}$ x $\frac{10}{1 \times 10^6}$

x .95 x $\frac{1}{380.68}$ x 28.97 x $\frac{1}{2000}$

= .0001 $\frac{Tons}{yr}$

Total H_2S Emissions From Flare Downtime

Maximum Emissions = .0002 $\frac{lbs}{hr}$ + .0001 $\frac{lbs}{hr}$

= .0003 $\frac{lbs}{hr}$

Average Emissions = .0007 $\frac{Tons}{yr}$ + .0001 $\frac{Tons}{yr}$

= .0008 $\frac{Tons}{yr}$

FUGITIVE EMISSIONS

NOTE: Calculation technique developed using API Publication No. 4322.

1) $$\text{Components per Well} = \frac{1}{(2.69 \times 10^{-4}) + [(8.61 \times 10^{-5}) \times \text{Number of Wells}]}$$

Number of Wells = 4

$$\text{Components per Well} = \frac{1}{(2.69 \times 10^{-4}) + [(8.61 \times 10^{-5}) \times 4]}$$

$$= 1630.2576$$

2) Total Components = Components per Well x Number of Wells at the Facility

$$= 1630.2576 \times 4$$

$$= 6521.0303$$

3) VOC Emissions $\frac{\text{lbs}}{\text{hr}}$ = Total Components x Emission Factor $\frac{\text{lbs/day}}{\text{component}} \times \frac{1}{24} \frac{\text{day}}{\text{hr}}$

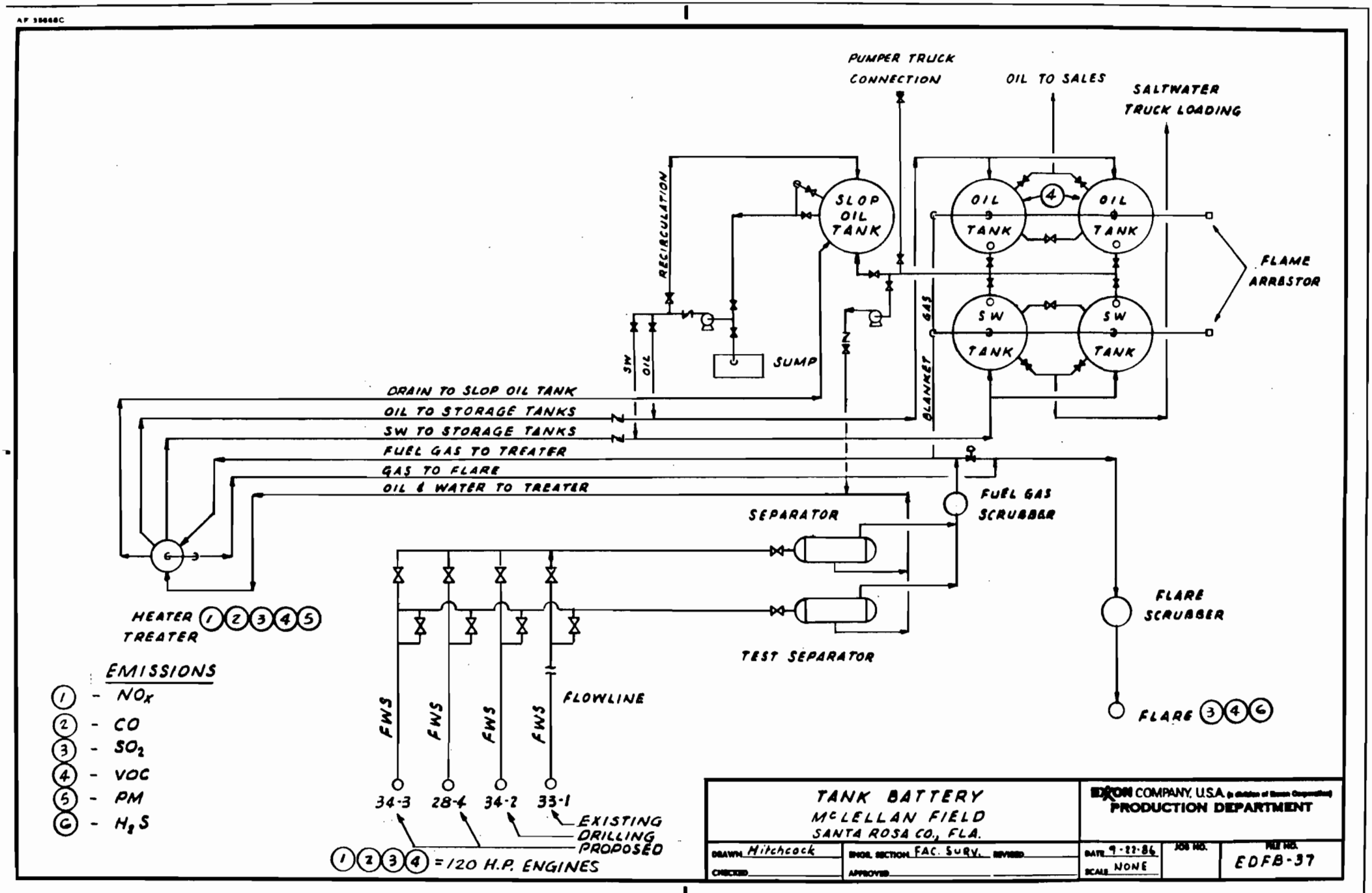
Emission Factor = .016558 (for onshore oil and gas production facilities)

VOC Emissions $= 6521.0303 \times .016558 \frac{\text{lbs/day}}{\text{component}} \times \frac{1}{24} \frac{\text{day}}{\text{hr}}$

$$= 4.4990 \frac{\text{lbs}}{\text{hr}}$$

$$= 19.7055 \frac{\text{tons}}{\text{yr}}$$

ILLUSTRATION I

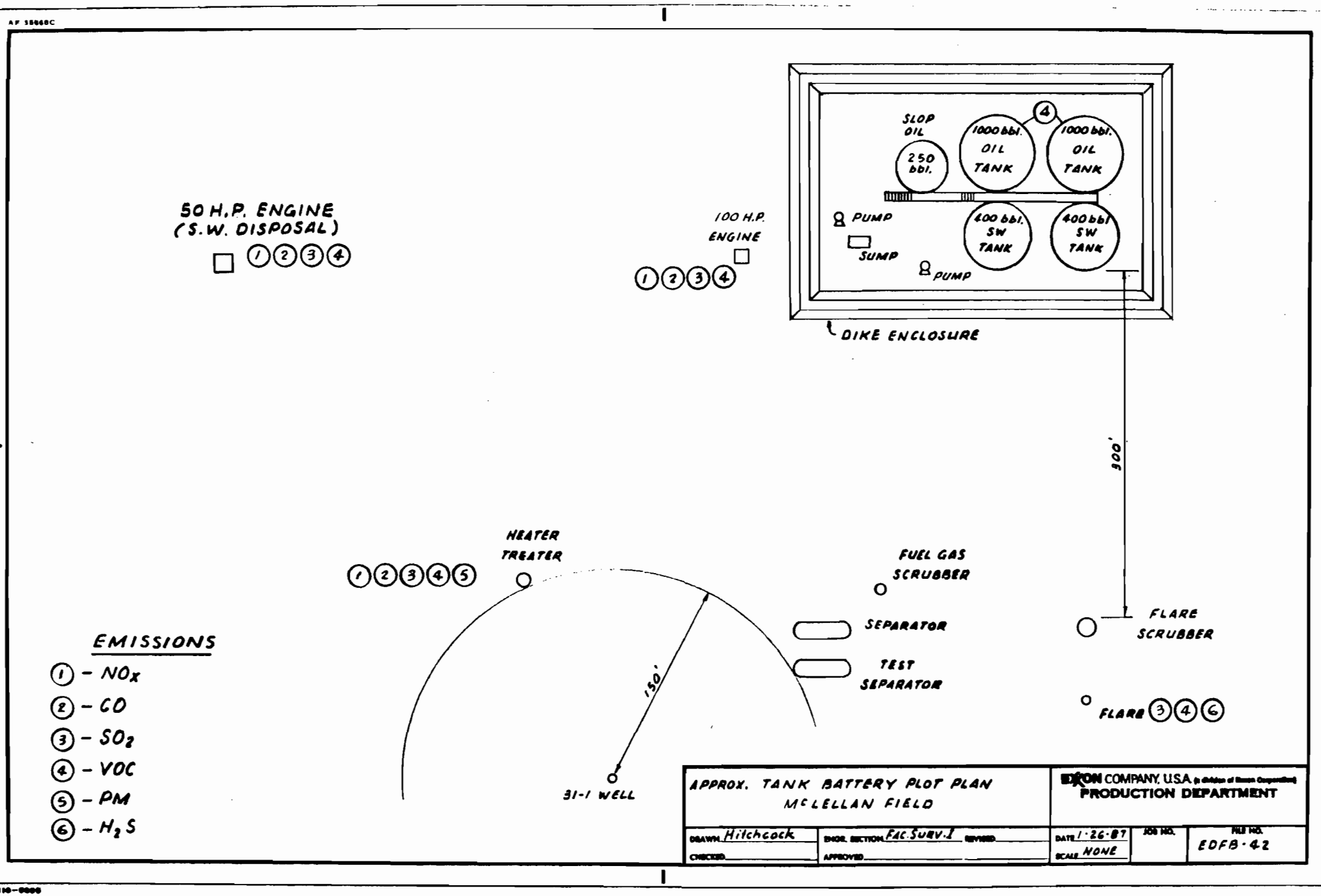


TANK BATTERY
McLELLAN FIELD
SANTA ROSA CO., FLA.

EXXON COMPANY, U.S.A. (a division of Exxon Corporation)
PRODUCTION DEPARTMENT

DRAWN Mitchcock	ENGR. SECTION FAC. SURV.	REVISED	DATE 9-22-86	JOB NO.
CHECKED	APPROVED		SCALE NONE	FILE NO. EDFB-37

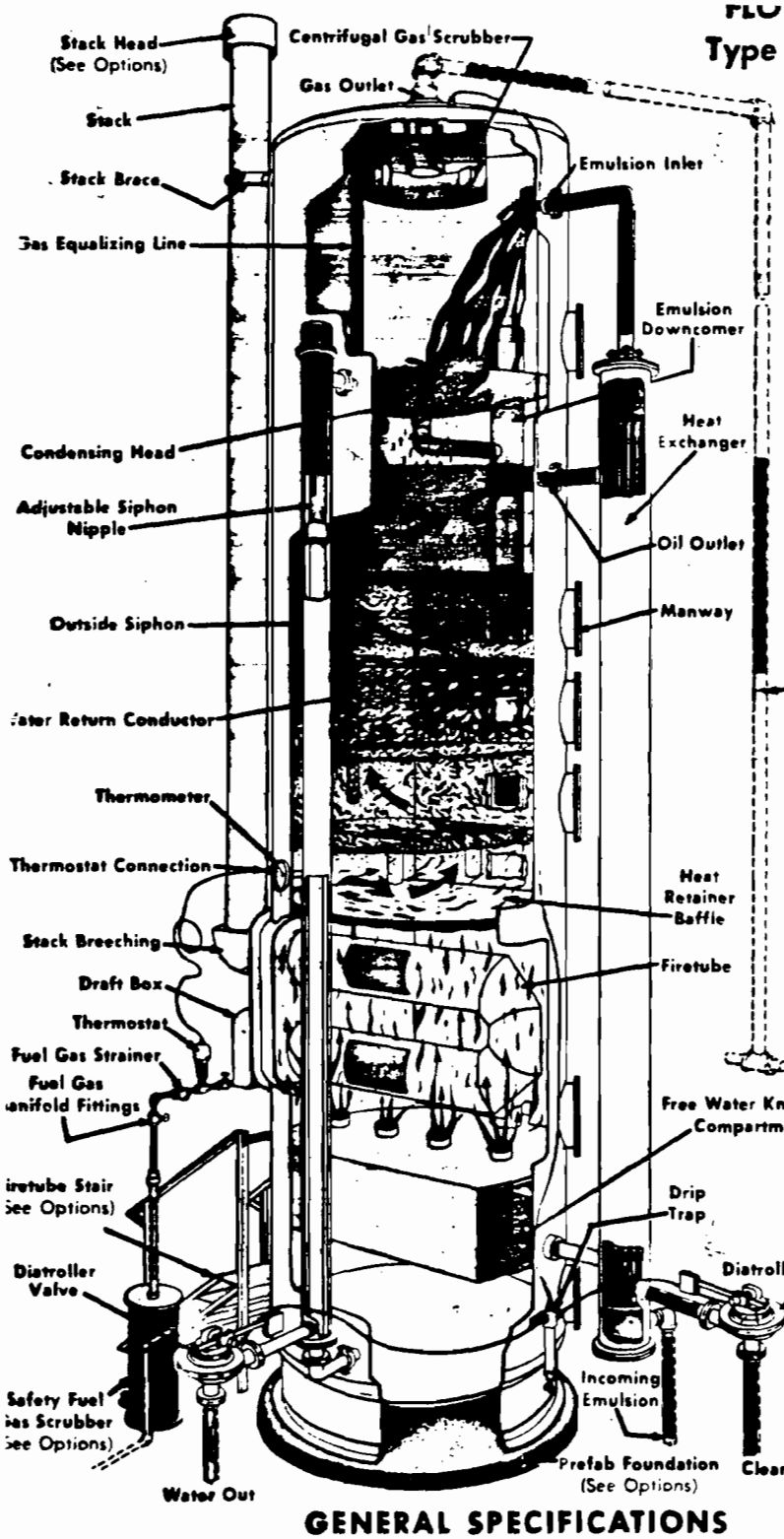
ILLUSTRATION II



FLOW DIAGRAM
Type "ICP" Treaters

ILLUSTRATION III

BEST AVAILABLE COPY



LEGEND

- RAW EMULSION
- CLEAN OIL
- WATER
- GAS
- HEAT AND FIRE

OPTIONAL EXTRA PRICE ITEMS COMMONLY ORDERED WITH UNIT

- Flame Arrestor
- Siphon Isolation Valves
- Gas Back-Pressure Valve
- Fuel Gas Scrubber With Safety Level Shut-off
- Fuel Gas Manifold By-Pass Fittings
- Field Piping And Installation
- Prefab Foundation
- Stack Head
- Heat Exchanger
- OCF Baffles
- Firetube Stair

OTHER EQUIPMENT FURNISHED (Not Shown)

- Ladder
- Gauge Cock And Glass
- Pressure Gauge
- Drip Trap
- Safety Railing

PLUS VALUES OF THE "ICP" TREATER

- Engineered for safety; performance and automatic operation.
- Field Proven.
- Complete Flexibility throughout capacity range.
- Easy one-man start up.
- Full-size centrifugal type gas scrubbing element — nothing to plug up.
- Multi-orifice cross-flow baffles.
- Extra heat retaining cross-flow baffle.
- Exclusive free water knockout compartment with oil retaining and good-oil skimming feature. (Reduces heat load — increases treating capacity.)
- Tripple excelsior section with equally disposed multi-orifice cross-flow baffles, having water return conductors.
- Large diameter, reversible single "U" Tube self-descaling firetube design with low thermally stressed welds. Large diameter permits 100% welding of joints inside, as well as outside.
- Manways are pressed steel, one-piece.
- Shell and head joints are double-welded butt welded.
- All baffles and inside heads are continuous seal-welded to shell — no skip welding.
- Skirt is continuous-welded to shell.
- Condensing inside head originated by National.
- Provides its own fuel source.
- Needs no auxiliary power.
- Available with all controls and valves manufactured by National; one supplier — one source.
- Competent field engineers available in all areas for your convenience. These men live and work in your locality.
- Wherever you may transfer National Units, National parts and service are already there.

GENERAL SPECIFICATIONS

SIZE: Diameter x Height	Working Pressure Psig (1)	Recommended Maximum Btu/Hr. Use Rate	Shipping Weight Lbs.	CAPACITY		GAS (4) Gas/Oil Ratio
				OIL (2) Bbls./Hr.	FREE WATER (3) Bbls./Day	
4' x 27½'	50	350,000	10,000#	5 — 30	250-1800	1000:1
6' x 27½'	50	500,000	14,900#	10 — 50	550-4000	1000:1
8' x 27½'	25	1,000,000	20,900#	20 — 100	1000-7000	1000:1
10' x 27½'	25	1,350,000	28,900#	35 — 150	1500-10000	1000:1

NOTES:

(1) Units are available manufactured to non-code or ASME Sec. VIII Code in the standard pressures as well as higher pressures. Shipping weights will be higher for higher pressure units.

(2) OIL CAPACITIES are quite variable, depending upon viscosity of crude relative densities of oil and water, heating and settling requirements, and other variables. Contact the nearest National Tank Company Representative for recommendations on specific applications.

(3) WATER CAPACITIES are for free water, i.e. will settle without further heat within a few minutes.

(4) GAS CAPACITIES of standard units are designed for peak performance for GOR of 1000:1 or less. If higher GOR's are encountered at treating conditions, please advise at time of order.

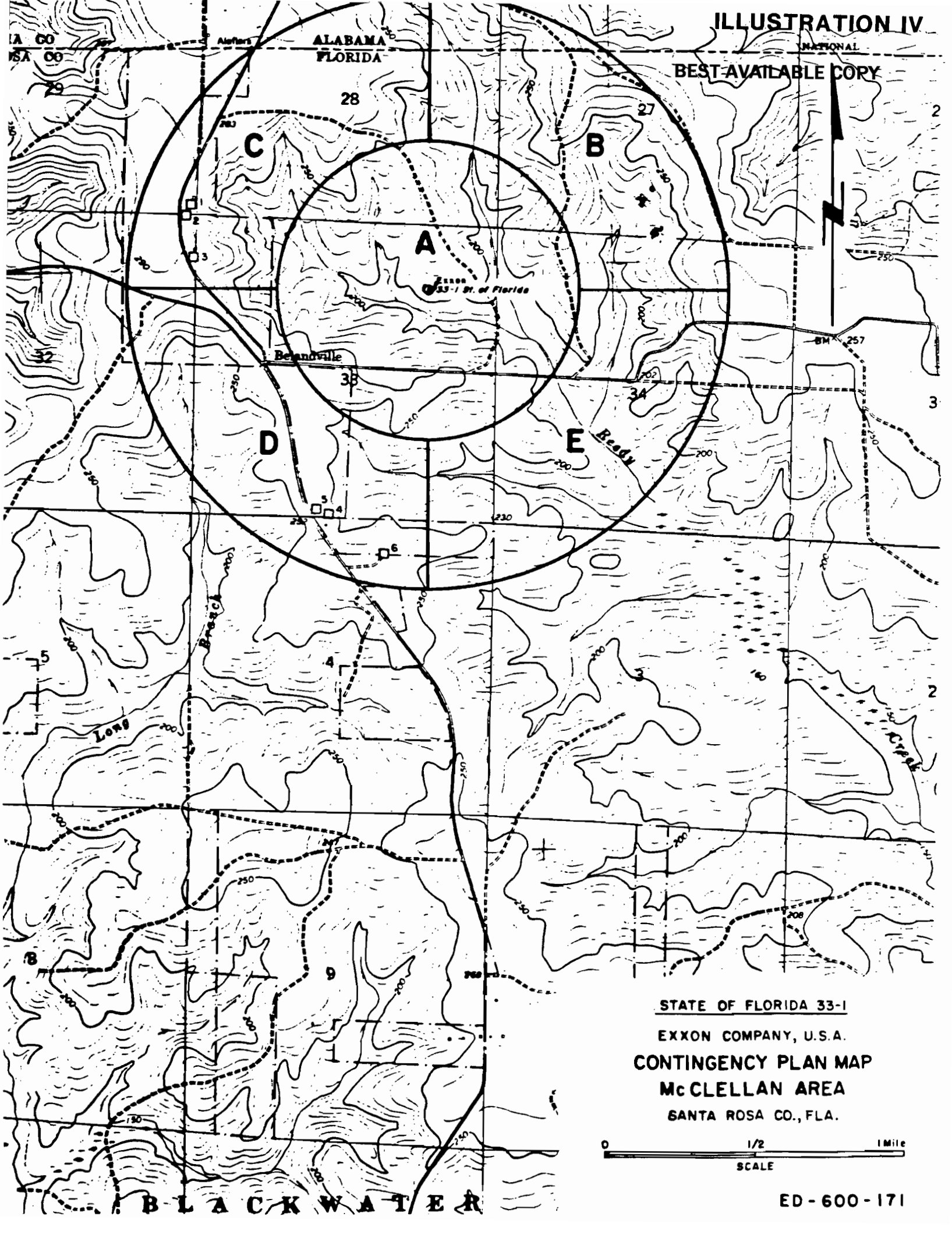


ILLUSTRATION IV
BEST AVAILABLE COPY
ALABAMA
FLORIDA
A
B
C
D
E
Exxon 33-1 St. of Florida
Bellandville
Brady
Long
Creek
BLACKWATER
STATE OF FLORIDA 33-1
EXXON COMPANY, U.S.A.
CONTINGENCY PLAN MAP
McCLELLAN AREA
SANTA ROSA CO., FLA.
0
1/2
1 Mile
SCALE
ED-600-171

BEST AVAILABLE COPY

McLELLAN WELLS

ILLUSTRATION V

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

STATE C

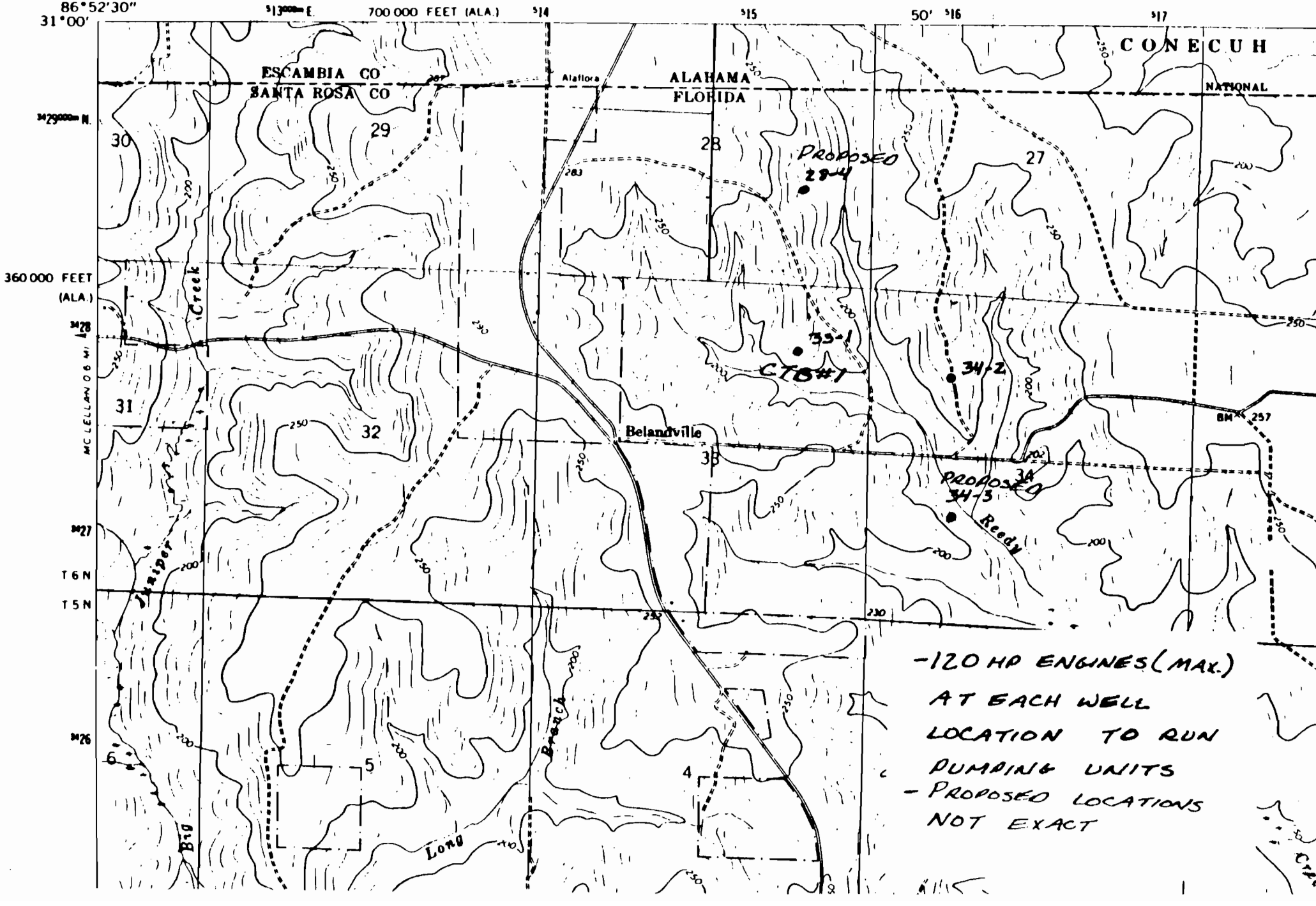
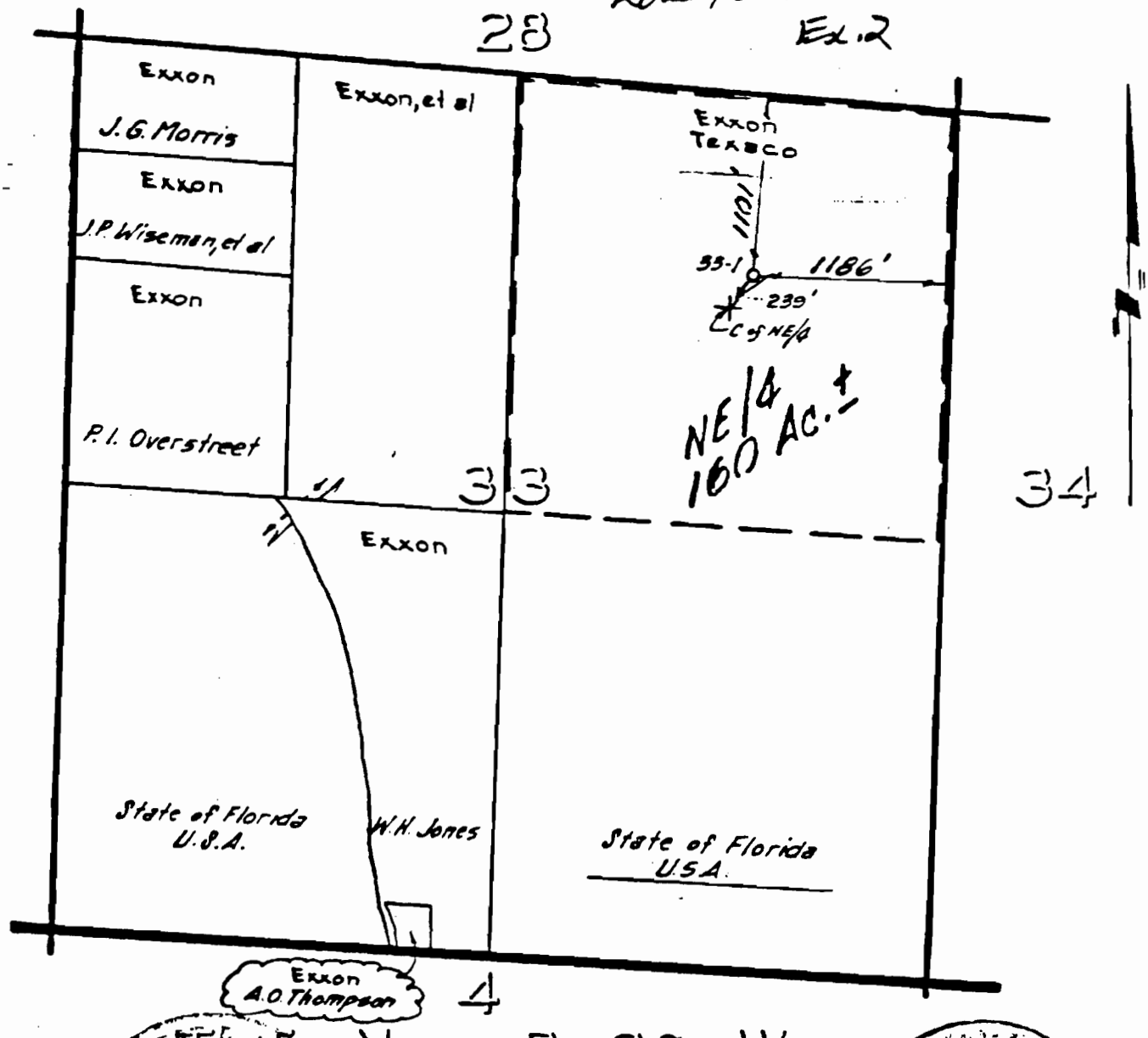


ILLUSTRATION VI

BEST AVAILABLE COPY

T 5 N - R 26 W

Road / Culvert Ex. 2



T 6 N - R 26 W

ROBERT E. LEE CERTIFICATE NO. 2277 STATE OF FLORIDA REGISTERED LAND SURVEYOR

PERMIT 57109313

Prepared by Robert E. Lee
Fla. Reg. Land Surveyor No. 2277

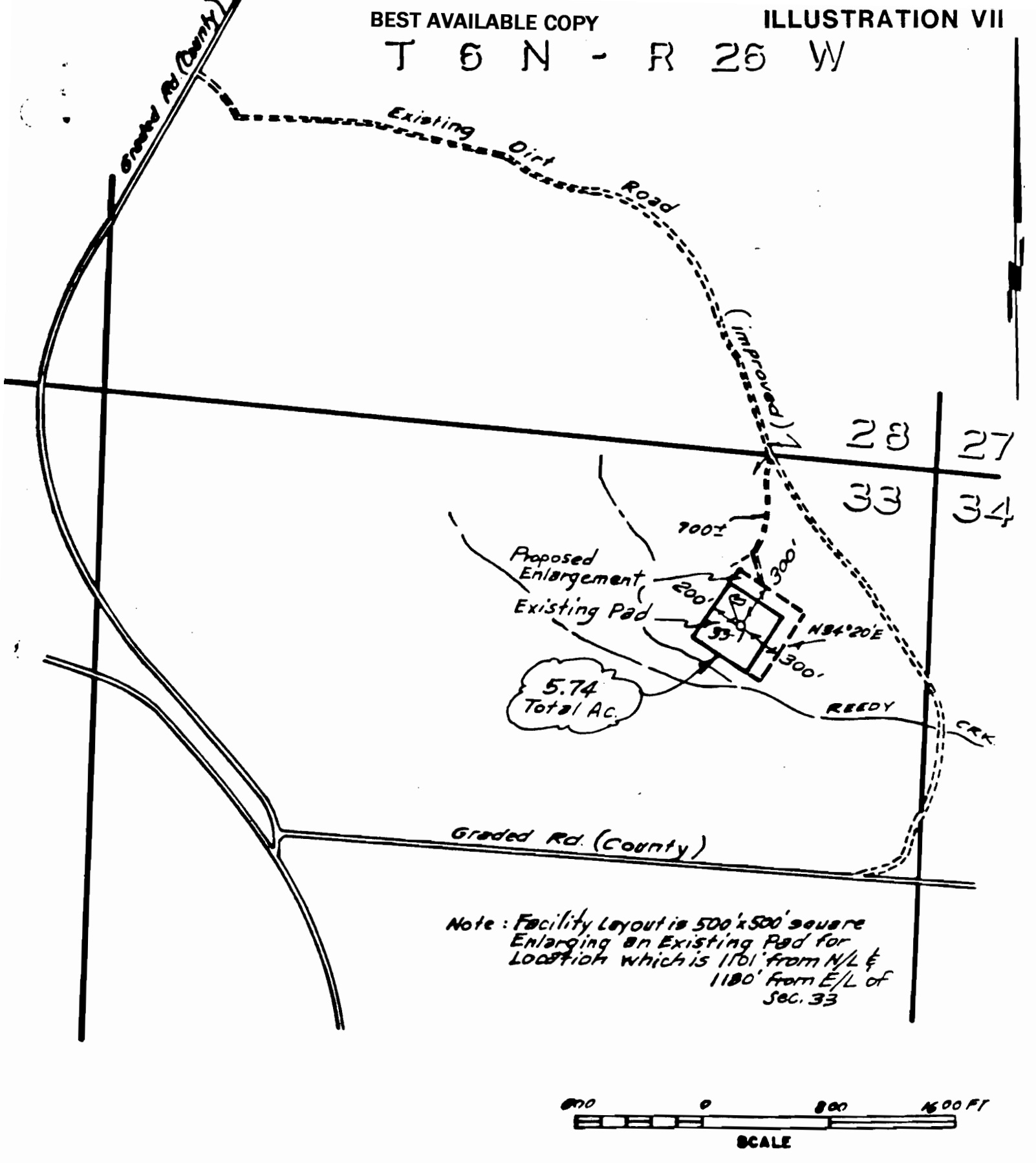
1000 0 1000 2000 FT.
SCALE

STATE OF FLORIDA McCLELLAN AREA SANTA ROSA CO., FLORIDA	Exxon Company, U.S.A. (A DIVISION OF EXXON CORPORATION) PRODUCTION DEPARTMENT NEW ORLEANS

DRAWN R.A. Gutierrez	ENGR SECTION	REVISED	SCALE 1" = 1000'	JOB NO.	FILE NO.
CHECKED	APPROVED		DATE 7/26/85		EA-6244

BEST AVAILABLE COPY

ILLUSTRATION VII

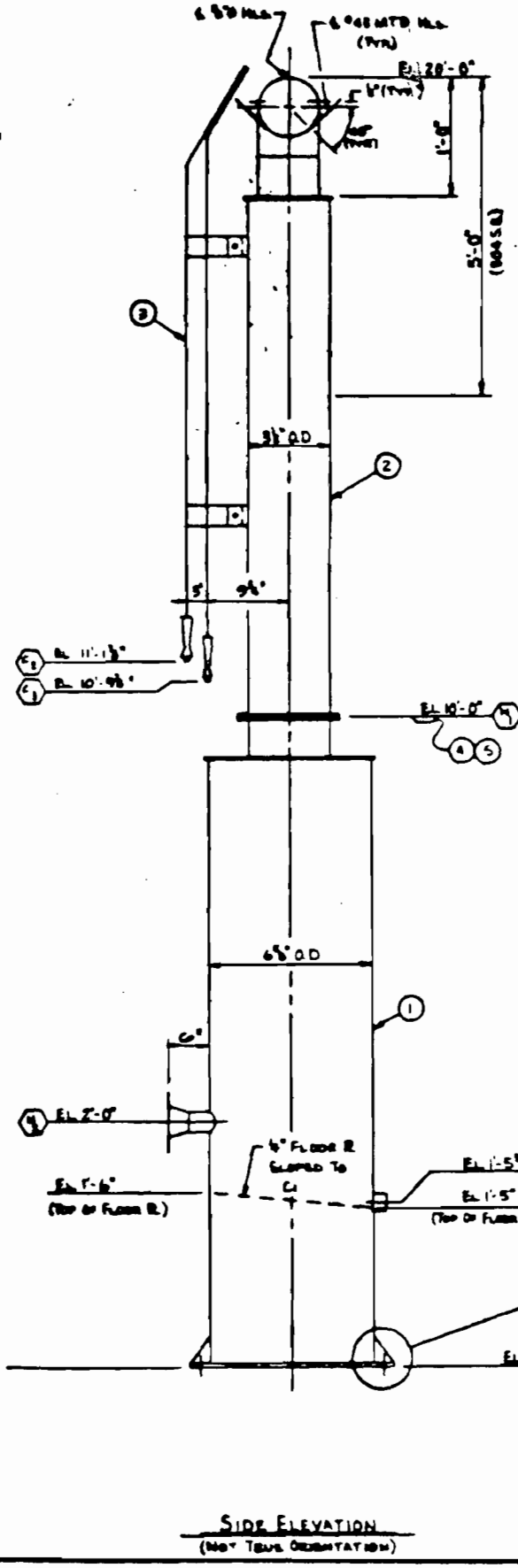


PROPOSED PRODUCTION FACILITY
To Serve STATE OF FLORIDA No 33-1
McCLELLAN AREA SANTA ROSA Co, FLA.

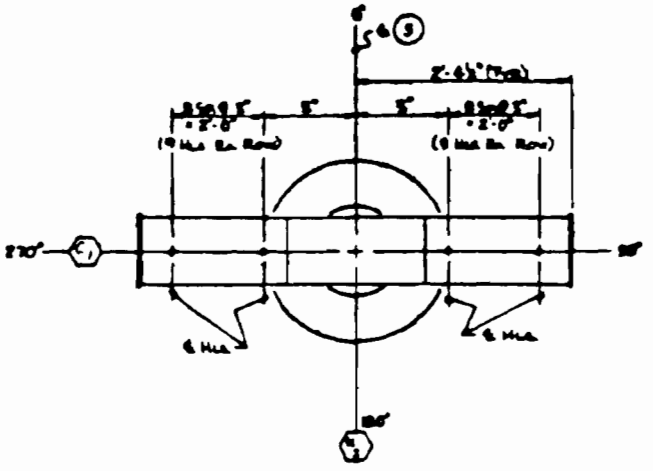
Exxon Company, U.S.A.
(DIVISION OF EXXON CORPORATION)
PRODUCTION DEPARTMENT
NEW ORLEANS

DRAWN R.A. Gutierrez	ENGR. SECTION	REVISED 9-29-80	SCALE 1" = 800'	JOB NO.	FILE NO.
CHECKED	APPROVED R.C. Lane	JKM	DATE 8-1-80		EA-6245-

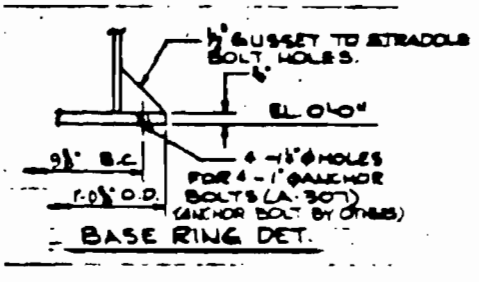
ILLUSTRATION VIII



SIDE ELEVATION
(NOT TRUE ORIENTATION)



PLAN VIEW
(TRUE ORIENTATION)



REPRESENTATIVE DESIGN:
FLARE STACK W/ AUTO RELIGHT
(DIMENSIONS NOT CORRECT)

EXXON COMPANY, U.S.A.
A DIVISION OF EXXON CORPORATION
PRODUCTION DEPARTMENT

DRAWN	ENGR SECTION	REVISED	SCALE	JOB NO / FILE NO
CHECKED	APPROVED		DATE	

110-0004-1A