San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

OCT 14 2011

Larry Landis
Chevron U.S.A., Inc.
P.O. Box 1392
Bakersfield, CA 93302

Re: Notice of Preliminary Decision - Authority to Construct
Project Number: S-1102789

Dear Mr. Landis:

Enclosed for your review and comment is the District's analysis of Chevron U.S.A., Inc.'s application for an Authority to Construct for the addition of 400 thermally enhanced wells, at Chevron's Heavy Oil Central Stationary Source.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Kris Rickards of Permit Services at 661-392-5611.

Sincerely,

David Warner
Director of Permit Services

DW:ktr

Enclosures

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
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www.valleyair.org www.healthyairliving.com

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

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OCT 14 2011

Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

Re: Notice of Preliminary Decision - Authority to Construct
Project Number: S-1102789

Dear Mr. Tollstrup:

Enclosed for your review and comment is the District's analysis of Chevron U.S.A., Inc.'s application for an Authority to Construct for the addition of 400 thermally enhanced wells, at Chevron's Heavy Oil Central Stationary Source.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Kris Rickards of Permit Services at 661-392-5611.

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Bakersfield Californian
Bakersfield Californian

**NOTICE OF PRELIMINARY DECISION
FOR THE PROPOSED ISSUANCE OF
AN AUTHORITY TO CONSTRUCT**

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of Authority to Construct to Chevron U.S.A., Inc. for the addition of 400 thermally enhanced wells, at Chevron's Heavy Oil Central Stationary Source.

The analysis of the regulatory basis for this proposed action, Project #S-1102789, is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the District office at the address below. Written comments on this project must be submitted within 30 days of the publication date of this notice to **DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 34946 FLYOVER COURT, BAKERSFIELD, CA 93308.**

San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Modification of a TEOR Operation

Facility Name:	Chevron U.S.A., Inc.	Date:	September 8, 2011
Mailing Address:	P.O. Box 1392 Bakersfield, CA 93302	Engineer:	Kris Rickards
		Lead Engineer:	Rich Karrs
Contact Person:	Larry Landis		Lance Erickson, Consultant
Telephone:	661-654-7141		661-654-7145
Fax:	661-654-7606		661-654-7606
E-Mail:	landilr@chevron.com		Lance.Erickson@chevron.com
Application #(s):	S-1131-1036-10		
Project #:	S-1102789		
Deemed Complete:	June 8, 2010		

I. Proposal

Chevron U.S.A., Inc. (hereafter referred to as CUSA) operates a Thermally Enhanced Oil Recovery (TEOR) operation in the Kern River Oilfield. CUSA has requested an Authority to Construct (ATC) to add 400 additional wells to the existing 485 closed casing vent wells.

Additionally, CUSA has requested to revise emission factors to use CAPCOA's screening value range emission factors.

CUSA facility S-1131 received their Title V Permit December 31, 2002. This modification can be classified as a Title V minor modification pursuant to Rule 2520, Section 3.20, and can be processed with a Certificate of Conformity (COC). But the facility has not requested that this project be processed in that manner; therefore, CUSA will be required to submit a Title V minor modification application prior to operating under the revised provisions of the ATC issued with this project.

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 4001 New Source Performance Standards (4/14/99)
Rule 4002 National Emissions Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4401 Steam Enhanced Crude Oil Production Well Vents (12/14/06)
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The equipment will be located at the Kern River oilfield within CUSA's Heavy Oil Central Stationary Source. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

Steam is produced from steam generators and injected into the heavy crude oil bearing strata via injection wells to enhance the oil extraction. Heat from the steam makes the heavy crude oil less viscous; therefore, easier to pump from the well. Gasses are also produced as a result of the steaming process, and include water vapor, CO2, CO, H2S, and hydrocarbons. These gasses are comingled with the fluids and sent downstream along with well production and separated in separator vessels or front-line processing tanks.

Oilfield equipment is expected to operate 24 hours/day and 365 days/year.

V. Equipment Listing

Pre-Project Equipment Description:

S-1131-1036-6: TEOR OPERATION WITH 485 CYCLIC AND STEAM DRIVE WELLS WITH CLOSED CASING VENTS

Proposed Modification:

S-1131-1036-10: MODIFICATION OF TEOR OPERATION WITH 485 CYCLIC AND STEAM DRIVE WELLS WITH CLOSED CASING VENTS: ADD 400 WELLS TO WELL ROSTER, UPDATE EMISSION FACTORS BY USING CAPCOA SCREENING FACTORS, REVISE EQUIPMENT DESCRIPTION TO READ "885 THERMALLY ENHANCED WELLS WITH CLOSED CASING VENTS"

Post Project Equipment Description:

S-1131-1036-10: 885 THERMALLY ENHANCED WELLS WITH CLOSED CASING VENTS

VI. Emission Control Technology Evaluation

Fugitive volatile organic compounds (VOCs) are emitted from the well casing collection and control systems due to leaking components.

VOC emissions from the well casing collection system are controlled with ≥ 99% efficiency, in accordance with District Rule 4401. The vapor control consists of disposal of collected VOCs by incineration in approved devices downstream of the front-line tanks.

VII. General Calculations

A. Assumptions

- Facility will operate 8,760 hours per year
- Percentage of VOCs of the total hydrocarbons is 100%
- The VOC emission factors on the current PTO – 0.0216 lb/well component and 0.0194 lb/polishing rod – are out of date. Revising emission factors to more representative generally accepted emissions factors pursuant to District Policy APR 1110 is not an NSR modification. Revised emissions factors will be used to calculate both pre and post project emissions.
- Leaking components will be evenly distributed across component types
- Casing gas consists of 0.375 lb-CH_4/lb-TOC
- Greenhouse Gas emissions are comprised of 100% by weight methane
- Greenhouse Gas emission increases ≤230 metric tons/year are equal to zero (per APR 2015, Zero Equivalency Policy for Greenhouse Gases)
- 23 lbs-CO_2e = 1 lb-CH_4 (California Climate Change Action Registry (CCAR), Version 3.1, January, 2009 (Appendix C, Tables C.7 and C.8) and APR 2015)
- 100% of fugitive emissions is TOC which consists of VOC and CH_4 with CH_4 = 0.6 VOC (ARB Guidance Document – Appendix)

  TOC = VOC + CH_4
  = VOC + 0.6 VOC
  = 1.6 VOC
  VOC = 0.625 TOC
  CH_4 = 0.6 x VOC = 0.6 x (0.625 TOC) = 0.375 TOC

B. Emission Factors

- Criteria pollutant emissions are calculated using the "revised screening" emissions factors of CARB/CAPCOA "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities", Table IV-2c. *Oil and Gas Production Screening Value Ranges Emission Factors*. -See Appendix B

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Leaking component percentage is calculated using total number of steam enhanced wells and number of allowable leaking components as allowed by Rule 4401, Table 3.

Pre-project steam enhanced wells total 485 with 15 leaking components allowed by Rule 4401. The potential to emit for unit S-1131-1036 is summarized in the following table (see Appendix B for detailed fugitive emission calculation):

Pre-Project Potential to Emit (PE1)		
Pollutant	Daily Emissions (lb/day)	Annual Emissions (lb/year)
VOC	53.3	19,460

GHGs are calculated as follows:

$$\frac{19{,}460\ lb \cdot VOC}{year}\left(\frac{0.375\ lb \cdot CH_4}{lb \cdot VOC}\right)\frac{23\ lb \cdot CO_2e}{lb \cdot CH_4}\left(\frac{short\ ton}{2{,}000\ lb}\right)\frac{0.9072\ metric\ tons}{short\ ton} = 76.1\frac{metric\ tons \cdot CO_2e}{year}$$

2. Post Project Potential to Emit (PE2)

Leaking component percentage is calculated using total number of steam enhanced wells and number of allowable leaking components as allowed by Rule 4401, Table 3.

Post project steam enhanced wells total 885 with 44 leaking components allowed by Rule 4401 (1 leak/20 wells). The potential to emit for unit S-1131-1036 is summarized in the following table (see Appendix B for detailed fugitive emission calculation):

Post Project Potential to Emit (PE2)		
Pollutant	Daily Emissions (lb/day)	Annual Emissions (lb/year)
VOC	146.6	53,523

GHGs are calculated as follows:

$$\frac{53{,}523\ lb \cdot VOC}{year}\left(\frac{0.375\ lb \cdot CH_4}{lb \cdot VOC}\right)\frac{23\ lb \cdot CO_2e}{lb \cdot CH_4}\left(\frac{short\ ton}{2{,}000\ lb}\right)\frac{0.9072\ metric\ tons}{short\ ton} = 209.4\frac{metric\ tons \cdot CO_2e}{year}$$

The increase in GHG emissions is 209.4 – 76.1 = 133.3 metric tons-CO_2e/year. Per District Policy, project specific greenhouse gas emissions less than or equal to 230 metric tons-CO2e/year are considered to be zero for District permitting purposes and are exempt from further environmental review.

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-Project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Facility emissions are already above the Offset and Major Source Thresholds for VOC emissions; therefore, SSPE1 calculations are not necessary.

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Facility emissions are already above the Offset and Major Source Thresholds for VOC emissions; therefore, SSPE2 calculations are not necessary.

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a Major Source is a stationary source with post-project emissions or a Post Project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values. However, Section 3.24.2 states, "for the purposes of determining major source status, the SSPE2 shall not include the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site."

This source is an existing Major Source for VOC emissions and will remain a Major Source for VOC. No change in other pollutants are proposed or expected as a result of this project.

6. Baseline Emissions (BE)

The BE calculation (in lbs/year) is performed pollutant-by-pollutant for each unit within the project, to calculate the QNEC and if applicable, to determine the amount of offsets required.

Pursuant to Section 3.7 of District Rule 2201, BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201.

BE VOC

Clean Emissions Unit, Located at a Major Source

Pursuant to Rule 2201, Section 3.12, a Clean Emissions Unit is defined as an emissions unit that is "equipped with an emissions control technology with a minimum control efficiency of at least 95% or is equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

The TEOR operation sends casing gas comingled with fluids to front-line tanks and separator vessels equipped with vapor control where the gas is eventually incinerated in approved disposal devices. This method of incineration reduces VOC emissions by at least 99%, which meets the requirements for achieved-in-practice BACT. Therefore, Baseline Emissions (BE) are equal to the Pre-Project Potential to Emit (PE1).

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

As this project involves an increase in fugitive emissions only, and fugitive emissions from oil production operations are not counted in major modification determinations, this project does not result in a major modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As discussed in Section I above, there are no new emissions units associated with this project; therefore BACT for new units with PE > 2 lb/day purposes is not triggered.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

AIPE = PE2 – HAPE

Where,
AIPE = Adjusted Increase in Permitted Emissions, (lb/day)
PE2 = Post-Project Potential to Emit, (lb/day)
HAPE = Historically Adjusted Potential to Emit, (lb/day)

HAPE = PE1 x (EF2/EF1)

Where,
PE1 = The emissions unit's Potential to Emit prior to modification or relocation, (lb/day)
EF2 = The emissions unit's permitted emission factor for the pollutant after modification or relocation. If EF2 is greater than EF1 then EF2/EF1 shall be set to 1
EF1 = The emissions unit's permitted emission factor for the pollutant before the modification or relocation

AIPE = PE2 – (PE1 * (EF2 / EF1))

The emissions factor is not changing as a result of this project; therefore, EF1 = EF2, and;

AIPE = 146.6 – (53.3 * (1)) = 93.3 lb/day

d. Major Modification

As discussed in Section VII.C.7 above, this project does not constitute a Major Modification; therefore BACT is not triggered.

2. BACT Guideline

BACT Guideline 7.1.1, applies to thermally enhanced oil recovery – steam drive oil wells (See Appendix C).

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the attached Top-Down BACT Analysis (see Appendix C), BACT has been satisfied with the following:

VOC: A closed casing vent system that transfers production with entrained gasses to frontline tanks equipped with vapor control that transfers non-condensable vapors to gas pipeline, re-injects to formation, or to approved incineration devices

B. Offsets

1. Offset Applicability

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post Project Stationary Source Potential to Emit (SSPE2) equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The following table compares the post-project facility-wide annual emissions in order to determine if offsets will be required for this.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post Project SSPE (SSPE2)	≥20,000	≥54,750	≥29,200	≥200,000	≥20,000
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	Yes	Yes	Yes	Yes	Yes

2. Quantity of Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for NO_X and VOC; therefore offset calculations will be required for this project.

Per Sections 4.7.1 and 4.7.3, the quantity of offsets in pounds per year for VOC (only pollutant emitted by this unit) is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
PE2 = Post Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8
BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE)

Baseline Emissions for the TEOR operation are equal to the pre-project potential to emit since this is a clean emissions unit. Also, there are no increases in cargo carrier emissions; therefore offsets can be determined as follows:

Offsets Required (lb/year) = Σ[PE2 – BE]

VOC offsets required = 53,523 – 19,460
= 34,063 lb-VOC/year

Calculating the appropriate quarterly emissions to be offset is as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
8,516	8,516	8,516	8,516

The applicant has stated that the facility plans to use ERC certificate S-2887-1 to offset the increases in VOC emissions associated with this project. This certificate is owned by CUSA (facility S-1127) and was generated within CUSA's Heavy Oil Central Stationary Source, S-1127, and will be applied to CUSA's Heavy Oil Central Stationary Source, S-1131. Pursuant to Rule 2201 section 4.8 the distance offset ratio will be equal to 1.0 (generated at the same station source as the new or modified stationary source) and the following reservations will be made in PAS:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
8,516	8,516	8,516	8,516

This certificate has available quarterly VOC credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-2887-1	113,431	114,707	116,073	116,094

This certificate has no other reservations

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

Proposed Rule 2201 (offset) Conditions:

S-2010-142:

- Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 8,516 lb, 2nd quarter - 8,516 lb, 3rd quarter - 8,516 lb, and fourth quarter - 8,516 lb. The offset amounts listed above include the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]
- ERC Certificate Number S-2887-1 (or a certificate split from this certificate) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201]

C. Public Notification

1. Applicability

Public noticing is required for:
a. Any new Major Source, which is a new facility that is also a Major Source,
b. Major Modifications,
c. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
d. Any project which results in the offset thresholds being surpassed, and/or
e. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.

a. New Major Source

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

b. Major Modification

As demonstrated in VII.C.7, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE > 100 lb/day

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. As seen in Section VII.C.2 above, this project does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant; therefore public noticing for PE > 100 lb/day purposes is not required.

d. Offset Threshold

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	≥20,000	≥20,000	20,000 lb/year	No
SO_X	≥54,750	≥54,750	54,750 lb/year	No
PM_{10}	≥29,200	≥29,200	29,200 lb/year	No
CO	≥200,000	≥200,000	200,000 lb/year	No
VOC	≥20,000	≥20,000	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

e. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table (project results in VOC increase only and is a result of unit S-1131-1036 only):

Stationary Source Increase in Permitted Emissions [SSIPE] – Public Notice					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	≥20,000	≥20,000	0	20,000 lb/year	No
SO_x	≥54,750	≥54,750	0	20,000 lb/year	No
PM_{10}	≥29,200	≥29,200	0	20,000 lb/year	No
CO	≥200,000	≥200,000	0	20,000 lb/year	No
VOC	≥20,000	≥20,000	34,063	20,000 lb/year	Yes

As demonstrated above, the SSIPE for VOC was greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Action

As discussed above, public noticing is required for this project for VOC emissions increase greater than 20,000 lb/year. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

Daily Emissions Limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.15.1 and 3.15.2, the DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

The following proposed DEL conditions will be listed to ensure compliance with this rule:

- Well casing vents shall remain closed at all times except during periods of actual service or repair when wells are not producing. [District Rules 2201 and 4401]
- All valves, fittings and connectors serving closed well vents shall be constructed and maintained in a leak free condition except during periods of actual service and repair. [District Rules 2201 and 4401]

- Wells authorized by this permit shall only be operated with closed casing vents. Well casing vents shall remain closed at all times except during periods of actual service or repair provided such activity is attended and done as expeditiously as possible with minimal spillage of material and VOC emissions to the atmosphere. [District Rules 2201 and 4401]
- Total fugitive emission of volatile organic compounds (VOC) from entire operation shall not exceed 146.6 lb/day. [District Rule 2201]
- Permittee shall maintain with the permit accurate fugitive component counts for well vent vapor control systems and resulting emissions calculated using CAPCOA's "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities," Table IV-2c(Feb 1999) Screening Range emission factors. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

Pursuant to District Policy APR 1705, source testing is not required to demonstrate compliance with Rule 2201.

2. Monitoring

No modification to or additional monitoring requirements are needed to demonstrate compliance with Rule 2201. Monitoring requirements pursuant to Rule 4401 are evaluated in the following Rule 4401 discussion.

3. Recordkeeping

The following recordkeeping condition will be listed on the permit:

- Permittee shall maintain with the permit a listing (updated annually within 60 day of permit anniversary) of all steam-enhanced wells authorized by this permit and such listing shall be made available for District inspection upon request. [District Rules 2201 and 1070]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

Rule 4001 New Source Performance Standards (NSPS)

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60. However, no subparts of 40 CFR Part 60 apply to steam enhanced oil well operations.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

This rule incorporates NESHAPs from Part 61, Chapter 1, Subchapter C, Title 40, CFR and the NESHAPs from Part 63, Chapter 1, Subchapter C, Title 40, CFR; and applies to all sources of hazardous air pollution listed in 40 CFR Part 61 or 40 CFR Part 63. However, no subparts of 40 CFR Part 61 or 40 CFR Part 63 apply to steam enhanced oil well operations.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

This operation is currently in compliance with this rule. Continued compliance is expected.

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix D), the total facility prioritization score including this project was greater than one. Therefore, a health risk assessment was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

HRA Summary		
Unit	Cancer Risk	T-BACT Required
S-1131-1036-10	0.17 per million	No

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 10 in a million). As outlined by the HRA Summary in Appendix D of this report, the emissions increases for this project was determined to be less than significant.

Rule 4401 Steam-enhanced Crude Oil Production Well Vents

The purpose of this rule is to limit the VOC emissions from steam-enhanced crude oil production well vents. This rule is applicable to all steam-enhanced crude oil production wells and any associated vapor collection and control systems.

Section 5.5: Well Vents

An operator shall not operate a steam-enhanced crude oil production well unless either of the following two conditions are met: 1) The steam-enhanced crude oil production well vent is closed and the front line production equipment downstream of the wells that carry produced fluids is connected to a VOC collection and control system as defined in Section 3.0 of this Rule, or 2) the steam-enhanced crude oil production well vent is open and the well vent is connected to a VOC collection and control system that has a VOC collection and control system as defined in Section 3.0 of this Rule.

Section 5.6: Leak Standards

1) There shall be no open-ended line or a valve located at the end of the line that is not sealed with a blind flange, plug, cap, or a second closed valve that is not closed at all times, except during attended operations requiring process fluid flow through the open-ended lines. Attended operations include draining or degassing operations, connection of temporary process equipment, sampling of process streams, emergency venting, and other normal operational needs, provided such operations are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

2) There shall be no components with a major liquid leak as defined in Section 3.20.2.

3) There shall be no components with a gas leak of greater than 50,000 ppmv.

4) There shall be no more than one component leak per twenty wells tested, including minor liquid leaks, minor gas leaks or gas leaks between 10,000 ppmv and 50,000 ppmv.

Section 5.7: Operating Requirements

1) No leaking components (as defined in Section 5.6.2) may be used unless they have been identified with a tag for repair, are repaired, or awaiting re-inspection after being repaired within the applicable time frame specified in Section 5.9.

2) Each hatch shall be closed at all times except during attended repair, replacement, or maintenance operations, providing such activities are done as expeditiously as possible with minimal spillage or material and VOC emissions into the atmosphere.

3) The operator shall comply with the requirements of Section 6.7 if there is any change in the description of major components or critical components.

Section 5.8: Inspection and Re-inspection Requirements

Unless otherwise specified in Section 5.8, an operator shall perform all component inspections and gas leak measurements pursuant to the requirements of Section 6.3.3.

Except for pipes and unsafe-to-monitor components, an operator shall inspect all other components pursuant to the requirements of Section 6.3.3 at least once every year.

An operator shall visually inspect all pipes at least once every year. Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected within 24 hours after detecting the leak. If a leak is found, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table 4 of this rule.

In addition to the inspections required by Section 5.8.1, an operator shall inspect for leaks all accessible operating pumps, compressors, and PRDs in service as follows:

1) An operator shall audio-visually (by hearing and by sight) inspect for leaks all accessible operating pumps, compressors, and PRDs in service at least once each calendar week.

2) Any audio-visual inspection of an accessible operating pump, compressor, and PRD performed by an operator that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected not later than 24 hours after conducting the audio-visual inspection. If a leak is found, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table 4 of this Rule.

The operator shall also perform the following inspections:

1) An operator shall initially inspect a PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the discovery of the release. An operator shall re-inspect the PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the initial inspection.

2) An operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 72 hours of placing the component in service.

3) Except for PRDs subject to the requirements of Section 5.8.4.1 of this Rule, an operator shall inspect a component that has been repaired or replaced not later than 15 calendar days after the component was repaired or replaced.

An operator shall inspect all unsafe-to-monitor components during each turnaround.

A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator.

Section 5.9: Leak Repair Requirements

Upon detection of a leak, an operator shall affix a readily visible weatherproof tag to that leaking component that includes the following information: 1) The date and time of leak detection; 2) The date and time of the leak measurement; 3) For a gaseous leak, the leak concentration in ppmv; 4) For a liquid leak, whether it is a major or minor liquid leak; and 5) Whether the component is an essential component, and unsafe-to-monitor component, or a critical component.

The tag shall remain affixed to the leaky component until all the following requirements are met:

1) The component is repaired or replaced,

2) The component is re-inspected as set forth in Section 6.3, and

3) The component is found to be in compliance with this rule.

An operator shall minimize a component leak in order to stop or reduce leakage to the atmosphere immediately to the extent possible, but not later than one (1) hour after detection of the leak.

Except for leaking critical components or leaking essential components subject to the requirements of Section 5.9.7, if an operator has minimized a leak but the leak still exceeds the applicable leak limits as defined in Section 3.0, an operator shall comply with at least one of the following three requirements as soon as practicable but not later than the time period specified in Table 4:

1) Repair or replace the leaking component,

2) Vent the leaking component to a VOC collection and control system as defined in Section 3.0, or

3) Remove the leaking component from operation.

The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the applicable repair period specified in Table 4.

The time of the initial leak detection shall be the start of the repair period specified in Table 4.

If the leaking component is an essential component or a critical component that cannot be immediately shut down for repairs, and if the leak has been minimized but the leak still exceeds the applicable leak standard of this rule, the operator shall repair or replace the essential component or critical component to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier.

Section 6.1: Recordkeeping and Submissions

The following records shall be retained for a period of five years and made available for District inspection upon request.

1) The dates and well identification where steam injection occurs,

2) Monthly records of county-specific crude oil production as set forth by the California Division of Oil, Gas and Geothermal Resources, For the purpose of this rule, the monthly crude oil production records required by the California Division of Oil, Gas, and Geothermal Resources may be used to satisfy this requirement,

3) All source test records which demonstrate compliance with the VOC collection and control efficiency as defined in Section 3.0,

4) All source test data conducted pursuant to Section 4.6.2 shall be submitted to the District with 60 days thereafter,

5) The operator shall maintain an Inspection Log pursuant to Section 6.4,

6) All records of each calibration of the portable hydrocarbon detection instrument shall be maintained, including a copy of the current calibration gas certification from the vendor, the date of calibration, the concentration of the calibration gas, the instrument reading of the calibration before and after adjustment, the calibration gas expiration date and the calibration gas cylinder pressure at the time of calibration,

7) Records of the facility training records shall be maintained of the training program operated pursuant to Section 6.5,

8) A copy of the APCO-approved Operator Management Plan shall be maintained.

9) A list of all gauge tanks shall be submitted to the District including the size, identification number, the location of each gauge tank and specify whether the gauge tank is upstream of all front line production equipment,

10) Records of results of all gauge tank TVP testing conducted pursuant to Section 6.2.5 shall be submitted to the District within 60 days thereafter,

11) Any operator that has discovered that a pressure regulating device has released shall record the date that the release was discovered along with the identity and location of the release. All such records shall be submitted to the District within 60 days after the end of the calendar year.

Section 6.2: Compliance Source Testing

An operator shall source test annually all vapor collection and control systems used to control emissions from steam-enhanced crude oil production well vents to determine the control efficiency of the device(s) used for destruction or removal of VOC by source testers certified by ARB. Testing shall be performed during June, July, August, or September of

each year if the system's control efficiency is dependent upon ambient air temperature. In addition, all tests required by Section 6.2 should be carried out pursuant to the test methods specified in Section 6.3.

Section 6.3: Test Methods

1) The control efficiency of any VOC control device, measured and calculated as carbon, shall be determined by EPA Method 25, except when the concentration must be below 50 ppmv, in which case EPA Method 25a may be used. EPA Method 18 may be used instead, providing the requirements under Section 6.3.1 are met.

2) VOC content shall be analyzed using the latest revision of ASTM Method E-168, E169 or E260 as applicable. Analysis of halogenated exempt compounds shall be performed using ARB Method 432.

3) Leak inspection, other than audio-visual, and measurements of gaseous leak concentrations shall be conducted according to EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in EPA Method 21 or the manufacturer's instruction, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. Where safety is a concern, such as measuring leaks from compressor seals or pump seals when the shaft is rotating, a person shall measure leaks by placing the instrument probe inlet at a distance of one (1) centimeter or less from the surface of the component interface.

4) For the purpose of Section 4.6.2, the VOC mass emission rate shall be determined according to the procedures described in the document USEPA-909/9-81-003, "Assessment of VOC Emissions from Well Vents Associated with Thermally Enhanced Oil Recovery".

5) The VOC content by weight percent shall be determined using ASTM D1945 for gasses and SCAQMD Method 304-91 or the latest revision of ASTM Method E169, E169 or E260 for liquids.

Section 6.4: Inspection Log

The operator shall maintain an inspection log in which the operator records at least all of the following information for each inspection performed:

1) The total number of components inspected, and the total number and percentage of leaking components found by component type,

2) The location, type and name or description of each leaking component and description of any unit where the leaking component is found,

3) The date of leak detection and the method of leak detection,

4) For gaseous leaks, the leak concentration in ppmv and, for liquids leaks, whether the leak is major or minor,

5) The date of repair, replacement or removal from operation of leaking components,

6) The identity and location of essential components and critical components as defined in this Rule, found leaking, that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes earlier,

7) The methods used to minimize the leak from essential components and critical components found leaking that cannot be repaired until the next process unit turnaround or not later than 1 year after detection, whichever comes earlier,

8) The date or re-inspection and the leak concentration in ppmv after the component is repaired or replaced,

9) The inspectors name, business mailing address, and business telephone number, and

10) The date and signature of the facility operator responsible for the inspection and repair program certifying the accuracy of the information recorded in the log.

Section 6.5: Employee Training Program

The operator shall establish and implement an employee training program for inspecting and repairing components and recordkeeping procedures as necessary.

Section 6.6: Operator Management Plan

By June 30, 2008, an operator whose existing wells are subject to this rule or whose existing wells are exempt pursuant to Section 4.0 of this rule on or before December 14, 2006 shall prepare and submit an Operator Management Plan for approval by the APCO. An operator may use diagrams, charts, spreadsheets, or other methods approved by the APCO to describe the information required by Section 6.6.4 through Section 6.6.7 below. The Operator Management Plan shall include, at a minimum, all of the following information:

1) A description of all wells and all associated VOC collection and control systems subject to this rule, and all wells and all associated VOC collection and control systems that are exempt pursuant to Section 4.0 of this rule.

2) Identification and description of any known hazard that might affect the safety of an inspector,

3) Except for pipes, the number of components that are subject to this Rule by component type,

4) Expect for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components,

5) Except for pipes, the location of components subject to this Rule,

6) Except for pipes, components exempt pursuant to Section 4.8 (except for components buried below ground) may be described in the Operator Management Plan by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the applicable exemption criteria for components for which an exemption is being claimed pursuant to Sections 4.8 shall be submitted with the Operator Management Plan.

7) A detailed schedule of inspections of components to be conducted as required by this Rule and whether the operator inspections of components required by this Rule will be performed by a qualified contractor or in-house team,

8) A description of training standards for personnel that inspect and repair components,

9) A description of leak detection training for conducting the test method specified in Section 6.3.3 for new operators, and experienced operators as necessary.

Section 6.7:

By January 30 of each year after 2008, an operator shall submit to the APCO for approval, in writing, an annual report indicating any changes to an existing Operator Management Plan.

Section 6.8:

The APCO shall provide written notice to the operator of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Operator Management Plan. If the APCO fails to respond in writing within 60 days after the date of receiving the Operator Management Plan, it shall be deemed approved. No provision of the Operator Management Plan, approved or not, shall conflict with or take precedence over any provision of this rule.

Section 7: Compliance Schedule

1) The operator of any new steam-enhanced crude oil production well, or any nonsteam-enhanced crude oil production well converted to a steam-enhanced crude oil production well, which commences steam-enhancement operations on or after April 11, 1991, shall comply with the requirements of this rule and the applicable permit requirements of Rule 2201 (New and Modified Stationary Source Review Rule) before steam injection and no later than the first detectable flow at the casing vent.

2) Steam-enhanced crude oil production wells and components that are exempt pursuant to Section 4.3, 4.4, 4.5, 4.8 or 4.9 that become subject to this rule through loss of exemption status shall not be operated until such time that they are in full compliance with the requirements of this rule.

3) Effective on and after January 1, 2009, an operator shall be in full compliance with the requirements of this rule, unless otherwise specified in the provisions of this rule.

Conditions have been added to the ATC to ensure compliance with this Rule.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.
- Identify the ways that environmental damage can be avoided or significantly reduced.
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The District's engineering evaluation (this document) demonstrates that the project would not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District determined that no other agency has broader discretionary approval power over the project and that the District is the first agency to act on the project, therefore

establishing the District as the Lead Agency for the project (CEQA Guidelines §15051(b). An Initial Study was prepared, which demonstrated that through a combination of project design elements, compliance with District rules, permit conditions, and mitigation measures, the project would have a less than significant effect on the environment. Consistent with CEQA Guidelines §15072(a), the District will publish a Notice of Intent to Adopt a Mitigated Negative Declaration for the project and provide a 30-day public comment period. Prior to making a final determination regarding approval of the project, the District will consider any comments received during the public review process.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful public noticing period, Issue Authority to Construct S-1131-1036-10 subject to the permit conditions on the attached draft Authority to Construct in Appendix E.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-1131-1036-10	3020-09-B	885 TEOR wells without vapor recovery	$1,400.00

Appendices

A: Current PTO
B: Pre/Post Project Fugitive Emission Calculations
C: BACT Guideline and Analysis
D: HRA Summary
E: Draft ATC
F: ARB Guidance Document

Appendix A

Current PTO

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: S-1131-1036-6 **EXPIRATION DATE:** 02/28/2007

EQUIPMENT DESCRIPTION:
TEOR OPERATION WITH 485 CYCLIC AND STEAM DRIVE WELLS WITH CLOSED CASING VENTS

PERMIT UNIT REQUIREMENTS

1. Permittee shall comply with all applicable requirements of Rule 4401. [District Rule 4401] Federally Enforceable Through Title V Permit
2. Emissions from each closed casing vent well covered by this permit shall not exceed 0.0216 lb VOC/hr-well for components and 0.0194 lb VOC/hr-well for polished rod stuffing boxes. [District NSR Rule] Federally Enforceable Through Title V Permit
3. Fluids produced from these steam-enhanced wells with closed well casing vents shall be introduced only to tanks vented to a District approved vapor collection and control system, or to permit exempt storage equipment as defined by Rule 2020, Section 6.6. [District NSR Rule] Federally Enforceable Through Title V Permit
4. Well casing vents shall remain closed at all times except during periods of actual service or repair when wells are not producing. [District NSR Rule and 4401] Federally Enforceable Through Title V Permit
5. Formerly permit number S-1109-361-1.

Appendix B

Pre/Post Project Fugitive Emission Calculations

Chevron U.S.A., Inc.
S-1102789, S-1131-1036-6

Fugitive Emissions Using Screening Emission Factors

California Implementation Guidelines for Estimating Mass Emissions
of Fugitive Hydrocarbon Leaks at Petroleum Facilities
Table IV-2c. Oil and Gas Production
Screening Value Ranges Emission Factors

Weight percentage of VOC in the total organic compounds in gas (neglect non-organics)? 100 %
Weight percentage of VOC in the total organic compounds in oil (neglect non-organics)? 100 %

Equipment Type	Service	Component Count	Total allowable leaking components	Screening Value EF - TOC < 10,000 ppmv (lb/day/source)	Screening Value EF - TOC ≥ 10,000 ppmv (lb/day/source)	VOC emissions (lb/day)
Valves	Gas/Light Liquid	1,222	2	1.852E-03	7.333E+00	16.93
	Light Crude Oil	0	0	1.005E-03	3.741E+00	0.00
	Heavy Crude Oil	0	0	7.408E-04	N/A*	0.00
Pump Seals	Gas/Light Liquid	0	0	5.270E-02	4.709E+00	0.00
	Light Crude Oil	0	0	1.402E-02	4.709E+00	0.00
	Heavy Crude Oil	0	0	N/A	N/A	N/A
Others	Gas/Light Liquid	58	1	7.778E-03	7.281E+00	7.72
	Light Crude Oil	0	0	6.931E-03	3.757E-01	0.00
	Heavy Crude Oil	0	0	3.016E-03	N/A*	0.00
Connectors	Gas/Light Liquid	3,492	8	6.349E-04	1.370E+00	13.18
	Light Crude Oil	0	0	5.291E-04	1.238E+00	0.00
	Heavy Crude Oil	0	0	4.233E-04	4.233E-04	0.00
Flanges	Gas/Light Liquid	1,746	4	1.482E-03	3.228E+00	15.49
	Light Crude Oil	0	0	1.270E-03	1.376E+01	0.00
	Heavy Crude Oil	0	0	1.217E-03	N/A*	0.00
Open-ended Lines	Gas/Light Liquid	0	0	1.270E-03	2.905E+00	0.00
	Light Crude Oil	0	0	9.524E-04	1.175E+00	0.00
	Heavy Crude Oil	0	0	7.937E-04	3.762E+00	0.00

* Emission factor not available. All components from equipment type and service will be assessed as < 10,000 ppmv

Total VOC Emissions = 53.3 lb/day
19,460 lb/yr

Chevron U.S.A., Inc.
S-1102789, S-1131-1036-10

Fugitive Emissions Using Screening Emission Factors

California Implementation Guidelines for Estimating Mass Emissions
of Fugitive Hydrocarbon Leaks at Petroleum Facilities
Table IV-2c. Oil and Gas Production
Screening Value Ranges Emission Factors

Weight percentage of VOC in the total organic compounds in gas (neglect non-organics)? 100 %
Weight percentage of VOC in the total organic compounds in oil (neglect non-organics)? 100 %

Equipment Type	Service	Component Count	Total allowable leaking components	Screening Value EF - TOC < 10,000 ppmv (lb/day/source)	Screening Value EF - TOC ≥ 10,000 ppmv (lb/day/source)	VOC emissions (lb/day)
Valves	Gas/Light Liquid	2,230	8	1.852E-03	7.333E+00	62.78
	Light Crude Oil	0	0	1.005E-03	3.741E+00	0.00
	Heavy Crude Oil	0	0	7.408E-04	N/A*	0.00
Pump Seals	Gas/Light Liquid	0	0	5.270E-02	4.709E+00	0.00
	Light Crude Oil	0	0	1.402E-02	4.709E+00	0.00
	Heavy Crude Oil	0	0	N/A	N/A	N/A
Others	Gas/Light Liquid	106	1	7.778E-03	7.281E+00	8.10
	Light Crude Oil	0	0	6.931E-03	3.757E-01	0.00
	Heavy Crude Oil	0	0	3.016E-03	N/A*	0.00
Connectors	Gas/Light Liquid	6,372	23	6.349E-04	1.370E+00	35.55
	Light Crude Oil	0	0	5.291E-04	1.238E+00	0.00
	Heavy Crude Oil	0	0	4.233E-04	4.233E-04	0.00
Flanges	Gas/Light Liquid	3,186	11	1.482E-03	3.228E+00	40.21
	Light Crude Oil	0	0	1.270E-03	1.376E+01	0.00
	Heavy Crude Oil	0	0	1.217E-03	N/A*	0.00
Open-ended Lines	Gas/Light Liquid	0	0	1.270E-03	2.905E+00	0.00
	Light Crude Oil	0	0	9.524E-04	1.175E+00	0.00
	Heavy Crude Oil	0	0	7.937E-04	3.762E+00	0.00

* Emission factor not available. All components from equipment type and service will be assessed as < 10,000 ppmv

Total VOC Emissions = 146.6 lb/day
53,523 lb/yr

Appendix C

BACT Guideline and Analysis

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 7.1.1*

Last Update: 3/11/1994

Thermally Enhanced Oil Recovery - Steam Drive Oil Wells**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
PM10		1. Vapor control system with either a) Scrubber with 50% PM10 removal, or b) Non-condensables incinerated at steam generator, incinerator, or equal and having a vapor sulfur content no greater than 0.2gr S/100 dscf	1. Vapor control system with either a) Transfer of noncondensable vapors to gas pipeline or b) Re-injection to formation
SOx		1. Vapor control system with either a) Scrubber with 95% sulfur removal, or b) Non-condensables incinerated at steam generator, incinerator, or equal and having a vapor sulfur content no greater than 0.2gr S/100 dscf	1. Vapor control system with either a) Transfer of noncondensable vapors to gas pipeline or b) Re-injection to formation
VOC	1. Vapor control system and inspection and maintenance program with either a) Non-condensables balanced casing vent system tied into tank vapor control system or b) Noncondensables incinerated at steam generator, incinerator, or equal		1. Vapor control system with either a) Transfer of noncondensable vapors to gas pipeline or b) Re-injection to formation

** Control Options wording clarified 10/1/02. No change to any options or limits.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

BACT Analysis for VOC Emissions:

Volatile organic compounds (VOC) emissions are released through the assortment of components that make up this operation.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 7.1.1, 2nd quarter 1994, identifies achieved in practice BACT for VOC emissions from Thermally Enhanced Oil Recovery – Steam Drive Oil Wells as follows:

1) Vapor control system and inspection and maintenance program with either; a) Non-condensables balanced casing vent system tied into tank vapor control system, or b) Non-condensables incinerated at steam generator, incinerator, or equal.

In addition, the SJVUAPCD BACT Clearinghouse guideline 7.1.1, 2nd quarter 1994, identifies alternate basic equipment for VOC emissions from Thermally Enhanced Oil Recovery – Steam Drive Oil Wells as follows:

1) Vapor control system with either; a) Transfer of non-consensable vapors to gas pipeline, or b) Re-injection to formation.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

The District recognizes the following options as having the same control effectiveness:

1) Vapor control system with either; a) Transfer of non-consensable vapors to gas pipeline, or b) Re-injection to formation.

2) Vapor control system and inspection and maintenance program with either; a) Non-condensables balanced casing vent system tied into tank vapor control system, or b) Non-condensables incinerated at steam generator, incinerator, or equal.

d. Step 4 - Cost effectiveness analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions. Since these options have the same control effectiveness, no ranking is necessary and a cost analyses is not required.

e. Step 5 - Select BACT

BACT for VOC emissions from this closed casing vent system is a vapor system that transfers non-condensable vapors to gas pipeline, re-injects to formation, or through incineration. The applicant has proposed to modify a closed casing vent system that transfers production with entrained gasses to frontline tanks equipped with vapor control that transfers non-condensable vapors to gas pipeline, re-injects to formation, or to approved incineration devices; therefore BACT for VOC emissions is satisfied.

Appendix D

HRA Summary

Revised
San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Kristopher Rickards – Permit Services
From:	Cheryl Lawler – Technical Services
Date:	July 11, 2011
Facility Name:	Chevron USA, Inc.
Location:	Multiple Sections in Kern County
Application #(s):	S-1131-1036-10
Project #:	S-1102789

A. RMR SUMMARY

RMR Summary			
Categories	**TEOR Operation (Unit 1036-10)**	**Project Totals**	**Facility Totals**
Prioritization Score	21.2	21.2	>1.0
Acute Hazard Index	0.04	0.04	0.27
Chronic Hazard Index	0.00	0.00	0.53
Maximum Individual Cancer Risk	**1.70E-07**	1.70E-07	3.64E-06
T-BACT Required?	**No**		
Special Permit Conditions?	**No**		

B. RMR REPORT

I. Project Description

Technical Services received a request on June 28, 2011, to perform a revised Risk Management Review for a proposed modification to a TEOR operation. The modification consists of adding 400 new TEOR wells in various sections in Kern County.

II. Analysis

Technical Services performed a health risk assessment using the Toxic Fugitive Emissions from Oilfield Equipment. The cumulative prioritization scores were greater than 1.0, thus modeling was conducted using the AERMOD model, with the parameters outlined below and concatenated five-year meteorological data from Bakersfield to determine the maximum dispersion factors at the nearest business or residence receptor. Since the units will be located within several sections that are near each other, only one section (which currently has the most wells located within it) was modeled using the total emissions in order to achieve worst case results.

The following modeling parameters were used:

Analysis Parameters for Unit 1036-10			
Source Type	Area	**Location Type**	Urban
X-Length (m)	50	**Closest Receptor (m)**	30.48
Y-Length (m)	50	**Type of Receptor**	Residential or Business
Release Height (m)	1.22	**Pollutant Type**	VOC
		Emission Rate	14.01 lb/hr

III. Conclusion

The Acute and Chronic Indices are below 1.0 and the Individual Cancer Risk associated with the TEOR operation is **1.70E-07**, which is less than the 1 in a million threshold. In accordance with the District's Risk Management Policy, the project is approved **without** Toxic Best Available Control Technology (T-BACT).

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

Appendix E

Draft ATC

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-1131-1036-10

ISSUANCE DATE: DRAFT

LEGAL OWNER OR OPERATOR: CHEVRON USA INC
MAILING ADDRESS: PO BOX 1392
BAKERSFIELD, CA 93302

LOCATION: HEAVY OIL CENTRAL
KERN COUNTY, CA

EQUIPMENT DESCRIPTION:
MODIFICATION OF TEOR OPERATION WITH 485 CYCLIC AND STEAM DRIVE WELLS WITH CLOSED CASING VENTS: ADD 400 WELLS TO WELL ROSTER, UPDATE EMISSION FACTORS BY USING CAPCOA SCREENING FACTORS, REVISE EQUIPMENT DESCRIPTION TO READ "885 THERMALLY ENHANCED WELLS WITH CLOSED CASING VENTS"

CONDITIONS

1. {1829} The facility shall submit an application to modify the Title V permit in accordance with the timeframes and procedures of District Rule 2520. [District Rule 2520] Federally Enforceable Through Title V Permit
2. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 8,516 lb, 2nd quarter - 8,516 lb, 3rd quarter - 8,516 lb, and fourth quarter - 8,516 lb. The offset amounts listed above include the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]
3. ERC Certificate Number S-2887-1 (or a certificate split from this certificate) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201]
4. During the time any steam-enhanced crude oil production well is undergoing service or repair while the well is not producing, it shall be exempt from the emission control requirements of District Rule 4401, 5.0. [District Rule 4401, 4.1] Federally Enforceable Through Title V Permit
5. All valves, fittings and connectors serving closed well vents shall be constructed and maintained in accordance with leak standards described in Rule 4401 except during periods of actual service and repair. [District Rules 2201 and 4401]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

DAVID WARNER, Director of Permit Services
S-1131-1036-10 : Oct 11 2011 1:08PM – RICKARDK : Joint Inspection NOT Required

6. Wells authorized by this permit shall only be operated with closed casing vents. Well casing vents shall remain closed at all times except during periods of actual service or repair provided such activity is attended and done as expeditiously as possible with minimal spillage of material and VOC emissions to the atmosphere, and the front line production equipment downstream of the wells that carry produced fluids be connected to a VOC collection and control system. [District Rules 2201 and 4401]
7. Fluids produced from these steam-enhanced wells with closed well casing vents shall be introduced only to tanks vented to a District approved vapor collection and control system, or to permit exempt storage equipment as defined by Rule 2020, Section 6.6. [District Rule 2201] Federally Enforceable Through Title V Permit
8. Total fugitive emission of volatile organic compounds (VOC) from entire operation shall not exceed 146.6 lb/day. [District Rule 2201]
9. Permittee shall maintain with the permit accurate fugitive component counts for well vent vapor control systems and resulting emissions calculated using CAPCOA's "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities," Table IV-2c(Feb 1999) Screening Range emission factors. [District Rule 2201]
10. The operator shall be in violation of Rule 4401 if any District inspection or if any operator inspection conducted pursuant to Rule 4401, Section 5.8 are found to be leaking in excess of the applicable leak standards in section 5.6.2. [District Rule 4401, 5.6.1]
11. There shall not be an open-ended line or a valve located at the end of the line that is not sealed with a blind flange, plug, cap, or a second closed valve that is not closed at all times, except during attended operations requiring process fluid flow through the open-ended lines. Attended operations include draining or degassing operations, connection of temporary process equipment, sampling of process streams, emergency venting, and other normal operational needs, provided such operations are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere. [District Rule 4401, 5.6.2.1]
12. There shall be no components with major liquid leaks or with gas leaks greater than 50,000 ppmv. [District Rule 4401, 5.6.2.2 and 5.6.2.3]
13. There shall not be more minor liquid leaks, minor gas leaks, or gas leaks greater than 10,000 ppmv up to 50,000 ppmv than the following: 3 leaks for 1 - 25 wells, 6 leaks for 26 - 50 wells, 8 leaks for 51 - 100 wells, 10 leaks for 101 - 250 wells, 15 leaks for 251 - 500 wells, and 1 leak for each 20 wells (with a minimum of 50 wells test) for more than 500 wells connected to a VOC collection and control system. [District Rule 4401, 5.6.2.4]
14. Components that have been found leaking in excess of the applicable leak standards of this rule may be used provided such leaking components have been identified with a tag for repair, are repaired, or are awaiting re-inspection after being repaired, within the applicable time period specified in this permit. [District Rule 4401, 5.7.1]
15. Except for pipes and unsafe-to-monitor components, all other components shall be inspected pursuant to the requirements of section 6.3.3 at least once every year. [District Rule 4401,5.8.1]
16. All pipes shall be visually inspected at least once every year. Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected within 24 hours after detecting the leak. If a leak is found, the leak shall be repaired as soon as practicable but not later than as allowed by Rule 4401 and specified in this permit. [District Rule 4401, 5.8.2]
17. The operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 72 hours of placing the component in service. The operator shall inspect a component, other than PRDs, that has been repaired or replaced not later than 15 calendar days after the component was repaired or replaced. The operator shall inspect all unsafe-to-monitor components during each turnaround. [District Rule 4401, 5.8.4.2, 5.8.4.3, 5.8.5]
18. A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator. [District Rule 4401, 5.8.6]

CONDITIONS CONTINUE ON NEXT PAGE

19. The operator, upon detection of a leaking component, shall affix to that component a weatherproof, readily visible tag, bearing the date and time when the leak was detected and the date and time of the leak measurement. For gaseous leaks, the tag shall indicate the leak concentration in ppmv. For liquid leaks, the tag shall indicate whether it is a major liquid leak or a minor liquid leak. The tag shall indicate, when applicable, whether the component is an essential component, an unsafe-to-monitor component, or a critical component. The tag shall remain in place until the leaking component is repaired or replaced and reinspected and found to be in compliance with the requirements of this rule. [District Rule 4401 5.9.1, 5.9.2]

20. The operator shall minimize all component leaks immediately, to the extent possible, but not later than one hour after detection of the leak in order to stop or reduce leakage to the atmosphere. Except for leaking critical components or leaking essential components, if the leak has been minimized but the leak still exceeds the applicable leak standards specified in this permit, the operator shall do one of the following within the timeframes specified within this permit: 1) repair or replace the leaking component; 2) vent the leaking component to a closed vent system; 3) or remove the leaking component from operation. A closed vent system is a District approved system that is not open to the atmosphere. It is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gas or vapor from a piece or pieces of equipment to a District approved control device that has a overall VOC collection and destruction or removal efficiency of at least 99%, or that transports gases or vapors back to a process system. [District Rule 4401, 5.9.4]

21. The operator shall repair minor gas leaks within 14 days, major gas leaks which less than or equal to 50,000 ppmv within 5 days., major gas leaks which are greater than 50,000 ppmv within two days, minor liquid leaks within 3 days, and major liquid leaks within 2 days. The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the applicable repair period. The start of the repair period shall be the time of the initial leak detection. [District Rule 4401, 5.9.4, 5.9.5, and 5.9.6]

22. If a leaking component is an essential component or a critical component which cannot be shut down immediately for repairs, and after being minimized still exceeds the applicable leak standard, the operator shall repair or replace the component to eliminate the leak during the next process unit turnaround or no later than one year from the date of original leak detection, which ever is earlier. [District Rule 4401, 5.9.7]

23. The operator of any steam-enhanced crude oil production well shall maintain records of the date and well identification where steam injection or well stimulation occurs. [District Rule 4401, 6.1.1]

24. An operator of any steam-enhanced crude oil production well shall keep source test records which demonstrate compliance with the control efficiency requirements of the VOC collection and control system. [District Rule 4401, 6.1.3]

25. Records shall be maintained of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components. The records shall include a copy of the current calibration gas certification from the vendor of the calibration gas cylinder, the date of calibration, the concentration of calibration gas, the instrument reading of calibration gas before adjustment, the instrument reading of calibration gas after adjustment, the calibration gas expiration date, and the calibration gas cylinder pressure at the time of calibration. [District Rule 44019, 6.1.6]

26. Leak inspection, other than audio-visual, and measurements of gaseous leak concentrations shall be conducted according to EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in EPA Method 21 or the manufacturer's instruction, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. Where safety is a concern, such as measuring leaks from compressor seals or pump seals when the shaft is rotating, a person shall measure leaks by placing the instrument probe inlet at a distance of one (1) centimeter or less from the surface of the component interface. [District Rule 4401, 6.3.3]

27. The VOC content by weight percent (wt.%) shall be determined using American Society of Testing and Materials (ASTM) D1945 for gases and South Coast Air Quality Management District (SCAQMD) Method 304-91 or the latest revision of ASTM Method E168, E169 or E260 for liquids. [District Rule 4401, 6.3.5]

CONDITIONS CONTINUE ON NEXT PAGE

28. The operator shall maintain an inspection log that has been signed and dated by the facility operator responsible for the inspection, certifying the accuracy of the information recorded in the log. The inspection log shall contain, at a minimum, all of the following information: 1) The total number of components inspected, and the total number and percentage of leaking components found by component types; 2) The location, type, name or description of each leaking component and the description of any unit where the leaking component is found; 3) Date of the leak detection and method of the leak detection; 4) For gaseous leaks, record the leak concentration in ppmv, and for liquid leaks record whether the leak is a major liquid leak or a minor liquid leak; 5) The date of repair, replacement, or removal from operation of the leaking component(s); 6) The identification and location of essential components and critical components found leaking that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes first; 7) The method(s) used to minimize the leak from essential components and critical components found leaking that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes earlier; 8) The date of re-inspection and the leak concentration in ppmv after the component is repaired or is replaced; 9) The inspector's name, business mailing address, and business telephone number. [District Rule 4401, 6.4]
29. The operator shall establish and implement an employee training program for inspecting and repairing components and recordkeeping procedures, as necessary. [District Rule 4401, 6.5]
30. The operator shall maintain copies of training records and a copy of the latest APCO-approved Operator Management Plan (OMP) at the facility and make such available to the APCO, ARB, and US EPA upon request. [District Rule 4401, 6.1.7, 6.1.8]
31. The operator shall maintain an APCO approved Operator Management Plan (OMP). The OMP shall include, at a minimum, a description of all wells and all associated VOC collection and control systems subject to this rule, and all wells and all associated VOC collection and control systems that are exempt; an identification and description of any known hazard that might affect the safety of an inspector; except for pipes, the number of components that are subject to this rule by component type; except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components that are subject to this rule and the reason(s) for such designation; except for pipes, the location of components subject to the rule (components may be grouped together functionally by process unit or facility description); except for pipes, components exempt pursuant to Section 4.8 (except for components buried below ground) may be described in the OMP by grouping them functionally by process unit or facility description (the results of any laboratory testing or other pertinent information to demonstrate compliance with the applicable exemption criteria for components for which an exemption is being claimed pursuant to Sections 4.8 shall be submitted with the OMP); a detailed schedule of an operator's inspections of components to be conducted as required by this rule and whether the operator inspections of components required by this rule will be performed by a qualified contractor or by an in-house team; a description of the training standards for personnel that inspect and repair components; and a description of the leak detection training for conducting the test method specified in Section 6.3.3 for new operators, and for experienced operators, as necessary. [District Rule 4401, 6.6]
32. By January 30th of each year the operator shall submit to the District for approval, in writing, an annual report indicating any changes to the existing OMP on file at the District. [District Rule 4401, 6.7]
33. Permittee shall maintain with the permit a listing (updated annually within 60 day of permit anniversary) of all steam-enhanced wells authorized by this permit and such listing shall be made available for District inspection upon request. [District Rules 2201 and 1070]

Appendix F

ARB Guidance Document

CHAPTER 10: PETROLEUM REFINERIES
(Guidance for Regulation Section 95113)

As listed in section 95113(a) of the regulation, the emissions data report for a petroleum refinery must include the following information as applicable:

1. Stationary combustion CO_2 emissions by fuel type
2. Stationary combustion CH_4 and N_2O emissions by fuel type
3. Consumption data for fuels and feedstocks
4. Hydrogen production plant emissions of CO_2, CH_4, and N_2O
5. Specified process emissions
6. Specified fugitive emissions
7. Flaring emissions
8. Emissions from electricity generating units
9. Emissions from co-generation facilities
10. Indirect energy purchases

Calculation methods for each of these reporting requirements are discussed in this chapter. Note that in addition to referring to the common methodologies section of the regulation (section 95125), you will find general guidance on applicable methods in Chapter 13 of this document. Information specific to refineries is included here.

10.1 Stationary Combustion Emissions

As indicated by the regulation's general requirements (section 95103(a)(2)), the operator needs to calculate and report emissions for each GHG separately for each fuel type used (except where a CEMS is deployed, discussed below). Thus, in compiling and reporting stationary combustion emissions you will be effectively populating a matrix that looks something like the one below. The fuels you combust may be different than those shown in the Table below, of course.

Table 10.1 Stationary Combustion GHG Emissions

Fuel	CO_2	CH_4	N_2O
Refinery fuel gas			
Natural Gas			
Associated Gas			
Diesel Fuel			
Residual Fuel			
Propane			
CNG			
Gasoline			
Kerosene			
Naphtha			
CEMS (fuel mixtures)		n/a	n/a

The purpose of this chapter is to provide guidance on the requirements of section 95113 of the mandatory GHG reporting regulation. As described more specifically in Chapter 1 of this document, this guidance does not add to, substitute for, or amend the regulatory requirements as written in these or other sections of the regulation (Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations).

connected to a functioning destruction device. If this is the case at your facility, you are not required to report GHG emissions here. The destruction of low Btu gases such as those recovered from an oil/water separator are covered in section 95113(d)(3). Table 13 does provide methane emission factors for gravity, DAF and IAF oil/water separators when they are either covered or uncovered, and not connected to a destruction device. In these cases you will report methane emissions using the method in this section. You need to know the volume of water annually treated by the separator. The volume of treated water is used along with the appropriate oil/water separator EF from Table 13 to calculate methane emissions. A conversion factor of 0.6 is used to convert from nonmethane hydrocarbons to methane.

Table 10.5.2 Fugitive Emissions from Oil/water Separators - Methane

Required Data	*Units/Value*	*Data Source*
EF_{sep} - NMHC emission factor	kg NMHC/m^3	operator determined from Table 13, regulation Appendix A
V_{water} - volume of water treated annually	m^3/year	operator measured
CF_{NMHC} - NMHC to CH_4 conversion factor	unit-less - 0.6	supplied
Conversion factor - kg to metric tonnes	0.001	supplied

$$CH_4 = EF_{sep} * V_{water} * CF_{NMHC} * 0.001$$

10.5.3 Reporting Storage Tanks Fugitive Emissions

There are three types of emissions from hydrocarbon storage tanks: working losses, breathing losses and flashing losses. Working losses occur as a result of the filling and emptying processes. Internal headspace gas is expelled and external air is pulled into a storage tank as product enters and exits the tank. Breathing losses as a result of changes in environmental parameters, such as solar and thermal heating and cooling, cause changes in internal liquid and vapor volumes. Ambient winds can also cause tank breathing emissions as they pass the tank exterior. Flashing losses occur when liquid introduced into a tank changes pressure and volatiles contained in the liquid "flash" off.

Fugitive tank emissions will be determined using the U.S. EPA TANKS model.[1] This model calculates working and breathing VOC emissions. Model generated VOC outputs will converted to methane emissions using a default conversion factor of 0.6 (CH_4 = 0.6 * VOC). Alternatively, you may use the results of storage tank headspace analysis to

[1] Note that this program was developed by the American Petroleum Institute (API). API retains the copyright and has granted permission for the nonexclusive, noncommercial distribution of this material to governmental and regulatory agencies. TANKS is available for public use but cannot be sold without written permission from API, the U.S. EPA, Midwest Research Institute, and The Pechan-Avanti Group.