Case Nos. 24278, 24277, 24123, 23775, 23614-23617, and 24018-24027
OCD Exhibit No. 12A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

December 22, 2014

Jonathan Bishop
Chief Deputy Director
California State Water Resources Control Board
P.O. Box 100
Sacramento, CA 95812-0100

Steven Bohlen
Oil and Gas Supervisor
Division of Oil, Gas and Geothermal Resources
California Department of Conservation
801 K Street, MS 18-05
Sacramento, CA 95814-3530

Dear Messrs. Bishop and Bohlen:

I am writing to follow up on EPA's July 17, 2014 letter to CalEPA and the Resources Agency regarding the State's administration of the federal Safe Drinking Water Act Class II Oil and Gas Underground Injection Control program. In that letter, we described serious deficiencies in California's Class II program and inconsistencies with federal UIC regulations and State Program primacy requirements. The letter also set forth comprehensive requirements and deadlines for the State to address the deficiencies and bring the program into compliance. Enclosed is a summary of the status of the State's responses to the July 17 letter.

Our frequent dialogue and your efforts in the last six months have illuminated the breadth and complexity of the challenges and the substantial workload faced by the State agencies in overcoming the program's deficiencies. The State's submittals and conceptual plans presented since July are a step in the right direction. However, a more definitive overall plan of State actions and milestones is critically needed by February 6, 2015, to bring the Class II program into compliance by February 15, 2017.

This letter highlights the main areas of recent discussion and provides direction for the State's submittal of a program revision plan by February 6, 2015. This plan should comprehensively address the results of EPA's 2011 audit and 2012 review, and any other related reviews available to the State; assure completion of the outstanding items listed in the enclosure; provide a detailed list of planned actions based on a two-year schedule of tiered priorities, specific deliverables, interim and final milestones; and identify the resources to be deployed to accomplish this work.

Injection Well Evaluations: Priority must be given to completing and submitting the review of existing Class II wells which may be injecting into non-exempt aquifers, particularly in non-hydrocarbon producing zones, as this is the critical path for evaluating the highest potential impacts to drinking water sources. The drinking water source evaluation for these wells should then proceed expeditiously, followed by appropriate actions to address any threats to drinking water (e.g., emergency orders to cease injection, permit rescission, information orders or exercise of other authorities).

Where injection for enhanced oil recovery or waste disposal is contemplated to continue via existing wells into aquifers without approved exemptions, or into portions of aquifers that are outside the specific areas exempted, the State needs to establish a process, priorities, and a schedule to evaluate and address any potential threats from these operations, and for timely development of aquifer exemption proposals. The schedule should reflect environmental and public health priorities and provide adequate time for public participation and for EPA to finalize any needed decisions on these aquifers over the course of the next two years, and no later February 15, 2017. The State must take actions to prohibit injections after February 15, 2017 in any aquifers for which EPA has not approved an aquifer exemption.

Further, State approval of any new wells in aquifers without approved exemptions or into portions of aquifers that are outside the specific area exempted should be limited to State-approved projects in hydrocarbon producing zones, and should include considerations such as: information from drinking water well surveys and recent water quality data in the vicinity of the injection wells; use of formations with greater than 3000 ppm TDS (as we understand the State is analyzing the conditions, if any, under which continued injection into hydrocarbon producing zones with water quality of less than 3000 ppm TDS should be permitted); use of compliance orders or exercise of comparable State authorities to compel operators' submittal of complete applications for aquifer exemptions, and to prohibit injections after February 15, 2017 in any aquifers for which EPA has not approved an aquifer exemption; availability of alternate disposal options; public review processes undertaken; and concurrence by DOC/DOGGR and State/Regional Boards. It is important to note that the State's granting of an authorization for an injection well prior to obtaining EPA's approval of an aquifer exemption does not guarantee EPA's approval, which will be based on regulatory criteria.

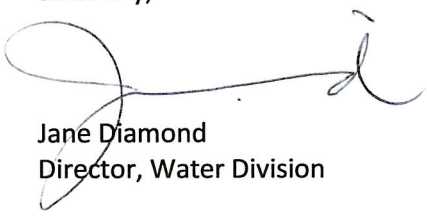
Aquifer Exemption Process: Aquifer exemptions are an essential component of the State's Class II well permitting program. The State must determine which aquifers to exempt, provide for public participation and submit proposed exemptions to EPA for approval. The State must support the proposed exemptions with strong technical data and robust evaluations before presenting them to the public and EPA. Given the multiple state agencies involved, explicit internal processes and procedures are needed to guide the gathering and thorough evaluation of the necessary data, and seek EPA approval regarding the specific aquifer exemptions. EPA's Aquifer Exemption Checklist, provided previously and again as an enclosure with this letter, outlines the requirements for aquifer exemptions. We also provided several examples and met with State staff on November 3, 2014 to discuss required documentation.

Historic Aquifer Exemptions: In addition to wells known to the State to be injecting into zones that do not have aquifer exemptions, some existing wells inject into 11 aquifers which have been historically treated as exempt, though data provided by the State to EPA with its 1981 primacy application indicate that these 11 aquifers were non-hydrocarbon producing and contained water that was less than 3000 ppm TDS. Pursuant to Section II(H) of the Underground Injection Control Program Memorandum of Agreement Between California Division of Oil and Gas and the United States Environmental Protection Agency, EPA believes the collection and consideration of current data on the water quality of these aquifers will afford the State the opportunity to determine whether existing wells in these aquifers should continue to operate. The State's program revision plan should outline performance of specific activities by the State and operators on a schedule that will allow EPA to finalize any needed decisions on these aquifers by December 31, 2016. No new wells should be authorized in an aquifer prior to the conclusion of this process for that aquifer.

EPA is committed to working with the State under 40 CFR 145.33 to enable the State to maintain primacy for the Class II Oil and Gas Underground Injection Control program. Given the need to resolve the program's serious deficiencies in a timely matter, EPA has strengthened oversight and support of the program. As part of this investment, EPA is prepared to re-direct a portion of the State's anticipated FY15 federal UIC grant allocation of approximately $550,000 to specific efforts targeted to advance the State's Class II program toward compliance with the Safe Drinking Water Act. We will consult with you on work to be led by EPA with these funds.

We look forward to continuing our collective efforts towards achieving our shared commitment to protect California's underground sources of drinking water, and anticipate receiving your program revision plan by February 6, 2015.

Sincerely,



Jane Diamond
Director, Water Division

Enclosures
(1) Status of State Response to EPA's July 17, 2014 letter
(2) EPA Aquifer Exemption Checklist

Status of State Response to EPA's July 17, 2014 Letter

1. **Drinking Water Source Evaluation**

State to provide initial assessment of whether any existing and potential sources of drinking water are at risk of contamination from improper Class II injection (due Sept 15th).

Location of private and public water system wells that may be at risk due to permitted Class II injection ***SEPTEMBER 15 SWRCB SUBMITTAL OF INITIAL REVIEW COMPLETED. DOGGR review of records and list of all remaining injection wells that are discharging into non-exempt, non-hydrocarbon zones of aquifers planned for completion and submittal to the State Water Board by January 5, 2015. Depending on the number of wells that are submitted, State Water Board expects to be able to identify any injection wells that are potentially impacting water supply wells by February 6, 2015.***

A plan to ensure protection of human health from actual or potential exposure to DW affected by any injection wells ***IN PROGRESS. State has issued some shut-in orders and information orders and plans to expand use of these tools as needed as evaluations are completed.***

A plan to communicate information to the public and to address subsequent questions/concerns ***OVERDUE.***

2. **Documentation of Aquifer Exemptions**

Provide all documents that pertain to the State's requests for aquifer exemptions, EPA's approval or denial of such requests, and any post-primacy appeals by the State regarding aquifer exemptions (due August 18th). ***COMPLETED--State has indicated orally that all documents have been provided. Some documents received via e-mail on August 18, 2014; one CD of 175 documents received on September 5, 2014; one CD of 40 documents received on November 4, 2014.***

3. **Tiered Review of Class II Wells**

a. Provide the number and location of all Class II wells permitted to inject in non-hydrocarbon producing formations with water quality less than 10,000 ppm TDS (excluding the formations known to be exempt). For each well, submit: operator's name, well type, depth, field and formation names, date injection commenced, water quality of both injection formation and injection fluid, and other pertinent details. (Due August 18th). ***PARTIAL DATA SET RECEIVED; STATE ACKNOWLEDGED IT WAS INCOMPLETE AND CONTAINED INACCURACIES.***

b. Provide the number and location of all Class II wells permitted to inject in non-exempt hydrocarbon-producing formations with water quality below 10,000 ppm TDS. For each well, submit: operator's name, well type, depth, field and formation names, date injection commenced, water quality of both injection formation and injection fluid, and other pertinent details. (Due October 15th). ***PARTIAL DATA SET RECEIVED; STATE ACKNOWLEDGED IT WAS INCOMPLETE AND CONTAINED INACCURACIES.***

c. Submit a plan and timeline for completion of a searchable database of all Class II injection well information statewide (along with a GIS overlay of the injection wells, injection formations, and aquifer exemptions). (Due September 15th). ***OVERDUE. The Division of Oil Gas and Geothermal Resources' web site contains a searchable database available to the public; however, we are awaiting a plan and timeline for making the database more robust and including additional information, such as aquifer exemptions.***

Develop a plan and timeline for submission to EPA of any new or revised aquifer exemption requests, which the State determines are appropriate. (Due September 15th). ***IN PROGRESS.***

4. State Program Consistency

Provide a status report on DOGGR's progress on the November 2012 Action Plan, which addressed Class II program deficiencies identified by EPA in our 2011 program audit. EPA also asked for a schedule for any proposed revisions to the Plan and for completing implementation of the Action Plan. (Due August 18th). ***IN PROGRESS.***

Aquifer Exemption Checklist

Reviewed by: _____ ***Date*** _____

A- Regulatory Background and Purpose

An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" in § 146.3 may be determined to be an "exempted aquifer". The aquifer exemption criteria at 146.4 must be met as follows:

- Class I-V wells must meet criteria **146.4(a) and 146.4(b)(1)**; or **146.4(a) and 146.4(b)(2)**; or **146.4(a) and 146.4(b)(3)**; or **146.4(a) and 146.4(b)(4)**; or **146.4(a) and 146.4(c).**
- Class VI wells must meet the criteria **146.4(d)**[1].

Regardless of the AE request or the type of injection activity, in all cases, first and foremost a demonstration that the aquifer or portion thereof does not currently serve as a source of drinking water is the required first step in the process. **EPA must evaluate each AE request to ensure the criteria are met prior to approval. EPA should also document its rationale for approving or disapproving each AE request in its statement of basis and, in case of exemptions that are substantial program revisions, EPA must provide public notice and an opportunity for the public to comment and request a public hearing.**

The purpose of this checklist is to ensure that appropriate and adequate information is collected to facilitate review of AE requests, and documentation of AE decisions. Some information described here may not apply to all AE requests.

B- General Information

AE request received by EPA on _____

Is the aquifer exemption Substantial_____ **Non-Substantial**_____
Describe basis for substantial/non-substantial determination_____
Is the aquifer exemption Complex? (Existence of drinking water wells, populated area ...) _____
Did the state or tribe provide public notice and opportunity for public hearing on the aquifer exemption request (144.7 (b)) Y/N
Were there any public comments? Y/N If yes, identify where they may be located_____
Date(s) of notice(s) published_____, Public meeting(s) held_____, Hearing held _____, any notable findings or pending litigation _____
Describe the notice and comment process and the final decision_____
Describe the basis for the decision to exempt the aquifer or the basis for the decision to withhold or deny approval of the exemptions request_____
Any anticipated issues associated with EPA approval or disapproval of the AE request Y/N_____
Any meetings between EPA/States/Tribes/Operator to discuss issues Y/N list_____

Is the request submitted by a primacy state or tribe? Y/N If yes name the State/Tribe/Agency _____ **Contact:**_____
AE identified by the Primacy State or tribe and submitted for EPA review and final determination on _____

Name of the Owner/operator_____
Well/Project Name:_____ **Well Class** _____
Purpose of injection: _____(mineral mining/oil and gas/other)

Where is the proposed aquifer exemption located? Township, Section, Range, Quarter Section or other method used to identify the area _____ Latitude and longitude information _____County_____ City_____ State_____ Add information about distance to nearest Town, County _____

Name of aquifer or portion of aquifer to be exempted _____

_____

[1] Additional Class VI only requirements in 40 CFR 144.7(d)(1) and (2) apply. This checklist does not address those requirements.

Areal extent of the area proposed for exemption_____

Depth and thickness of the aquifer _____

Discuss the total dissolved solid (TDS) content of the aquifer, including the TDS at the top and bottom of the exempted zone, and the locations and depths of all fluids samples taken. _____

C- Regulatory Criteria

An aquifer or a portion thereof may be determined to be an exempted aquifer for Class I-V wells if it meets the criteria in paragraphs (a) –(c) below. Other than EPA approved aquifer exemption expansions that meet the criteria set forth in 146.4(d), new aquifer exemptions for Class VI wells shall not be issued.

146.4: ( ) **(a)** ***Not currently used as a drinking water source*** **and:**

( ) **(b)(1)** It is mineral, hydrocarbon, or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or Class II operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible; or

( ) **(b)(2)** It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or

( ) **(b)(3)** It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; or

( ) **(b)(4)** It is located over a Class III well mining area subject to subsidence or catastrophic collapse; or

( ) **(c)** TDS is more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system.

( ) **(d)** *The areal extent of an aquifer exemption for a Class II enhanced oil recovery or enhanced gas recovery well may be expanded for the exclusive purpose of Class VI injection for geologic sequestration under § 144.7(d) if it does not currently serve as a source of drinking water; and the TDS is more than 3,000 mg/l and less than 10,000 mg/l; and it is not reasonably expected to supply a public water system.*

1- Demonstration that the aquifer or portion thereof does not currently serve as a source of drinking water per 146.4(a)

Describe the proposed exempted area and how it was determined:_____

_____

TDS:_____ **Top:**_____ **Bottom:**_____

Lithology: _____

Permeability: _____ **Porosity:** _____ **Groundwater flow direction:** _____

Upper and Lower Confining Zone(s) and description of vertical confinement from USDWs:

_____

Oil or mineral production history:_____

Are there any public or private drinking water wells within and nearby the proposed exempted area for which the proposed exempted portion of the aquifer might be a source of drinking water Y/N If yes, list all those wells

_____

- *Include*: pertinent map(s) visually showing the areal extent of exemption boundary, depth and thickness of the aquifer proposed for exemption, all known subsurface structures such as faults affecting the aquifer, and each of the inventoried water well locations by well # or owner name.
- *Include*: Table of all inventoried water wells showing: Well Name/#, Owner, (Private/Public), Contact information, Purpose of well (Domestic, Irrigation, Livestock, etc.), depth of source water, name of aquifer, well completion data, age of well (if known), and the primary source of well data (Applicant/State/Tribe/EPA).
- *Include*: Map showing the areal extent of exemption boundary, all domestic water wells considered potentially down gradient of the exemption and hydraulically connected to the exemption. If wells are deemed horizontally and/or vertically isolated from the exemption, this should be foot noted on the Table as well. Use arrow(s) to indicate the direction and speed of GW in the aquifer proposed for exemption.

- Describe the evidence presented in the application and/or methodology used to conclude GW direction and speed when relevant.
- *Include*: any source water assessment and/or protection areas and designated sole source aquifers located within the delineated area.

What is the appropriate area to examine for drinking water wells? Although guidance 34 says it should be a minimum of 1/4 mile, the determination of the appropriate area is on a case by case basis. Describe area and give a rationale.

Are there any public or private drinking water wells or springs capturing (or that will be capturing) or producing drinking water from the aquifer or portion thereof within the proposed exemption area? Y/N*

- Evaluate the capture zone of the well (s) in the area near the proposed project (i.e., the volume of the aquifer(s) or portion(s) thereof from within which groundwater is expected to be captured by that well).
- A drinking water well's current source of water is the volume (or portion) of an aquifer which contains water that will be produced by a well in its lifetime. What parameters were considered to determine the lifetime of the well?

_____

- (*) If the answer to this question is Yes, therefore the aquifer currently serves as a source of drinking water.

2- Demonstration that the aquifer or portion thereof is mineral, hydrocarbon or geothermal energy producing per 146.4(b)(1)

Did the permit applicant for a Class II or III operation demonstrate as part of the permit application that the aquifer or portion thereof contains minerals or hydrocarbons that, considering their quantity and location are expected to be commercially producible? Did the permit applicant furnish the data necessary to make the demonstration as required by 40 C.F.R. 144.7(c)(1) and (2)? Summarize this demonstration and data _____

- Include narrative statement, logs, maps, data and state issued permit.
- If the proposed exemption is to allow a Class II enhanced oil recovery well operation in a field or project containing aquifers from which hydrocarbon were previously produced, commercial producibility shall be presumed by the Director upon a demonstration of historical production having occurred in the project area or field. Many times it may be necessary to slightly expand an existing Class II operation to recover hydrocarbons and an aquifer exemption for the expanded area may be needed. If the expanded exemption for the Class II EOR well is for a well field or project area where hydrocarbons were previously produced, commercial producibility would be presumed.
- For new or existing Class II wells not located in a field or project containing aquifers from which hydrocarbons were previously produced, information such as logs, core data, formation description, formation depth, formation thickness and formation parameters such as permeability or porosity shall be considered by the Director, to the extent available.
- Many Class II injection well permit applicants may consider much information concerning production potential to be proprietary. As a matter of policy, some states/tribes do not allow any information submitted as part of a permit application to be confidential. In those cases where potential production information is not being submitted, EPA would need some record basis for concluding that the permit application demonstrates that the aquifer contains commercially producible minerals or hydrocarbons. For example, the permit application may include the results of any R & D pilot project. In this case, the applicant should state the reasons for believing that there are commercially producible quantities of minerals within the expanded area. Also, exemptions relating to new or existing Class II wells not located in a field or project containing aquifers from which hydrocarbons were previously produced should include the following types of information:
  - a- Production history of the well if it is a former production well which is being converted.
  - b- Description of any drill stem tests run on the horizon in question. This should include information on the amount of oil and water produced during the test
  - c- Production history of other wells in the vicinity which produce from the horizon in question.
  - d- Description of the project, if it is an enhanced recovery operation including the number of wells and there location.

For Class III wells, the Director must require an applicant to furnish data necessary to demonstrate that the aquifer is expected to be mineral or hydrocarbon producing and the Director must consider information contained in the mining plan for the proposed project, such as a map and general description of the mining zone, general information on the mineralogy and geochemistry of the mining zone, analysis of the amenability of the mining zone to the proposed mining

method, and a time-table of planned development of the mining zone. Information to be provided may also include: a summary of logging which indicates that commercially producible quantities of minerals or hydrocarbons are present.

3- Demonstration that the aquifer or portion thereof is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical per 146.4(b)(2)

Is the aquifer or portion thereof situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical? _____

- List evidence in the application showing how this demonstration was made.
- EPA consideration of an aquifer exemption request under this provision would include information related to: The availability of less costly and more readily available alternative supplies, the adequacy of alternatives to meet present and future needs, and costs for treatment (including cost of disposal of treatment residuals) and or development associated with the use of the aquifer.
- The economic evaluation, submitted by the applicant, should consider the above factors, and these that follow:

1. Distance from the proposed exempted aquifer to public water supplies.
2. Current sources of water supply for potential users of the proposed exempted aquifer.
3. Availability, quantity and quality of alternative water supply sources.
4. Analysis of future water supply needs within the general area.
5. Depth of proposed exempted aquifer.
6. Quality of the water in the proposed exempted aquifer.

4- Demonstration that the aquifer or portion thereof is too contaminated per 146.4(b)(3)

Is the aquifer or portion thereof proposed for exemption so contaminated that it would be economically or technologically impractical to render that water fit for human consumption _____

- List evidence in the application showing that the area to be exempted is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.
- Economic considerations would also weigh heavily in EPA's decision on aquifer exemption requests under this section. Unlike the previous section, the economics involved are controlled by the cost of technology to render water fit for human consumption. Treatment methods can usually be found to render water potable. However, costs of that treatment may often be prohibitive either in absolute terms or compared to the cost to develop alternative water supplies.
- EPA's evaluation of aquifer exemption requests under this section will consider the following information submitted by the applicant:

(a) Concentrations, types, and source of contaminants in the aquifer.
(b) If contamination is a result of a release, whether contamination source has been abated.
(c) Extent of contaminated area.
(d) Probability that the contaminant plume will pass through the proposed exempted area.
(e) Ability of treatment to remove contaminants from ground water.
(f) Current and alternative water supplies in the area.
(g) Costs to develop current and future water supplies, cost to develop water supply from proposed exempted aquifer. This should include well construction costs, transportation costs, water treatment costs, etc.
(h) Projections on future use of the proposed aquifer.

5- Demonstration that the aquifer or portion thereof is located over a Class III well mining area subject to subsidence or catastrophic collapse per 146.4(b)(4)

Is the aquifer or portion thereof proposed for exemption located over a Class III well mining area subject to subsidence or catastrophic collapse?

- List evidence in the application showing that the area to be exempted is located over a Class III well mining area subject to subsidence or catastrophic collapse_____

- Discuss the mining method and why that method necessarily causes subsidence or catastrophic collapse. The possibility that non-exempted underground sources of drinking would be contaminated due to the collapse should also be addressed in the application.

6- Demonstration that the aquifer or portion thereof has TDS more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system per 146.4(c)

Is the TDS of the aquifer or portion thereof proposed for exemption more than 3,000 and less than 10,000 mg/l?_____

Is the aquifer proposed for exemption or portion thereof not reasonably expected to supply a public water system?____

- Identify and discuss the information on which the determination that the total dissolved solids content of the ground water in the proposed exemption is more than 3,000 and less than 10,000 mg/l and the aquifer is not reasonably expected to supply a public water system.
- Include information about the quality and availability of water from the aquifer proposed for exemption. Also, the exemption request must analyze the potential for public water supply use of the aquifer. This may include: a description of current sources of public water supply in the area, a discussion of the adequacy of current water supply sources to supply future needs, population projections, economy, future technology, and a discussion of other available water supply sources within the area.

7- Demonstration that a Class II aquifer exemption may be expanded to Class VI per 146.4(d) *(Refer to additional requirements in EPA's regulations for Class VI aquifer exemptions for this demonstration)*

May the areal extent of an aquifer exemption for a Class II enhanced oil recovery or enhanced gas recovery well be expanded for the exclusive purpose of Class VI injection for geologic sequestration under § 144.7(d)? _____

- List evidence in the application showing an existing Class II operation associated with AE that is being converted into Class VI_____

DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

February 6, 2015

Ms. Jane Diamond
Director, Water Division
Region IX
United States Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105-3901

Re: Class II Oil and Gas Underground Injection Control

Dear Ms. Diamond:

Thank you for your letter of December 22, 2014, regarding the several meetings and dialogue we have been engaging in for the past several months, and your request for a more detailed plan of action to address issues with California's Class II Oil and Gas Underground Injection Control program.

Our agencies share a common goal with the United States Environmental Protection Agency (US EPA): to ensure public health and safety and the protection of groundwater resources for California residents who live and work near oil producing areas of California. The Division of Oil, Gas, and Geothermal Resources (Division) is responsible for ensuring that operators of oil and gas injection wells adhere to environmental rules and permit requirements that protect groundwater and other resources. The State Water Resources Control Board (State Water Board) assists the Division with the protection of water resources. Consistent with our mutual roles related to ongoing injection activities, the Division and the State Water Board are working closely together for more integrated oversight of the underground injection control program.

Following a discussion of the relevant background, we lay out the intended approach jointly developed by the Division and the State Water Board to address what has been the primary focus of our discussions since last summer: details about the review and, where necessary, redirection of underground injection operations in this State. We then address your request for detail on our intended plan to meet the critique expressed in the 2011 report of the Horsley Witten Group (Horsley Witten). Finally, we conclude with a discussion of plans to communicate these developments to the public.

BACKGROUND

Oil and gas production in California is a $34 billion annual industry, employing more than 25,000 people with an annual payroll of over $1.5 billion. California is the third largest oil-producing state in the nation, producing about 575,000 barrels per day. Property and other tax payments to the State and local governments from the industry amount to about $800 million annually. There are approximately 90,000 active or idle production and injection wells in the State.

Injection wells have been an integral part of California's oil and gas operations for more than 50 years. Currently, over 50,000 oilfield injection wells are operating in the State. Injection wells are used to increase oil recovery and to safely dispose of fluid produced with oil and natural gas. About 75 percent of California's oil production is the result of Enhanced Oil Recovery (EOR) methods such as steam flood, cyclic steam, water flood, and natural gas injection. Of these injection wells subject to UIC regulations, approximately 1,500 are fluid disposal wells, which are necessary to re-inject water produced with oil and gas and other fluids that cannot be disposed of through any other method, such as treatment, beneficial use, or recycling for other industrial applications. Most of the oil and gas fields in the State are quite mature. Many are in the waning stages of their productive cycle and require EOR techniques for continued development. The use of injection wells has been increasing in recent years. The increased use of injection potentially creates additional health and safety risks.

The protection of California's aquifers from contamination is a matter of the highest priority for the Division and the State Water Board, and of special importance given the state of emergency resulting from our unprecedented drought. Therefore, this effort to modernize the regulation of the State's injection wells must be both urgent and thorough. As explained more fully below, the Division has begun systematically reviewing these wells and applicable regulations as part of its mandate to protect public health and safety.

2011 Audit and Horsley Witten Report

In 2010, the Division worked with US EPA to conduct an audit to review the Division's practices and regulations, and ensure the Division's compliance with its obligations to properly administer its Class II injection program as a primacy state under the US Safe Drinking Water Act (SDWA) and applicable California law. The audit, conducted by the Horsley Witten Group, was completed in the summer of 2011. Horsley Witten highlighted several areas of concern, and the US EPA requested a plan to address the gaps identified. The Division responded in November 2012 (Enclosure A) by committing to adopt regulations and provide additional resources to close the gaps identified in the audit and create a stronger, more robust regulatory program.

In 2013, the Department took important steps toward meeting this commitment, including:

- Added 36 staff positions and enhanced staff training on UIC Program mandates and requirements
- Added resources to address orphan well plugging and abandonment
- Worked with the Legislature to help it enact revisions for the financial requirements for bonding
- Established a Division monitoring and compliance unit to conduct internal assessment of the UIC Program

Injection Project Review and Aquifer Exemptions

The Division acknowledges that in the past it has approved UIC projects in zones with aquifers lacking exemptions. The Division has not kept up with the task of applying for the necessary aquifer exemptions in hydrocarbon-bearing zones required by statute, even though many of these zones possess attributes that would qualify them for exemption. The Division has thus been slow to reconcile the reality that industry has expanded the productive limits of oil fields established in the 1982 primacy agreement with SDWA requirements to obtain aquifer exemptions.

Complicating matters, 11 aquifers with historical injection activities before 1982 were described in State documents in the early 1980s as proposed for exemption, and were endorsed as exempt in subsequent federal documents.[1] This led to the issuance of a number of injection permits in those 11 aquifers. However, the geologic basis for such exemptions is now in question. Therefore, in addition to the zones of aquifers that are lacking exemptions, these 11 aquifers that have historically been treated as exempt will also be evaluated to determine their appropriate exemption status.

Injection Project Review Process

The Division acknowledges injection project review continues, and a process has been developed to determine the wells with the highest risks associated with injection, and the steps to be taken to bring injection well permits into compliance with the primacy agreement with US EPA. This review examines the following groups of wells, in this order:

[1] Among these documents are (1) a December 13, 1982, Region IX memo forwarding to US EPA headquarters a version of the Memorandum of Agreement containing no significant exemption denials, described by Region IX as resolving "all known issues" with California's primacy application, and (2) a May 17, 1985, letter from Frank Covington, US EPA's then-Director of the Water Management Division for Region IX that appears to confirm that US EPA did not deny any of the exemptions proposed by the Division in its primacy application.

Category 1 Wells: Class II water disposal wells injecting into non-exempt, non-hydrocarbon-bearing aquifers or the 11 aquifers historically treated as exempt

Category 2 Wells: Class II enhanced oil recovery (EOR) wells injecting into non-exempt, hydrocarbon-bearing aquifers

Category 3 Wells: Class II water disposal and EOR wells that are inside the surface boundaries of exempted aquifers, but that may nevertheless be injecting into a zone not exempted in the primacy agreement

This review covers over 30,000 wells, more than 29,000 of which are cyclic steam wells in hydrocarbon zones. Review of wells in Category 1 is nearing completion. Review of wells in Categories 2 and 3 is expected to be complete in early 2016 as annual project reviews are completed in compliance with regulation. When completed, this review will serve to clarify records and improve data quality so that the full review of the UIC program can be completed.

An initial list of wells injecting into non-exempt USDW aquifers was previously provided to US EPA. That list includes Category I and II wells. While updating, reviewing, and validating that list is ongoing, attached (Enclosure B) is a summary of the information. Of the 2,553 wells on the list, approximately 140 of the active wells have been tabbed for immediate review by the State Water Board because the aquifers are reported to be lacking hydrocarbons and contain water with less than 3,000 mg/l total dissolved solids (TDS). The State Water Board is currently reviewing those wells to screen for proximity to water supply wells or any other indication of risk of impact to drinking water and other beneficial uses.

The Division review and updating of all injection well records in this list will be completed by May 15, 2015. The State Water Board expects to be able to review each injection well at a rate of approximately 150 wells per month.

Aquifer Exemptions Process

Together, the Division and the State Water Board have identified a process for aquifer status evaluation and potential aquifer exemptions. Although injection is occurring into aquifers that have not been exempted and the 11 aquifers historically treated as exempt, the potential risks associated with such injection differ from zone to zone. Last summer, as you know, some injection wells that potentially presented health or environmental risks were ordered to cease injection, and the operators ordered to provide specific data so that the regulatory agencies could fully evaluate whether these

wells could potentially have had any measurable impact on nearby water supply wells. To date, the analytical data from the water supply wells that the State ordered to be tested have not shown any contamination of the water supply wells by oil and gas injection activities.

As injection activities in non-exempt aquifers and the 11 aquifers historically treated as exempt are delineated and described, the Division will require relevant oil and gas operators to obtain and prepare the necessary supporting documentation to justify aquifer exemptions. If these data support an aquifer exemption proposal, the Division will prepare and submit draft proposals for aquifer exemptions to the State Water Board for their concurrence. Once both agencies are satisfied with the proposed exemption and justification, the Division will submit the aquifer exemption applications to the US EPA for approval. A more detailed statement of the Division's and State Water Board's process for development of aquifer exemption applications is described in Enclosure C.

Going forward, the Division will take the following steps in this general order:

1. Work with US EPA to clearly articulate to the public the requirements for aquifer exemptions. This will be undertaken via two US EPA-sponsored workshops, one in Bakersfield the last week of February 2015 and the second in Los Angeles the last week of March 2015. The purpose of these workshops is to inform interested stakeholders, of the kind of data and data analysis essential to the development of a robust application by the State for an exemption of a portion of an aquifer from the SDWA by the US EPA.

2. Delineate a clear process for operators to supply the required supporting data to support and justify an aquifer exemption application. The Division will prepare its own guidance document to facilitate receiving appropriate information and data from operators to prepare justifiable aquifer exemption applications. A guidance document should be available by April 1, 2015.

Although this timeline suggests that the Division may not be able to move forward with aquifer exemptions until after April 1, 2015, this is not necessarily the case. The Division has already been evaluating the data supplied by operators for the preparation of a number of aquifer exemption requests by the State. Moreover, to enhance efficiency and reduce duplication of efforts, the Division is instructing oil and gas operators to develop a process by which several adjacent operators can combine data so that portions of aquifers relevant to the operations of different operators can be considered as a whole.

The Division will provide the data and an analysis of the data to the State Water Board for consultation prior to submitting them to US EPA. The Division will submit the exemption request to US EPA if the portion of the aquifer meets the criteria for exemption and the State Water Board determines that injection into the aquifer will not adversely affect existing or potential beneficial uses of groundwater.

Wind-Down of Existing Injection and Permitting of New Injection

The Division proposes to use a combination of administrative mechanisms to ensure that existing and new injection into non-exempt aquifers and the 11 aquifers historically treated as exempt is either phased out or covered by an aquifer exemption, and that any threats to drinking water or other beneficial uses of water are urgently addressed.

To summarize, the Division will use rulemaking to codify a wind-down schedule that provides transparency to the regulated community and the public at large. The schedule will provide for the phased elimination of new and existing injection into aquifers that have not been approved as exempt by the US EPA by February 15, 2017. New injection will be allowed only if strict criteria are met, and, like existing injection, will have to cease if no new exemption has been timely obtained. At the same time, the Division, in consultation with the State Water Board, will issue administrative orders to address specific circumstances where injection poses a threat to drinking water or other beneficial uses of water. Major highlights of the approach to address existing injection and new injection into these aquifers are presented below. A more detailed and complete description of the approach is contained in Enclosure D.

Rulemaking

By April 1, 2015, the Division will initiate rulemaking to establish a regulatory-compliance schedule to eliminate Class II injection into undisputedly non-exempt aquifers statewide. The proposed regulations will require the following:

1. The first principle of the regulations will be that all Class II injection into non-exempt aquifers with less than 10,000 TDS must, in all cases, cease by February 15, 2017, unless and until an aquifer exemption has been duly approved by US EPA. Injection may be ordered to cease earlier if a well is determined to potentially impact water supply wells,[2] as discussed further, below. ("Administrative Orders.")

[2] Injection wells potentially impacting water supply wells include injection wells into aquifers with 3,000 TDS or less that meet either of the following criteria: (1) the uppermost depth of the injection zone is less than 1,500 feet below ground surface (regardless of whether any existing supply wells are in the vicinity of the injection well), or (2) the injection depth is within 500 feet vertically and 1 mile horizontally of the screened portion of any existing water supply well.

2. Where a non-exempt aquifer contains 3,000 TDS or less and is non-hydrocarbon producing, injection must cease by October 15, 2015, unless and until an aquifer exemption has been approved by US EPA.

3. Where a non-exempt aquifer is hydrocarbon producing, new wells that are part of a previously approved project may be permitted if groundwater in the vicinity of the hydrocarbon-bearing zone does not currently have any beneficial use.[3] Such approvals will include the express condition that the permit expires on February 15, 2017, unless US EPA approves an aquifer exemption before then.

4. With respect to the 11 aquifers historically treated as exempt, the State Water Board and the Division will work with US EPA to evaluate these 11 aquifers. If any portion of these aquifers meets the criteria for exemption and the State Water Board determines that injection into the aquifer will not adversely affect existing or potential beneficial uses of groundwater, the Division will prepare and submit an exemption evaluation to US EPA. The evaluation and subsequent decision for these 11 aquifers will be completed by February 15, 2017. Either by the planned regulation or by other appropriate means, the Division may allow for limited new injection into these 11 aquifers in the unusual case where the proposed injection well is part of an approved project and an initial screening of the target zone shows that the zone contains hydrocarbons, has very high levels of naturally-occurring constituents (e.g., arsenic or boron), or there are other factors that make any affected groundwater unsuitable for beneficial use. Finally, the regulation would provide that any approval is subject to evaluation of the appropriate exemption status of the aquifer.

Administrative Orders

During the process of codifying the compliance schedule to phase out injection into non-exempt aquifers, the Division will issue administrative orders to halt any injection that potentially impacts water supply wells. The Division and the State Water Board are presently evaluating all injection into non-exempt USDWs and the 11 aquifers historically treated as exempt to identify potential for such impacts. The evaluation includes screening for water wells in the area of the injection well and collection and review of data regarding the water quality and depth of the aquifer where injection is occurring. Where the evaluation indicates that an injection well potentially impacts

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[3] Note that this does NOT include any use of produced water.

water supply wells, the Division will issue an emergency order to the operator to cease injecting immediately.

Issues Identified in the Horsley Witten Report

The Class II UIC Program is complex, consisting of several components that have distinct attributes and therefore require focused sets of regulations, compliance approaches, and review requirements. Given the rapid evolution of technologies and industry practices to extract more oil and gas from the State's mature fields, regulations developed even a decade ago may not fully address all of the issues created by what is now routine industry practice.

Horsley Witten included several recommendations pertaining to the practices, processes and policies of the Division used to implement the State's oil and gas regulations (Enclosure C). Report recommendations address a wide range of the Division's practices, activities and regulations, either directly or indirectly, in these areas:

- The definition and protection of underground sources of drinking water (USDW) area of review (AOR) and zone of endangering influence (ZEI)
- Well construction and cementing requirements
- Plugging and abandoning requirements
- Requirements for fluid disposal
- Requirements for monitoring of zone pressure
- Annual project reviews
- Well monitoring requirements
- Idle-well planning and testing program
- Financial responsibility requirements
- Cyclic steam injection wells
- Production from diatomite

Regulation Development

Many aspects of the recommendations of the Horsley Witten report can be implemented through existing Division regulations. However, others will require new regulation. Moreover, though cyclic steam injection wells and techniques employed for oil production in diatomite formations were not specifically addressed in the Horsley Witten report, they are extensively used in California, and existing regulations in these areas can be improved.

The Division has not had significant changes to its UIC regulations since the original primacy application. Regulatory amendments will be pursued through a rulemaking process to address these needs. The Division's goal is to ensure its regulations:

- Protect public health, the environment, and resources
- Address the UIC program mandates
- Address industry practices now and into the foreseeable future
- Are developed with the public participation contemplated by statute
- Set predictable standards for the regulated community
- Are implemented and enforced properly

These regulations will be quite extensive and will take some time to develop. The Division anticipates scheduling workshops, public meetings and other outreach to discuss regulations to cover a range of topics. The workshops should include at least the following: US EPA, State Water Board, Regional Water Quality Control Boards, Department of Toxic Substances Control, Air Resources Board, oil and gas operators, county and city agencies, non-government organizations, and the general public.

Potential Areas for New and Modified Regulations

We envision that a thorough review of the UIC program, the necessary attendant revision of existing regulations, and the development of needed new regulatory measures will require a period of approximately three years. The areas in which the Division is contemplating new or modified regulations include:

- Well construction and cementing requirements
- Plugging and abandoning requirements
- Evaluation of the zone of endangering influence (ZEI)
- Requirements for fluid disposal
- Requirements for monitoring of zone pressure
- Annual project reviews
- Well monitoring requirements
- Inspections and compliance/enforcement practices and tools
- Idle-well planning and testing program
- Cyclic steam injection wells
- Production from diatomite

Exclusive of proposed program revisions and aquifer exemption, the following milestones need to be met:

- Review of each and all current UIC projects for completeness of records and development of a list of deficiencies.
- Meetings with operators to review records and project deficiencies, and develop a compliance schedule (exclusive of aquifer exemptions).
- Initiate and complete rulemaking as a comprehensive package.

The Division will prepare a more detailed work plan for UIC rulemaking by April 15, 2015.

Searchable Database for Class II Wells

Activities to review UIC projects, check and revise data on all injection wells, and the development of aquifer exemption applications will all drive improvement in the Division's data that in turn will drive the need for vastly improved data management systems.

The Division's data management systems need significant upgrades. In response to the demands created by the requirements of the well stimulation program as a result of Senate Bill 4, the Division has hired additional GIS staff whose combined capabilities will be sufficient to manage all of the Division's needs. However, other aspects of the data management problem will be more difficult to resolve and will be conducted continuously in the background as project reviews, well reviews, and aquifer exemption information are compiled in a GIS environment.

You asked for a forecast of when the Division might be able to have a fully searchable database of injection wells available. Unfortunately, we cannot respond with specificity to this request due to inadequacies in the data management environment itself, and current lack of financial resources needed to create an adequate environment. The Division is, however, strongly committed to this effort and will follow up with US EPA when we can provide a more definitive answer.

The Division has created a team to develop a Feasibility Study Report (FSR) that will consider the Division's current and future requirements for data management and the kind of data environment that is needed for the Division to serve all stakeholders far more efficiently and effectively in the future. The FSR is a fundamental first step in the State's IT-procurement process and will be completed in December 2015. An approved

FSR will lead to a budget change proposal to seek the funds needed for system development.

Communication Plans

The closure of injection wells in Kern County during the summer of 2014, has required focused attention to communication with key stakeholder groups. These include industry, environmental organizations, elected officials – especially the state and federal elected representatives – the press, and via the press, the public.

The Division and the State Water Board have responded to a large number of stakeholder and public inquiries, and, to enhance public awareness, have developed frequently asked questions, statements, and presentations delivered at numerous public fora.

In short, much preparatory work has been accomplished. However we will continue to build on this communications foundation with additional attention to meet growing inquiries. We take seriously our responsibility to address growing public concern and press inquiries in a timely and informative manner.

Communication and outreach can be amplified by providing regularly updated information on the UIC program, background documents and reports, frequently asked questions, and work status on priority items noted above, specifically aquifer exemption applications, all clearly linked on the Division's web page. This page will serve as a clearinghouse for information on program activities, items of interest to stakeholders, and meeting and other notifications.

The Division and the State Water Board will continue to meet regularly with industry, environmental and other non-governmental organizations, elected officials, as well as US EPA.

CONCLUSION

The severe drought emergency, new regulations for well stimulation with ground water monitoring and other requirements, as well as long overdue revisions to the UIC program, have fundamentally changed how the Division and the State Water Board work together to protect public health and ensure the security of the State's

groundwater resources. We are committed to making this relationship effective so that the State can achieve full compliance with the SWDA, and we are committed to revising the UIC program efficiently, and with public safety as a first priority. We look forward to continuing our active dialog with you and to advancing our Federal-State partnership.

Sincerely,

Steve Bohlen
State Oil and Gas Supervisor

Sincerely,

Jonathan Bishop
Chief Deputy Director

Attachments

cc: Cliff Rechtschaffen, Governor's Office
John Laird, Natural Resources Agency
Matthew Rodriquez, CalEPA

Enclosure A: Division's November 16, 2012 Response to Report of Horsley Witten Group

DEPARTMENT OF CONSERVATION

Managing California's Working Lands

DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

801 K STREET • MS 20-20 • SACRAMENTO, CALIFORNIA 95814

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November 16, 2012

David Albright, Manager
Ground Water Office
United States Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105-3901

Dear Mr. Albright:

The Division of Oil, Gas, and Geothermal Resources (Division) has reviewed the California Class II UIC Program Review report, prepared by Horsley Witten Group, Inc. (the Horsley Report), and has developed a plan to address the concerns and recommendations referenced in the report. As we have previously discussed, the Division began to evaluate its Underground Injection Control (UIC) program in 2009 with the hopes of bringing the program into conformance with state laws and regulations. Although we have improved our UIC program, and continue to evaluate it, the Division is aware that more work is required.

In your letter dated July 18, 2011, US EPA requested an action plan that includes clarification, improved procedures, and consistent standardized implementation in several areas, including:

- UIC staff qualifications;
- annual project reviews;
- mechanical integrity surveys and testing;
- inspections and compliance/enforcement practices and tools;
- idle well planning and testing program;
- financial responsibility requirements; and
- plugging and abandonment requirements.

Attached, please find the Division's plan to address the concerns of the US EPA and to identify those areas where the Division can improve its UIC program to more fully advance the objectives of the Safe Drinking Water Act. The Division views this action plan as a living document, which can be updated to incorporate any additional needed changes.

The Division looks forward to continuing our long-standing partnership with US EPA in protecting California's water resources. This plan will provide guidance as we update our UIC Program. We welcome your feedback and discussions regarding the elements in this action plan.

Sincerely,

Tim Kustic
State Oil and Gas Supervisor

cc: Mark Nechodom, Director, Department of Conservation
Rob Habel, Chief Deputy
Dan Wermiel, Technical Program Manager
Jerry Salera, UIC Program Manager

Department of Conservation
Division of Oil, Gas, and Geothermal Resources

Underground Injection Control Action Plan

RESPONSE TO THE US EPA JUNE 2011 REVIEW OF CALIFORNIA'S UIC PROGRAM

Background and Introduction

The EPA approved the Division of Oil, Gas, and Geothermal Resources' (Division, or DOGGR) application for primacy in the regulation of Class II injection wells under section 1425 of the Safe Drinking Water Act in March 1983. This approval gave the Division primary responsibility and authority over all Class II injection wells in the State of California. The EPA remains a Division regulatory partner with Division oversight authority and separate enforcement authority for Class II well operators. Class II wells inject fluids associated with oil and natural gas production.

The Division is fully committed to implementing a strong Underground Injection Control (UIC) program and will continue to pursue additional resources to address program growth and/or UIC well count increases.

This Action Plan is in response to a review of California's UIC program, requested by EPA's Region Nine Ground Water Office, and performed by the Horsley Witten Group. The Horsley Report, March 2011 (Report) was submitted to EPA in June 2011, and forwarded to the Division on July 18, 2011.

The Report included several recommendations pertaining to the practices, processes and policies of the Division used to implement the State's oil and gas regulations. To address a number of Report recommendations and other needed UIC regulatory updates, the Division will begin a rulemaking in 2013 to update the UIC program, well construction, and plugging and abandonment regulations. Additionally, the Division will determine whether statutory changes are needed and work with the California Legislature as necessary.

It is important to note the Division has added 43 staff positions during the past three years; these staff are working in UIC program or other closely related programs. Additionally, the Division implemented an internal review processes such as audits and mandatory Headquarters technical reviews to ensure greater compliance with UIC mandates.

The Division has followed the Report's format in this Action Plan and responded to each recommendation as presented in the Report. Each recommendation is presented in summary form below in bulleted paragraphs using italicized text.

USDW DEFINITION AND PROTECTION

- *The DOGGR Class II UIC Program should address the lack of clarity regarding USDW protection and ensure that all USDWs are fully protected from fluid movement and resulting degradation. USDWs containing more than 3,000 mg/l TDS should be protected as much as fresh water aquifers are protected in the permitting, construction, operation, and abandonment of injection wells.*

The Division's UIC program protects underground sources of drinking water (USDW) and requires that all injection is confined to the approved zone of injection. When the injection fluid is confined to the intended zone, all other zones and waters are protected.

Sections 3220 and 3228 of the California Public Resources Code (PRC) require zonal isolation. These standards have been followed for setting casing in, and plugging and abandonment of, all wells, including injection wells. Since these statutes predate the Safe Drinking Water Act, the USDW term is not found in state law.

During the rulemaking process to begin in 2013, the Division will pursue, as necessary, additional plugging and cementing requirements to increase USDW protection.

AREA OF REVIEW / ZONE OF ENDANGERING INFLUENCE

These recommendations address area of review/zone of endangering influence (AOR/ZEI) determinations, well construction practices and the status of wells located within the AOR, and corrective action requirements.

AOR/ZEI Determinations

- *The ZEI should be calculated, especially for disposal wells, with an accurate representation or reasonable estimate of all the relevant parameters that determine the ZEI, including the static pressures of the injection zone and USDWs in the project area.*
- *Disposal into non-hydrocarbon zones and normally* [sic] *pressure hydrocarbon bearing zones should be carefully monitored for reservoir pressure increases beyond normal hydrostatic pressures that could cause the ZEI to increase beyond the AOR over time.*
- *A fall-off pressure test should be run to determine the static reservoir pressure in wells in which shut-in pressures do not fall to zero after an*

extended shut-in period. If not done, the permit to inject should be rescinded.

- *The ZEI calculations should be reviewed if fall-off test results indicate higher than normal hydrostatic pressure in the injection zone. If the original AOR is smaller than the ZEI, the AOR should be expanded, or the permit to inject should be rescinded.*

Well Construction Practices and Status of Wells Located within the AOR

- *When casing repairs occur or when wells are plugged and abandoned, cement placement should be required at the base of USDWs in injection wells and AOR wells.*
- *Unless USDWs are known to be absent in the area, new injection wells should be required to have long string casing cemented to the surface.*

As outlined in our Primacy Application (ftp://ftp.consrv.ca.gov/pub/oil/publications/safe_water.pdf), the Division utilizes the one-quarter (1/4) mile fixed radius; if appropriate data is available, a radial flow equation may also be used to determine the ZEI. Although the Division has typically utilized the one-quarter mile fixed radius, we are now using other methods, such as Bernard's equation, the modified Theis equation, and equations included in the EPA's publication *Radius of Pressure Influence of Injection* (EPA-066/2-79-170) to determine the ZEI. The Division is pursuing new requirements for waste fluid disposal wells, and will consider including a more in-depth evaluation of the ZEI.

The Division is concerned with any injection well where injection zone pressure exceeds hydrostatic pressure. This may indicate an over-pressurized injection zone and a greater threat of non-confinement. In these cases, the Division looks at the ZEI and evaluates all wellbores within the ZEI to ensure fluid confinement to the intended zone of injection. In addition to the AOR, the Division requires mechanical integrity testing of all injection wells on a periodic basis. If a well lacks mechanical integrity, the Division requires the operator to immediately cease injection and to repair the well.

As for well construction requirements, the Division's long-standing requirements set by regulation dictate isolation of all oil and gas zones and any underground or surface water suitable for irrigation or domestic purposes. This is accomplished by requiring the cementing of casing and the placement of cement plugs. In addition, when wells are plugged and abandoned, the Division requires the use of heavy drilling mud in those portions of the hole that do not have cement. All these requirements will be evaluated for adequacy and updated as necessary in the rulemaking to

begin in 2013 to ensure UIC program requirements are adequate for USDW protection.

DIVISION ANNUAL PROJECT REVIEW

- *This recommendation addresses records of well activity, pressures, inactive well and noncompliance data associated with injection well projects. Comprehensive project reviews should be conducted annually for all active injection well projects, including meetings with the operators for the most critical projects.*

The Division is fully committed to comprehensive project reviews. There are now two processes in place to address this concern -- a project audit, and an annual project review.

The Division has acquired additional staff who will audit injection projects to ensure that the projects are:

- permitted in accordance with state mandates;
- continued in compliance with mandates and approvals; and
- monitored and tested to ensure that fluid is injected into the intended zone.

This practice is authorized by the broad protection mandates of PRC section 3106 (a).

Additionally, the Division has increased UIC staff to ensure an annual project review for all injection projects. This amounts to a review of District office project data, and when necessary, a corresponding request that operators submit any missing data. Division staff will also meet with operators to discuss injection project operations to ensure that projects are operating in accordance with their project applications and approvals.

MONITORING PROGRAM

These monitoring program recommendations address mechanical integrity tests (MIT) and maximum allowable surface pressure (MASP).

Mechanical Integrity Tests

- *SAPT pressures equal to the maximum allowable surface injection pressure should be required if it will not cause damage to the casing. The newer wells should be able to withstand the MASP.*
- *If tested at less than the MASP, more frequent SAPTs and monitoring/reporting for anomalous pressure on the annulus should be required.*
- *Static temperature logs should be required more often in slimhole/tubingless completions where USDWs are present and especially for USDWs that are protected by only one casing string and/or lack cement at the base of USDWs.*

- *Cement bond logs should be required in new and newly converted injection wells unless USDWs are known to be absent in the area.*
- *Static temperature logs should be required if an existing well lacks sufficient cement at the base of USDWs, and/or squeeze cementing should be considered at the USDW base to ensure isolation from fluid movement.*

Maximum Allowable Surface Injection Pressures

- *Injection pressure should be maintained below fracture pressure in all new and existing projects, as determined by approved SRTs.*
- *SRTs should be required in new wells to determine the fracture pressure of the injection zone unless the formation fracture gradient is known with acceptable confidence based on SRTs in nearby wells.*
- *A pressure gauge should be required to measure bottom-hole pressures in SRTs directly rather than relying on calculation of friction losses from surface pressure measurements and injection rates.*

The Division now mandates that the Standard Annular Pressure Test (SAPT) be performed either to the approved injection pressure or 200 psi, whichever is higher. The Division does not allow variance from this policy unless there is the potential to damage well casing.

Since continuous monitoring of the annular space has advantages over the once-every-5-years SAPT, the Division now allows a positive-pressure annulus monitoring system with regular reporting with a lower-pressure, 5-year SAPT. These two testing options verify annular integrity while providing flexibility to operators.

The Division agrees that if wells are completed by way of slimhole/tubingless completions, static temperature logs should be required more often than for traditional completions. Division staff is moving forward to develop a policy to address this issue; if additional regulations are necessary, the Division will include this item in the rulemaking to begin in 2013.

The Division's regulations require that injection pressure be maintained below the fracture pressure as determined by a Step Rate Test (SRT). The Division has implemented a new SRT policy, based largely on EPA's procedures, which require downhole pressure monitoring. These improvements, along with additional field inspection staff and upgrades to electronic data management systems, increase the Division's oversight of injection operations, particularly the injection pressure.

INSPECTIONS AND COMPLIANCE / ENFORCEMENT PRACTICES AND TOOLS

- *A high priority should be placed for inspection of wells in or near residential areas and where USDWs are present.*
- *Cement placement operations should be witnessed to ensure the correct volumes and quality of cement are pumped into a well.*
- *Witnessing RATs in enhanced recovery wells should be given a higher priority, especially where USDWs may be present. At least 25 percent of RATs and all SAPTs in wells where USDWs are present should be witnessed.*
- *Whenever possible, districts should avoid giving advance notice of routine inspections to operators.*
- *Copies of an inspection report should be provided to the operator whether or not deficiencies are found during inspections.*
- *The installation of a pressure gauge on the tubing and the casing/tubing annulus should be required as a permanent fixture on all injection wells.*
- *Wells that fail MITs should be repaired or plugged and abandoned within a set time period, preferably within six months or sooner depending on the nature of the leak and potential threat to USDWs.*

The Division has successfully pursued additional UIC field staffing resources to increase UIC oversight in all areas. Although the Division regulations do not distinguish between rural and urban injection wells, the Division does allocate additional resources to oil fields in highly urbanized areas.

The Division's additional UIC resources have increased its oversight of wells in direct relation to their priority. The Division places a higher priority on inspecting water disposal wells which can pose a greater risk of contaminating USDW and fresh water.

The Division requires the witnessing of cement plugging operations. The witnessing of the plugging operations continues to be one of the highest priorities for Division field staff. In the office, detailed reviews of well work histories by Division engineers determine whether plugging operations comply with State mandates. If not, remedial work is ordered. Additional staffing, along with increased training, is ensuring the Division is properly evaluating cementing operations.

The Division has a goal to witness at least 25% of the Mechanical Integrity Tests (MIT), with a higher emphasis on disposal wells. Once new UIC personnel are fully trained the Division intends to increase this percentage.

The Division has been evaluating the performance of cyclic steam wells, which should be tested at least once a year, or immediately if evidence of casing damage or failure is found. This testing requirement is supported by data showing that cyclic steam wells undergo more stress than other types of injection wells. The Division will address additional cyclic steam well testing in the rulemaking to begin in 2013.

When staff witness detailed tests, a report is provided to the operator. In addition to witnessing tests, the Division performs thousands of inspections a year without prior notice to the operators. Because of the volume of inspections, the Division only documents that an inspection was performed and what deficiencies were found. The list of deficiencies is included in a letter to the operator, which details what must be done and the timeframe to bring the operation into compliance.

The permanent installation of pressure gauges on UIC wells is not a current requirement. With technological advancements, capturing pressure data is non-burdensome to operators. In 2013 when the Division moves forward with updating its UIC regulations, pressure monitoring via a gauge or equivalent equipment will be pursued.

If the MIT should indicate a mechanical integrity issue, the well is required to be shut-in immediately. The Division does not allow injection until the well is repaired. If the well should become idle (i.e. no injection for six continuous months over a five-year period) the well previously fell under the Division's idle well program (IWP) only. The IWP, which includes fluid level and casing integrity testing, is designed to eliminate the potential threat caused by idle wells. In addition to IWP, the Division has changed processes to ensure idle injection wells remain within the UIC program to ensure UIC program testing is conducted. Since current regulations lack clarity on when a well is to be repaired or plugged and abandoned, the Division will pursue such clarity in the rulemaking to begin in 2013.

IDLE WELL PLANNING AND TESTING PROGRAM

- *The idle well management and testing guidelines at Section 138 in the MOI should be modified to clarify which provisions apply statewide and which apply only to District 4.*
- *Idle well fees and bond/escrow amounts should be reviewed and increased amounts to levels that would encourage operators to reactivate or plug idle wells.*
- *The testing program should be modified to base the fluid level survey pass/fail results on the rise of fluid to the base of USDWs rather than the BFW.*
- *SAPTs should be required in wells after two years of inactivity and every two years after that where USDWs are present.*

- *Regardless of the fluid level survey results, an SAPT should be required if USDWs are present in wells with tubing and packers installed.*
- *Bridge plugs or cement plugs above the injection and below the base of USDWs should be required where USDWs are present in wells lacking tubing and packers. In addition, wells should be required to successfully pass an SAPT to remain in idle status.*
- *Idle wells that fail the SAPT should be repaired or plugged and abandoned within six months in areas where USDWs are present or within 60 days if USDWs are at risk of potential fluid movement.*

The Division will revisit the Idle IWP through the legislative process with the intent to update the law to address the excessive number of idle wells. The solution will address the potential financial liability to the State, the obligations of owners, and intends to address all of the recommendations listed in the above. Although program implementation in the 1990s did result in a drop in the idle well count, the idle well count in recent years has stabilized or crept upward.

Since all wells within an AOR are evaluated for zonal isolation, idle wells are reviewed as part of the Division's UIC program. The Division's IWP is operated separately from the Division's UIC program. However, both programs share the common goal of resource protection.

FINANCIAL RESPONSIBILITY REQUIREMENTS

- *Bond amounts should be reviewed and updated periodically to cover current plugging and abandonment costs.*
- *The financial responsibility program should be modified to require bonds and other financial responsibility instruments be held until wells are plugged and abandoned.*
- *Operator funding requirements and the number of deserted wells plugged and abandoned should be increased to numbers that will significantly reduce the inventory of orphan/deserted wells each year.*

The current bonding amount requirements are specified in State statute passed by the legislature; these amounts are outdated and therefore insufficient. Additionally California oil and gas wells are not required to have life-of-the-well bonding. The Division is committed to working with the legislature, the oil and gas industry, and interested parties to bring bonding requirements up to reasonable standards.

To partially offset the financial liability to California's citizens from orphan wells, the legislature has provided the Division with funding for orphan well plugging and abandonments.

PLUGGING AND ABANDONMENT REQUIREMENTS

- *Cement plugs should be placed at the base of USDWS to ensure long-term protection from fluid movement into or between USDWs.*
- *The presence of a DIVISION inspector should be required during cement placement in P&A operations to monitor and ensure that adequate cement quality and adequate quantities are pumped into a well.*

The Division's mandates require resource protection. Because the Division's UIC program requires that the injected fluid remain confined to the intended zone and that all oil and gas zones are isolated, USDWs are protected from any harm caused by injection. These basic requirements have not changed since the Division was granted Class II primacy; however the Division will review them to determine if updates are necessary for USDW protection.

Division inspectors are present during well plugging operations. To address the volume of plugging operations, regulations require that Division staff witness either the plug placement or the plug tagging (location and hardness) to verify that the plugging operation was completed in accordance with State mandates.

UIC STAFF QUALIFICATIONS

- *UIC-specific training (e.g., EPA-sponsored UIC Inspector Training Course) should be provided to new and recent hires in the DIVISION UIC Program within one year of employment.*
- *Inspectors should be required to hold a petroleum engineering or geology bachelor's degree or related degree or equivalent college courses and relevant experience.*
- *Consideration should be taken to adjusting compensation and benefits for UIC professional positions to levels more consistent with the oil and gas industry.*

The work required from Division staff is based on geology and petroleum engineering, and the Division is taking steps to ensure that the most qualified individuals are hired and promoted.

In the UIC program, knowledge of geology and petroleum engineering are critical. In addition to the knowledge acquired through formal education, the Division is seeking individuals with experience relevant to the duties they will be performing.

The Division is assessing existing staff to identify weaknesses and is providing training to ensure that staff is knowledgeable in critical areas. In cases where staff lack the appropriate education, their job duties will be limited until they gain the necessary knowledge and skill sets.

The Division operates within the State's civil service compensation mandates. Salaries are negotiated with established bargaining units. The Division has interest in ensuring that compensation mandates meet our needs and will work with the administration to achieve our goals.

GENERAL AND DISTRICT-SPECIFIC RECOMMENDATIONS

Although this section of the Report listed specific cases in various District offices, the Division is responding in more general terms. The Division has had several meetings with staff to discuss and explain duties and expectations. It has been made clear to staff that these expectations will be enforced uniformly throughout the Division.

To address UIC shortcomings the Division aggressively pursued and was granted additional resources. The Division has focused on the evaluation of new and existing project applications, and field surveillance to ensure compliance. The recommendation to acquire software to aid staff with regulating UIC operations is being pursed along with other Division data management needs.

The Division's UIC program includes more than protecting USDWs and fresh water; the Division is also mandated to protect hydrocarbon zones from damage. Under our statutes, the protection of fresh water and USDW s coexists with the protection of hydrocarbon resources.

The Report recommends higher inspection priority for wells located near residential areas or when a USDW is present. Although inspection frequency is not addressed in regulations, additional staffing is augmenting Division resources for all UIC inspection needs. As indicated above, the Division's regulations do not distinguish between rural and urban injection wells. However, the Division does allocate additional resources to oil fields in highly urbanized areas.

Conclusion

The Division has been required to protect oil, gas, and water resources, since its inception in 1915. Some statutes have changed very little since that time. With changes in oilfield practices and advancements in technology, the Division has been slow to change its regulatory framework. Although the Division has a strong regulatory program, the Division is pursuing greater and more consistent enforcement.

In 2009, the Division began an in-depth evaluation of the UIC program and identified some barriers to full compliance. This was the first of many steps to bring the Division's program back into greater compliance with our mandates. The Division has already ensured greater UIC program compliance by:

- Providing staff greater understanding of UIC program mandates and staff expectations;
- Adding 43 additional staff to UIC and associate programs;
- Creating an internal audit program; and
- Requiring an additional technical review for UIC projects.

The Division acknowledges that some operators have operated UIC projects without meeting all the requirements outlined in statutes and regulations, and have resisted coming into full compliance. The Division is committed to bringing all operators into compliance.

The Division has not had significant changes to its UIC regulations since the original primacy application. Regulatory amendments will be pursued through a rulemaking process to address these needs. The Division's goal is to ensure our regulations are:

- adequate for protection of public health, the environment, and resources;
- adequate to address the UIC program mandates;
- flexible to address industry practices now and into the foreseeable future;
- created in a transparent process;
- predictable for the regulated community; and
- properly implemented and enforced.

Tim Kustic
State Oil and Gas Supervisor
November 2012

Enclosure B: Breakdown of Wells Potential Injecting into Non-exempt USDW Zones.

Enclosure B: Breakdown of Wells Potentially Injecting into Non-exempt USDW Zones and the Eleven Aquifers that have Historically Been Treated As Exempt

Breakdown review completed as of February 5, 2015

A. List of Water Disposal Wells – 532 Wells

Wells with…	Number of Wells	Number of wells issued orders	Number of wells (idle) in the 11 aquifers historically treated as exempt	Total Number of idle wells
Total Dissolved Solids (TDS) less than 3,000 mg/l	176	10	87 (20)	48
TDS between 3,000 and 10,000 mg/l	282	0	7 (4)	47
TDS under review or Data Requested	32	0	0	14
Subtotal	**490**	**10**	**94 (24)**	**109**
TDS greater than 10,000 mg/l (Wells being removed from list)	**42**			
Total	**532**			

B. List of Enhanced Oil Recovery Wells – 2021 Wells

Wells with…	Number of Wells	Number of wells issued orders	Number of wells (idle) in the 11 aquifers historically treated as exempt	Total Number of idle wells
Total Dissolved Solids (TDS) less than 3,000 mg/l	503	0	0	57
TDS between 3,000 and 10,000 mg/l	1327	0	0	225
TDS under review or Data Requested	157	0	0	62
Subtotal	**1987**	**0**	**0**	**344**
TDS greater than 10,000 mg/l (Wells being removed from list)	**34**			
Total	**2021**			

Enclosure C: Division and Water Board Aquifer Exemption Submittal and Review Process

Enclosure C: Division and Water Board Aquifer Exemption Submittal and Review Process

Division of Oil, Gas, and Geothermal Resources - Aquifer Exemption Submittal and Review Process

The Division of Oil, Gas, and Geothermal Resources (Division) is the state agency responsible for approving the injection of Class II fluid through an agreement with the United States Environmental Protection Agency (US EPA). Through this agreement, which is referred to as "Primacy", the Division is responsible for ensuring proposed zones of injection are exempt under the Safe Drinking Water Act and the criteria of 40 CFR 146.4. If an operator, or operators, wish to inject Class II fluid into a zone where the water quality is less than 10,000 mg/l TDS, and the zone has not been previously exempted, DOGGR will request data from the operator(s) to provide supporting documentation necessary to meet the aquifer exemption criteria as specified in 40 CFR 146.4 (see Exhibit A).

DOGGR's evaluation of the supporting documentation provided by the operator(s) must verify:

A) The aquifer does not currently serve as a source of drinking water.

This evaluation will/must include a survey of all water wells in the area of the proposed injection that are likely to have hydrologic conductivity with the zone of injection. Although the area of proposed injection may be smaller than the area of hydrologic conductivity, the supporting documentation must include data and hydrologic modeling that indicates the impacts of injection into the formation would not impact wells in the surrounding areas. Although this criteria states that the aquifer does not serve as a sources of drinking water, the State will evaluate this criterion to a higher standard, that of evaluating whether the aquifer is currently being used for beneficial uses.

B) The aquifer cannot now, and will not in the future, serve as a source of beneficial water because:

(1) The aquifer is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible.

Supporting documentation must include such data as: production data and/or maps generated using geophysical logs to indicate the oil/water contact of historic and/or current hydrocarbon production. To extent the area will include future hydrocarbon production, the supporting documentation must include definitive data of potential future hydrocarbon production.

(2) The aquifer is situated at a depth or location that makes recovery of water for drinking water purposes economically or technologically impractical.

Data must be provided that clearly indicates the depth of all impacted water that has the potential to be used for beneficial purposes. Based on current data, water wells are being drilled deeper and deeper because of the drought. Many wells are being drill below 4,000 feet. Because wells are being drilled increasingly deeper, supporting data must be current and accurate.

(3) The aquifer is so contaminated that it would be economically or technologically impractical to render that water fit for beneficial use.

The drought has forced people of the State to use water of lesser quality to meet their needs. Data provided to support the claim that the water is so contaminated that it would be economically or technologically impractical to render that water fit for beneficial use must be current and accurate. Although the initial application will be evaluated by DOGGR, the State Water Resources Control Board and the Regional Water Quality Control Board(s) will be providing their expertise in the final analysis.

(4) The total dissolved solids content of the ground water is more than 3,000 and less than 10,000 mg/l and other water quality constituents render the water to be of a certain quality that it is not reasonably expected to be used for beneficial uses.

During the process of evaluating the supporting documentation, the Division will confer with the State Water Board, and the operators as necessary to ensure the supporting data is accurate, up-to-date, and complete. Once the Division is satisfied with the supporting documentation, all supporting documentation, an application, and a draft letter to the US EPA requesting an aquifer exemption will be forwarded to the State Water Board for comment. If necessary, the Division and the State Water Board will meet and discuss the supporting documentation. Where appropriate, the operators affected by the proposed aquifer exemption may be included in meetings to clarify or to provide additional supporting documentation. If both the Division and the State Water Boards are in agreement, and if appropriate, the State Water Board will provide a written concurrence to the application.

Although timelines to prepare an aquifer exemption would be helpful, the variety in the complexity and size of each individual application makes it impossible to clarify a definitive timeline to prepare a specific application. However, it is the Division's goal to collect the necessary documentation, evaluate the supporting data, and provide a draft application to the State Water Board as soon as possible after receiving and verifying the required supporting documentation.

Once DOGGR and the State Water Board have reached an agreement to forward an aquifer exemption application to the US EPA, DOGGR will proceed with providing the appropriate public notification and solicit comments on the proposed aquifer exemption. Upon conclusion of the public comment period, and once comments have been appropriately addressed, the Division will forward the application to US EPA – Region 9.

State Water Resources Control Board - Aquifer Exemption Application and Review Process

Aquifer Exemption Application

1. Aquifer exemption applications, along with the Division of Oil, Gas, and Geothermal Resources' (DOGGR) recommendations are submitted to the State and Regional Water Quality Board (State Water Boards).
2. State Water Boards review the aquifer exemption application and DOGGR's recommendations (submittal review criteria detailed below). If necessary, this review may include meetings with DOGGR and operator(s) affect by the application. Review time will depend on the scale of the application and complexity of the proposed aquifer exemption (estimated 30 to 60 days).
3. State Water Boards and DOGGR will work towards reaching a consensus that the aquifer exemption application contains sufficient documented evidence to meet the criteria for an aquifer exemption. If additional information is required to justify an aquifer exemption, DOGGR and/or the State Water Board, depending on the information required, will request additional data from the affected operator(s). This is anticipated to take 15 to 30 days, depending on the data requested.

Every effort will be taken to work both with DOGGR and the affected operator(s) to resolve a lack of supporting data to justify an aquifer exemption.

Note: Review of an aquifer exemption application by the Water Boards is estimated to take 50 to 95 days. If additional information is required, the review process will be greater.

Review Process Criteria

The State Water Boards will review and evaluate the aquifer exemption application(s) in accordance with the following criteria:

1. Identification of underground sources of drinking water and exempted aquifers (Code of Federal Regulations, Title 40, Section 144.7)
2. U.S. Environmental Protection Agency (EPA) Guidance for Review and Approval of State Underground Injection Control (UIC) Programs and Revisions to Approved State Programs (Attachment 3: Guidelines for Reviewing Aquifer Exemption Requests)
3. EPA Aquifer Exemption Checklist
4. Technical demonstration by operator that the waste will remain in the exempted portion of the aquifer(s)

5. A review of current and future beneficial sources of water (e.g. domestic, municipal, irrigation, industrial)
6. Pertinent elements of Regional Water Board Basin Plan(s)

Upon conclusion of the State Water Boards review, the State Water Boards will provide one of the following findings:

a. If the State Water Boards concur with DOGGR that the aquifer exemption application meets the review criteria, the State Water Board will send a letter of concurrence to DOGGR, and copies to the affected operator(s). This is anticipated to take 5 days after concurring with DOGGR's recommendations.

b. If the State Water Boards concur that only portions of the aquifer exemption application meet the review criteria, the State Water Boards will send a letter to DOGGR and copies to the affected operator(s) requesting additional information. This is anticipated to take 5 days after making a determination.

c. If the State Water Boards conclude that the aquifer will not meet the criteria of an aquifer exemption, the State Water Boards will send a letter of its findings to DOGGR, with copies of these findings being sent to the affected operator(s). This is anticipated to take 5 days after making a determination.

Exhibit A - 40 CFR 146.4: Criteria for Exempted Aquifers

An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" in § 146.3 may be determined under § 144.7 of this chapter to be an "exempted aquifer" for Class 1-V wells if it meets the criteria in paragraphs (a) through (c) of this section. Class VI wells must meet the criteria under paragraph (d) of this section:

(a) It does not currently serve as a source of drinking water; and

(b) It cannot now and will not in the future serve as a source of drinking water because:

(1) It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible.

(2) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical;

(3) It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; or

(4) It is located over a Class III well mining area subject to subsidence or catastrophic collapse; or

(c) The total dissolved solids content of the ground water is more than 3,000 and less than 10,000 mg/1 and it is not reasonably expected to supply a public water system

(d) The areal extent of an aquifer exemption for a Class II enhanced oil recovery or enhanced gas recovery well may be expanded for the exclusive purpose of Class VI injection for geologic sequestration under§ 144.7(d) of this chapter if it meets the following criteria:

(1) It does not currently serve as a source of drinking water; and

(2) The total dissolved solids content of the ground water is more than 3,000 mg/1 and less than 10,000 mg/1; and

(3) It is not reasonably expected to supply a public water system.

Priorities, timelines and process

Taken in series, the sequence and timelines leading to a decision on aquifer exemptions will create a high level of concern that: 1. The body of work needing to be accomplished in a two-year period either cannot be managed, or, 2. The process will result in a large proportion of applications sent to US EPA in the final months of the period, without hope for resolution by February 15, 2017. Hence there is an essential need for the Water Board and DOGGR to work together in parallel as data are accrued by operators in support of exemptions to maximize parallel efforts and minimize serial efforts. To a large degree, such parallel work can only be possible if the data submitted are accurate, up to date and compiled in a readily accessible, standardized way. Further, the case for exemption must be rendered in a succinct, fact-driven form, supported by supporting data in appendices.

To facilitate an efficient workflow, DOGGR will establish a team of staff whose sole purpose will be to manage aquifer exemptions applications, and whose job it will be to know the status of any application at a given time and to work with operators to facilitate the development of a complete data set needed for the development of an aquifer exemption application to US EPA.

There are potentially as many as 100 aquifers for which portions are of interest to multiple operators and are likely candidates for consideration for exemption. Though a clear set of priorities is being developed in consultation with industry associations, who will assist in this effort, criteria that will drive priority consideration will include: date all data and justifications are certified as complete by DOGGR, impact on production levels within the state, impact on operator ability to produce, quality of the data submitted, timeliness of operator response to questions and data requests, and clarity of the case for exemption.

Enclosure D:
More Detailed Look At Administrative Concepts

ENCLOSURE D: MORE DETAILED LOOK AT ADMINISTRATIVE CONCEPTS

The following actions will be initiated through an appropriate combination of proposed rulemaking and enforceable orders.

1. Disposal into non-hydrocarbon producing zones[1] of aquifers that are clearly not exempt:

    a. No new disposal wells will be permitted unless and until EPA approves an aquifer exemption.
    b. Existing disposal wells:
        i. If potentially impacting water supply wells,[2] the Division will issue emergency order to operator to cease injection immediately. Water Board will issue an information order.[3]
        ii. If not potentially impacting water supply wells, and the aquifer is 3,000 mg/L total dissolved solids (TDS) or less, injection must cease no later than October 15, 2015 unless EPA approves an aquifer exemption. Water Board will issue an information order.
        iii. If not potentially impacting water supply wells, and the aquifer is more than 3,000 mg/L TDS and less than 10,000 mg/L TDS, injection must cease no later than February 15, 2017 unless EPA approves an aquifer exemption. Water Board will issue an information order. If there are supply wells in any portion of the aquifer, or if any portion of the aquifer is at a depth that may be reasonably expected to supply a public water system, the Division and the Water Board may issue orders on a higher priority basis.

2. Injection into hydrocarbon producing zones of aquifers that are clearly not exempt:

    a. If groundwater in the vicinity of the hydrocarbon producing zone does not currently have any beneficial use[4]

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[1] Hydrocarbon producing zone is the portion of an aquifer that "cannot now and will not serve as a source of drinking water" because: "It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible." (40 CFR § 146.4 (b)(1).)

[2] Injection wells potentially impacting water supply wells include injection wells into aquifers with 3,000 mg/L total dissolved solids (TDS) or less that meet either of the following criteria: (1) the uppermost depth of the injection zone is less than 1500 feet below ground surface (regardless of whether any existing supply wells are in the vicinity of the injection well), or (2) the injection depth is within 500 feet vertically and 1 mile horizontally of the screened portion of any existing water supply well.

[3] Water Board information order will require that the operator submit information related to the injection and the quality of groundwater.

[4] Note that this does not include any use of produced water.

i. New wells that are part of an approved project may be permitted with the express condition that permit expires on February 15, 2017, unless EPA approves an aquifer exemption.
ii. For existing wells, injection must cease by February 15, 2017, unless EPA approves an aquifer exemption.

b. If groundwater in the vicinity of the hydrocarbon producing zone has any current beneficial use
    i. No new permits will be issued.
    ii. For existing wells, injection must cease by February 15, 2017 (or sooner, depending on the use of the groundwater), unless EPA approves an aquifer exemption.

3. Injection into eleven aquifers with disputed exemption status:

    a. No new disposal wells will be permitted unless and until EPA approves an aquifer exemption evaluation. An exception may be made in the unusual case where the proposed injection well is part of an approved project, and an initial screening of the target zone shows that the zone contains hydrocarbons, has very high levels of naturally-occurring constituents (e.g., arsenic or boron), or there are other factors that make it unsuitable for beneficial use.
    b. Existing disposal wells:
        i. If potentially impacting water supply wells, the Division will issue emergency order to operator to cease injection immediately. Water Board will issue an information order.
        ii. If not potentially impacting water supply wells, injection must cease no later than February 15, 2017, unless EPA approves an aquifer evaluation. Water Board will issue an information order. If there are supply wells in any portion of the aquifer, or if any portion of the aquifer is at a depth that may be reasonably expected to supply a public water system, the Division and the Water Boards may issue orders on a higher priority basis.

4. The Division will submit any exemption requests or evaluations for the above three categories of aquifers over time, and with sufficient opportunity for EPA to review the requests and approve or disapprove all of them by February 15, 2017.

Case Nos. 24278, 24277, 24123, 23775, 23614-23617, and 24018-24027
OCD Exhibit No. 12C

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

March 9, 2015

Jonathan Bishop
Chief Deputy Director
California State Water Resources Control Board
P.O. Box 100
Sacramento, CA 95812-100

Steven Bohlen
State Oil and Gas Supervisor
Division of Oil, Gas Geothermal Resources
California Department of Conservation
801 K Street, MS 18-05
Sacramento, CA 95814-3530

Dear Messrs. Bishop and Bohlen:

Thank you for your February 6, 2015 letter setting forth a comprehensive plan to ensure that California's Class II Underground Injection Control ("UIC") program will come into compliance with the Safe Drinking Water Act (SDWA). We are pleased that you have initiated action to implement the plan, for example by issuing orders on March 3, 2015 to operators to immediately cease injection where your ongoing evaluation revealed that an injection well was potentially impacting water supply wells. To ensure that the State continues to make progress towards full compliance with the SDWA, we have indicated to you the need to establish additional milestones prior to February 15, 2017, which is the final compliance deadline for Class II wells currently injecting into a non-exempt aquifer. Enclosed is a schedule of required activities and deliverables, with target milestones and compliance deadlines, which are described below.

Drinking Water Protection Well Evaluations: Getting a complete picture of the scope of the problem is key to achieving full compliance, and the State's plan includes an ongoing process to review wells that may be injecting into non-exempt aquifers. The process described on pages 3-4 of the February 6th letter divides the wells into three categories based on the potential risk to groundwater and includes review by both DOGGR and the State Water Board. The February 6th letter states that you anticipate completing this review in early 2016. EPA has established deadlines for the State's completion of the combined injection well and water supply well screening for each of the three categories identified in the February 6th letter. The deadlines are as follows:

- May 15, 2015 for Class II water disposal wells injecting into non-exempt, non-hydrocarbon-bearing aquifers and the 11 aquifers historically treated as exempt (Category 1);
- July 31, 2015 for Class II enhanced oil recovery (EOR) wells injecting into non-exempt, hydrocarbon-bearing aquifers (Category 2); and

- February 15, 2016 for Class II disposal and EOR wells that are inside the surface boundaries of exempted aquifers, but that may be injecting into a zone not exempted by EPA (Category 3).

DOGGR has continued to review well records and in the process has proposed that EPA consider an additional category of wells which inject steam into hydrocarbon producing formations to enhance product recovery (cyclic steam). We understand you are in the process of collecting information on these wells, which were not included in Enclosure B of your February 6th letter. By May 15, 2015, DOGGR shall update Enclosure B to include cyclic steam wells and provide a schedule for completing the State's review of these wells and bringing them into compliance by February 15, 2017.

Keeping these well evaluations on schedule will facilitate prompt issuance of emergency orders, as needed, to protect water supply wells, as described on pages 7-8 of the February 6th letter.

Aquifer Exemption Process: The State's plan describes an aquifer exemption process that requires both DOGGR and the State Water Board to agree that an aquifer exemption is appropriate before the State forwards an exemption application to EPA for consideration. Informing the public and the regulated community about this process and the requirements, in addition to obtaining public input on specific exemptions, is essential. DOGGR's planned release of guidance on the aquifer exemption process around April 1, 2015 will facilitate this outreach. We appreciated the opportunity to participate in the public workshop you held in Bakersfield on February 24; we plan to participate in a second workshop in Long Beach on March 24 and will make ourselves available as needed for future outreach.

A critical aspect of the aquifer exemption process will be providing EPA with adequate time to review any proposed exemption to determine whether it satisfies the SDWA's regulatory requirements. Given the compliance deadlines to eliminate all injection into non-exempt aquifers by October 15, 2015 (for wells injecting into non-hydrocarbon bearing zones under 3,000 mg/L TDS) and February 15, 2017 (for all remaining Class II wells), EPA is establishing interim milestones to make sure that EPA does not receive a substantial number of aquifer exemption applications to review at the last minute, and to prioritize any exemptions sought for disposal wells injecting into non-hydrocarbon-bearing aquifers. Accordingly, EPA expects that the State will submit aquifer exemption applications as follows:

- 100% of proposed aquifer exemptions for Category 1 disposal wells injecting into non-exempt, non-hydrocarbon-bearing aquifers containing 3,000 mg/L TDS or less: July 15, 2015;
- 90% of proposed aquifer exemptions for Category 1 disposal wells with injection into non-exempt, non-hydrocarbon bearing aquifers containing 3,000 -10,000 mg/L TDS, and all proposed exemptions for any of the 11 aquifers historically treated as exempt: November 15, 2015;
- 90% of proposed aquifer exemptions for Category 2 wells: February 15, 2016;
- 90% of proposed aquifer exemptions for Category 3 wells: August 15, 2016; and
- 100% of remaining proposed aquifer exemptions for existing wells by October 15, 2016.

Failure to submit applications in accordance with this schedule will seriously jeopardize EPA's ability to take final action on aquifer exemption requests in advance of the compliance deadlines.

With respect to the 11 aquifers that have historically been treated as exempt, we look forward to working with your agencies to evaluate whether those aquifers meet State and EPA criteria for Class II injection. As an initial step, we request that the State evaluate the current quality of each of these

aquifers and provide a preliminary assessment by July 15, 2015 of whether available data would support an aquifer exemption proposal. Given existing data that indicates these aquifers contain less than 3,000 mg/L TDS and are not hydrocarbon-bearing, the State shall not permit new injection wells in these aquifers, even in the limited circumstances proposed on page 7 (and Enclosure D) of the February 6th letter, prior to State submittal of supporting information to EPA and an EPA decision. Further, the State shall require that existing wells cease injection into these aquifers by December 31, 2016, absent an EPA decision that the aquifer(s) meet criteria for Class II injection based on State submittal of supporting information between now and then.

To facilitate consideration of aquifer exemption requests, the State should require operators to provide the State with all necessary data and analyses in a manner that allows for review, public notice, and timely application to EPA for exemption, if appropriate. Anticipating that there will be situations where an operator, or the State, decides not to seek an exemption from EPA for an existing well in a non-exempt aquifer, the State should establish a plan and timeframes to discontinue use of wells after such decisions are made. Please submit this plan to EPA by July 15, 2015.

Rulemakings for Corrective Action and Class II UIC Program Improvements: The February 6th letter describes the State's plan to implement the compliance deadlines for winding down of injection activity in non-exempt aquifers through an administrative rulemaking. The target dates for this corrective action rulemaking process are:

- Submit Proposed Emergency Rulemaking to the Office of Administrative Law (OAL) by April 9, 2015;
- Finalize Emergency Rule by April 30, 2015;
- Initiate Permanent Rulemaking by June 1, 2015; and
- Finalize Permanent Rulemaking by April 30, 2016

Further, DOGGR is continuing to evaluate its entire Class II program and proposing to make programmatic improvements through a series of rulemaking actions and revisions to DOGGR's internal processes and program implementation. In lieu of submitting a work plan for a programmatic UIC rulemaking on April 1, 2015 as described in the February 6th letter, DOGGR will submit to EPA a detailed plan for comprehensive Class II program improvements that covers both proposed rulemaking and non-rulemaking program improvements by July 15, 2015. In addition, the target dates for regulatory revisions are:

- Submit initial proposed regulatory revisions to OAL by September 30, 2016; and
- Complete regulatory revisions by September 2018

EPA encourages earlier implementation of program improvements and the completion of interim steps and corrective action as soon as possible.

As one of these program improvements, DOGGR shall create a searchable injection well database. An effectively designed searchable database is necessary for DOGGR to properly manage permitting and enforcement of injection activity across the State, for EPA to conduct its oversight of the Class II program, and for the public to monitor injection activity. We understand that to accomplish this task, DOGGR must prepare and submit a Feasibility Study Report (FSR) to the California Technology Agency. The February 6th letter states that DOGGR has created a team to develop the FSR, which is targeted for completion by December 2015, to be followed by proposed inclusion in the State budget and a February

2017 target date to initiate operation of the database. EPA looks forward to close communication with the State regarding the progress and proposed framework for this essential database resource.

Communication and Outreach: In addition to the aquifer exemption workshops already mentioned, the State and EPA should continue to coordinate outreach and conduct additional informational workshops in the future, as needed. Also, we plan to meet monthly with representatives from your agencies to discuss the progress of the State's plan and the steps identified above. Please provide us with a detailed progress report prior to each meeting, and notify us as soon as you become aware of circumstances that may affect the plan's implementation.

We look forward to continuing our joint effort to protect California's underground sources of drinking water and ensure compliance with the SDWA.

Sincerely,

Jane Diamond
Director
Water Division

Enclosure

California Class II UIC Program Corrective Action Plan Schedule

A. Drinking Water Protection Well Evaluations

- Complete evaluations for "Category 1" injection wells **(May 15, 2015)**
- Complete evaluations for "Category 2" injection wells **(July 31, 2015)**
- Revise Enclosure B of the State's February 6th letter to incorporate cyclic steam wells and provide a schedule for completing a review of these wells and submitting proposed aquifer exemptions, as applicable, to meet the February 15, 2017 compliance deadline **(May 15, 2015)**
- Complete evaluations for "Category 3" injection wells **(February 15, 2016)**

B. Well Shut-Ins

- Shut-in deadline for wells injecting into non-exempt, non-hydrocarbon-bearing aquifers with TDS levels below 3,000 mg/l TDS **(October 15, 2015)**
- Shut-in deadline for wells injecting into the 11 aquifers historically treated as exempt, unless aquifer(s) is exempted by EPA pursuant to this corrective action plan **(December 31, 2016)**
- Shut-in deadline for all existing wells injecting into non-exempt aquifers with TDS levels below 10,000 mg/L TDS **(February 15, 2017)**

C. Aquifer Exemption Process

- Issue Aquifer Exemption Guidance **(April 1, 2015)**
- Deadline for submission to EPA of all proposed aquifer exemptions for Category 1 wells injecting into aquifers containing 3,000 mg/L TDS or less (excluding wells injecting into the 11 aquifers historically treated as exempt) **(July 15, 2015)**
- Deadline for submission to EPA of an evaluation of each of the 11 aquifers historically treated as exempt with a preliminary assessment of whether current data would support an aquifer exemption proposal by the State **(July 15, 2015)**
- Deadline for submission to EPA of a plan and timeframes to address closure of injection wells for which the State is not seeking an aquifer exemption **(July 15, 2015)**
- Category 1 wells: Target for submission of 90% of proposed aquifer exemptions, and 100% of proposed exemptions for any of the 11 aquifers historically treated as exempt **(November 15, 2015)**
- Category 2 wells: Target for submission of 90% of proposed aquifer exemptions **(February 15, 2016)**
- Category 3 wells: Target for submission of 90% of proposed aquifer exemptions **(August 15, 2016)**
- Deadline for submission to EPA of all proposed aquifer exemptions for decision by February 15, 2017 **(October 15, 2016)**

D. Rulemakings for Well Shut-Ins, Corrective Action and Class II UIC Program Improvements

Well Shut-Ins

- Initiate Emergency Rulemaking - submit proposed rule to OAL **(April 9, 2015)**
- Final Emergency Rule – estimated completion date **(April 30, 2015)**
- Initiate Permanent Rulemaking **(June 1, 2015)**
- Final Permanent Rulemaking – estimated completion date **(April 30, 2016)**

Regulatory Revisions and Non-Regulatory Improvements

- Submit detailed plan for comprehensive Class II program improvements to EPA (proposed rulemaking actions and non-rulemaking steps) **(July 15, 2015)**
- Submit initial proposed regulatory revisions to OAL **(September 30, 2016)**
- Complete regulatory revisions **(September 2018)**

Searchable Well Database

- Complete Feasibility Study Report **(December 31, 2015)**
- Award Database contract **(July 2016)**
- Implement database **(February 2017)**

E. Communication and Outreach

- Aquifer Exemption workshop **(March 24, 2015)**
- Agencies meet monthly to review progress. Prior to each meeting DOGGR/SWRCB will provide a progress report to EPA **(March 2015 - March 2017)**

State of California • Natural Resources Agency
Department of Conservation
Division of Oil, Gas, and Geothermal Resources
801 K Street • MS 18-05
Sacramento, CA 95814
(916) 445-9686 • FAX (916) 319-9533

Edmund G. Brown Jr., *Governor*
Kenneth A. Harris Jr., *State Oil and Gas Supervisor*

March 7, 2017

Mr. Michael Montgomery
United States Environmental Protection Agency – Region IX
75 Hawthorne Street
San Francisco, CA 94105-3901

Dear Mr. Montgomery:

By letter of March 9, 2015, the United States Environmental Protection Agency (US EPA) directed the Division of Oil, Gas, and Geothermal Resources (Division) to evaluate eleven aquifers that were historically treated as exempt to determine whether available data would support an aquifer exemption proposal for any of these aquifers or portions thereof. The Division, with concurrence from the State Water Resources Control Board (State Water Board), has completed its evaluation and has determined that the eleven aquifers should not be considered exempt, except with respect to the portions of the Walker Formation and Santa Margarita Formation that were exempted under the recently approved Round Mountain and Fruitvale aquifer exemptions, and except with respect to any portion(s) that the State identifies for exemption and US EPA approves in the future as the result of an exemption proposal. The Division hereby requests that US EPA enter into the addendum (attached hereto as Enclosure A) to the 1982 Underground Injection Control Program Memorandum of Agreement between the Division and US EPA for the purpose of clarifying the current, non-exempt status of the eleven aquifers.

By its terms, the addendum would not preclude future consideration of new exemption proposals or changes in exemption status for these aquifers. If the Division in the future receives new information establishing that any of these aquifers (or portions thereof) meet the exemption criteria and are appropriate for injection, the Division may elect to submit an aquifer exemption proposal to US EPA following the required legal procedure. This is important to note in part because the Division has formally requested in separate correspondence that US EPA approve an aquifer exemption for portions of one of the eleven aquifers (the Walker Formation underlying the Round Mountain Field). While the addendum to the Memorandum of Agreement is not intended to preclude or affect in any way US EPA's consideration of that exemption proposal, the Division nevertheless requests that the aquifer's current status be clarified along with the others as non-exempt unless and until, and only so far as, US EPA approves an exemption for the aquifer.

The Division's determinations and request for formal clarification regarding these eleven aquifers is the result of an evaluation of available water quality data for these formations (attached hereto as Enclosure B). The Division made this data its preliminary assessments available on November 15, 2016 for a 30-day public comment period, which included a public comment hearing on December 14, 2016. A copy of the November 15, 2016 public notice is attached hereto as Enclosure C. The public comments received did not change the Division's determination to request this clarifying addendum from US EPA. The Division's comment summaries and responses are attached hereto as Enclosure D.

If you have questions or wish to discuss this matter, please contact me at (916) 323-1777 or by email at Ken.Harris@conservation.ca.gov.

Sincerely,

Kenneth A. Harris Jr.,
State Oil and Gas Supervisor

Enclosures:

Enclosure A: Addendum to Underground Injection Control Program Memorandum of Agreement Between California Division of Oil, Gas, and Geothermal Resources and the United States Environmental Protection Agency Region 9.

Enclosure B: Preliminary assessment of the eleven aquifers historically treated as exempt.

Enclosure C: November 15, 2016 notice of public comment and hearing.

Enclosure D: Division's public comment summaries and responses.

ADDENDUM to

Underground Injection Control Program
Memorandum of Agreement
Between
California Division of Oil, Gas, and Geothermal Resources
and
the United States Environmental Protection Agency Region 9

Whereas the California Division of Oil, Gas, and Geothermal Resources ("Division") and the United States Environmental Protection Agency ("EPA") (collectively, the "Parties") desire to clarify, as specified below, that eleven aquifers are not exempted aquifers for purposes of the Safe Drinking Water Act, the Parties hereby agree to the following Addendum to the Underground Injection Control Program Memorandum of Agreement signed by the Parties on September 28, 1982 and September 29, 1982 ("1982 Agreement"):

1. Notwithstanding any prior statement or attachment to the 1982 Agreement or historical practice to the contrary, the following aquifers are not exempted aquifers except with respect to any portion(s) that the State identifies for exemption and EPA approves as exempt as a result of a future exemption proposal:

    - The Pico Formation underlying the boundaries of the South Tapo Canyon Field;
    - The Tumey Formation underlying the boundaries of the Blackwell's Corner Field;
    - The Kern River Formation underlying the boundaries of the Kern Bluff Field;
    - The Santa Margarita Formation underlying the boundaries of the Kern Front Field, except for portions exempted by the Fruitvale aquifer exemption;
    - The Chanac Formation underlying the boundaries of the Kern River Field;
    - The Santa Margarita Formation underlying the boundaries of the Kern River Field;
    - The Walker Formation underlying the boundaries of the Mount Poso Field;
    - The Olcese Formation underlying the boundaries of the Round Mountain Field;
    - The Walker Formation underlying the boundaries of the Round Mountain Field, except for portions exempted by the Round Mountain aquifer exemption;
    - All aquifers underlying the boundaries of the Bunker Gas Field that are not in a hydrocarbon-producing zone; and
    - All aquifers underlying the boundaries of the Wild Goose Field that are not in a hydrocarbon-producing zone

2. This Addendum does not preclude future consideration of exemption proposals, or changes to exemption status following the applicable legal procedure, for the above aquifers or portions thereof.

3. All other terms and conditions of the Agreement remain unchanged and in effect.

4. The effective date of this Addendum shall be the date of execution.

_____	_____
Alexis Strauss Acting Regional Administrator Environmental Protection Agency Region 9	Kenneth A. Harris Jr. State Oil and Gas Supervisor California Division of Oil, Gas, and Geothermal Resources
_____	_____
Date	Date

Division of Oil, Gas, and Geothermal Resources

Preliminary Assessment of Eleven Aquifers Historically Treated as Exempt

July 15, 2015

Executive Summary

The Division of Oil, Gas and Geothermal Resources has made a preliminary evaluation of whether current data support a determination that the eleven aquifers historically treated as exempt currently meet the criteria for an aquifer exemption.

The eleven aquifers historically treated as exempt, and significant relevant data for each, are as follows:

- The **South Tapo Canyon** field - the **Pico** formation (no longer being used);

  Injection Wells: 0 TDS: 1,900 ppm NaCl Depth: 0-1,000'

- The **Blackwell's Corner** field - The **Tumey** formation (no longer being used);

  Injection Wells: 0 TDS: 2,100 -2,600 mg/l Depth: 945' – 1,473'

- The **Kern Bluff** field – the **Kern River** formation (no longer being used);

  Injection Wells: 0 TDS: 400 – 900 mg/l Depth: 0-200'

- The **Kern Front** field – the **Santa Margarita** formation;

  Injection Wells: 13 TDS: 460 – 2,318 mg/l Depth: 2,197' – 2,840'

- The **Kern River** field -the **Chanac** formation;

  Injection Wells: 12 TDS: 926 – 3,325 mg/l Depth: 425' – 1,335'

- The **Kern River** field – the **Santa Margarita** formation;

  Injection Wells: 32 TDS: 490 – 1,584 mg/l Depth: 760' – 2,285'

- The **Mount Poso** field – the **Walker** formation;

  Injection Wells: 5 TDS: 1,069 mg/l Depth: 1,740' – 1,796'

- The **Round Mountain** field – the **Olcese** formation;

  Injection Wells: 6 TDS: 2,693 mg/l Depth: 710' – 850'

- The **Round Mountain** field - the **Walker** formation;

  Injection Wells: 30 TDS: 2,335 mg/l Depth: 1,890' – 2,590'

- The **Bunker Gas** field - **all aquifers** within the field that are not in a hydrocarbon producing zone (no longer being used);

  Injection Wells: 0 TDS: 1,215 mg/l Depth: 3,000'

- The **Wild Goose** field - **All aquifers** within the field that are not in a hydrocarbon producing zone (no longer being used);

  Injection Wells: 0 TDS: 2,800 -5,000* mg/l Depth: 2,700' - 3,400'

  *More recent analysis indicate TDS around 24,000 mg/l

Key portions of the above data, in spreadsheet form:

Historically Treated as Exempt Aquifers Snapshot						
Field	Formation	Number of Active Injection Wells	Total Dissolved Solids of Formation	Total Disolved Solids of Injected Fluid	Depth	Historic Volumes Injected Since 1983 in Barrels
South Tapo Canyon	Pico	0	1,900 ppm NaCl	600 ppm NaCl	1,000'	0
Blackwell's Corner	Tumey	0	2,100 - 2,600 mg/l	29,000 ppm NaCl	945' - 1,475'	2,425
Kern Bluff	Kern River	0	400 - 900 mg/l	600 mg/l	200	5,816,190
Kern Front	Santa Margarita	13	460 - 2,318 mg/l	360 - 6,400 mg/l	2,197' - 2,840'	151,820,215
Kern River	Chanac	12	926 -3,325 mg/l	491 - 2,000 mg/l	425' - 1,335'	568,987,463
Kern River	Santa Margarita	32	490 - 1,584 mg/l	491 -74,924 mg/l	760' - 2,285'	799,041,272
Mount Poso	Walker	5	1,069 mg/l	650 mg/l	1,740' - 1,796'	63,777,556
Round Moutain	Olcese	6	2,693 mg/l	1,900 mg/l	710' - 850'	160,798,008
Round Mountain	Walker	30	2,335 mg/l	1,600 - 2,900 mg/l	1,890' - 2,590'	1,529,910,014
Bunker	Undifferentiated	0	1,215 mg/l	10,675 - 11,025 ppm Chloride	3,000'	51,454
Wild Goose	Undifferentiated	0	24,349 mg/l	24,349 mg/l	2,700' - 3,400'	0

Division of Oil, Gas, and Geothermal Resources

Preliminary Assessment of Eleven Aquifers Historically Treated as Exempt

July 15, 2015

The US EPA, State Water Board, and the Division have agreed that the State will submit an evaluation of each of the 11 Historically Treated as Exempt (HTAE) aquifers with a preliminary assessment as to whether current data would support a determination that the criteria for an aquifer exemption are met.

11 HTAE aquifers historically treated as exempt are as follows:

- The **Pico** formation within the boundaries of the **South Tapo Canyon** field (no longer being used);
- The **Tumey** formation within the boundaries of the **Blackwell's Corner** field (no longer being used);
- The **Kern River** formation within the boundaries of the **Kern Bluff** field;
- The **Santa Margarita** formation within the boundaries of the **Kern Front** field;
- The **Chanac** formation within the boundaries of the **Kern River** field;
- The **Santa Margarita** formation within the boundaries of the **Kern River** field;
- The **Walker** formation within the boundaries of the **Mount Poso** field;
- The **Olcese** formation within the boundaries of the **Round Mountain** field;
- The **Walker** formation within the boundaries of the **Round Mountain** field;
- **All aquifers** within the **Bunker Gas** field that are not in a hydrocarbon producing zone and that have groundwater that has less than 10,000 TDS (no longer being used); and
- **All aquifers** within the **Wild Goose** field that are not in a hydrocarbon producing zone and that have groundwater that has less than 10,000 TDS (no longer being used).

More detail on each aquifer is set out below.

South Tapo Canyon Field, Pico Zone, Ventura District

1) Number of disposal wells permitted in the zone:
   0

2) Number of active producers:
   0

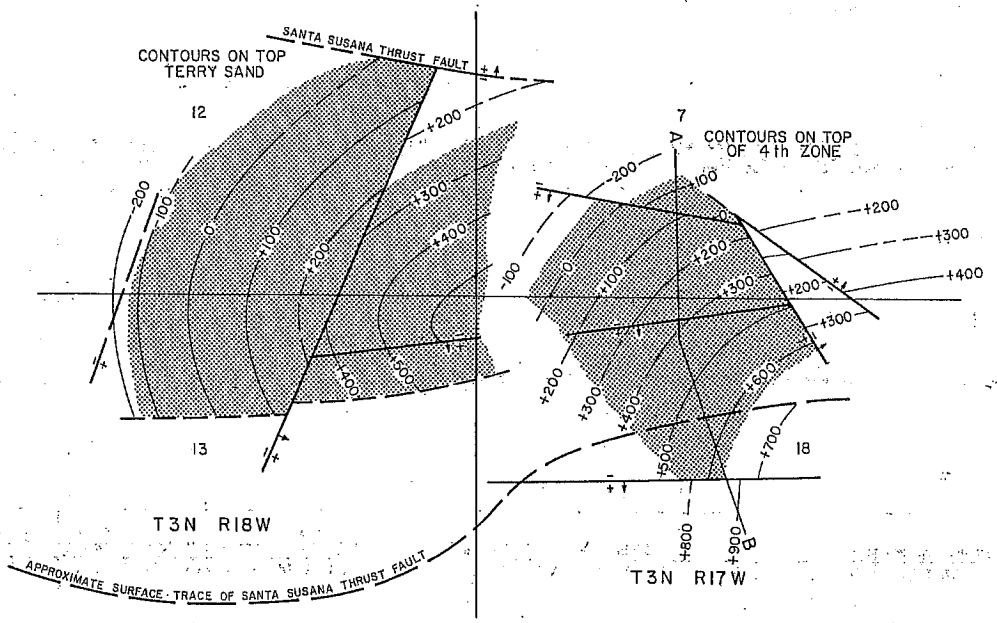
3) Depth of the zone across the field:
   At the surface on the south side of the field to 1,000' below surface depth on the north side. There are opposing thrust faults therefore, there is a wide range in zone depth across the field. Zone dips to the north across the field. This is based on the data sheet.

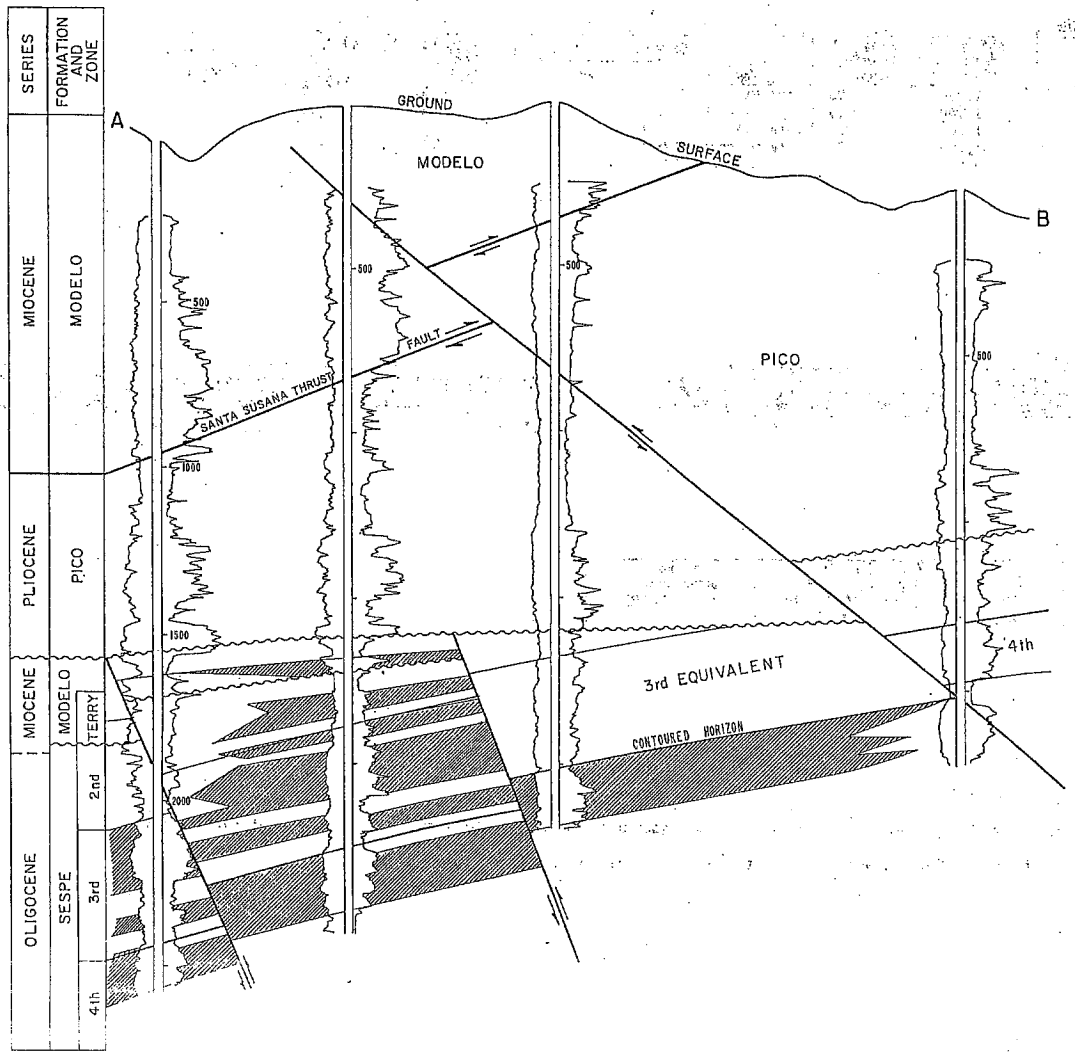
4) Volumes Injected Historically since 1983:
   None. District confirmed that there is no documentation that injection ever historically occurred in the Pico zone. The 5/17/1985 EPA letter contradicts this and indicates that injection did occur starting in 1948 and 1,903,000 Bbls was historically injected in this zone.

5) TDS of zone:
   1,900 ppm NaCl according to 5/17/1985 EPA letter

6) TDS of injection water:
   600 ppm NaCl according to the 5/17/1985 EPA letter

SOUTH TAPO CANYON OIL FIELD





LOCATION: 32 miles northeasterly of Ventura

TYPE OF TRAP: Faulted anticline

ELEVATION: 2,440

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Terry	Crown Central Petroleum Corp. "Tapo" 2	Terry and Jensen "Tapo" 2	13 3N 18W	SB	720	100	Feb 1953
2nd Sespe	Union Oil Co. of Calif. "South Tapo-Gillibrand" 11-7	Union Oil Co. of Calif. "Simi" 11-7	7 3N 18W	SB	99	411	Jul 1954
3rd Sespe	Same as above	Same as above	7 3N 18W	SB	*	*	Jul 1954
4th Sespe	Same as above	Same as above	7 3N 18W	SB	*	*	Jul 1954

Remarks: * Initial production from the 2nd, 3rd and 4th Sespe zones was commingled.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Havenstrite Oil Co. "Tapo" 1	Same	Jan 1949	13 3N 18W	SB	8,394	Llajas	Eocene

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Terry	2,200	60	Miocene	Modelo	32	*90	II
2nd Sespe	1,800	70	Oligocene	Sespe	18	1,030	II
3rd Sespe	1,880	220	Oligocene	Sespe	18	1,030	II
4th Sespe	2,200	180	Oligocene	Sespe	18	1,030	II

PRODUCTION DATA (Jan. 1, 1974)

1973 Production: Oil (bbl)	1973 Production: Net gas (Mcf)	1973 Production: Water (bbl)	1973 Proved acreage	1973 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
40,260	509	140,374	210	14	4,332,509	1,905,031	905,009	1953	50	35	240

STIMULATION DATA (Jan. 1, 1974)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: None

CURRENT CASING PROGRAM: 11 3/4" cem. 100; 7" combination string landed through zone and cemented through ports above zone.

METHOD OF WASTE DISPOSAL: All waste water is injected into a water-disposal well.

REMARKS: * Terry zone water is high in bicarbonates and total dissolved solids. A cyclic-steam project was started in 1964 and was discontinued in 1965 after the injection of 11,063 bbls. of water (in the form of steam).

REFERENCES: Hardoin, J.L., South Tapo Canyon Oil Field, Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 44, No. 1 (1958).

Blackwell's Corner Field, Tumey Zone, Bakersfield District office

1) Number of disposal wells permitted in the zone:
   0

2) Number of active producers:
   0

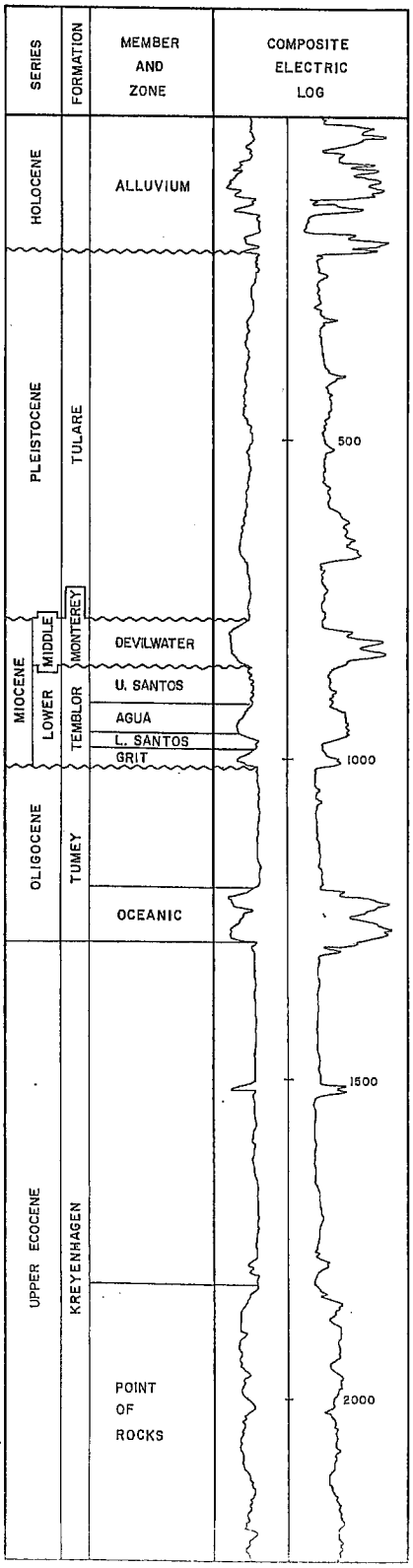
3) Depth of the zone across the field:
   945' to 1,473' below surface depth. Zone dips significantly to the Southeast across the field. Zone truncated by angular unconformity about ½ mile northwest of field.

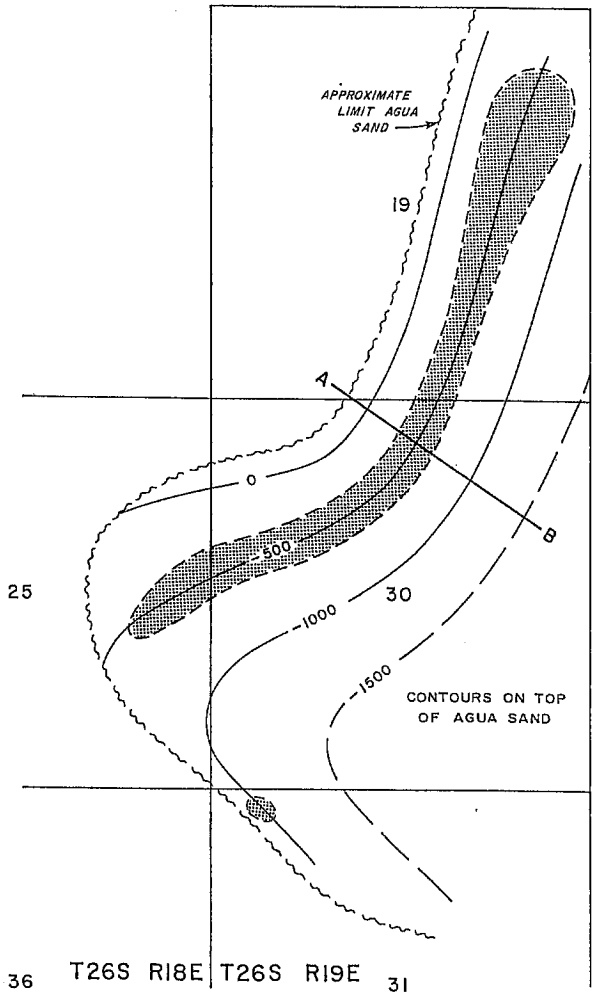
4) Volumes injected historically since 1983:
   2,425 Bbls, last injected on 5/1/1986

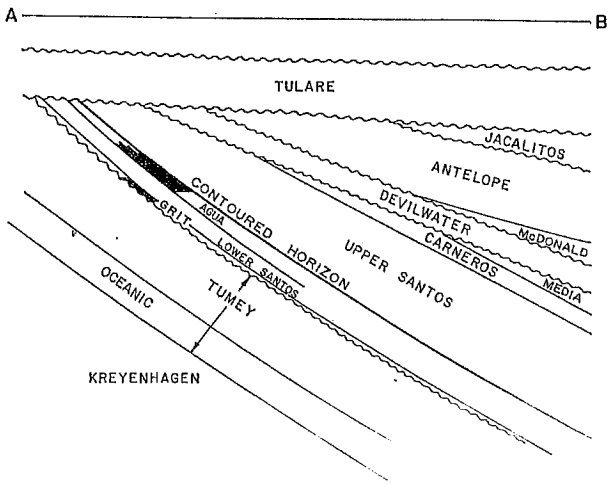
5) TDS of zone:
   Prior to injection 2,100 – 2,600 mg/l TDS (calculated) according to the 5/17/1985 EPA letter

6) TDS of injection water:
   29,000 ppm NaCl according to the 5/17/1985 EPA letter

BLACKWELLS CORNER OIL FIELD







LOCATION: 45 miles northwest of Taft

TYPE OF TRAP: Permeability barrier on an anticlinal nose

ELEVATION: 700

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production Oil (bbl)	Initial daily production Gas (Mcf)	Date of completion
Devilwater	General Crude Oil Co. Oper. "Occidental" 10	Etienne Lang "Occidental" 10-N.W. 30	30 26S 19E	MD	20	N.A.	Jun 1944
Agua	General Crude Oil Co. Oper. "Occidental" 3	Etienne Lang "Occidental" 3-N.W. 30	30 26S 19E	MD	50	N.A.	Dec 1943
Grit	General Crude Oil Co. Oper. "Occidental" 5	Etienne Lang "Occidental" 5-N.W. 30	30 26S 19E	MD	30	N.A.	Aug 1944

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
The Superior Oil Co. "O.L.C." 7	Same	Jul 1954	30 26S 19E	MD	3,224	Tumey	Oligocene

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Devilwater	700	25	middle Miocene	Temblor	13	N.A.	None
Agua	1,300	85	early Miocene	Temblor	14	790	None
Grit	1,400	5	early Miocene	Temblor	14	790	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
15,659	0	111,178	240	18	813,907	90,521	81,106	1946	63	38	250

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: None

CURRENT CASING PROGRAM: 7" cem. above zone; 5 1/2" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps.

REMARKS: Formerly known as Shale Hills Area.

REFERENCES: Karmelich, F.J., Blackwells Corner Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 37, No. 2 (1951).

Kern Bluff Field, Kern River Zone, Bakersfield District, East Side

1) Number of disposal wells permitted in the zone:
   0

2) Number of active producers:
   0

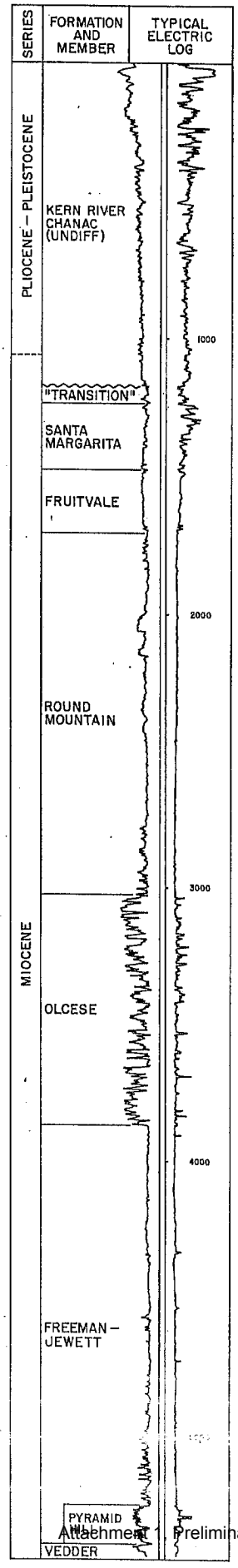
3) Depth of the zone across the field:
   Surface depth. Former WD well (API #02908849) uppermost perf is at 200' depth.

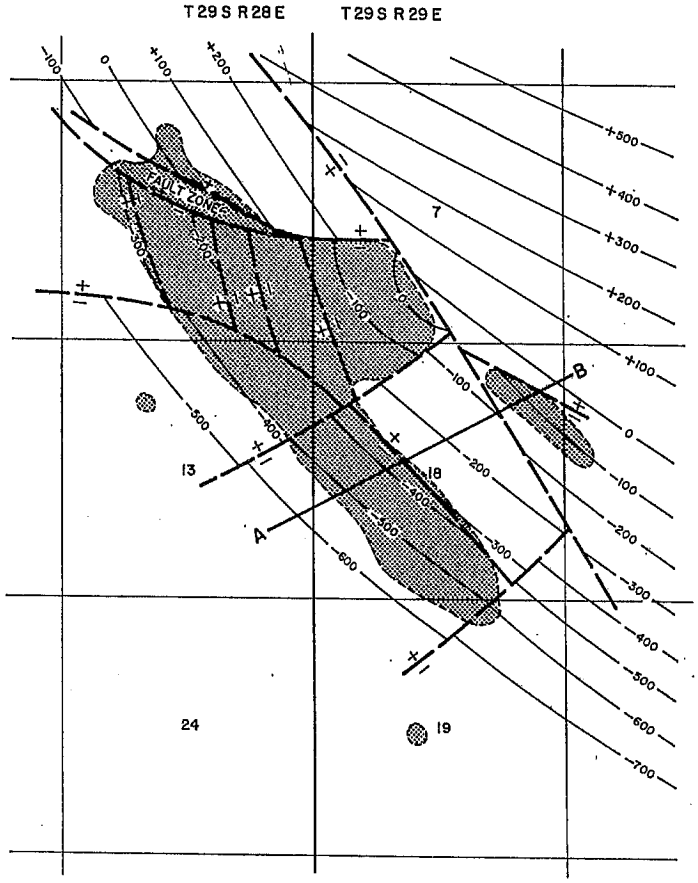
4) Volumes injected historically since 1983:
   5,816,190 Bbls, last injected on 6/1/1993

5) TDS of zone:
   400 – 900 mg/l according to the 5/17/1985 EPA letter

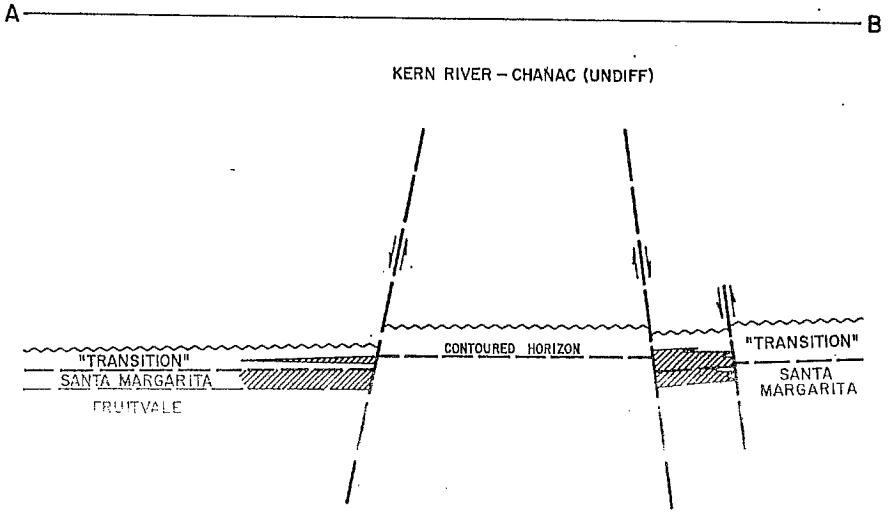
6) TDS of injection water:
   600 mg/l according to 5/17/1985 EPA letter

KERN BLUFF OIL FIELD





CONTOURS ON TOP OF SANTA MARGARITA



LOCATION: 6 miles northeast of Bakersfield

TYPE OF TRAP: Faulted homocline

ELEVATION: 800

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production Oil (bbl)	Initial daily production Gas (Mcf)	Date of completion
Transition	Shell Oil Co. "Afana" 1	Same as present	18 29S 29E	MD	18	N.A.	Feb 1944
Santa Margarita	Gulf Oil Corp. "Needham-Bloemer" 15	Oceanic Oil Co. "Needham-Bloemer" 1	7 29S 29E	MD	90	N.A.	Sep 1947

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Kernview Oil Co. "Muir" 13	Gene Reid Exploration Co. "Muir" 13	Feb 1949	18 29S 29E	MD	5,425	Vedder	early Mio

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Transition	740 - 1,350	30 - 80	late Miocene	Transition	14	5	None
Santa Margarita	950	55	late Miocene	Santa Margarita	14	5	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
216,477	0	3,365,718	670	131	9,410,522	0	845,373	1949	214	166	690

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
Cyclic-steam	1965	3,701,855	124

SPACING ACT: Applies

BASE OF FRESH WATER: 950

CURRENT CASING PROGRAM: 8 5/8" cem. above zone and across base of fresh-water sands; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Waste water is injected in disposal wells (808,148 bbls. in 1972), steam injection wells, and in unlined sumps where water quality meets Div. of Oil and Gas standards.

REMARKS:

REFERENCES: Corwin, C.H., Kern Bluff Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 36, No. 1 (1950).

Kern Front Field, Santa Margarita Zone, East Side Bakersfield District

1) Number of disposal wells permitted in the zone:
   13

2) Number of active producers:
   0

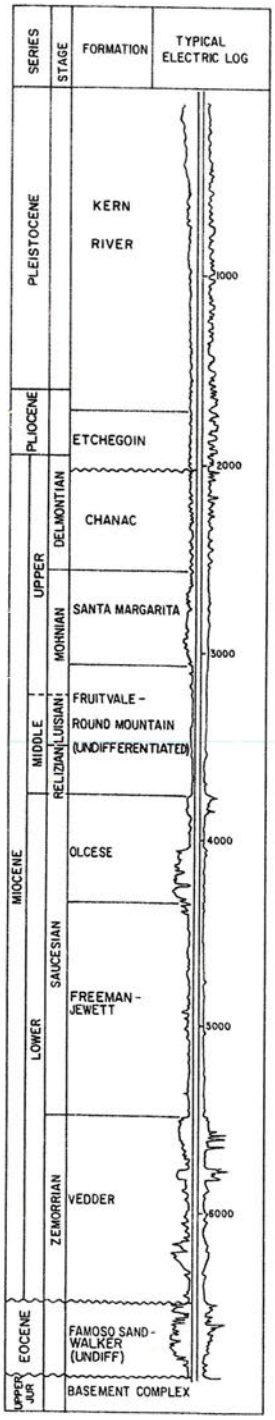
3) Depth of the zone where the injection wells are located:
   2,197' to 2,840' below surface

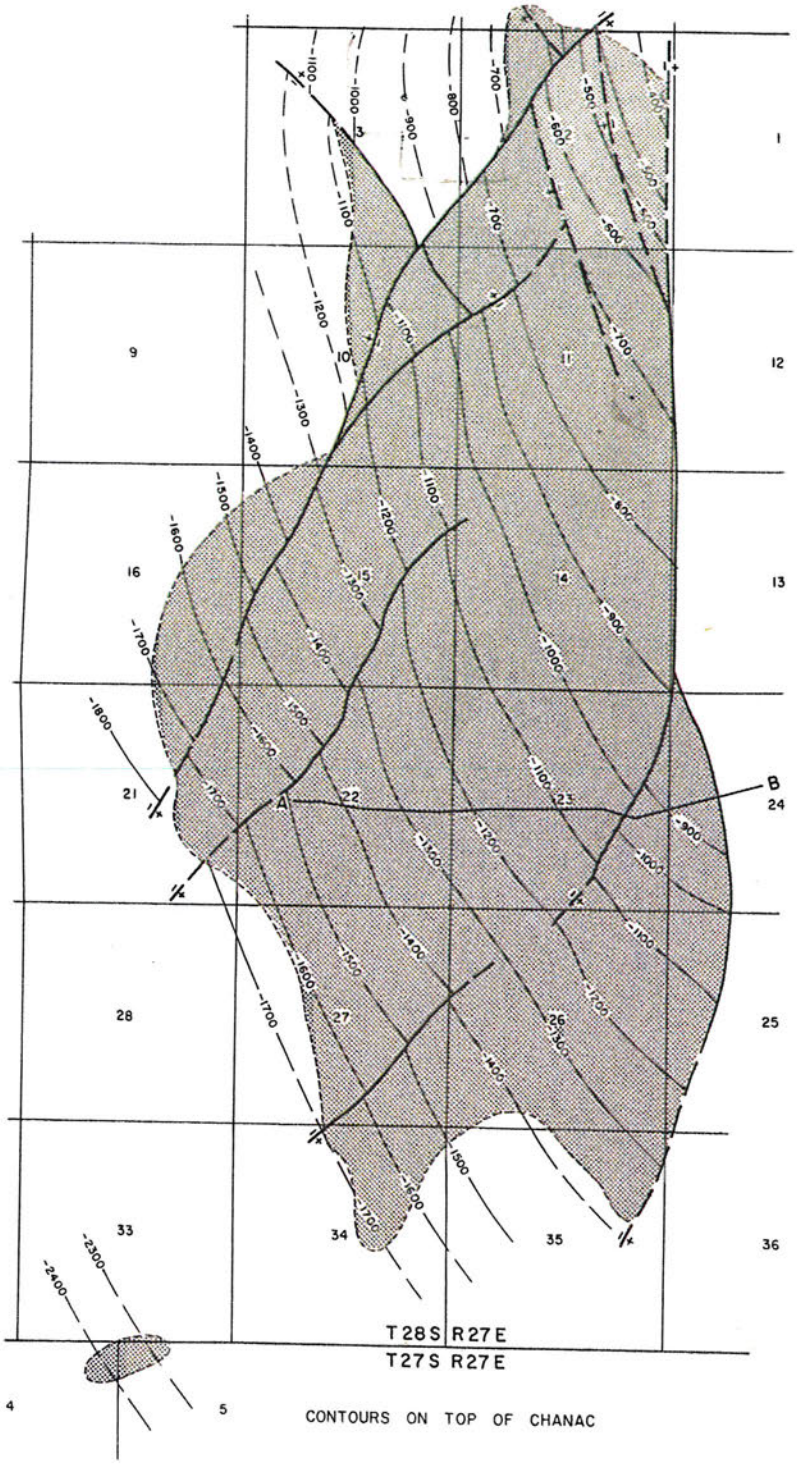
4) Volumes injected historically since 1983:
   151,820,215 Bbls injected, last injected on 3/1/2015

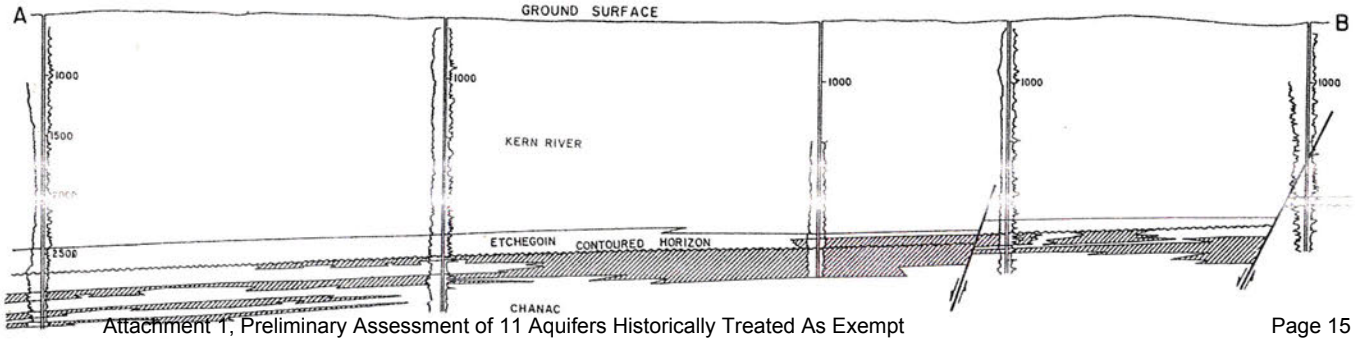
5) TDS of zone:
   460 mg/l - 2,318 mg/l TDS
   The 460 mg/l TDS sample is from the lower Santa Margarita zone in 4-4W well (029-62979) collected at a depth between 3,425'-3,255' on 12/9/1988 and the 2,318 mg/l TDS sample is from WD#1 (029-54754) well at a depth of 2,300' on 9/17/1975.

6) TDS of injection water:
   360 mg/l – 880 mg/l and 6,400 mg/l TDS.
   The 360mg/l TDS sample is from "injection wells "Movius" 3, 2 and D11 on 8/27/2010, the 880 mg/l TDS sample is from well Sec. 27 waste water to "Valley Waste KFF" on 11/2/1997 and the 6,400 mg/l TDS sample is the only high concentration sample collected from "waste water at injection well" on 4/11/2011. The 6,400 mg/l TDS sample is from project #33800012 and is most likely from the cogeneration and scrubber brine waste water. The permitted injection fluids in the Kern Front field, Santa Margarita zone consists of produced water from the Chanac, Etchegoin and Santa Margarita zones and cogeneration and scrubber brines from a plant.

KERN FRONT OIL FIELD







LOCATION: 5 miles northwest of Bakersfield

TYPE OF TRAP: Permeability variations on a faulted homocline

ELEVATION: 750

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production Oil (bbl)	Initial daily production Gas (Mcf)	Date of completion
Etchegoin	Standard Oil Co. of Calif. No. 1	Same as present	15 28S 27E	MD	10	N.A.	1912
Chanac	Standard Oil Co. of Calif. No. 1	Same as present	27 28S 27E	MD	190	N.A.	Aug 1914

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Atlantic Richfield Co. "Kramer" 1	Richfield Oil Corp. "Kramer" 1	Sep 1941	34 28S 27E	MD	7,738	Basement (slate)	Late Jur

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Etchegoin	2,265	70	Pliocene	Etchegoin	14	N.A.	None
Chanac	2,320	250	late Miocene	Chanac	15	5	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
3,148,559	293,008	25,578,898	5,000	852	128,591,808	14,667,840	4,535,059	1929	1,322	1,206	5,055

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
Cyclic-steam	1964	14,142,183	478

SPACING ACT: Does not apply

BASE OF FRESH WATER: 1,300

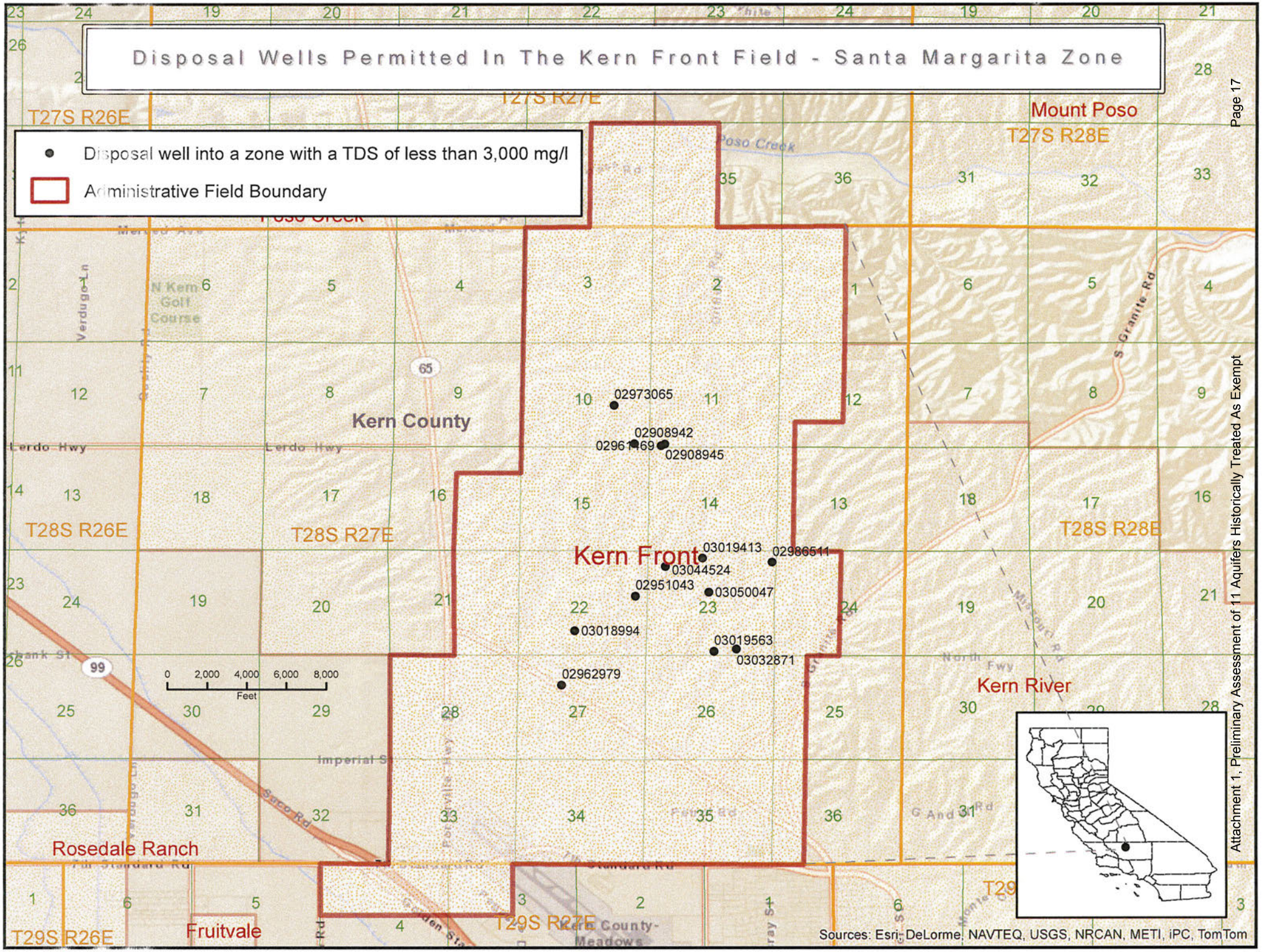
CURRENT CASING PROGRAM: 8 5/8" cem. above zone and across base of fresh-water sands; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Unlined sumps.

REMARKS: A steam displacement project was started in the Kern River - Chanac zone in 1966 and terminated after 99,587 bbls. was injected.

REFERENCES: Brooks, T.J., Kern Front Oil Field, A.A.P.G., S.E.P.M., S.E.G., Guidebook Joint Annual Meeting, Los Angeles, Calif., 1952, p. 159-161.
Park, W.H., Kern Front Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 51, No. 1 (1965).

Disposal Wells Permitted In The Kern Front Field - Santa Margarita Zone



Attachment 1, Preliminary Assessment of 11 Aquifers Historically Treated As Exempt

Kern River Field, Chanac Zone, East Side Bakersfield District

1) Number of disposal wells permitted in the zone:
   12 (10 of these are permitted in both the Santa Margarita and Chanac Zones in the Kern River field)

2) Number of active producers:
   0

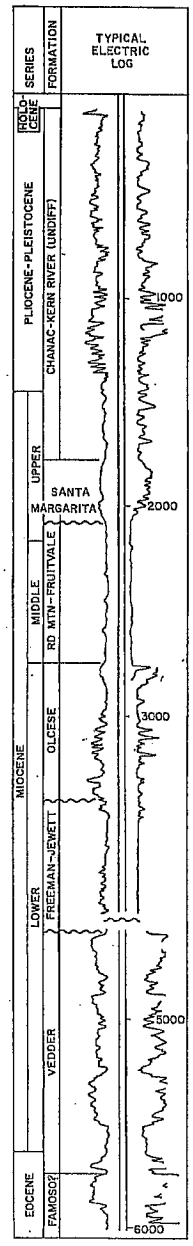
3) Depth of the zone where the injection wells are located:
   425' to 1,335' below surface. Zone dips to the Southwest across the field.

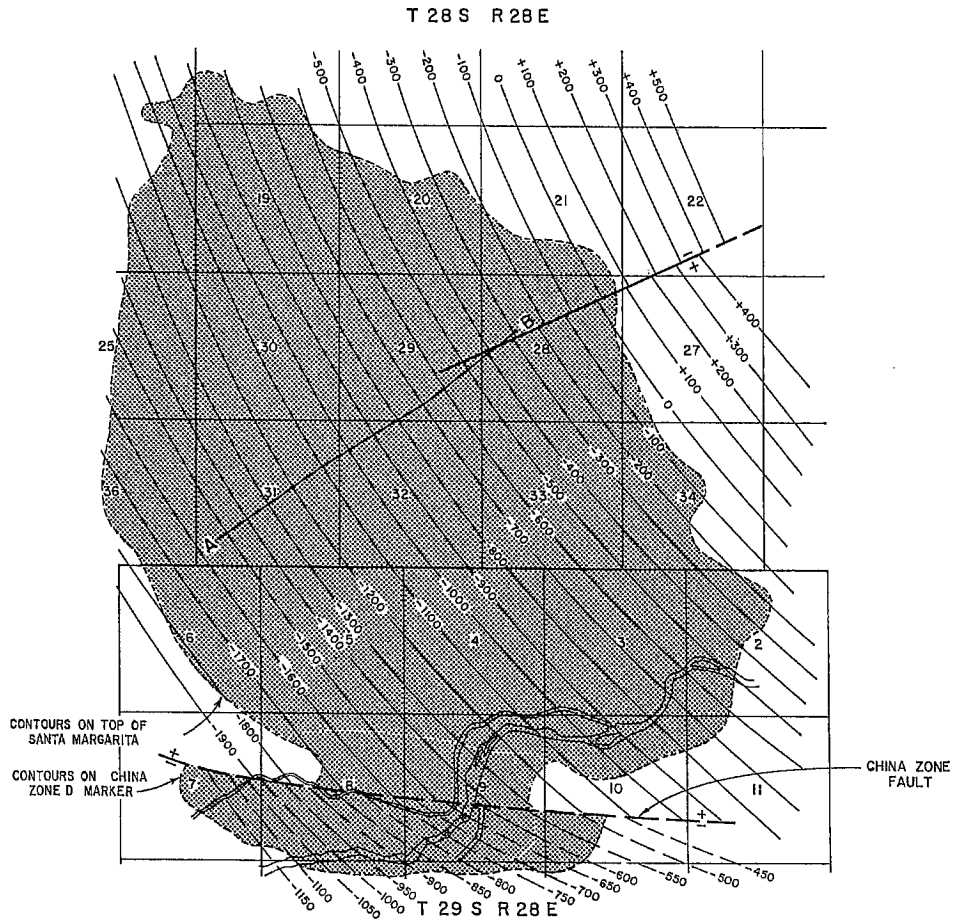
4) Volumes injected historically since 1983:
   568,987,463 Bbls, last injected on 3/1/2015

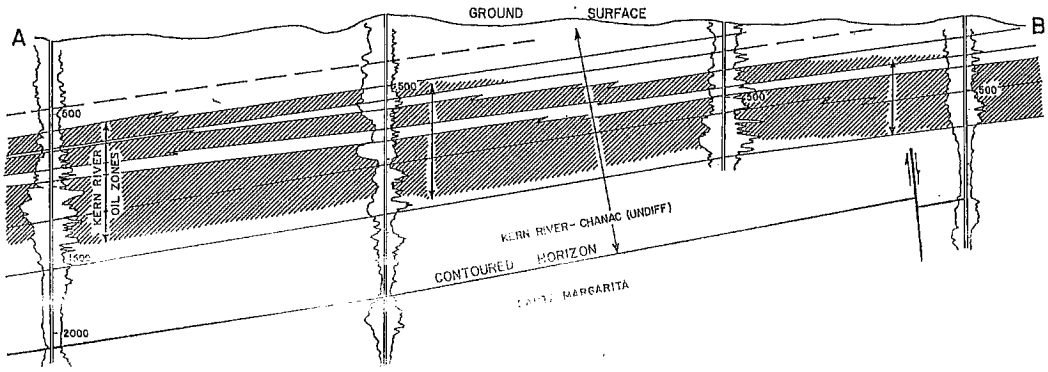
5) TDS of zone:
   926 mg/l – 3,325 mg/l TDS
   The 926 mg/l TDS sample is from well 21-4 top zone perf 1,220-1,223" (upper Chanac) on 05/22/1978 and sample 3,325 mg/l TDS sample is from "Chanac Zone KCL-10 2x" on 2/11/1987.

6) TDS of injection water:
   491 mg/l – 2,000 mg/l TDS
   The 491 mg/l TDS sample is from "Jost Plant Sec. 10, T29S/28E Waste disposal plant tank" on 11/23/1999 and sample 2,000 mg/l TDS sample is from "Cogen Disposal Water" on 11/26/1997. Permitted fluid in the Chanac zone, Kern River field consists of produced Kern River produced water from Kern River field and co-gen waste.

KERN RIVER OIL FIELD







LOCATION: 5 miles north of Bakersfield

TYPE OF TRAP: Permeability variations on a homocline

ELEVATION: 400 - 1,000

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Kern River	Elwood Brothers (no name well)	Same as present	3 29S 28E	MD	N.A.	N.A.	1899
China Zone	Westates Petroleum Co. "KCL" 1	Horace Steele and L.C. Gould "KCL" 1	8 29S 28E	MD	50	0	Sep 1947

Remarks: The discovery well was dug by hand in the spring of 1899 on what is now Chanslor-Western Oil Development Co. property. "Gassy vapors" caused the well to be abandoned without a test of its commercial possibilities. In June 1899 McWhorter Bros. drilled the first commercial well 400 feet north of the discovery well.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Standard Oil Co. of Calif. "KCL 26" 1-11	Same	Oct 1948	9 29S 28E	MD	6,986	Granite	Jurassic

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Kern River	900	700	late Pliocene	Kern River	13	5	None
China Zone	1,300	100 - 500	late Pliocene	Kern River	13	40	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
27,154,427	4,165	188,121,732	9,535	4,526	576,511,857	2,599,678	27,154,427	1972	7,942	6,978	9,850

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
Cyclic-steam	1961	300,849,501	5,215
Steam flood	1962	189,380,134	780

SPACING ACT: Does not apply

BASE OF FRESH WATER: 2,500

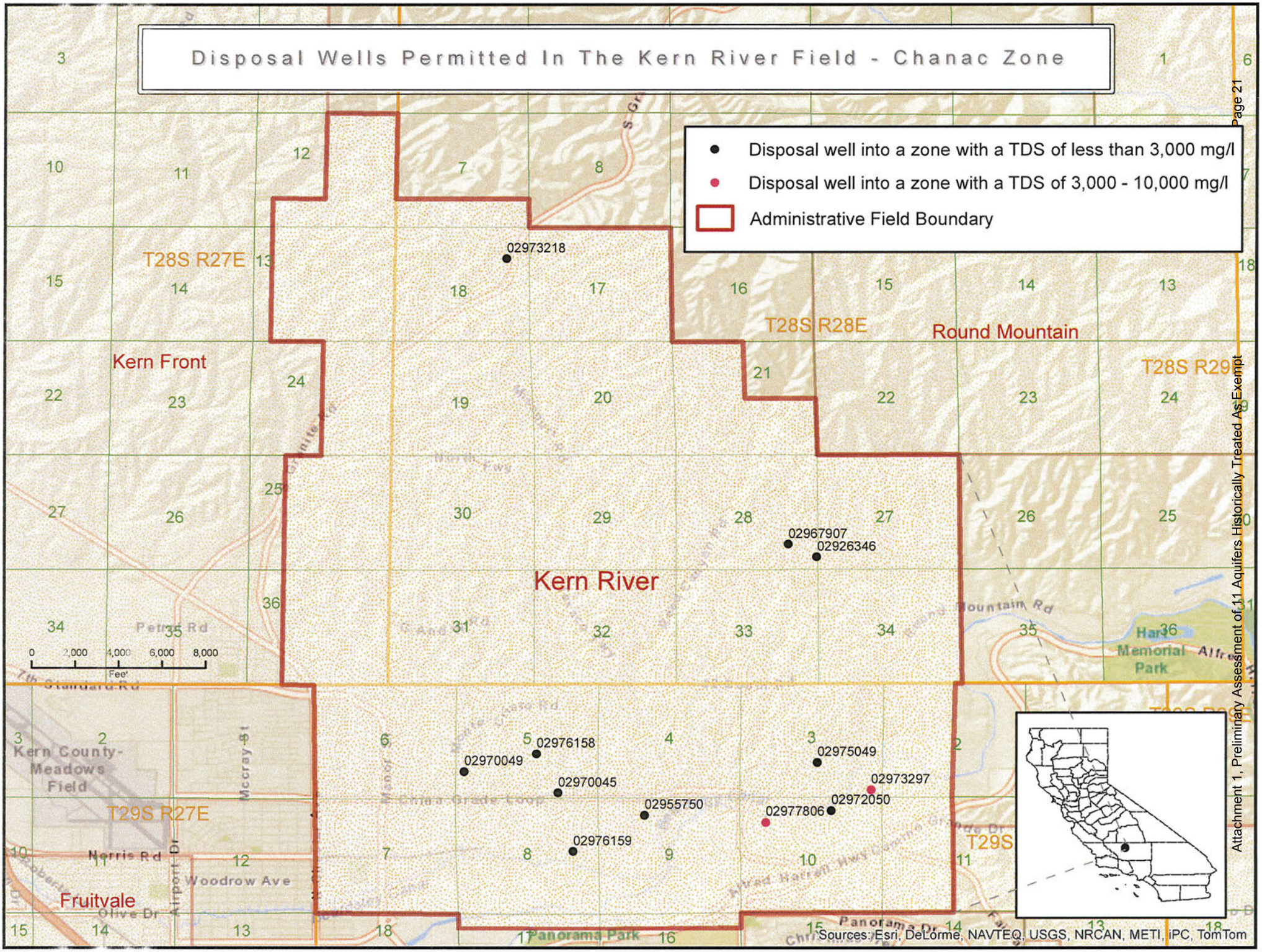
CURRENT CASING PROGRAM: 6 5/8" cem. through zone.

METHOD OF WASTE DISPOSAL: Waste water is injected into the Santa Margarita and Vedder, 12,143,578 bbls. in 1972. Waste water is also used in steam generation. The balance of the water is of a suitable enough quality that it is allowed to enter percolation ponds, irrigation canals, & the Kern River

REMARKS:

REFERENCES. Crowder, R.E., Kern River Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 38, No. 2 (1952).

Disposal Wells Permitted In The Kern River Field - Chanac Zone



Attachment 1, Preliminary Assessment of 11 Aquifers Historically Treated As Exempt

Kern River Field, Santa Margarita Zone, East Side Bakersfield District

1) Number of disposal wells permitted in the zone:
   32 (10 of these are permitted in both the Santa Margarita and Chanac Zones in the Kern River field)

2) Number of active producers:
   0

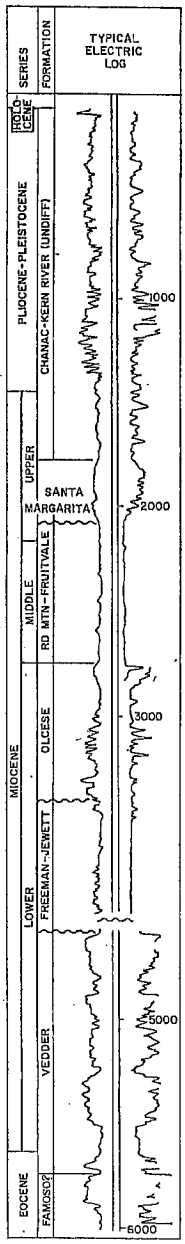
3) Depth of the zone where the injection wells are located:
   760' to 2,285' below surface. Zone dips to the Southwest across the field.

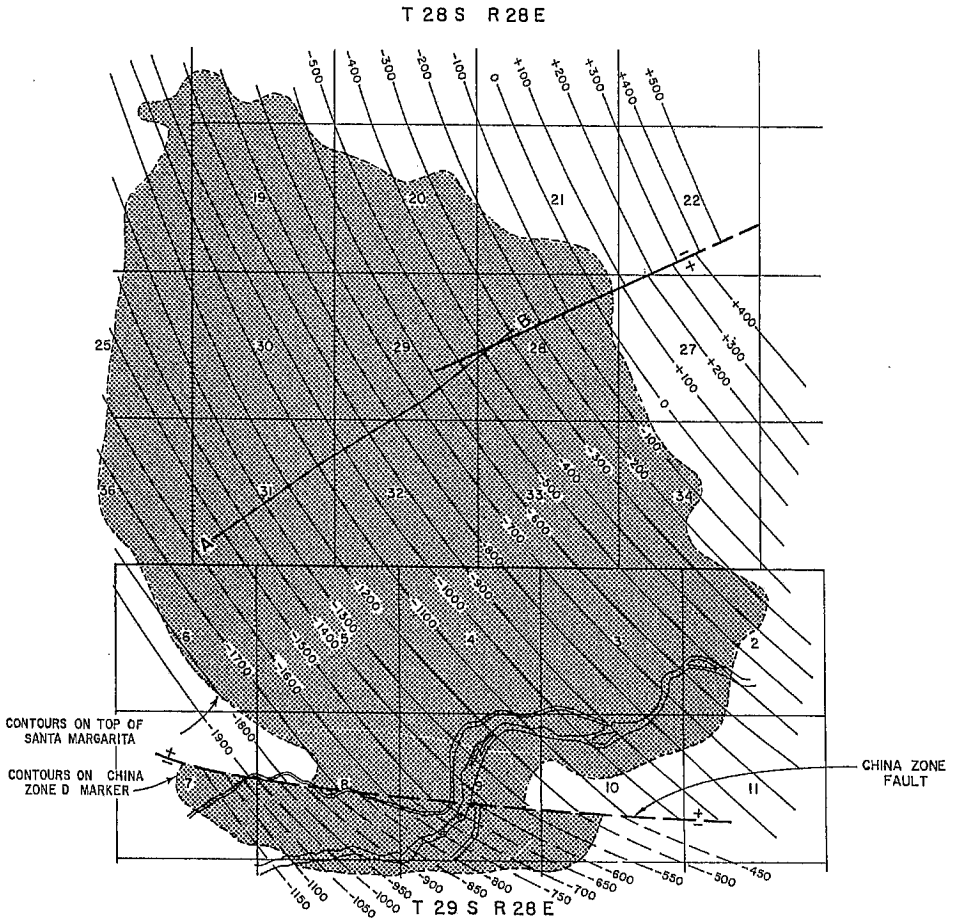
4) Volumes injected historically since 1983:
   799,041,272 Bbls, last injected on 3/1/2015

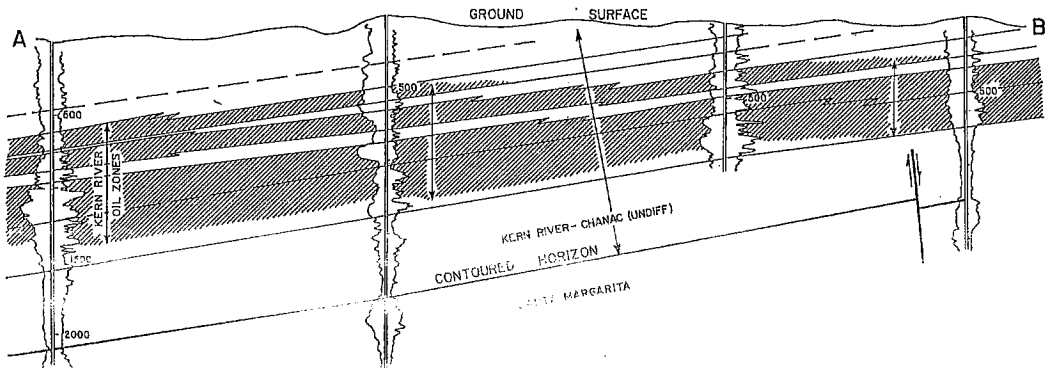
5) TDS of zone:
   490 mg/l – 1,584 mg/l TDS
   The 490 mg/l TDS sample is from "KCL – 10 Well #2X" (perf 1,068 – 1,196') on 12/30/1985 and the 1,584 mg/l TDS sample is from ""Rambler" 71 W" (perf 1,667-1,875') on 12/22/1965.

6) TDS of injection water:
   491 mg/l – 855 mg/l and 74,924 mg/l TDS
   The 491 mg/l TDS sample is from the "Jost plant Sec. 10 T29S/28E Waste Disposal Tank" on 11/23/1999, the 855 mg/l TDS sample is from the "Overland plant Sec. 28 T28S/R28E, produced water injection tank" on 11/23/1999, and the 74,924 mg/l is from the "Overland plant Sec. 28 T28S/R28E Brine Disposal Tank" (project 34000035). Permitted fluids for injection into the Santa Margarita zone, Kern River field consist of Kern River produced water, cogeneration and regeneration brine.

KERN RIVER OIL FIELD







LOCATION: 5 miles north of Bakersfield

TYPE OF TRAP: Permeability variations on a homocline

ELEVATION: 400 - 1,000

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Kern River	Elwood Brothers (no name well)	Same as present	3 29S 28E	MD	N.A.	N.A.	1899
China Zone	Westates Petroleum Co. "KCL" 1	Horace Steele and L.C. Gould "KCL" 1	8 29S 28E	MD	50	0	Sep 1947

Remarks: The discovery well was dug by hand in the spring of 1899 on what is now Chanslor-Western Oil Development Co. property. "Gassy vapors" caused the well to be abandoned without a test of its commercial possibilities. In June 1899 McWhorter Bros. drilled the first commercial well 400 feet north of the discovery well.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Standard Oil Co. of Calif. "KCL 26" 1-11	Same	Oct 1948	9 29S 28E	MD	6,986	Granite	Jurassic

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Kern River	900	700	late Pliocene	Kern River	13	5	None
China Zone	1,300	100 - 500	late Pliocene	Kern River	13	40	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
27,154,427	4,165	188,121,732	9,535	4,526	576,511,857	2,599,678	27,154,427	1972	7,942	6,978	9,850

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
Cyclic-steam	1961	300,849,501	5,215
Steam flood	1962	189,380,134	780

SPACING ACT: Does not apply

BASE OF FRESH WATER: 2,500

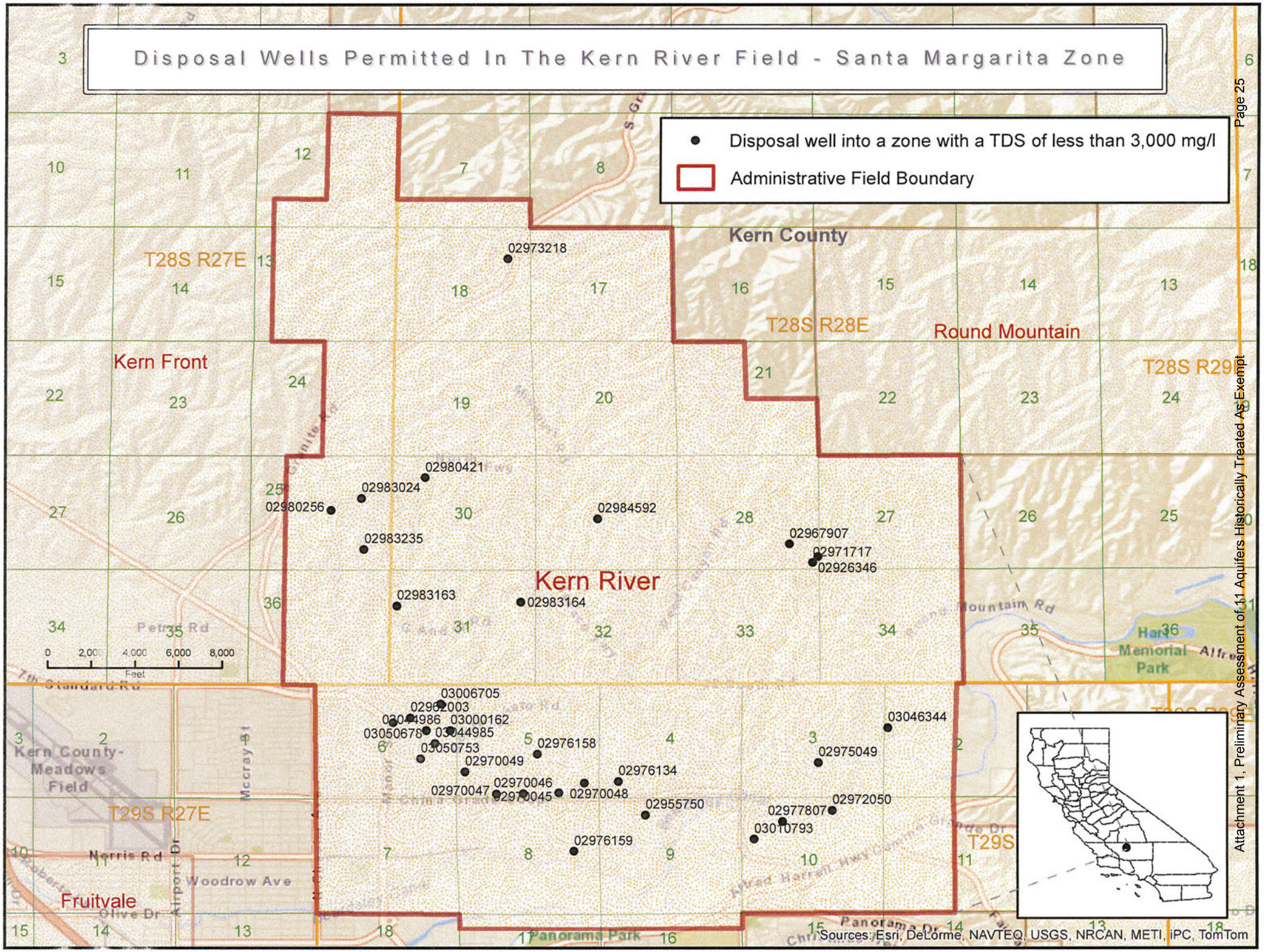
CURRENT CASING PROGRAM: 6 5/8" cem. through zone.

METHOD OF WASTE DISPOSAL: Waste water is injected into the Santa Margarita and Vedder, 12,143,578 bbls. in 1972. Waste water is also used in steam generation. The balance of the water is of a suitable enough quality that it is allowed to enter percolation ponds, irrigation canals, & the Kern River.

REMARKS:

REFERENCES: Crowder, R.E., Kern River Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 38, No. 2 (1952).

Disposal Wells Permitted In The Kern River Field - Santa Margarita Zone



Attachment 1, Preliminary Assessment of 11 Aquifers Historically Treated As Exempt

Mount Poso Field, Walker Zone, East Side Bakersfield District

1) Number of disposal wells permitted in the zone:
   5

2) Number of active producers in the zone:
   0

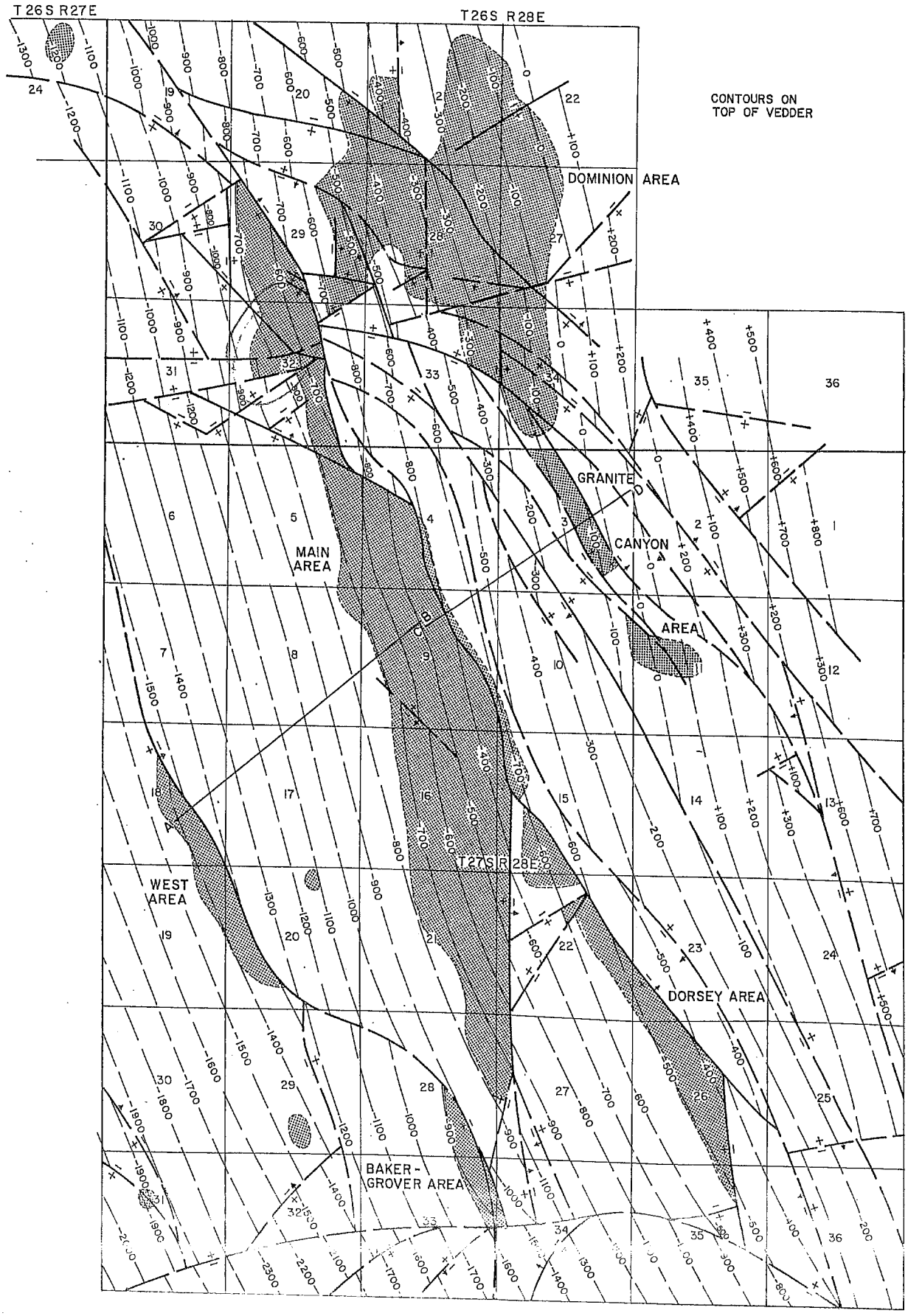
3) Depth of the zone where the injection wells are located:
   1,740' to 1,796' below surface (top of the Vedder/Walker zone). Injected only in combination with the laterally interfingered Vedder, which extends throughout the field.

4) Volumes injected historically since 1983:
   63,777,556 Bbls, last injected on 3/1/2015

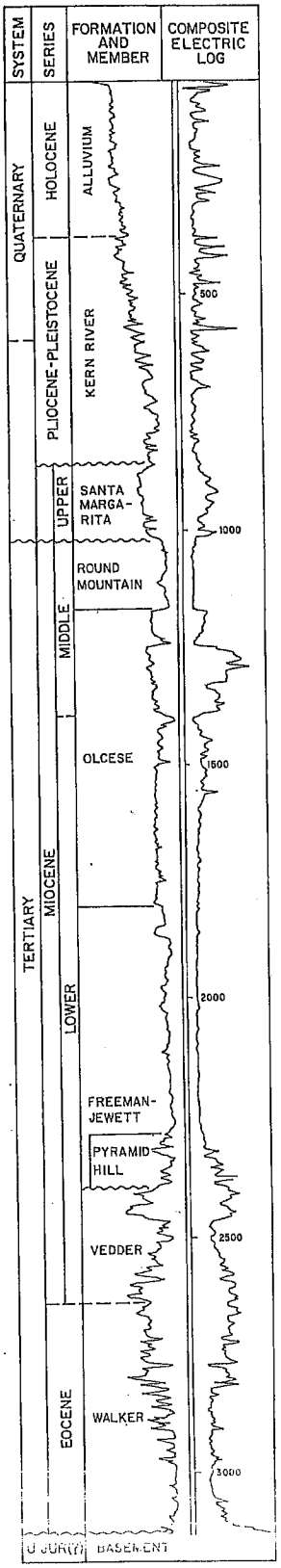
5) TDS of zone:
   1,069 mg/l TDS
   The 1,069 mg/l TDS zone sample is from "Black Foot Sump" on 05/31/1973.

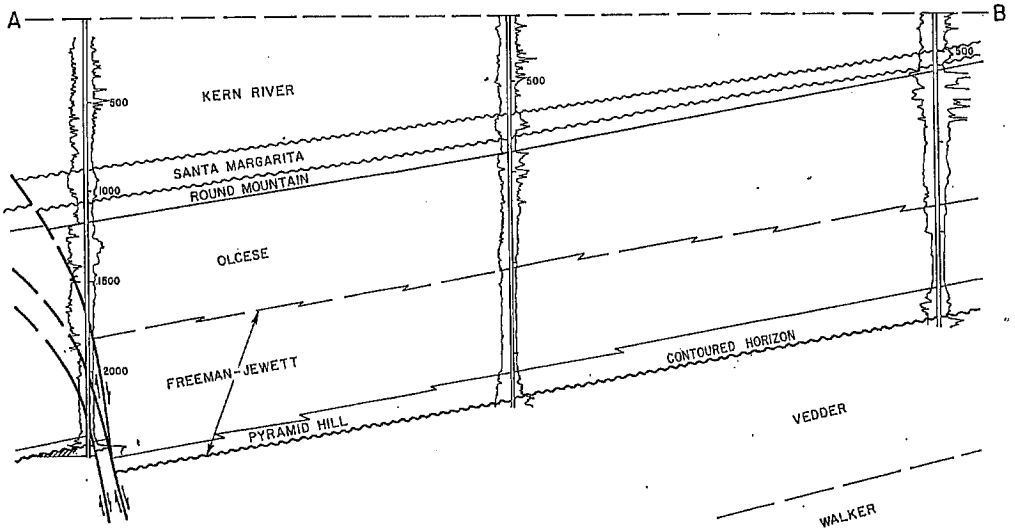
6) TDS of injection water:
   650 mg/l TDS
   The 650 mg/l TDS sample is from "Shapiro 234 Water Sample from Water Disposal" on 12/4/2008.

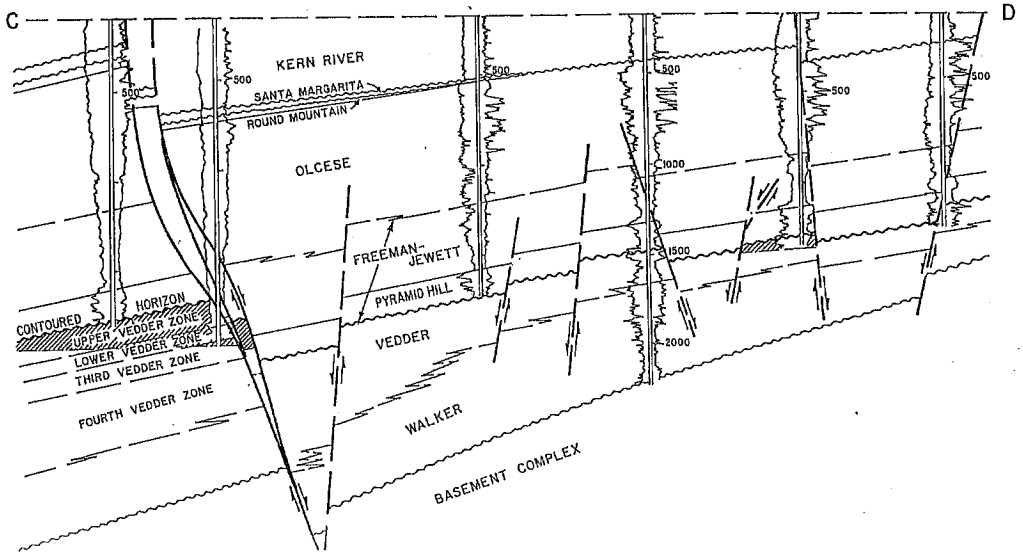
MOUNT POSO OIL FIELD



MOUNT POSO OIL FIELD







LOCATION: 13 miles northeast of Bakersfield

TYPE OF TRAP: See areas

ELEVATION: 650 - 1,450

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Pyramid Hill and Upper Vedder	Shell Oil Co. "Vedder" 1	Shell Co. of California "Vedder" 1	9 27S 28E	MD	300	N.A.	Jul 1926

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Pacific Oil and Gas Dev. Corp. "City of San Francisco" 56-32	Same	Aug 1957	32 27S 28E	MD	3,759	Walker	Eocene

PRODUCING ZONES (See areas)

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
1,830,017	728	84,316,129	3,630	532	164,558,017	1,977,245	8,427,304	1943	1,184	828	3,805

STIMULATION DATA (Jan. 1, 1973) (See areas)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection

SPACING ACT: See areas.

BASE OF FRESH WATER: See areas.

CURRENT CASING PROGRAM: See areas.

METHOD OF WASTE DISPOSAL: See areas.

REMARKS:

REFERENCES: Albright, M.B., A.G. Hluza, and J.C. Sullivan, Mount Poso Oil Field, Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 43, No. 2 (1957).

LOCATION. See map sheet of Mount Poso Oil Field

TYPE OF TRAP: Faulted regional homocline

ELEVATION: 650 - 1,050

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production Oil (bbl)	Initial daily production Gas (Mcf)	Date of completion
Upper Vedder	Emjayco "Baker" 1	Baker-Grover Co. "Baker" 1	33 27S 28E	MD	250	N.A.	Jul 1935

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
The White Hills Oil Co. No. 1	Ralph R. Whitehill No. 1	Apr 1961	34 27S 28E	MD	2,483	Vedder	early Mio

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Upper Vedder	1,750	25	early Miocene	Vedder	15	190	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
9,991	0	883,158	80	4	3,700,652	0	276,899	1937	49	23	90

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: 1,100

CURRENT CASING PROGRAM: 7" cem. above zone; 5 1/2" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps (to be phased out).

REMARKS:

REFERENCES

LOCATION: See map sheet of Mount Poso Oil Field

TYPE OF TRAP: Faulted homocline; lithofacies variations

ELEVATION: 1,100 - 1,350

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Vedder	Robert B. Doe, "Dominion" 2	A. Bruce Frame "Dominion" 2	28 26S 28E	MD	435	N.A.	Dec 1928

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Glen H. Mitchell "SP" 1	Same	May 1945	33 26S 28E	MD	2,512	Schist	Late Jur

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Vedder	1,560	35	early Miocene	Vedder	15	10	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
107,317	0	4,482,093	675	74	5,735,208	0	197,189	1933	195	128	690

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
Cyclic-steam	1964	177,242	12

SPACING ACT: Does not apply

BASE OF FRESH WATER: No saline waters present

CURRENT CASING PROGRAM: 7" cem. above zone; 5 1/2" liner landed through zone.

METHOD OF WASTE DISPOSAL: Injection into the Vedder; evaporation and percolation sumps.

REMARKS:

REFERENCES:

LOCATION: See map sheet of Mount Poso Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION. 900 - 1,250

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production		Date of completion
					Oil (bbl)	Gas (Mcf)	
Upper Vedder	Thomas Oil Co. "Dorsey" 2	R.S. Lytle "Dorsey" 2	26 27S 28E	MD	570	N.A.	Sep 1928

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth	
						Strata	Age
Emjayco "Glide" 15-1	Harry H. Magee, Opr. "Glide" 15-1	Oct 1956	15 27S 28E	MD	2,000	Vedder	early Mio

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic		Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
			Age	Formation			
Upper Vedder	1,500	30	early Miocene	Vedder	16	5	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production			1972 Proved acreage	1972 Average number producing wells	Cumulative production		Peak oil production		Total number of wells		Maximum proved acreage
Oil (bbl)	Net gas (Mcf)	Water (bbl)			Oil (bbl)	Gas (Mcf)	Barrels	Year	Drilled	Completed	
86,429	0	1,913,270	375	47	4,676,008	0	204,880	1958	142	76	410

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Does not apply

BASE OF FRESH WATER: Basement

CURRENT CASING PROGRAM: 8 5/8" cem. above zone; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Percolation and evaporation sumps on outcrop of Round Mountain Silt; injection wells.

REMARKS: Vedder zone water contains 1.75 ppm boron.

REFERENCES:

LOCATION: See map sheet of Mount Poso Oil Field

TYPE OF TRAP: Faulted homocline; lithofacies variations

ELEVATION: 1,300

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Upper Vedder	Road Oil Sales, Inc. "SP" 2	J.J. Chevalier "Southern Pacific" 2	3 27S 28E	MD	50	N.A.	Nov 1936

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Lyle A. Garner & Assoc. "S.P." 3-1	Same	May 1952	3 27S 28E	MD	2,226	Granite	Late Jur

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Upper Vedder	1,390	30	early Miocene	Vedder	15	10	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
3,808	0	20,675	80	10	823,450	0	65,780	1949	65	30	130

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: Basement

CURRENT CASING PROGRAM: 8 5/8" cem. above zone; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation sumps on outcrop of Round Mountain Silt.

REMARKS: A cyclic-steam project was started in 1967 and discontinued after 19,069 bbls. of water in the form of steam were injected. A pilot fire flood project, initiated in 1963, was terminated in 1965.

REFERENCES:

LOCATION: See map sheet of Mount Poso Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 700 - 1,450

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Pyramid Hill and Upper Vedder	Shell Oil Co. "Vedder" 1	Shell Oil Co. of Calif. "Vedder" 1	9 27S 28E	MD	300	N.A.	Jul 1926
Lower Vedder [A]	Shell Oil Co. "Vedder" 6	Same as present	9 27S 28E	MD	835	N.A.	Jan 1933
Third Vedder	Unknown	Unknown	4 27S 28E or 9	MD	N.A.	N.A.	Prior to 1957
Fourth Vedder [B]	Shell Oil Co. "Glide" 6	Same as present	15 27S 28E	MD	134	N.A.	Aug 1957

Remarks: The first separate well that produced from the Pyramid Hill zone was Shell Oil Co. "Security" 3, Sec. 9, T. 27S., R. 28E. Initial production was 4 barrels per day.
[A] Commingled production from Upper Vedder and Lower Vedder.
[B] Commingled production from Third Vedder and Fourth Vedder.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Trico Industries, Inc. "USL" 6-2	Trico Oil and Gas Co. "USL" 6-2	Jul 1960	6 27S 28E	MD	2,665	Vedder	early Mio

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Pyramid Hill	1,600	160	early Miocene	Pyramid Hill	17	N.A.	None
Upper Vedder	1,750	140	early Miocene	Vedder	16	80	None
Lower Vedder	1,900	80	early Miocene	Vedder	16	N.A.	None
Third Vedder	1,985	120	early Miocene	Vedder	16	75	None
Fourth Vedder	2,105	50	early Miocene	Vedder	16	65	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
1,590,436	728	75,595,054	2,225	374	146,734,300	1,977,245	7,982,576	1943	641	524	2,265

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
Steam flood	1963	9,351,042	11

SPACING ACT: Does not apply

BASE OF FRESH WATER: 1,000 - 1,500

CURRENT CASING PROGRAM: 8 5/8" cem. above zone and across base of fresh-water sands; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps; injection into Vedder sand.

REMARKS: A cyclic-steam project was started in 1963 and discontinued after 116,623 bbls. of water in the form of steam was injected. A water flood project was started in 1952 and discontinued after 608,470 bbls. of water was injected.

REFERENCES:

CALIFORNIA DIVISION OF OIL AND GAS

WEST AREA

MOUNT POSO OIL FIELD

Kern County

LOCATION: See map sheet of Mount Poso Oil Field

TYPE OF TRAP: Faulted homocline with permeability variations

ELEVATION: 700 - 1,075

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Upper Vedder	Thomas Oil Co. "Ring 18" 1	Dwight G. Vedder No. 1	18 27S 28E	MD	0	5,300	Dec 1943

Remarks: Gas cap was of limited volume. After being shut in for one year the discovery well was recompleted producing oil.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Pacific Oil & Gas Dev. Corp. "City of San Francisco" 56-32	Same	Aug 1957	32 27S 28E	MD	3,759	Walker	Eocene

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Upper Vedder	2,575	15 - 50	early Miocene	Vedder	16	60	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
32,036	0	1,421,879	195	23	2,888,399	0	190,765	1957	92	47	220

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

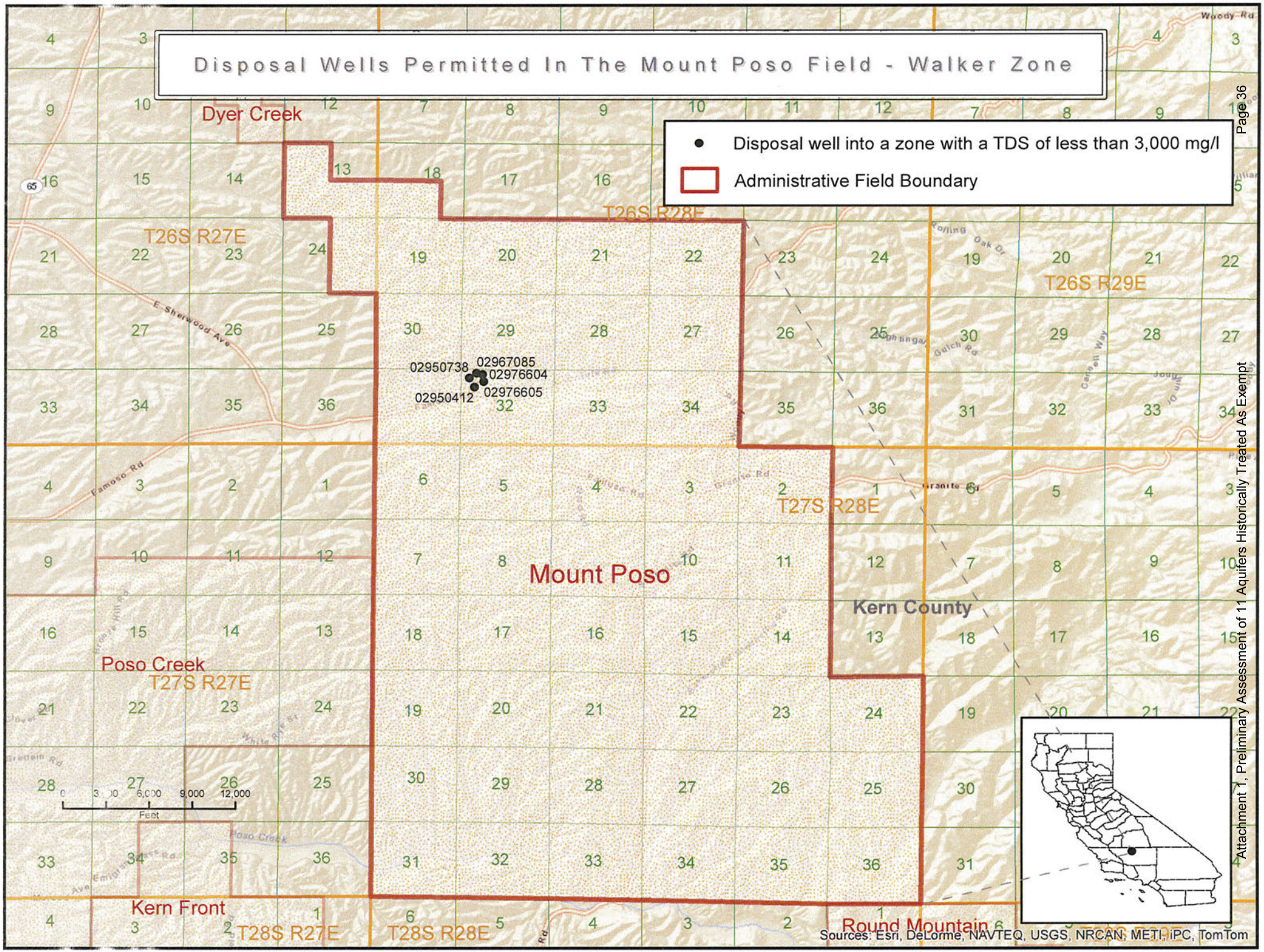
BASE OF FRESH WATER: 1,800

CURRENT CASING PROGRAM: 7" cem. above zone and across base of fresh-water sands; 5 1/2" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps (to be phased out).

REMARKS: Vedder zone water contains 3 to 4 ppm boron.

REFERENCES:


Disposal Wells Permitted In The Mount Poso Field - Walker Zone
Disposal well into a zone with a TDS of less than 3,000 mg/l
Administrative Field Boundary
Dyer Creek
T26S R28E
T26S R27E
T26S R29E
T27S R28E
Mount Poso
Kern County
Poso Creek
T27S R27E
Kern Front
T28S R27E
T28S R28E
Round Mountain
02950738
02967085
02976604
02950412
02976605
0 3,000 6,000 9,000 12,000
Feet
Sources: Esri, DeLorme, NAVTEQ, USGS, NRCAN, METI, iPC, TomTom

Round Mountain Field, Olcese Zone, East Side Bakersfield District

1) Number of disposal wells permitted in the zone:
   6 (4 wells are permitted in both the Olcese and Walker Zones in Round Mountain Field)

2) Number of active producers:
   0

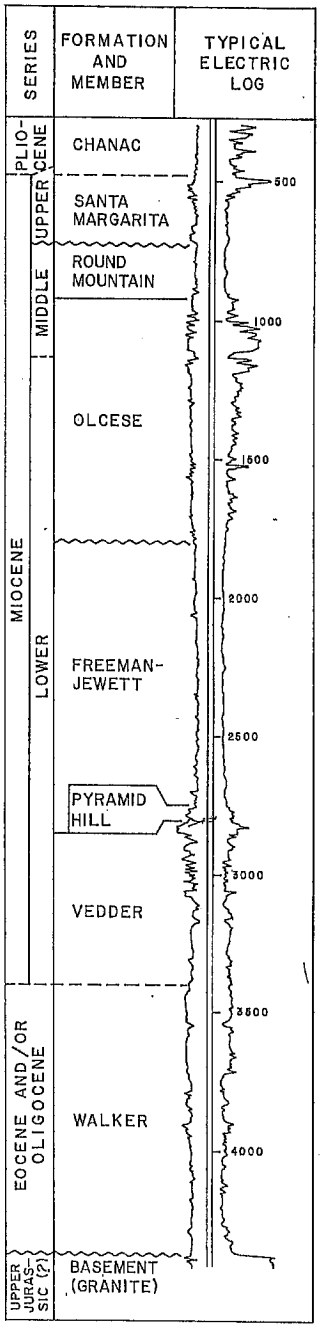
3) Depth of the zone where the injection wells are located:
   710' to 850' below surface. These zone depths are from wells API #029-18114 and API #029-18119, which are currently injecting in the Olcese zone. The remaining wells in the field (029-47441, 029-47543, 030-51960 and 030-51959) are permitted to inject in the Olcese, Freeman-Jewett, Vedder and Walker but are currently perforated in the Vedder and/or Walker zones only. For these 4 wells there are no logs available that pick the top of the Olcese zone since there is no injection there. Zone is fault bounded 1 ½ miles east of field limits, and pinches out 5 miles west of field limits.

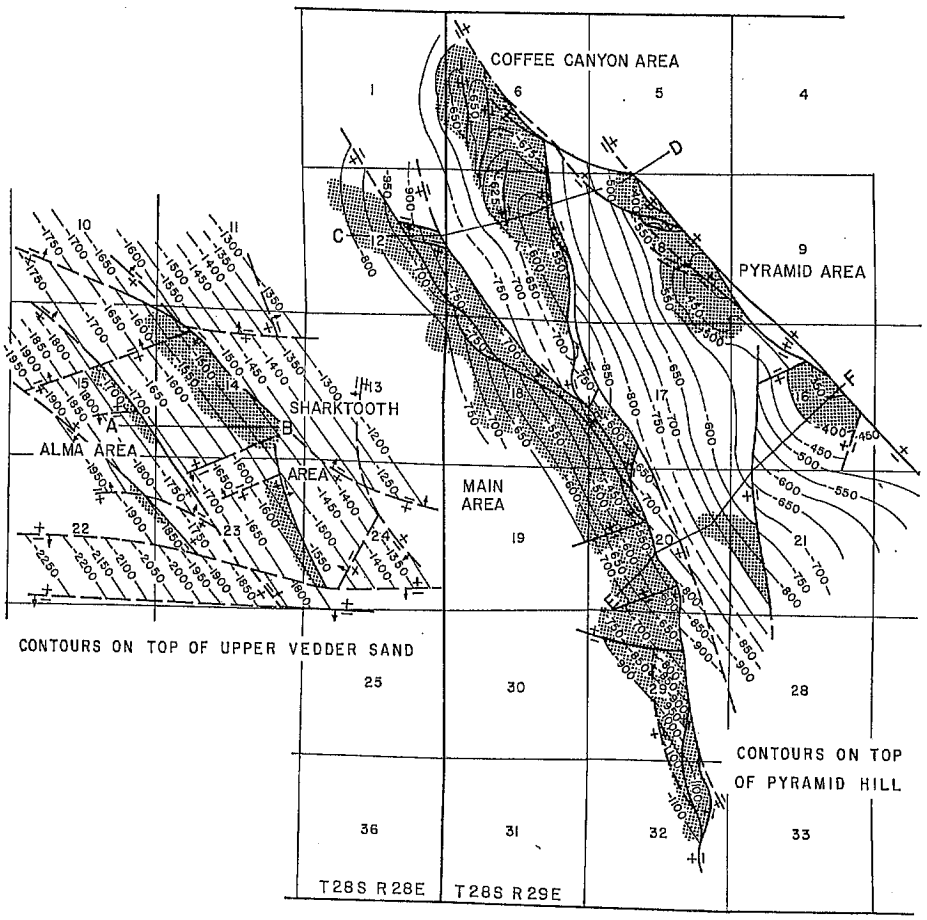
4) Volumes injected historically since 1983:
   160,798,008 Bbls, last injected on 1/1/2015

5) TDS of zone:
   2,693 mg/l TDS
   Sample collected from "water from Bishop #6 Bailer Sample at 600'" on 4/27/1974.

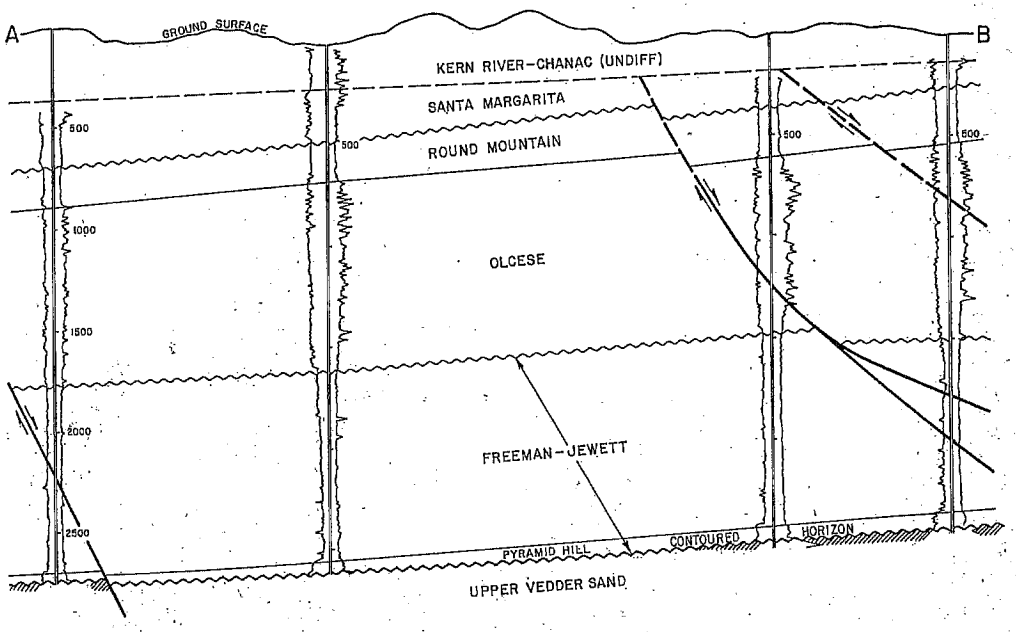
6) TDS of injection water:
   1,900 mg/l TDS
   Sample collected from "Sec. 20 produced water" (Olcese WD#342 & 343) on 2/23/2009. Permitted fluids for injection into the Olcese Zone in Round Mountain field consist of Pyramid Hill, Jewett, Freeman-Jewett and Vedder zones.

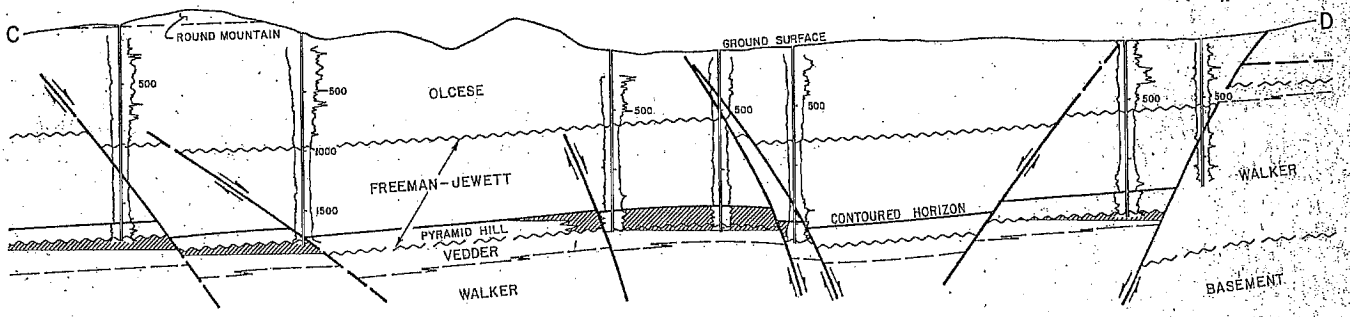
ROUND MOUNTAIN OIL FIELD

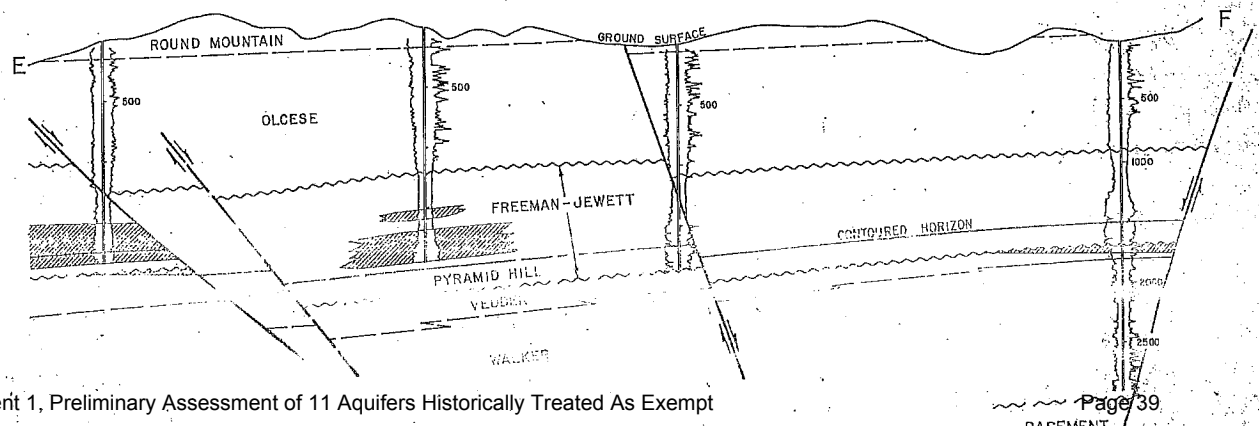




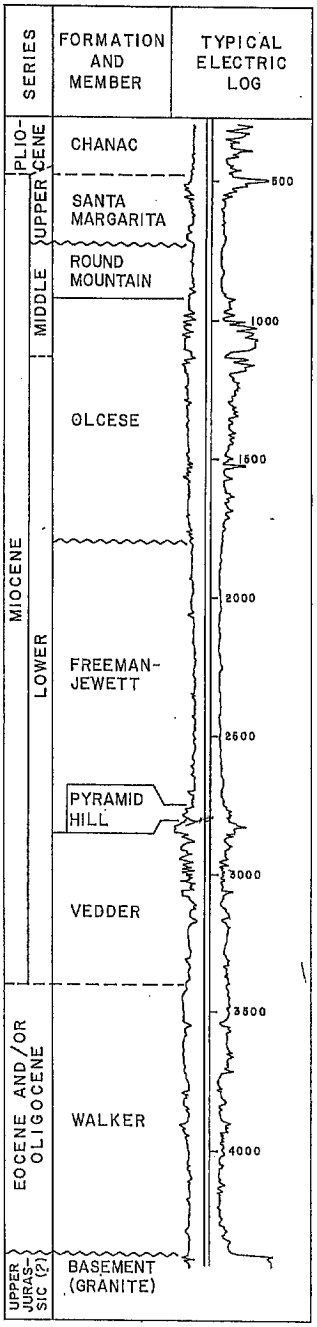
ROUND MOUNTAIN OIL FIELD

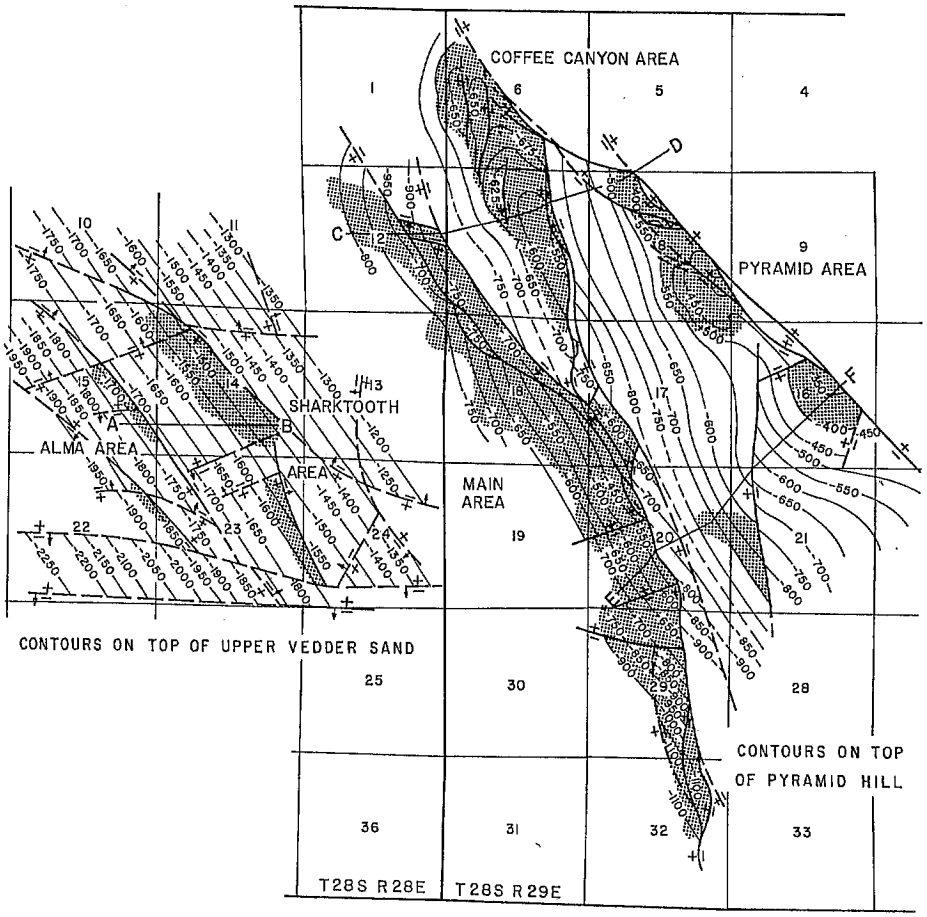






ROUND MOUNTAIN OIL FIELD





LOCATION: 14 miles northeast of Bakersfield

TYPE OF TRAP: See areas

ELEVATION: 600 - 1,500

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Jewett	Getty Oil Co. No. 2	Elbe Oil Land Dev. Co. No. 2	20 28S 29E	MD	*204	N.A.	May 1927
Pyramid Hill	Same as above	Same as above	20 28S 29E	MD	N.A.	N.A.	May 1927
Vedder	Same as above	Same as above	20 28S 29E	MD	N.A.	N.A.	May 1927

Remarks: * Production listed for Jewett is the combined production rate from the Jewett, Pyramid Hill, and Vedder zones.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
C.C. Killingsworth "Alma" 6	Barnsdall Oil Co. "Alma" 6	Mar 1948	15 28S 28E	MD	4,418	Basement (Granite)	Late Jur (?)

PRODUCING ZONES (See areas)

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
711,406	46,635	48,630,496	2,435	292	89,199,121	1,424,213	5,453,194	1938	665	468	2,590

STIMULATION DATA (Jan. 1, 1973) (See areas)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection

SPACING ACT: See areas.

BASE OF FRESH WATER: See areas.

CURRENT CASING PROGRAM: See areas.

METHOD OF WASTE DISPOSAL: See areas.

REMARKS:

REFERENCES: See areas.

CALIFORNIA DIVISION OF OIL AND GAS

ALMA AREA

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 700 - 1,270

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Vedder	Harold C. Morton & H.S. Kohlbush "Alma" 1	Same as present	15 28S 28E	MD	152	N.A.	Feb 1947

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
C.C. Killingsworth "Alma" 6	Barnsdall Oil Co. "Alma" 6	Mar 1948	15 28S 28E	MD	4,418	Basement (Granite)	Late Jur.

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Vedder	2,600	15	early Miocene	Vedder	13	N.A.	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
6,240	0	107,447	50	3	598,904	0	113,392	1948	47	21	80

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: None

CURRENT CASING PROGRAM: 8 5/8" cem. above zone; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps on outcrops of the Round Mountain Silt.

REMARKS:

REFERENCES: Albright, M.B. Jr., Sharktooth and Alma Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 42, No. 1 (1956).

CALIFORNIA DIVISION OF OIL AND GAS

COFFEE CANYON AREA

ROUND MOUNTAIN OIL FIELD

Kern County

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 690 - 1,300

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Pyramid Hill	Acacia Oil Co. "Coffee" 1	Reynolds Oil and Gas Co. No. 1	6 28S 29E	MD	*600	N.A.	Sep 1928
Vedder	Acacia Oil Co. "Lindsay" 1	Lindsay Oil Co. No. 1	6 28S 29E	MD	800	N.A.	Aug 1928

Remarks: * Production is commingled from Pyramid Hill and Vedder.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Richard S. Rheem, Opr. "Smoot-Vedder" 2	Same	May 1957	1 28S 28E	MD	2,313	Vedder	early Mio

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Pyramid Hill	1,500	150	early Miocene	Jewett	18	50	None
Vedder	1,650	30	early Miocene	Vedder	16	75	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
103,176	0	7,292,707	435	50	18,507,039	67,567	1,857,108	1937	133	104	475

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
Water flood	1960	3,815,746	1

SPACING ACT: Does not apply

BASE OF FRESH WATER: 0 - 200

CURRENT CASING PROGRAM: 7" cem. above zone; 5 1/2" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps on outcrops of the Round Mountain Silt.

REMARKS: A cyclic-steam injection project in the Pyramid Hill and Vedder zones was started in 1965 and terminated in 1968. Cumulative injection totals 12,200 bbls. The Pyramid Hill zone was originally known as the Elbe zone.

REFERENCES: Park, W.B., J.R. Weddle, J.A. Barnes, Main Coffee Canyon and Pyramid Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 49, No. 2 (1963).

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 600 - 1,500

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Jewett	Getty Oil Co. No. 2	Elbe Oil Land Dev. Co. No. 2	20 28S 29E	MD	*204	N.A.	May 1927
Pyramid Hill	Same as above	Same as above	20 28S 29E	MD	N.A.	N.A.	May 1927
Vedder	Same as above	Same as above	20 28S 29E	MD	N.A.	N.A.	May 1927

Remarks: * Production listed for Jewett is the combined production rate from the Jewett, Pyramid Hill, and Vedder zones.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Shell Oil Co. "Jewett" 3	Same	Jun 1928	29 28S 29E	MD	2,678	Walker	Eo &/or Olig

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Jewett	1,600	130	early Miocene	Freeman-Jewett	22	N.A.	None
Pyramid Hill	1,900	150	early Miocene	Jewett	18	N.A.	None
Vedder	2,000	80	early Miocene	Vedder	16	95	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
510,916	46,561	35,953,284	1,415	171	59,572,216	1,293,959	3,794,620	1938	302	225	1,465

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Does not apply

BASE OF FRESH WATER: None

CURRENT CASING PROGRAM: 7" cem. above zone; 5 1/2" liner landed through zone.

METHOD OF WASTE DISPOSAL: 4,845,286 bbl. of waste water was injected during 1972 into two disposal wells; percolation and evaporation sumps on outcrops of the Round Mountain Silt.

REMARKS: A water flood project in the Vedder zone was started in 1961 and terminated in 1963. Cumulative injection totals 872,587 bbls.

REFERENCES: Park, W.H., J.R. Weddle, J.A. Barnes, Main, Coffee Canyon, and Pyramid Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 49, No. 2 (1963).

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 730 - 1,470

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Pyramid Hill	Thomas Oil Co. "Olcese" 2	Harp & Brown "Olcese" 2	17 28S 29E	MD	5	0	May 1944
Vedder	Crestmont Oil Co. "Olcese" 1	Eastmont Oil Co. "Olcese" 1	16 28S 29E	MD	250	N.A.	May 1937
Walker	Crestmont Oil Co. "Staley" 11	Same as present	8 28S 29E	MD	40	N.A.	Jul 1943

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Piute Holding Co. "Smith" 1	Same	Oct 1929	17 28S 29E	MD	3,110	Walker	Eo &/or Olig

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Pyramid Hill	1,250	130	early Miocene	Jewett	18	50	None
Vedder	1,390	40	early Miocene	Vedder	16	80 - 110	None
Walker	1,535	50	Eo &/or Olig	Walker	20	N.A.	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
55,714	74	1,527,767	290	37	5,692,349	6,876	378,882	1946	98	60	300

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: None

CURRENT CASING PROGRAM: 8 5/8" or 7" cem. above zone; 6 5/8" or 5" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps on outcrops of the Round Mountain Silt.

REMARKS:

REFERENCES: Peak, W.H., J.R. Weddle, J.A. Barnes, Main, Coffee Canyon, and Pyramid Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 49, No. 2 (1963).

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 700 - 1,300

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Vedder	G M V Oil Co. "Signal-Mills" 1	Bandini Petroleum Co. "Signal Mills" 1	24 28S 28E	MD	214	N.A.	Sep 1943

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Mobil Oil Corp. "Bradford" 1	General Petroleum Corp. "Bradford" 1	Jun 1943	15 28S 28E	MD	2,995	Vedder	early Mio

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Vedder	2,400	25	early Miocene	Vedder	13	N.A.	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
35,360	0	3,749,291	245	31	4,828,613	55,811	503,449	1947	85	58	270

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: None

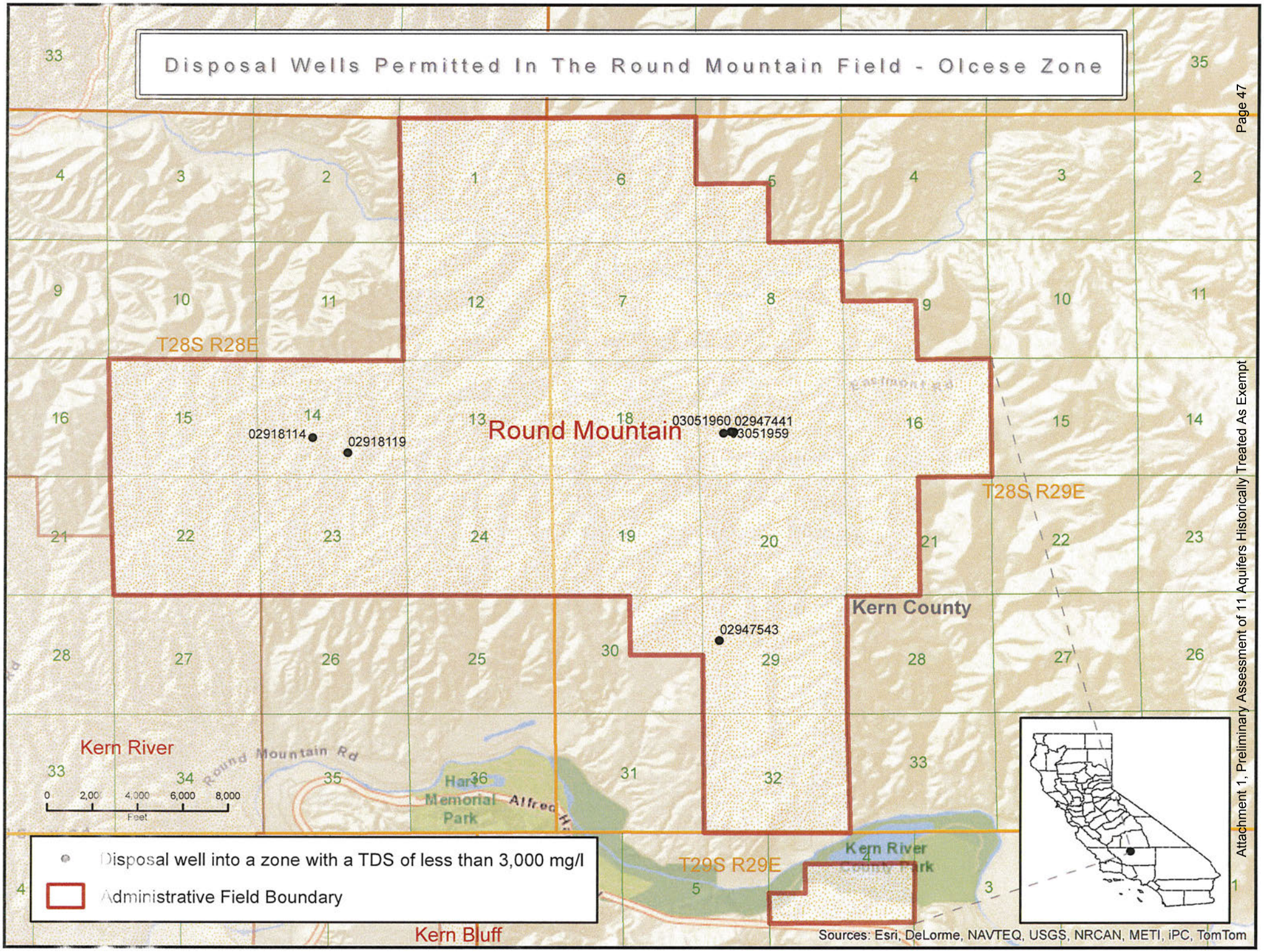
CURRENT CASING PROGRAM: 8 5/8" cem. above zone; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps on outcrops of the Round Mountain Silt.

REMARKS:

REFERENCES: Albright, M.B. Jr., Sharktooth and Alma Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas. Summary of Operations--Calif. Oil Fields, Vol. 42, No. 1 (1956).

Disposal Wells Permitted In The Round Mountain Field - Olcese Zone



Round Mountain Field, Walker Zone, East Side Bakersfield District

1) Number of disposal wells permitted in the zone:
   30 (4 of these are permitted in both the Olcese and Walker Zones in Round Mountain Field). There are 2 gas disposal wells.

2) Number of active producers:
   4 wells (Note that although this aquifer was historically treated as exempt as a non-hydrocarbon producing formation, the Walker zone within the field has current production.)

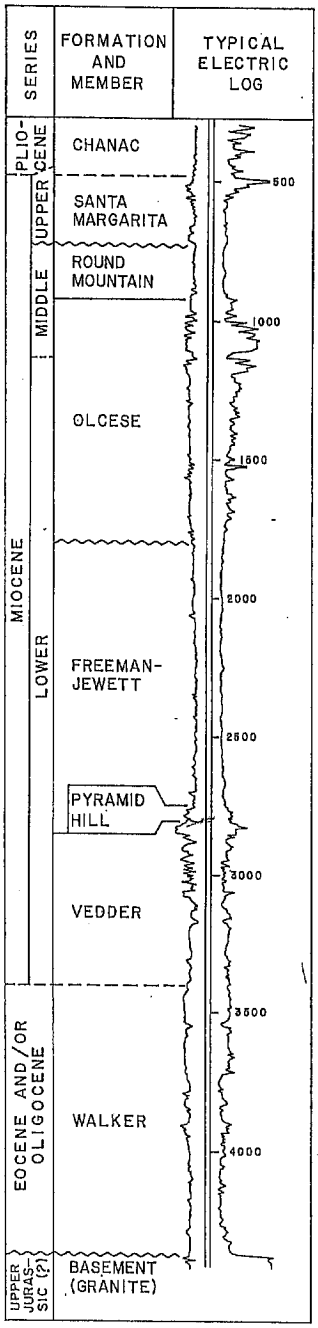
3) Depth of the zone where the disposal wells are located:
   1,890' to 2,590' below surface

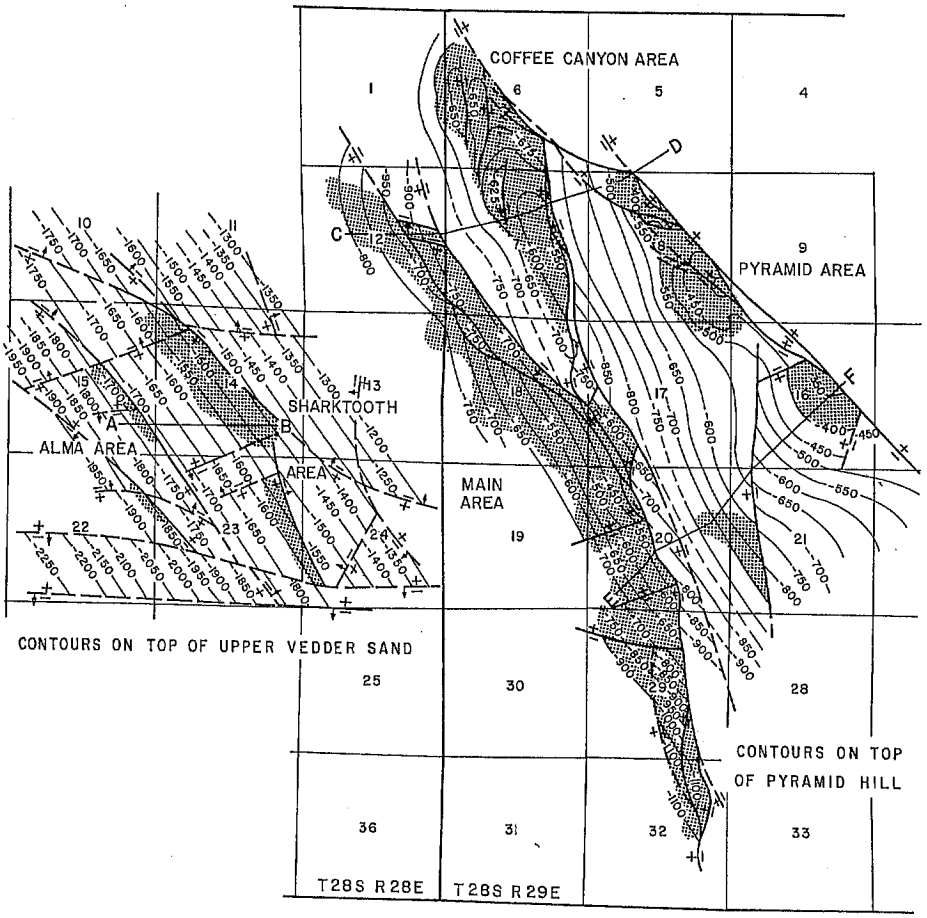
4) Volumes injected historically since 1983:
   1,529,910,014 Bbls, last injected on 3/1/2015

5) TDS of zone:
   2,335 mg/l TDS
   Sample 2,335 mg/l TDS is from "Walker zone formation water" (Round Mountain WD 1-20) on 10/17/1983.

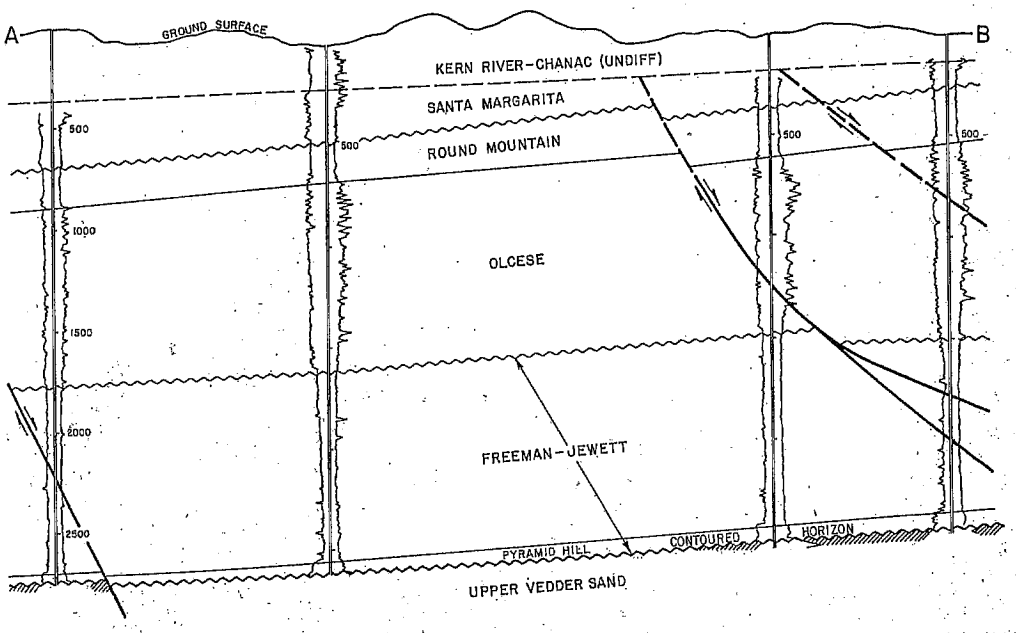
6) TDS of injection water:
   1,600 – 2,900 mg/l TDS
   The 1,600 mg/l TDS sample is from "NAM Produced water (West signal #8) on 1/1/2009 and the 2,900 mg/l TDS sample is from "18-WD7" on 9/20/2012. Permitted fluids for injection into the Walker Zone in Round Mountain field consist of Pyramid Hill, Jewett, Freeman-Jewett and Vedder zones production fluid.

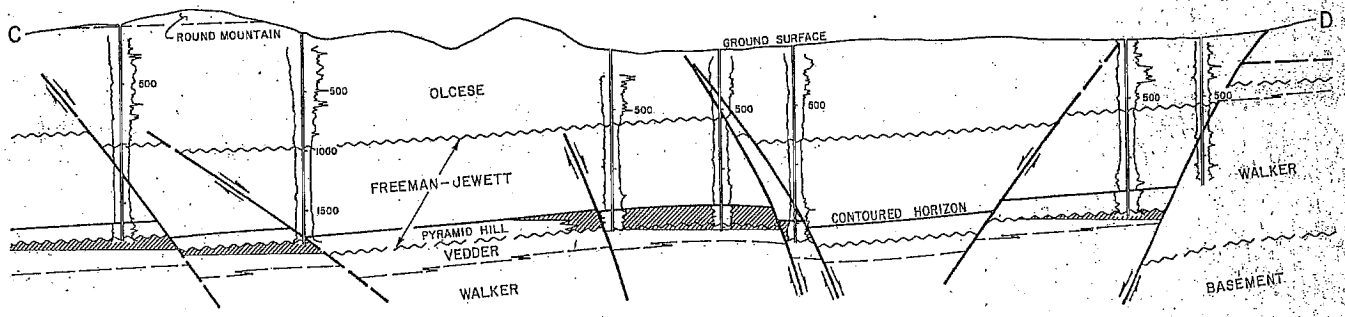
ROUND MOUNTAIN OIL FIELD

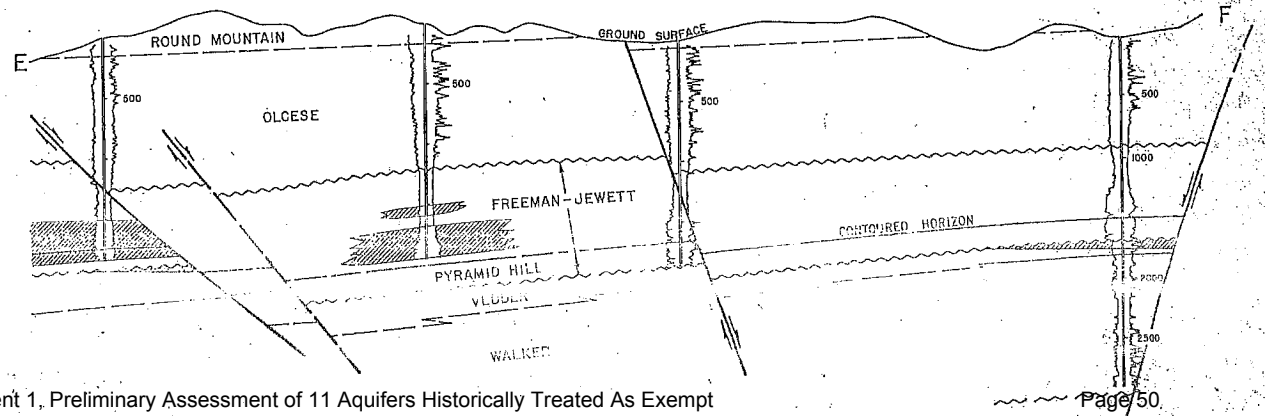




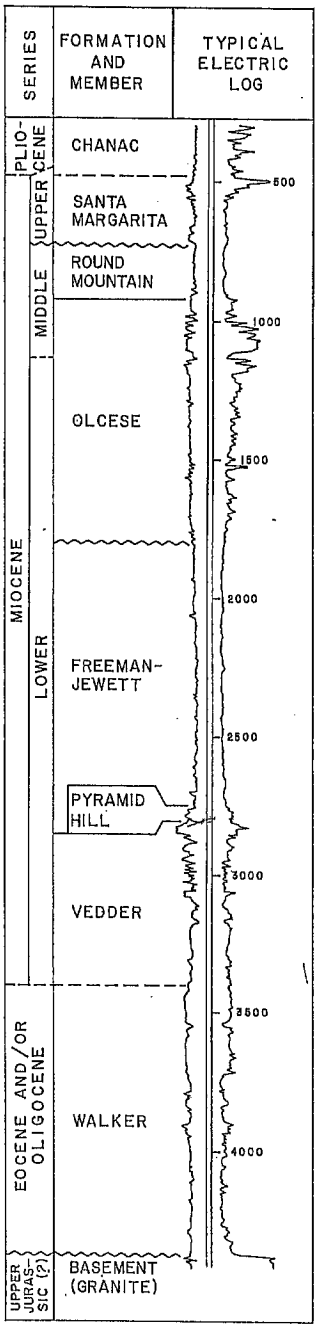
ROUND MOUNTAIN OIL FIELD

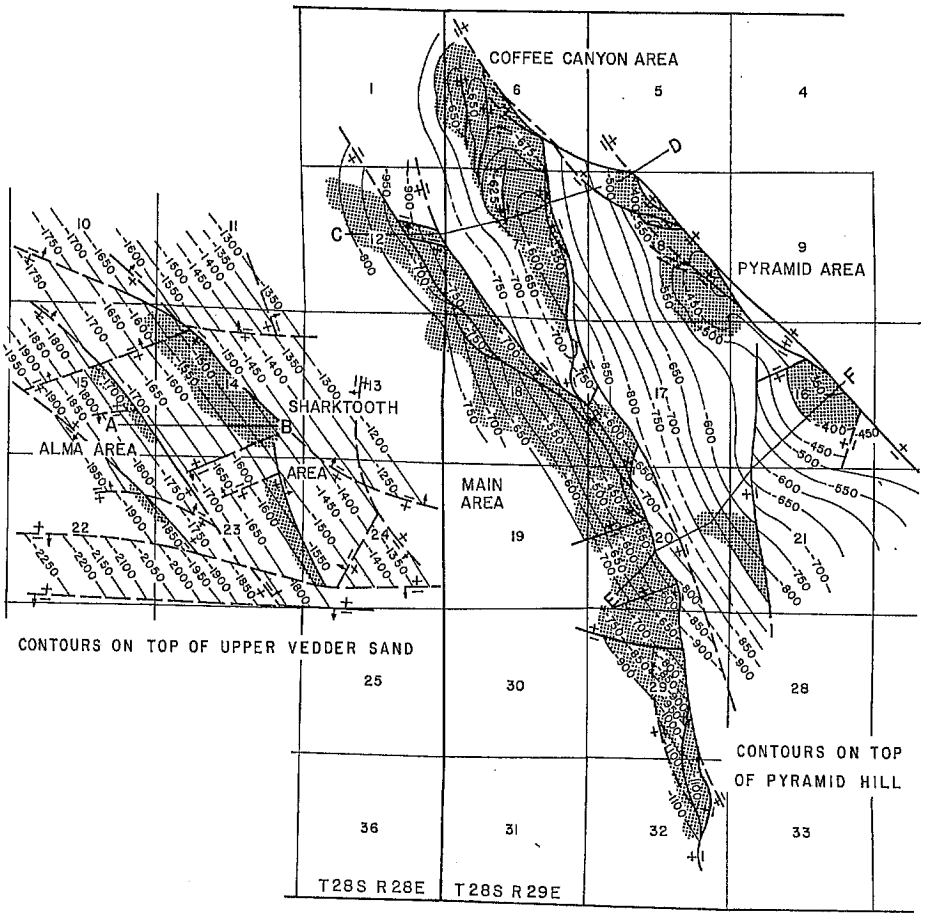






ROUND MOUNTAIN OIL FIELD





LOCATION: 14 miles northeast of Bakersfield

TYPE OF TRAP: See areas

ELEVATION: 600 - 1,500

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Jewett	Getty Oil Co. No. 2	Elbe Oil Land Dev. Co. No. 2	20 28S 29E	MD	*204	N.A.	May 1927
Pyramid Hill	Same as above	Same as above	20 28S 29E	MD	N.A.	N.A.	May 1927
Vedder	Same as above	Same as above	20 28S 29E	MD	N.A.	N.A.	May 1927

Remarks: * Production listed for Jewett is the combined production rate from the Jewett, Pyramid Hill, and Vedder zones.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
C.C. Killingsworth "Alma" 6	Barnsdall Oil Co. "Alma" 6	Mar 1948	15 28S 28E	MD	4,418	Basement (Granite)	Late Jur (?)

PRODUCING ZONES (See areas)

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
711,406	46,635	48,630,496	2,435	292	89,199,121	1,424,213	5,453,194	1938	665	468	2,590

STIMULATION DATA (Jan. 1, 1973) (See areas)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection

SPACING ACT: See areas.

BASE OF FRESH WATER: See areas.

CURRENT CASING PROGRAM: See areas.

METHOD OF WASTE DISPOSAL: See areas.

REMARKS:

REFERENCES: See areas.

CALIFORNIA DIVISION OF OIL AND GAS

ALMA AREA

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 700 - 1,270

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Vedder	Harold C. Morton & H.S. Kohlbush "Alma" 1	Same as present	15 28S 28E	MD	152	N.A.	Feb 1947

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
C.C. Killingsworth "Alma" 6	Barnsdall Oil Co. "Alma" 6	Mar 1948	15 28S 28E	MD	4,418	Basement (Granite)	Late Jur.

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Vedder	2,600	15	early Miocene	Vedder	13	N.A.	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
6,240	0	107,447	50	3	598,904	0	113,392	1948	47	21	80

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: None

CURRENT CASING PROGRAM: 8 5/8" cem. above zone; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps on outcrops of the Round Mountain Silt.

REMARKS:

REFERENCES: Albright, M.B. Jr., Sharktooth and Alma Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 42, No. 1 (1956).

COFFEE CANYON AREA

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 690 - 1,300

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Pyramid Hill	Acacia Oil Co. "Coffee" 1	Reynolds Oil and Gas Co. No. 1	6 28S 29E	MD	*600	N.A.	Sep 1928
Vedder	Acacia Oil Co. "Lindsay" 1	Lindsay Oil Co. No. 1	6 28S 29E	MD	800	N.A.	Aug 1928

Remarks: * Production is commingled from Pyramid Hill and Vedder.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Richard S. Rheem, Opr. "Smoot-Vedder" 2	Same	May 1957	1 28S 28E	MD	2,313	Vedder	early Mio

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Pyramid Hill	1,500	150	early Miocene	Jewett	18	50	None
Vedder	1,650	30	early Miocene	Vedder	16	75	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
103,176	0	7,292,707	435	50	18,507,039	67,567	1,857,108	1937	133	104	475

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
Water flood	1960	3,815,746	1

SPACING ACT: Does not apply

BASE OF FRESH WATER: 0 - 200

CURRENT CASING PROGRAM: 7" cem. above zone; 5 1/2" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps on outcrops of the Round Mountain Silt.

REMARKS: A cyclic-steam injection project in the Pyramid Hill and Vedder zones was started in 1965 and terminated in 1968. Cumulative injection totals 12,200 bbls. The Pyramid Hill zone was originally known as the Elbe zone.

REFERENCES: Park, W.H., J.R. Weddle, J.A. Barnes, Main, Coffee Canyon, and Pyramid Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 49, No. 2 (1963).

MAIN AREA

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 600 - 1,500

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Jewett	Getty Oil Co. No. 2	Elbe Oil Land Dev. Co. No. 2	20 28S 29E	MD	*204	N.A.	May 1927
Pyramid Hill	Same as above	Same as above	20 28S 29E	MD	N.A.	N.A.	May 1927
Vedder	Same as above	Same as above	20 28S 29E	MD	N.A.	N.A.	May 1927

Remarks: * Production listed for Jewett is the combined production rate from the Jewett, Pyramid Hill, and Vedder zones.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Shell Oil Co. "Jewett" 3	Same	Jun 1928	29 28S 29E	MD	2,678	Walker	Eo &/or Olig.

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Jewett	1,600	130	early Miocene	Freeman-Jewett	22	N.A.	None
Pyramid Hill	1,900	150	early Miocene	Jewett	18	N.A.	None
Vedder	2,000	80	early Miocene	Vedder	16	95	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
510,916	46,561	35,953,284	1,415	171	59,572,216	1,293,959	3,794,620	1938	302	225	17465

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Does not apply

BASE OF FRESH WATER: None

CURRENT CASING PROGRAM: 7" cem. above zone; 5 1/2" liner landed through zone.

METHOD OF WASTE DISPOSAL: 4,845,286 bbl. of waste water was injected during 1972 into two disposal wells; percolation and evaporation sumps on outcrops of the Round Mountain Silt.

REMARKS: A water flood project in the Vedder zone was started in 1961 and terminated in 1963. Cumulative injection totals 872,587 bbls.

REFERENCES: Park, W.H., J.R. Weddle, J.A. Barnes, Main, Coffee Canyon, and Pyramid Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 49, No. 2 (1963).

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 730 - 1,470

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Pyramid Hill	Thomas Oil Co. "Olcese" 2	Harp & Brown "Olcese" 2	17 28S 29E	MD	5	0	May 1944
Vedder	Crestmont Oil Co. "Olcese" 1	Eastmont Oil Co. "Olcese" 1	16 28S 29E	MD	250	N.A.	May 1937
Walker	Crestmont Oil Co. "Staley" 11	Same as present	8 28S 29E	MD	40	N.A.	Jul 1943

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Piute Holding Co. "Smith" 1	Same	Oct 1929	17 28S 29E	MD	3,110	Walker	Eo &/or Olig

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Pyramid Hill	1,250	130	early Miocene	Jewett	18	50	None
Vedder	1,390	40	early Miocene	Vedder	16	80 - 110	None
Walker	1,535	50	Eo &/or Olig	Walker	20	N.A.	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
55,714	74	1,527,767	290	37	5,692,349	6,876	378,882	1946	98	60	300

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
---			

SPACING ACT: Applies

BASE OF FRESH WATER: None

CURRENT CASING PROGRAM: 8 5/8" or 7" cem. above zone; 6 5/8" or 5" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps on outcrops of the Round Mountain Silt.

REMARKS:

REFERENCES: Park, W.H., J.R. Weddle, J.A. Barnes, Main, Coffee Canyon, and Pyramid Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 49, No. 2 (1963).

LOCATION: See map sheet of Round Mountain Oil Field

TYPE OF TRAP: Faulted homocline

ELEVATION: 700 - 1,300

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial daily production: Oil (bbl)	Initial daily production: Gas (Mcf)	Date of completion
Vedder	G M V Oil Co. "Signal-Mills" 1	Bandini Petroleum Co. "Signal Mills" 1	24 28S 28E	MD	214	N.A.	Sep 1943

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Mobil Oil Corp. "Bradford" 1	General Petroleum Corp. "Bradford" 1	Jun 1943	15 28S 28E	MD	2,995	Vedder	early Mio

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Oil gravity (°API) or Gas (btu)	Salinity of zone water gr/gal	Class BOPE required
Vedder	2,400	25	early Miocene	Vedder	13	N.A.	None

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Oil (bbl)	1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Average number producing wells	Cumulative production: Oil (bbl)	Cumulative production: Gas (Mcf)	Peak oil production: Barrels	Peak oil production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
35,360	0	3,749,291	245	31	4,828,613	55,811	503,449	1947	85	58	270

STIMULATION DATA (Jan. 1, 1973)

Type of project	Date started	Cumulative injection - Water, bbl; Gas, Mcf; Steam, bbl (water equivalent)	Maximum number of wells used for injection
--			

SPACING ACT: Applies

BASE OF FRESH WATER: None

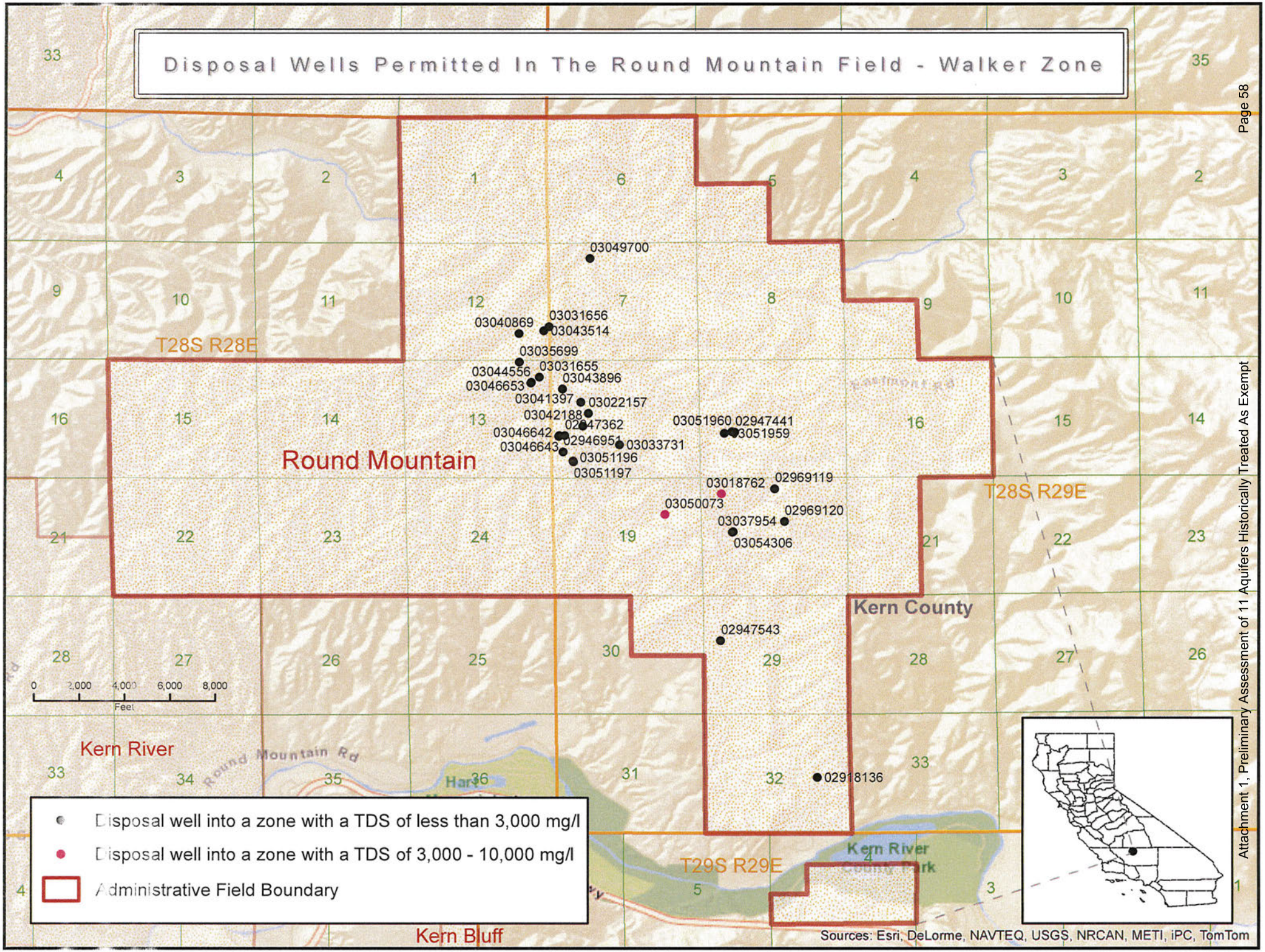
CURRENT CASING PROGRAM: 8 5/8" cem. above zone; 6 5/8" liner landed through zone.

METHOD OF WASTE DISPOSAL: Evaporation and percolation sumps on outcrops of the Round Mountain Silt.

REMARKS:

REFERENCES: Albright, M.B. Jr., Sharktooth and Alma Areas of Round Mountain Oil Field: Calif. Div. of Oil and Gas. Summary of Operations--Calif. Oil Fields, Vol. 42, No. 1 (1956).

Disposal Wells Permitted In The Round Mountain Field - Walker Zone



Bunker Gas Field, Undiff. (Post Eocene) Zone, Sacramento District Office

1) Number of disposal wells permitted in the zone:
   0

2) Number of active producers:
   0

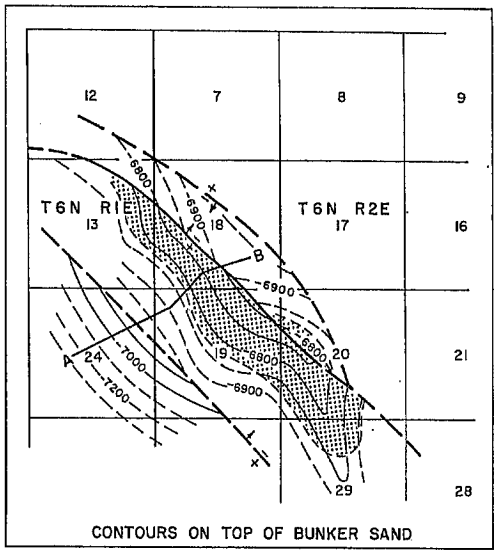
3) Depth of the zone across the field:
   3,000' below surface

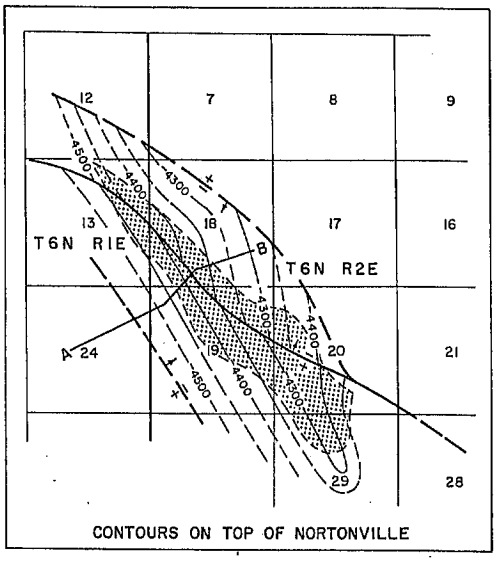
4) Volumes injected historically since 1983:
   51,454 Bbls, last injected on 11/1/1985. WD well API #095-00016 was P&A on 12/9/1986.

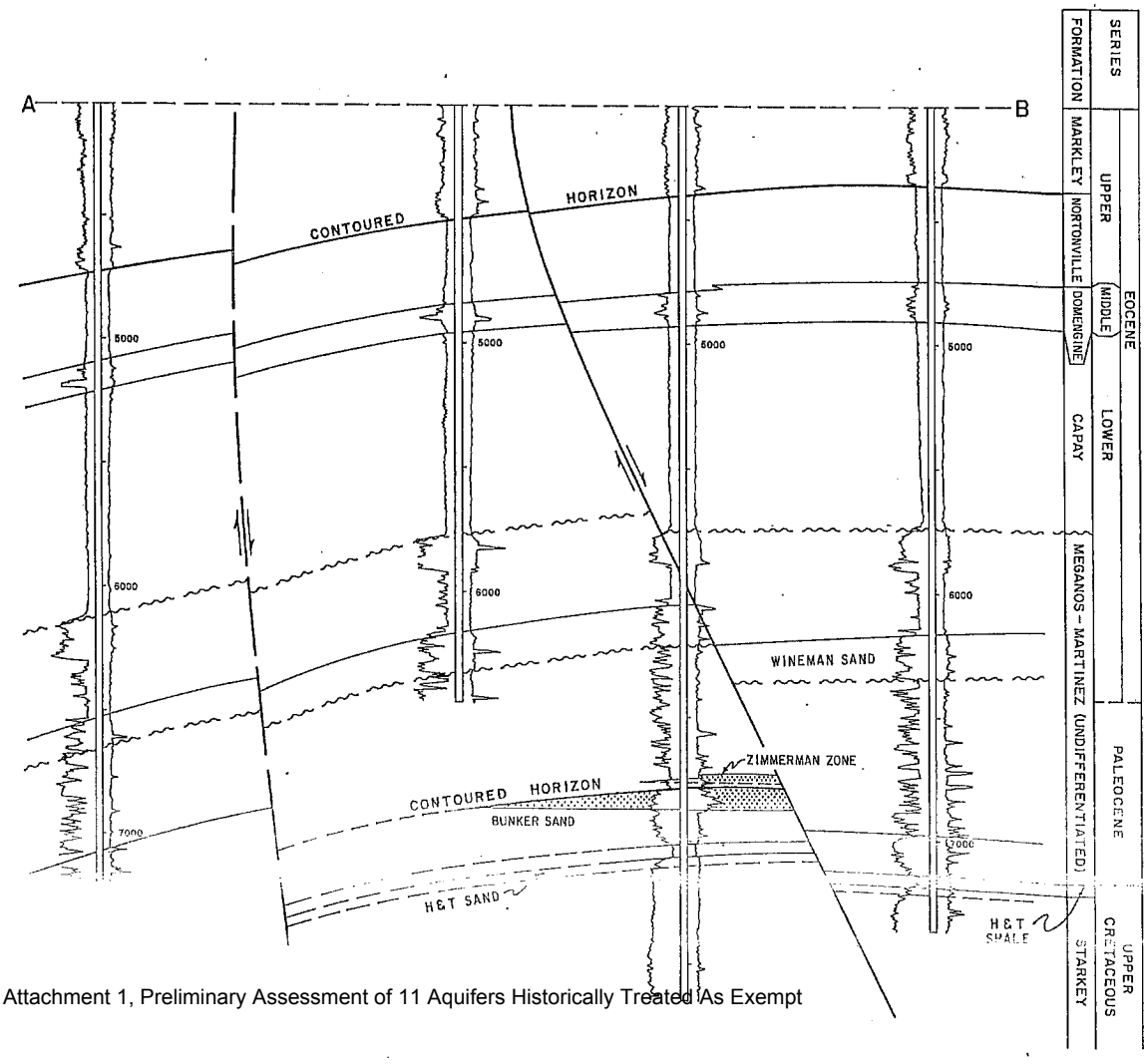
5) TDS of zone:
   1,215 mg/l TDS
   Sample collected from "BGZU" 601 well on January 16, 1974.

6) TDS of injection water:
   10,675 – 11,025 ppm Chloride
   Sample collected from "Bunker B-2 Zone" on April 26, 1973.

BUNKER GAS FIELD







LOCATION: 22 miles southwest of Sacramento

TYPE OF TRAP: Faulted anticline

ELEVATION: 25

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial production: Daily (Mcf)	Initial production: Flow pressure (psi)	Initial production: Bean size (in.)	Date of completion
Zimmerman	Amerada Hess Corp., Unit Oper. "BGZU" 901	Amerada Petroleum Corp., Oper. "Zimmerman" 1	29 6N 2E	MD	3,890	2,250	9/32	Aug. 1961
Bunker	Amerada Hess Corp., Unit Oper. "BGZU" 701	G.E. Kadane & Sons "Main Prairie Gas Unit A" 1	20 6N 2E	MD	3,425	2,250	1/4	Jun 1960

Remarks:

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Amerada Hess Corp., Unit Oper. "BGZU" 702	G.E. Kadane & Sons "Maine Prairie Gas Unit A" 2	Jan 1962	19 6N 2E	MD	10,098	Winters	Lt Cret

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Gas (btu)	Salinity of zone water gr/gal	Original zone pressure (psi)	Class BOPE required
Zimmerman	6,780	15	Paleocene	Martinez	1,075	4	2,930	IV
Bunker	6,845	25	Paleocene	Martinez	1,075	2	2,975	IV

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Maximum number producing wells	Cumulative gas production (Mcf)	Peak gas production: (Mcf)	Peak gas production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
3,073,729	6,704	810	8	53,141,694	10,457,830	1963	22	10	850

SPACING ACT: Applies

BASE OF FRESH WATER: 2,500 - 3,100

CURRENT CASING PROGRAM: 9 5/8" or 7" cem. 600; 4 1/2" cem. through zones and across base of fresh-water sands.

METHOD OF WASTE DISPOSAL:Disposal into sumps at well sites.

REMARKS: Commercial gas deliveries began in October 1961. 1972 condensate production 11,256 bbl.; cumulative condensate production 233,716 bbl.

REFERENCES: Hunter, W.J., Bunker Gas Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 47, No. 1 (1961).

Wild Goose Field, Undiff. Zone, Sacramento District Office

1) Number of disposal wells permitted in the zone:
   0 (only contains gas storage wells in this zone)

2) Number of active producers:
   0

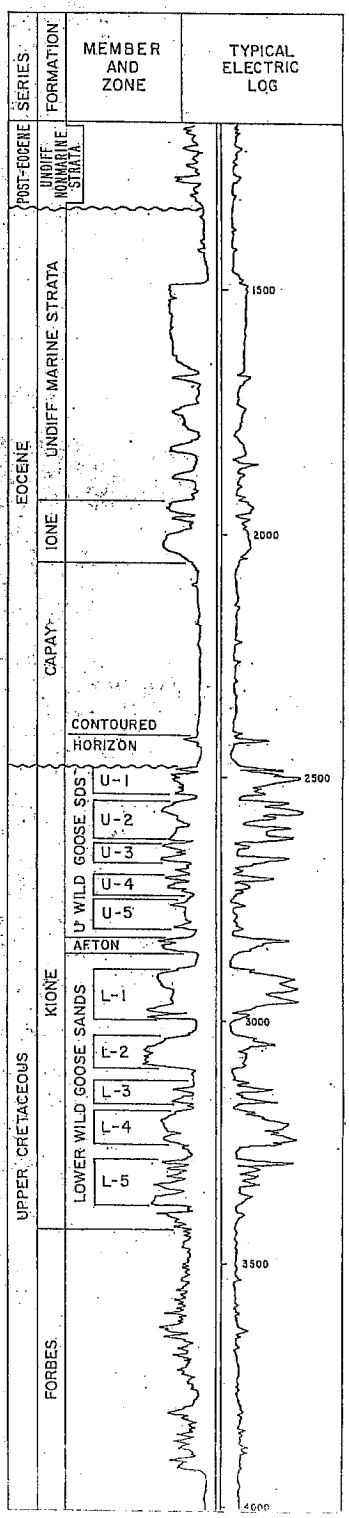
3) Depth of the zone across the field:
   2,700' – 3,400' below surface.

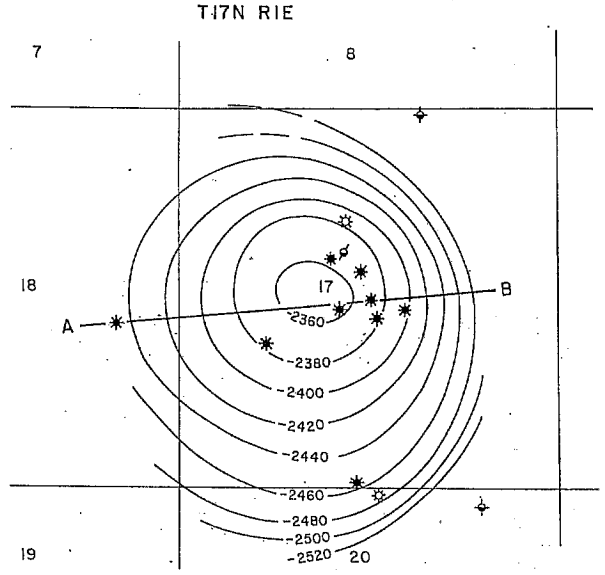
4) Volumes injected historically since 1983:
   None, only contains gas storage wells

5) TDS of zone:
   24,349 mg/l TDS
   Geochemical Analysis of Kione L4 sample provided in UIC Project File.

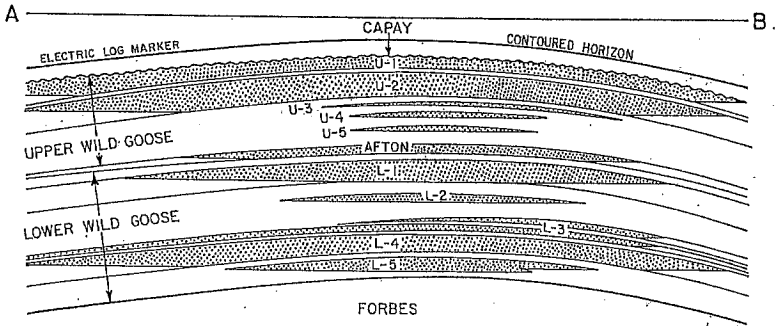
6) TDS of injection water:
   24,349 mg/l TDS
   Geochemical Analysis of Kione L4 sample provided in UIC Project File.

WILD GOOSE GAS FIELD





CONTOURS ON ELECTRIC LOG MARKER IN CAPAY



LOCATION: 10 miles northwest of Colusa

TYPE OF TRAP: Dome

ELEVATION: 65

DISCOVERY DATA

Zone	Present operator and well name	Original operator and well name	Sec. T. & R.	B & M	Initial production: Daily (Mcf)	Initial production: Flow pressure (psi)	Initial production: Bean size (in.)	Date of completion
Hangtown (Sub Capay)	Exxon Corp. "Wild Goose Gas Unit 1" 6	Humble Oil & Rfg. Co. "Wild Goose" 6	17 17N 1E	MD	4,000	940	24/64	Sep 1963
Upper Wild Goose	Exxon Corp. "Wild Goose Gas Unit 1" 4	Honolulu Oil Corp. "Honolulu-Humble Wild Goose" 4	17 17N 1E	MD	7,340	880	36/64	Jul 1953
Afton	Exxon Corp. "Wild Goose Gas Unit 1" 6	Humble Oil & Rfg. Co. "Wild Goose" 6	17 17N 1E	MD	*4,840	1,040	24/64	Sep 1963
Lower Wild Goose	Exxon Corp. "Wild Goose Gas Unit 1" 1	Honolulu Oil Corp. "Honolulu-Humble Wild Goose" 1	17 17N 1E	MD	4,020	1,370	24/64	Aug 1951

Remarks: * Commingled production from Afton and Upper Wild Goose. Honolulu Oil Corp. tested this zone in open hole at a maximum rate of 2,980 Mcf per day in "Honolulu-Humble Tule Goose" 1 (now Exxon Corp. "Wild Goose Gas Unit 1" 7) during July 1952.

DEEPEST WELL DATA

Present operator and well name	Original operator and well name	Date started	Sec. T. & R.	B & M	Depth (feet)	At total depth: Strata	At total depth: Age
Exxon Corp. "Wild Goose Gas Unit 1" 11	Humble Oil & Rfg. Co. "Wild Goose Country Club" 7	Aug 1967	18 17N 1E	MD	7,004	Dobbins	Late Cret

PRODUCING ZONES

Zone	Average depth (feet)	Average net thickness (feet)	Geologic: Age	Geologic: Formation	Gas (btu)	Salinity of zone water gr/gal	Original zone pressure (psi)	Class BOPE required
Hangtown (Sub Capay)	2,400	10	Lt Cretaceous	Kione	N.A.	N.A.	1,105	IV
Upper Wild Goose	2,500	200	Lt Cretaceous	Kione	800	1,780 - 3,250	1,200 - 1,310	IV
Afton	2,850	30	Lt Cretaceous	Kione	N.A.	N.A.	1,335	IV
Lower Wild Goose	2,900	250	Lt Cretaceous	Kione	805	1,800 - 2,650	1,345 - 1,500	IV

PRODUCTION DATA (Jan. 1, 1973)

1972 Production: Net gas (Mcf)	1972 Production: Water (bbl)	1972 Proved acreage	1972 Maximum number producing wells	Cumulative gas production (Mcf)	Peak gas production: (Mcf)	Peak gas production: Year	Total number of wells: Drilled	Total number of wells: Completed	Maximum proved acreage
1,382,761	0	340	9	99,229,200	8,248,811	1961	16	11	360

SPACING ACT: Applies

BASE OF FRESH WATER: 1,050

CURRENT CASING PROGRAM: 9 5/8" cem. 500; 5 1/2" cem. through zones and across base of fresh-water sands.

METHOD OF WASTE DISPOSAL: Water is injected into Exxon Corp. disposal well.

REMARKS: Commercial gas deliveries began in November 1951.

REFERENCES: Hunter, G.W., Wild Goose Gas Field: Calif. Div. of Oil and Gas, Summary of Operations--Calif. Oil Fields, Vol. 41, No. 1 (1955).

Attachment 2:

Plan for Class II Program Improvements

Introduction

Since at least the time of the US EPA's 1983 delegation of primacy to the Division of Oil, Gas and Geothermal Resources (Division), the Division's largest regulatory endeavor has been its Class II underground injection control (UIC) program. Significant improvements to this plan will, by necessity, require significant changes in all aspects of the Division – leadership, staffing, training, data management, establishment of metrics, internal review and monitoring against standards. Organizational change of this magnitude is profound, affecting every employee action every day. The Brown Administration, the Department of Conservation and the Division have committed to this organizational restructuring, of which this Plan for Class II UIC Program Improvements is an important – but not sole -- piece.

Given the years of work and level of resources required, it is critical to know what the target is. This plan should be understood in the context of this vision for the Division:

> The Division will become a modern, efficient, collaborative, science-driven agency that intelligently and consistently regulates State oil and gas activities using modern field tools integrated with advanced data management systems that allow for oversight of a greater number of activities. Safety and training will become integrated cultural norms. The Division will be much better connected with oil and gas-related research activities in industry, academia, and national laboratories so that it can see regulatory challenges coming in advance and apply regulations from an elevated platform of understanding. The Division will perform its duties with integrated collaboration of other State agencies to reduce the environmental impact of oil and gas development. Internal monitoring and compliance will be routine and fully integrated with all that we do so that Division performance can be measured objectively. The Division will be paperless and have instant access to data and information, and hence be able to support all stakeholder groups. Likewise, stakeholder groups will be able to routinely observe Division activities and retrieve information of interest. The Division will have more effective communications capabilities and be more comfortable engaging stakeholder groups.

BACKGROUND AND OVERVIEW

Injection wells have been an integral part of California's oil and gas operations for over 50 years. Currently, over 50,000 oilfield injection wells are operating in the state. Injection wells are used to increase oil recovery and to safely dispose of waste fluid produced with oil and natural gas. About 70-75 percent of California's oil production is the result of enhanced oil recovery (EOR) methods such as steam flood, cyclic steam, water flood, and natural gas injection, all of which involve some sort of injection activity.

Most of the oil and gas fields in the state are mature and require EOR to be productive. Each year more responsibility rests with the Division's Underground Injection Control (UIC) Program to deal with the enhanced recovery of the resource. This includes new methods and techniques developed by the industry to produce the oil and gas. The increased use of injection, such as cyclic steaming, also presents new public health and safety risks, especially in fields with older wells. These risks include groundwater contamination, reservoir fluids leaking to the surface, and fires and blowouts caused by the migration of oil and gas. Urban encroachment on or around older oil and gas wells raises additional issues and concerns.

The Horsley Witten audit, conducted at the request of the Division for the US EPA, was completed and sent to the Division in September 2011. The following issues were outlined in the audit:

- Additional plugging and cementing requirements to protect underground sources of drinking water (USDW)
- More in-depth evaluation of the zone of endangering influence (ZEI)
- Requirements for waste fluid disposal
- Changes to requirements for pressure gauges and/or monitoring of zone pressure
- Well construction and cementing
- Annual project reviews
- Standard Annual Pressure Test (SAPT) requirements
- Well monitoring requirements instead of the SAPT
- Mechanical integrity surveys and testing
- Inspections and compliance/enforcement practices and tools
- Idle well planning and testing program
- Financial responsibility requirements
- UIC staff qualifications
- Cyclic steam injection well testing requirements

In addition to the US EPA audit, the legislature has been involved with several UIC issues and has noted other areas that need to be addressed in regulation. These include:

- H2S/Waste Gas Disposal
- Freshwater usage relating to EOR projects
- CO2 EOR Projects

Additional areas of concern relating to the Division's UIC program include:

- Production from shallow diatomite formations
- Surface expressions
- Aquifer exemption process

- Well construction standards
- Injection relating to formation fracturing pressure

ACTIONS TAKEN TO DATE

The Division first identified issues with its UIC Program in 2009. Division management began a review of then-current practices in regards to approving injection projects, annual project reviews, and the evaluation of wells within the Area of Review (AOR). At the conclusion of the Division's self-assessment, it developed a general plan to work with the administration and Legislature to increase the number of staff so that several deficiencies in the program could be addressed proactively. 17 positions (PYs) established in the FY 2010-2011 budget were spread throughout the Division to add staff to the UIC program to ensure project applications were reviewed according to both the program specifications outline in the Primacy application to the US EPA and in accordance with State statutes and regulations. In addition, Division management also put in place a Letter of Expectations to remove any confusion regarding how injection project applications were to be evaluated. These expectations were issued in May 2010 and revised in November 2010. The Letter of Expectations was mentioned and supported in the Horsley Witten Report.

As the Division continued to monitor its performance and the pace of program improvements, the Division recognized that additional resources were needed to reach improvement goals and therefore requested and received additional staff in FY 2011-2012. Most of these positions were added to the UIC program to provide additional staff to conduct an adequate UIC project application review. Several PYs were used to form an internal monitoring and compliance group to dig deeper into the UIC project files to provide a more refined evaluation of the Division's internal adherence to UIC requirements. Once established, the Monitoring and Compliance Group began an assessment of the Division's activities in District 1 (Los Angeles Basin) regarding past and current work regarding UIC project approvals, area of review and zone of endangerment assessments, project monitoring and annual reviews.

To meet the objectives listed in the Letter of Expectations, Division management executed an internal strategy to explain and train staff regarding the requirements for an UIC project approval, and how existing projects were to be reviewed, remediated and monitored to move UIC projects to full compliance.

As these activities were underway, Division management recognized the need to address the emergence of cyclic steam enhanced oil recovery as not only a rapidly evolving technology but one that was being employed to produce a major fraction of the state's oil. Further, the Division set in motion steps to deal with the mismatch between existing regulations and the realities in the state's oilfields. Of greatest concern was cyclic steam production from shallow diatomite formations as this type of production was rapidly emerging, and the state's regulations were inadequate to properly regulate these activities and ensure protection of USDWs.

Moving Forward and UIC Assessment

Even though there has been consistent recognition by several top leaders within the Division that the UIC program has had significant deficiencies, Division plans and actions for UIC improvement have been less effective than needs demand. In part, the mismatch between plan objectives and results have been caused by numerous management changes. Furthermore, it was not fully understood that fundamental problems with the lack of consistent business processes, poor record-keeping and the lack of modern data management tools were only some of the root causes of the Division's lack of performance in the UIC program. Hence, until recently, a coherent plan addressing broad, fundamental foundational problems was not developed. This spring, with the strong support of the Brown administration, the Division requested and received 23 additional positions to address deficiencies in a number of areas – capacity in program leadership, monitoring and compliance, data management and geographic information systems, emerging technologies, and environmental review. Furthermore, as part of the overall plan, the Division requested and received funding for a modern data management system designed for the oil and gas regulatory environment. Further changes will be forthcoming in the weeks ahead to better align the Division for significant performance improvements.

The Division has already started its UIC program evaluation and will continue the following efforts:

- Identifying gaps in UIC Program compliance and develop a corrective action plan
- Hiring qualified personnel to fill retirement and new position vacancies
- Providing technical and regulatory training for UIC staff
- Increasing management oversight of UIC staff
- Increasing accountability for technical work
- Conducting outreach to the public regarding state and federal mandates
- Conducting outreach to the oil and gas industry to raise awareness of changes in Division regulatory approaches and monitoring
- Pursuing and implementing electronic data systems development

California is moving forward to meet the changing regulatory imperatives with respect to technology, demographics, and more aggressive oversight of oil and gas production. To reiterate, the target is to evolve the Division to a modern, efficient, collaborative, science-driven agency that intelligently and consistently regulates State oil and gas activities using modern field tools integrated with advanced data management systems that allow for oversight of a greater number of activities. Safety and continuous training and improvement will become integrated cultural norms. The Division will be much better connected with oil and gas-related research activities in industry, academia, and national laboratories so that it can see regulatory challenges coming in advance and apply regulations from an elevated platform of understanding. The Division will perform its duties with integrated collaboration of other State agencies to reduce the environmental impact of oil and gas development. Internal monitoring and compliance will be routine and fully integrated with all that is done so that Division performance can

be measured objectively. The Division will be able to support all stakeholder groups because it will be paperless and have instant access to data and information. Hence stakeholder groups will be able to routinely observe Division activities and retrieve information of interest. The Division will have more effective communications capabilities and be more comfortable engaging the constellation of stakeholder groups.

Such profound organizational renewal will consume several years and require constant, focused attention. This work plan is an important initial piece of that renewal. The UIC plan is designed to strengthen the current UIC Program through new regulations, consistent, ongoing training, enhanced compliance oversight, and an evaluation of existing projects and UIC operations.

Assessment by Monitoring and Compliance Unit

The Division has conducted a partial assessment of the Division UIC Program by sampling and reviewing program activities and compliance oversight in one of its District offices. In the development of the assessment, the Division considered the following concerns to help develop a priority list:

- Risk to the public
- Risk to health and safety
- Risk to property
- Risk to natural resources
- Risk of litigation

Based upon known conditions at the time of the assessment, the injection projects located in the Cypress District (Division – District 1) appeared to have the highest priority. The District has around 800 injection projects, which includes over 2,000 injection wells.

The assessment was designed to give greater insight into the range of shortcomings in the Division's UIC program. The UIC program standards that should be used are listed in both California's Primacy application and the federal regulations associated with the Safe Drinking Water Act and Class II injection wells. The assessment has:

- Evaluated a representative sampling of old projects that are in fields that were discovered in the 1930's and 1940's to determine if appropriate Area of Reviews (AOR) were completed and to determine if possible conduits for the injection fluid are present
- Evaluated a representative sampling of recent projects to determine if appropriate AORs were completed and to determine if possible conduits for injection fluid are present
- Evaluated a representative sampling of the records for annual project reviews to determine if they were performed and documented adequately to determine if the project is in compliance with the project approval

- Evaluated a representative sampling of the Division's UIC monitoring program to determine if adequate Mechanical Integrity Testing (MIT) surveys were conducted, evaluated, and documented to ensure mechanical integrity of the injection wells
- Evaluated a representative sampling of the Division's UIC monitoring program to determine if the Maximum Allowable Surface Pressures (MASP) are determined correctly and monitored to ensure compliance with the project approval
- Evaluated if the Division's UIC staff are appropriately educated and trained and have the necessary tools to enforce the Safe Drinking Water Act in regards to Class II wells
- Evaluated if the Division has enough staff and resources to adequately enforce the Safe Drinking Water Act in regards to Class II wells

A draft report that lists the results of the assessment in our Cypress district office has been prepared and is under final administration review.

Bonding

The State has already addressed some of the financial responsibility requirements. Effective January 1, 2014, the State has increased its bonding amounts to address the rising costs to remediate problem wells that become the responsibility of the State. These changes also affect the number of wells that may be covered by a blanket bond. What is not clear, pending further review, is the magnitude of the state's financial liabilities and whether the incremental changes heretofore are sufficient to address long-term needs.

DIVISION'S NEXT STEPS

Individual Project Evaluation

The Division will undertake improvements to its administration of the UIC Program through a series of actions including increasing program leadership talent, enhancing field monitoring of compliance with regulations, a series of rulemakings on priority topics, and a project-by-project review of each UIC project to assess the status of the project with respect to compliance with UIC regulations, testing requirements and adherence to limitations placed on the project in project approval letters. This plan will be informed based upon the findings of the partial assessment of the UIC program already conducted. The Division will take the following steps to ensure all injection projects are in compliance with State law and the Primacy agreement with the US EPA:

1. District staff will review all of the active injection projects in the State and determine what, if any, data are missing to fully evaluate the injection project and ensure the protection of Underground Sources of Drinking Water (USDW). Any data that need to be updated because of changes or modifications to the original approval, will be identified and collected, and the project files organized and

prepared to meet two goals: improved, consistent regulatory oversight and efficient uploading of project data into the coming new data management system.

2. As this project-by-project review is underway, Division staff will meet with operators to discuss the list of deficiencies and develop a compliance schedule for all issues. Operators will be given no more than 6-12 months to supply the Division with the missing or updated data. Depending on the data requests, this timeline may be greatly reduced. Based on the project-by-project review, projects could be terminated or modified.

3. Division staff will evaluate the data submitted and require operators to make changes to ensure the project is still viable. Projects will be modified or cancelled based on this analysis.

4. All projects will be evaluated by the District office and sent to Sacramento for review and concurrence by the program director prior to being approved.

5. Projects may require a new Project Approval Letter (PAL) with additional conditions and/or reporting requirements to ensure compliance.

6. All projects will be reviewed to assess containment of injection fluids. The Division will work closely with the State Water Quality Control Board on the evaluation of fluid containment and the adequacy of the required zone of endangering influence and area of review.

7. All injection data will be entered or verified in the State's databases. Because existing databases may not have the capacity to manage all the data required, the Division will implement a temporary database until the Division's data management system is developed and implemented.

8. All required mechanical integrity tests will be confirmed and verified.

9. Once every year thereafter, the projects will be evaluated to ensure the projects are operated in compliance with the PAL and all testing and monitoring requirements have been met in compliance with UIC regulations.

Project-by-Project Review Schedule

The project-by-project review process will be time consuming and demand significant investment if staff time. In the Cypress and Bakersfield districts, this effort will be very significant. Even though with the implementation of the Letter of Expectations, project applications and project files have improved, many of the injection projects were evaluated and approved under a less stringent process. Many of the Districts have had District policies in place that fell short of directives in the primacy application, statutes, and regulations. The time to complete this review will vary based upon the following:

- Number of projects in each District
- Number of injection wells in the project
- Number of wells within the AOR (project area)
- Amount and type of data missing from the project file
- Current status of the project

Division leadership expects that a review of this depth could require as much as a week (5 working days) to evaluate what is missing from a project file. Such a review can be complicated and complex since the data provided needs to be relevant and accurate, and requires comparison with the project application.

All projects are not equal in size or complexity, and based upon the project status and number of injection projects by District, the following is an estimate of time needed for initial review to evaluate existing data, identify gaps and the develop a list of compliance deficiencies:

District 1 (Cypress)
Number of projects: 817 (X 40 hours) = 32,680 hours

District 2 (Ventura)
Number of projects: 322 (X 40 hours) = 12,880 hours

District 3 (Orcutt)
Number of projects: 255 (X 40 hours) = 10,200 hours

District 4 (Bakersfield)
Number of projects: 1342 (X 40 hours) = 53,680 hours

District 5 (Coalinga)
Number of projects: 195 (X 40 hours) = 7,800 hours

District 6 (Sacramento)
Number of projects: 43 (X 40 hours) = 1,720 hours

The Division is mindful that review of all projects will not consume a full 40 hours. Some projects are no longer active, so the District staff will prioritize the projects based upon

their status. Based upon these numbers it is estimated to take anywhere from six to 18 months to complete this first phase. Phase II -- developing a compliance schedule required of operators and certifying the completion of requirements-- will consume, in total, approximately an additional 12-18 months. Therefore, the overall time to fully complete the project review, certify remedial work, and move the program into full regulatory compliance is estimated to be three years.

The Division anticipates that the review and compliance process can be completed in different districts on different schedules. Beginning October 1, 2015, the Division has developed the following schedule:

Districts 3 and 6, review complete within 7 months, compliance certification within 18 months (18 months start to finish);

Districts 2 and 5, review complete in 9 months, compliance certification in 24 months (24 months total).

District 1, review complete in 10 months, compliance certification in 28 months (28 months total).

District 4, review complete in 16 months, compliance certification in 36 months (36 months total)

A very significant unknown in this review will be the amount of time needed for joint Division and Water Board assessment and validation of containment of injected fluids. Furthermore, demands on staff time for aquifer exemption data review and preparation for the implementation of the new data management system will be significant and will have to be orchestrated to meet these timelines. Once an initial assessment of file status in each of the Districts is complete, the Division can develop a more refined assessment of schedule.

Aquifer Exemptions

The Division continues to evaluate wells that have been permitted to inject into non-exempt aquifers, according to the compliance schedule agreed upon by the Division, State Water Board, and US EPA. The Division, working with the State Water Board, is continuing to evaluate potential impacts to water supply wells and, where precautionary measures are needed, ordering wells to cease injection if there is a potential impact to any water supply well. In addition to the well evaluation, the Division and State Water Board are working with operators to obtain additional data on aquifers to determine if the State will pursue aquifer exemption applications to the US EPA. The State continues to meet its obligations to the compliance schedule and acknowledges that a failure to receive approval from the US EPA on proposed aquifer exemptions will result in additional injection well closures.

Staffing

As noted above, the Division has recently received 23 additional positions to augment the Division's program. Ten positions will be deployed to the district offices to enhance field presence and the review of UIC projects. Five positions will be added to the GIS/Data Management Unit to ensure data quality and support to the district staff evaluating UIC project applications and reviews. Three positions will be added to the California Environmental Quality Act (CEQA) Unit to ensure compliance with project approvals and environmental reviews associated with the approvals. Four positions will be added to the Monitoring and Compliance Unit, which will increase capacity to the current Monitoring and Compliance Unit to ensure there is consistency throughout the Division and that all districts are fully implementing the UIC program. We have also added one position to the legal staff to assist with rulemakings, litigation, and other legal issues associated to UIC issues.

The Division is also assessing its organizational structure, workload, and supervisory oversight requirements of the organization and is preparing to make adjustments to be more effective and to better assimilate the additional staff. These adjustments, based upon identified priorities, will be announced soon.

Compliance Monitoring

This work plan includes utilizing the Division's Monitor and Compliance Unit to verify District staff are following statutes, regulations, and policies in the regulating of the UIC projects. This unit is separate from the UIC Program and therefore can provide objective analysis of the adequacies of the UIC Program improvements. This unit is comprised of one Senior Oil and Gas Engineer to oversee the unit, seven Engineers, and one Associate Government Program Analyst. This team will provide the necessary resources to assist with the improvement plan implementation and execution, and then continued monitoring to ensure Division statutes, regulations, and policies are followed. This unit is providing feedback to the Technical Services Manager, UIC Program Manager, and the Chief Deputy to ensure accountability.

Training

The Division is seeking a Technical Training Coordinator to evaluate training needs of the Division's technical staff. As we move to fill this position, the Division is also moving to put in place training contracts and training requirements for staff to complete, prior to going into the field and evaluating UIC project applications. The Division is also in the process of developing a training plan that clearly outlines the necessary training requirements for each level of engineer as well as a list of skills, knowledge, and abilities for each level of engineer. This plan is also expected to be ready by autumn, 2015.

In addition to specific training courses, the Division will continue its meetings of engineers in the Districts. The Division has had two such meetings in the last year.

These meetings are designed to develop team work and share important information regarding different aspects of the work district engineers perform. They provide a forum to share findings regarding investigations of injection activities the Division has undertaken and provide guidance as to how to monitor and identify issues before problems occur.

Business Process

The Division lacks clear and consistent business process. To deal with this challenge, the Division has contracted for assistance with:

1. Identification of the various permitting processes throughout the Division
2. Identification of common relevant steps in each the process
3. Recommendations of statewide processes for our permitting

Along the way, the contract will ensure that legislative mandates are being captured in our existing processes. Much of the work done for this will also contribute to essential preparations for the implementation of our data management project.

Phase 1 of the contract will require 90 days. The contractor is now traveling to District offices to interview employees who have a part of the UIC program.

Data Management System

The Division has already begun working with the California Department of Technology to evaluate our current systems and to develop a plan to meet the Division's future data management needs. This plan will include looking at a data management system that captures all the required data and a method for either the Division to push data to an US EPA-wide data management system or a method for EPA to download data. The State employs a "Stage/Gate" model process to assess business needs and processes and develop deliverables and project completion schedules. The entire process of assessment to delivery of a complete system could take 3-4 years including the uploading of legacy data.

Rulemaking

The Division has identified an ambitious list of regulatory goals to be accomplished by rulemaking action. This list of regulatory goals is based on the Division's own evaluation of its UIC Program, concerns raised in the review prepared by the Horsley Witten Group, input from stakeholders, and input from other regulatory agencies. In addition, these regulatory goals dovetail with issues related to the UIC Program that were identified by the California Council on Science and Technology in the independent

scientific assessment of well stimulation treatments in California that it conducted pursuant to Senate Bill 4 (Pavley 2013).

These regulatory goals each relate to the Division's UIC Program, but some issues – such as well construction standards and idle well management – are actually broader in scope than just injection regulation. Because these rulemaking goals are likely to be more than could be effectively addressed at one time, the Division will undertake its rulemaking efforts around these goals in two phases. The regulatory goals to be addressed in these two phases of rulemaking are as follows:

Phase 1

- *Clarify standards for ensuring zonal isolation of injection projects*
- *Expressly define the quality of water to be protected when constructing wells*
- *Codify best practices for well construction*
- *Establish permitting and regulatory requirements specific to cyclic steam operations*
- *Establish requirements specific to cyclic steam in diatomite, including a regulatory framework for responding to surface expressions and clarification regarding injection above fracture gradient*
- *Clarifying process and standards for establishing maximum allowable surface pressure for injection operations*

Phase 2

- *Codify requirements for ongoing project review*
- *Establish requirements for securing idle wells and standards for well abandonment*
- *Elaborate on existing idle well testing requirements*

Generally, these rulemaking goals will be accomplished through a process of (1) identifying interested parties and engaging with stakeholders to solicit concerns and suggestions; (2) drafting proposed regulations and informally soliciting input on the draft regulations; and then (3) commencing formal rulemaking to adopt proposed regulations.

The Division has already started this process for Phase 1 of its rulemaking effort. The Division has circulated a notice identifying the Phase1 regulatory goals and encouraging people to identify themselves as interested parties for the rulemaking effort. In the near future, the Division will be sending notice to interested parties of workshops to be conducted this fall throughout the state, in order to provide an opportunity to provide

input on how to best accomplish the regulatory goals identified. The Division's goal is to informally circulate draft regulations in November 2015, commence formal rulemaking in January 2016, and complete the rulemaking process for the Phase 1 rulemaking effort by winter of 2016.

Although the Division has already begun giving consideration to Phase 2 regulatory goals, the Division will not begin working in earnest to pursue the Phase 2 rulemaking effort until formal rulemaking for the Phase 1 rulemaking effort is near completion. Accordingly, the Division estimates that the Phase 2 rulemaking effort will not begin until fall of 2016, and will not be completed until winter of 2017.

Conclusion

The job of meeting the many goals laid out here is indeed a substantial one. But with the continued support and effort of those involved, doing the job well will result in a modern and responsive regulatory unit that is able to meet the challenge of helping to shepherd our oil and gas resources in a way that will, to the greatest extent possible, both protect public health and the environment and maintain California's significant oil production economy.

Attachment 3: Public Participation Process For Aquifer Exemption Proposals

The purpose of this document is to explain the public participation process that the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (Division) will follow before submitting an aquifer exemption proposal to the US Environmental Protection Agency (U.S. EPA). The Division will not submit an aquifer exemption proposal to U.S. EPA without concurrence from the State Water Board and the appropriate Regional Water Quality Control Board (collectively Water Boards) that the proposal is appropriate, and the Division will not submit a proposal for public comment unless the Division and the Water Boards agree that the proposal merits consideration.

- **Public Notice and Comment**

    - Timing. Public notice and opportunity to comment will be provided after the Division and the Water Boards make an initial determination to request U.S. EPA approval of a new aquifer exemption, but before any final proposal is submitted to U.S. EPA.

    - Newspaper Publication. The Division will publish notice of proposed aquifer exemptions in at least one newspaper. The most appropriate newspaper will be determined on a case-by-case basis, but generally will be the most widely-circulated, daily-issue newspaper in the county where the aquifer is located. Notice may be published in a second newspaper, if deemed necessary to target a wider audience or more local community. All notices will be published for three consecutive days, beginning (but not necessarily ending) on a weekday.

    - Length of Notice and Comment Period. The Division will accept public comment for a period of at least 30 days beginning on the first day notice is published in the newspaper. If substantial changes are made to the proposed exemption after the close of the initial notice and comment period, the Division will reopen a supplemental, 15-day notice and comment period beginning on the first day the supplemental notice is published in the newspaper.

    - Website. The Division will establish a webpage within its current website to hold all notices, information submitted in support of exemptions, public comments, and other materials on which the Division relies. The notices will direct readers to the webpage for more information, which will more fully inform the public and enable a meaningful opportunity to comment.

    - List Serve. The webpage for aquifer exemptions will allow individuals to join a list serve for receiving email notification of all future aquifer

exemption proposals. Email notification will be sent on the same day notice is published in the newspaper, or as soon as possible thereafter.

- Outreach. On the same day notice is published in the newspaper, or as soon as possible thereafter, the Division will email or mail notice to the following:
  - Director of the Water Management Division, U.S. EPA Region IX;
  - Chairperson of the State Water Resources Control Board;
  - Chairperson of the Regional Water Quality Control Board(s) with jurisdiction over the area in which the aquifer is located;
  - The Board of Supervisors of the county(s) in which the aquifer is located, and any other local officials identified as likely to be interested;
  - State Senators in the following committees: Agriculture; Energy, Utilities and Communications; Environmental Quality; Natural Resources and Water;
  - State Assembly Members in the following committees: Agriculture; Natural Resources; Water, Parks & Wildlife; and
  - Industry associations and non-governmental organizations identified as likely to be interested;

- **Public Comment Hearings**
  - Schedule and Notice. A joint public comment hearing will be held with a designee from the State Water Board for the purpose of providing an opportunity for people to provide oral comments. The initial notices for a proposed aquifer exemption will specify the date of the hearing date, which will always be at least 30 days from the date of the notice.
  - Location. Hearings will be held at a location convenient for the parties involved or in Sacramento.
  - Consolidation. The Division and State Water Board will set aside one day every month (or every other month, depending on the rate of proposals under review) for holding a public hearing on proposed aquifer exemptions. Several aquifer exemption proposals will normally be considered at each hearing, with each proposal allocated a separate time slot. The number of exemption proposals at issue in a hearing will depend on readiness of the proposals and their relative complexity.
  - Requests for U.S. EPA Participation. The Division and State Water Board may elect to request U.S. EPA's participation at the hearing. Requests for

U.S. EPA participation will be made at least 10 days prior to the date of the hearing.

- Conduct. Public hearings will be conducted as follows:
  - Division staff will provide a brief introduction regarding each aquifer exemption;
  - The purpose of the public comment hearings is to receive public input – the Division and State Water Board will receive public comments but will not necessarily answer questions or debate issues;
  - All attendees will be provided an opportunity to provide oral or written statements, though the Division and State Water Board may impose reasonable limitations on oral presentations;
  - Hearings will be recorded by an audio/video recording device, or by a stenographer; and
  - If an attendance list or similar document is posted or circulated at the hearing, the document will state that signing-in is voluntary and that all persons may attend regardless of whether they sign-in.

- **Outcome**
  - Notice of Substantial Changes. As noted above, the Division will reopen a 15-day supplemental notice and comment period for substantial changes made to the proposed exemption following close of the initial comment period.
  - Decision and Response to Comments. If the Division and the Water Boards elect to submit an aquifer exemption proposal to U.S. EPA, it will prepare a document that (1) announces the decision, (2) provides a concise statement of the basis for the decision, and (3) summarizes the substantive comments received (including oral comments received at a hearing) and the disposition of those comments. This document will be included in the submittal to U.S. EPA.
  - Submission to U.S. EPA. In the unlikely event it takes the Division longer than one year from the date of initial notice to submit an aquifer exemption to U.S. EPA, the Division will consider whether there are any changed circumstances that may reasonably require a new round of notice and comment.

PUBLIC NOTICE OF DETERMINATION AND REQUEST FOR U.S. EPA ACTION REGARDING ELEVEN AQUIFERS HISTORICALLY TREATED AS EXEMPT:

The Pico Formation underlying the boundaries of the South Tapo Canyon Field

The Tumey Formation underlying the boundaries of the Blackwell's Corner Field

The Kern River Formation underlying the boundaries of the Kern Bluff Field

All aquifers underlying the boundaries of the Bunker Gas Field that are not in a hydrocarbon-producing zone

The Santa Margarita Formation underlying the boundaries of the Kern River Field

The Chanac Formation underlying the boundaries of the Kern River Field

The Walker Formation underlying the boundaries of the Mount Poso Field

The Olcese Formation underlying the boundaries of the Round Mountain Field

All aquifers underlying the boundaries of the Wild Goose Field that are not in a hydrocarbon-producing zone

The Walker Formation underlying the boundaries of the Round Mountain Field

The Santa Margarita Formation underlying the boundaries of the Kern Front Field

30-DAY PUBLIC COMMENT PERIOD

Notice Published November 15, 2016

NOTICE IS HEREBY GIVEN that the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources ("Division"), in consultation with the State Water Resources Control Board ("Water Board") (collectively, "State Agencies"), intends to advise the United States Environmental Protection Agency ("US EPA") that ten of the eleven aquifers historically treated as exempt do not meet the federal regulatory criteria for exemption from the federal Safe Drinking Water Act ("SDWA"). Accordingly, the State Agencies intend to request an amendment to the Memoranda of Agreement between the Division and US EPA for the purpose of clarifying that these aquifers are not exempt aquifers.

In addition, the State Agencies intend to advise US EPA that the one other aquifer historically treated as exempt – the Walker Formation underlying the Round Mountain Field – is currently the subject of aquifer exemption proposals. The proposal for the Walker Formation has been finalized and published for public comment (but not yet submitted to US EPA). Portions of this aquifer are included in the exemption proposal, while other portions are not included. The State Agencies therefore intend to also request that the amendment to the Memoranda of Agreement between the Division and US EPA clarify that this aquifer is *not* exempt, except with respect to any portion(s) that US EPA approves for exemption as a result of a future exemption proposal.

WRITTEN COMMENT PERIOD AND PUBLIC COMMENT HEARING

Any person, or his or her authorized representative, may submit to the Department of Conservation ("Department") written statements, arguments, or comments relevant to this determination. Comments may be submitted by email to comments@conservation.ca.gov, by facsimile (fax) to (916) 324-0948, or by mail to:

Department of Conservation
801 K Street, MS 24-02
Sacramento, CA 95814
ATTN: Eleven Aquifers

The written comment period closes at 5 p.m. on December 16, 2016. The Department will not consider any comments received at the Department's offices after that time.

Additionally, any interested person, or their authorized representative, may present, either orally or in writing, comments regarding the proposed action at the public hearing, to be held at the following time and place:

December 14, 2016 at 4pm
Four Points Sheraton
5101 California Avenue
Bakersfield, CA 93309

Services, such as translation between English and other languages, may be provided upon request. To ensure availability of these services, please make your request no later than ten working days prior to the hearing by calling the staff person identified in this notice.

Servicios, como traducción de inglés a otros idiomas, pueden hacerse disponibles si usted los pide en avance. Para asegurar la disponibilidad de éstos servicios, por favor haga su petición al mínimo de diez días laborables antes de la reunión, llamando a la persona del personal mencionada en este aviso.

BACKGROUND

The Division regulates the underground injection of fluids associated with oil and gas production ("Class II injection") through an underground injection control ("UIC") program approved by US EPA pursuant to the federal SDWA. The SDWA requires the protection of underground sources of drinking water ("USDWs"), which are defined broadly in federal regulation as including any aquifer that supplies or contains a sufficient quantity of groundwater to supply a public water system and that has a total dissolved solids ("TDS") composition of less than 10,000 mg/l. (See 40 C.F.R. § 144.3.)

Under federal law, an aquifer, or a portion of an aquifer, that would otherwise qualify as a USDW may be "exempted" from protection as a USDW if it meets specific exemption criteria enumerated in federal regulation and undergoes an exemption process that involves both the State and US EPA. (See 40 C.F.R., §§ 146.4, 144.7.) Specifically, a USDW may be exempted for purposes of Class II injection if it meets the following criteria:

(a) It does not currently serve as a source of drinking water; and

(b) It cannot now and will not in the future serve as a source of drinking water because:

(1) It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible.

(2) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical;

(3) It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; or

(c) The TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system.

(40 C.F.R. § 146.4.). Exempted aquifers may be designated by the State and submitted to US EPA for review and possible approval. No aquifer exemption is valid unless and until it is approved by US EPA. (*See* 40 C.F.R. § 144.7.)

When US EPA approved the State's UIC program in 1983, the Division and US EPA entered a Memorandum of Agreement ("Primacy MOA") that identified the aquifers for which US EPA granted aquifer exemptions. Program records have produced two competing versions of the Primacy MOA, each with the same signature page and dates, which differ with respect to the non-hydrocarbon-producing aquifers US EPA agreed to exempt. One version purports to deny exemptions for eleven non-hydrocarbon-producing aquifers, while the second version purports to approve exemptions for those same aquifers. The Division and US EPA have historically treated these eleven aquifers as exempt. Following a US EPA audit of the State's UIC program in 2012, US EPA determined that these eleven aquifers may not actually be exempt, and ordered the State to reevaluate the aquifers to ascertain whether the aquifers meet the federal exemption criteria and whether the aquifers are appropriate for ongoing injection of fluid associated with oil and gas production. Additionally, US EPA prescribed detailed corrective actions to bring the State's UIC program into compliance with the SDWA. One of the corrective actions requires the State to prohibit injection into the eleven aquifers "historically treated as exempt" by December 31, 2016 absent a US EPA determination that the aquifer(s) meet the regulatory criteria for exemption. The Division has implemented this and other compliance dates in its Aquifer Exemption Compliance Schedule Regulations. (Cal. Code Regs., tit. 14, § 1779.1.)

DETAILS OF THE STATE AGENCIES' DETERMINATION

Ten Aquifers Have Not Been Shown to Meet Exemption Criteria

Based on the available information, the State Agencies' current assessment is that ten of the eleven aquifers do not meet the federal regulatory criteria for exemption from the SDWA. These aquifers may in the future serve as a source of drinking water. The ten aquifers are:

- The Pico Formation underlying the boundaries of the South Tapo Canyon Field.
- The Tumey Formation underlying the boundaries of the Blackwell's Corner Field.
- The Kern River Formation underlying the boundaries of the Kern Bluff Field.

- All aquifers underlying the boundaries of the Bunker Gas Field that are not in a hydrocarbon-producing zone.
- The Santa Margarita Formation underlying the boundaries of the Kern River Field.
- The Chanac Formation underlying the boundaries of the Kern River Field.
- The Walker Formation underlying the boundaries of the Mount Poso Field.
- The Olcese Formation underlying the boundaries of the Round Mountain Field.
- All aquifers underlying the boundaries of the Wild Goose Field that are not in a hydrocarbon-producing zone. [*]
- The Santa Margarita Formation underlying the boundaries of the Kern Front Field.

The State Agencies' current assessment of these ten aquifers, and the proposed request to US EPA, would not preclude future consideration of exemption proposals. If the State Agencies in the future receive new information establishing that any of these aquifers, or portions thereof, meet the exemption criteria and are appropriate for injection, the State Agencies may elect to submit an aquifer exemption proposal to US EPA following the required legal procedure, including public notice and a public hearing.

Portions of One Aquifer May Qualify for Exemption

Portions of one of the eleven aquifers historically treated as exempt are being considered for exemption. That aquifer is:

- The Walker Formation underlying the boundaries of the Round Mountain Field.

An exemption proposal for the Walker Formation underlying the Round Mountain Field has been finalized and the Division is currently considering public comments on the proposal.[†] Only those portions of the Walker formation that are included in the State Agencies' exemption proposal and approved for exemption by US EPA should be confirmed as exempt. The omission of any portion(s) of the formations from a final exemption proposal would be due to there being a lack of evidence for the State Agencies to find that such portion(s) are eligible for exemption. Accordingly, the State Agencies intend to request an amendment to the Memoranda of Agreement between the Division and US EPA for the purpose of clarifying that the Walker Formation underlying the Round Mountain Field is not exempt, except with respect to any portions of the formation that US EPA approves for exemption as a result of a future exemption proposal submitted to US EPA.

DOCUMENTS AVAILABLE FOR REVIEW

Documents reviewed by the State Agencies in the course of making this determination are available on the Division's public internet website at:

http://www.conservation.ca.gov/dog/Pages/Aquifer_Exemptions.aspx.

[†] The proposal and supporting materials for the Round Mountain Field exemption are available at http://www.conservation.ca.gov/dog/Pages/Aquifer_Exemptions.aspx.

RESPONSE TO COMMENTS

The State Agencies will review and respond to all timely and relevant comments received (including oral comments received at the hearing) following the written comment period and public hearing. Thereafter, the Division may proceed with the request to US EPA to amend the Memoranda of Agreement between the Division and US EPA for the purpose of clarifying the exempt status of the eleven aquifers.

CONTACT PERSON

Inquiries concerning the proposed action may be directed to:

Tim Shular
Department of Conservation
801 K Street, MS 24-02
Sacramento, CA 95814
Phone: (916) 322-3080
Email: Comments@conservation.ca.gov

Department of Conservation, Division of Oil, Gas, and Geothermal Resources
Public Comment Solicitation for Assessment of
Eleven Aquifers Historically Treated as Exempt

PUBLIC COMMENT SUMMARIES AND RESPONSES

On November 15, 2016, the Department of Conservation, Division of Oil, Gas, and Geothermal Resources ("Division"), in consultation with the State Water Resources Control Board ("Water Board"), sent public notice regarding the intent to advise the United States Environmental Protection Agency ("US EPA") that, with the exception of portions of two aquifers that are addressed in recent aquifer exemption proposals, the eleven aquifers historically treated as exempt do not meet the federal regulatory criteria for exemption from the federal Safe Drinking Water Act ("SDWA"). Accordingly, the Division and the Water Board intend to request an amendment to the Memoranda of Agreement between the Division and US EPA for the purpose of clarifying that these aquifers are not exempt aquifers. The eleven aquifers are:

- The Pico Formation underlying the boundaries of the South Tapo Canyon Field.
- The Tumey Formation underlying the boundaries of the Blackwell's Corner Field.
- The Kern River Formation underlying the boundaries of the Kern Bluff Field.
- All aquifers underlying the boundaries of the Bunker Gas Field that are not in a hydrocarbon-producing zone.
- The Santa Margarita Formation underlying the boundaries of the Kern River Field.
- The Chanac Formation underlying the boundaries of the Kern River Field.
- The Walker Formation underlying the boundaries of the Mount Poso Field.
- The Olcese Formation underlying the boundaries of the Round Mountain Field.
- All aquifers underlying the boundaries of the Wild Goose Field that are not in a hydrocarbon-producing zone. [1]
- The Santa Margarita Formation underlying the boundaries of the Kern Front Field.

Following publication of a notice in a local newspaper, and mailing or emailing notice to interested parties, public comments on the proposal were accepted from November 15, 2016 through December 16, 2016. On December 14, 2016, the Division and the State Water Board jointly conducted a public comment hearing in Bakersfield. Included below is a summary of all of the comments received from the public together with the Division's and State Water Board's responses.

Over the course of the public comment period, the Division received a number of public comments via email, regular mail, and public comment hearing. Each commenter and subsequent comment was given a unique numerical signifier. The chart below provides the numerical signifier for each commenter. Below, you will find either grouped or individual comment numerical signifiers, followed by a summary or specific comment, followed by a response (italicized).

COMMENTERS:

Number	Name and/or Entity
0001	California Resources Corporation
0002	CA State Building and Construction Trades Council
0003	Brian Pellens
0004	Natural Resources Defense Council, Clean Water Action
0005	Nancy

COMMENT SUMMARIES:

COMMENTS IN SUPPORT

0004-1
The commenter concur with the Division of Oil, Gas, and Geothermal Resources' (Division) and the State Water Resources Control Board's (Board) (collectively "State Agencies") intent to advise the U.S. EPA that ten of the eleven aquifers historically treated as exempt do not meet the federal regulatory criteria for exemption from the federal Safe Drinking Water Act (SDWA). The State Agencies' assessment makes clear that the version of the Primacy Memorandum of Agreement (MOA) between the Division and U.S. EPA that purports to approve exemptions for these eleven non-hydrocarbon-producing aquifers was issued in error, and that the version denying these exemptions is correct.

0005-1
We have laws for a reason, and in this case it appears that public safety is being pitted against economic vitality and pecuniary interests. I urge you to reject all of the proposed exemptions to the Act.

Response to comments 0004-1, 0005-1:
Thank you for your comments.

COMMENTS IN OPPOSITION

General Opposition
0001-1, 0002-1
The public comment period should be extended passed the arbitrary December 31, 2016 deadline. CRC has invested millions of dollars in water treatment, conveyance systems, and use of reclaimed water; and has identified alternative zones for water disposal. The state has not forwarded a separate aquifer exemption package or reviewed additional UIC permits related to the alternate injection zone. Many jobs will be put in jeopardy if the deadline is not extended.

0001-2
The MOA between the Division and USEPA that has been used for decades, and which was used to issue multiple permits must be formally amended. Until this happens, there is no basis to interfere with or

penalize any injection into these exempted aquifers. The Division does not provide any specific finding of environmental harm or impact. The injectate at CRC's operations in Kern Front is higher quality than the zones into which it is being injected. It is unclear why there would need to be an amendment to the MOA.

Response to comments 0001-1, 0002-1, 0001-2:
California Code of Regulations, title 14, section 1779.1, subdivision (b) provides that injection in these aquifers must cease by December 31, 2016, unless and until US EPA, subsequent to April 20, 2015, determines that the aquifer or the portion of the aquifer where injection is occurring meets the criteria for aquifer exemption. Extended the period for the public to comment on this evaluation would not affect that regulation.

Deficient Analysis

0003-1
While a proper analysis should rely on potentially thousands of pages of data, maps, cross sections, modern logs, and thousands of hours of analysis by highly skilled professional geologists, petrophysicists and others; the Division's analysis consists mainly of photocopied pages from a document first published in 1960 (with data relying on decades-old information) to delineate general locations of oil. A complete technical and economic feasibility study is needed for each of the eleven aquifers before any determination of whether the exemption criteria are met or not. As the non-applicability of the exemption criteria have not been demonstrated, any determination with respect to these aquifers should be delayed until such time as a proper analysis has been prepared and vetted.

0003-2
Any of the four clauses of 40 CFR 146.4(b) may be used to determine an aquifer exempt. Conversely, due to the fact that the "or" conjunction is used between the criteria, if one is to determine that the criteria of 40 CFR 146.4(b) are not met, one must demonstrate that **none** are met. As such, the Division's analysis must show that none of the following are true: see 40 CFR 146.4 (b) (1-4).

0003-3
The Division's analysis is clearly not complete. For example, in the evaluation of (b)(3), I would offer that it is possible that a large desalinization plant could be built to produce drinking water from sea water (as has been done in many places around the world) and piped to these field locations far cheaper on a per gallon basis, than siting a much smaller plant on top of any of these naturally-impaired aquifers for local supply. It should be noted also for the required analysis that the federal standard for exemption in (b)(3) is to "render that water fit for human consumption" -- not for agricultural or other use, such that drinking water standards are the applicable treatment goal. It should further be noted that while some widely varying and scarce data is given for Total Dissolved Solids (TDS), there are many other naturally occurring contaminants in that water which would likely complicate any process to render it fit for human consumption. Another consideration is that a coastal desalination plant may use existing water transportation infrastructure if such infrastructure has available capacity, further decreasing the costs. There may be other alternatives to the scenario above as well which must be explored. If any of these alternatives are less expensive on a per gallon basis to supply drinking water fit for human consumption, it is economically infeasible to use the water subject to the Division's determination to supply drinking water.

Response to comments 0003-1, 0003-2, 0003-3:
California Code of Regulations, title 14, section 1779.1, subdivision (b) provides that injection in these aquifers must cease by December 31, 2016, unless and until US EPA, subsequent to April 20, 2015, determines that the aquifer or the portion of the aquifer where injection is occurring meets the criteria for aquifer exemption. The data and evaluation made available for public comment indicate that the aquifers in question meet the definition in federal regulation of an underground source of drinking water. In the two instances where data and analysis has been provided to the State that indicate that portions of these aquifers do meet the criteria in federal regulation for an aquifer exemption, the State Agencies have made aquifer exemption proposals that have been approved by US EPA. If other data and analysis are provided, then the State Agencies' will work the applicant to develop other such aquifer exemption proposals.

Other

0004-2
The Division and the Water Board should institute a full investigation to determine the extent of any contamination in these 11 aquifers. As detailed in the State Agency's assessment, the HTAE aquifers contain high-quality drinking water and in some cases injection of low quality brines has been occurring for decades. The State Agencies have a duty to determine the environmental and public health impacts from this improper injection and remediate any ongoing threats.

Response to comment 0004-2:
Thank you for your comments.