Occidental of Elk Hills, Inc.
A subsidiary of Occidental Petroleum Corporation

5 Greenway Plaza, Suite 110, Houston, Texas 77046-0506
P.O. Box 27756, Houston, Texas 77227-7756

DOCKET	
08-AFC-8	
DATE	JUL 23 2010
RECD.	JUL 26 2010

July 23, 2010

Via Email & Federal Express

Rod Jones
Project Manager
California Energy Commission
Siting, Transmission and Environmental Protection Division
1516 Ninth Street, #MS-15
Sacramento, CA 95814-5504

Dear Rod:

As promised, attached is a discussion draft of Oxy's proposed monitoring, reporting and verifying plan (MRV Plan) for the Oxy CO_2 EOR Project at the Elk Hills Unit in Kern County, California that is associated with the HECA Project. The draft MRV Plan is still undergoing peer review by several environmental NGOs which have been involved in preparing the document along with Oxy. It is important to note that we are still working on the element of project closure, and that section will be added to the draft MRV Plan when that element is completed.

Twelve hard copies of the MRV Plan will be sent via Federal Express for Monday delivery at your office.

Please feel free to call me if you have any questions at (713) 215-7139.

Best regards,

William Barrett
lg

William Barrett
CO_2 Business Manager
Occidental of Elk Hills

Enclosures

cc: Gregory Skannal (w/ encl. via email)

Oxy Elk Hills CO_2 EOR Project

MRV Plan

Table of Contents

1. Summary

Occidental of Elk Hills, Inc. (OEHI or Company) plans to use carbon dioxide (CO_2) from the proposed Hydrogen Energy California power plant (HECA Project) to extend OEHI's existing enhanced oil recovery (EOR) in an area within the Elk Hills Unit (EHU). The EHU is part of a large, mature oil and gas field (Elk Hills Oil Field or EHOF) that OEHI operates near Bakersfield, California. The Company's planned CO_2 EOR project is hereinafter referred to as the Oxy CO_2 EOR Project or the Oxy Project. The Oxy CO_2 EOR Project is designed to meet a number of objectives, which are summarized below.

- Extend and enhance the useful and productive life of the EHU, thereby increasing domestic oil and gas energy supplies and improving energy security.
- Provide an accounting of the CO_2 received onsite and used for EOR, which will: 1) demonstrate the safe and cost-effective sequestration of CO_2 through EOR, 2) help demonstrate that the HECA Project meets its greenhouse gas (GHG) requirements, and 3) facilitate OEHI's compliance with evolving requirements for GHG reporting.
- Minimize environmental impacts associated with the construction and operation of the Oxy Project through choice of technology, project design and implementation of feasible and appropriate mitigation measures. In addition, the Oxy CO_2 EOR Project will provide significant net environmental and economic benefits in air emissions, habitat conservation, and the efficient use of existing infrastructure.
- Provide economic benefit to the local and California economies through jobs associated with construction and operations at the EHU where approximately 500 employees and 3,000 contractors currently work.
- Further demonstrate the commercial viability of the process wherein CO_2 used for EOR becomes sequestered.

Much like the existing EHU water-flood project, the Oxy CO_2 EOR Project is a process to enhance the recovery of existing oil that would otherwise be left stranded. Since it will be purchasing CO_2 from HECA, OEHI has a strong economic interest to ensure that the CO_2 is being used as effectively as possible. This document reviews the Oxy CO_2 EOR Project and presents a proposed plan for monitoring, reporting, and verifying (MRV Plan) the sequestration of injected CO_2.

1.1 Expansion of EOR Operations in the EHU Using CO_2

The Elk Hills Oil Field, one of the largest oil fields in the United States, has been in operation for more than 100 years. The EHOF occupies about 75 square miles as indicated in Figure 1. There are multiple oil reservoirs at various intervals within the EHOF, as well as multiple layers of stratigraphic seals overlying the oil reservoirs. Current and historic EOR operations include injection of produced brine water, nitrogen gas, methane, and Alkali Surfactant Polymer (ASP). In addition, a successful CO_2-injection pilot project was performed in 2005.

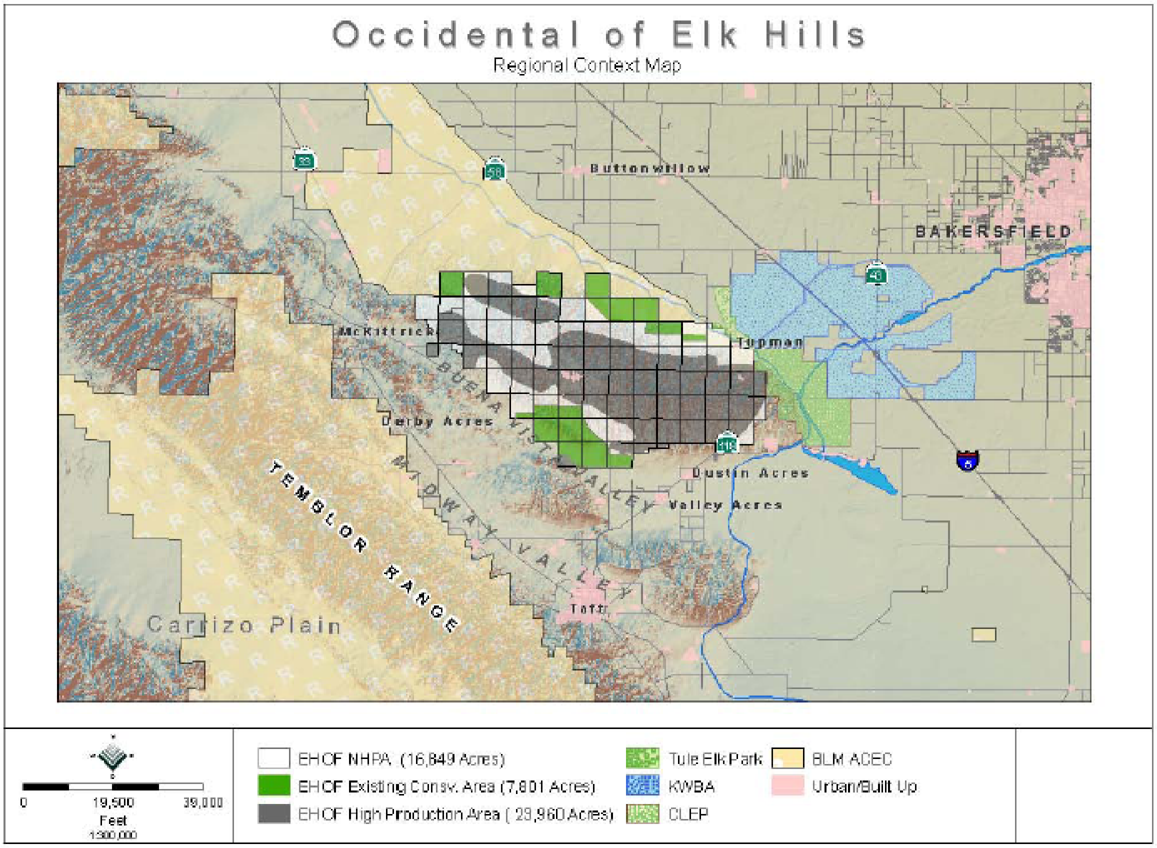

Figure 1 - Location of Elk Hills Oil Field

OEHI plans to use CO_2 to enhance the production of oil in the EHU. Although several oil-producing reservoirs would be attractive targets for CO_2 EOR, the Stevens reservoirs have been identified as being particularly well suited for such operations. Because they have good injectivity and more than sufficient available pore space to accept the total volume of CO_2 planned to be purchased from the HECA Project over 20 years, the Stevens reservoirs are the target CO_2 injection zones.

The Stevens reservoirs are located approximately 5,000 feet below ground surface and are overlain by the Reef Ridge Shale, a natural geologic feature with a minimum thickness of approximately 750 feet over the target injection zones in the NWS and 31S structures. As discussed below, the "Reef Ridge Shale" is continuous throughout the EHOF and is a proven physical seal that prevents upward migration of CO_2 out of the Stevens reservoirs. Further, there is ongoing oil and gas production in other reservoirs located above and adjacent to the Stevens reservoirs, and these overlying and adjacent reservoirs are isolated from and operate at different pressures than the Stevens reservoirs. Therefore, production wells in these nearby reservoirs provide an excellent system to monitor for the unlikely event of CO_2 migration out of the target injection zones.

1.2 CO_2 EOR Is a Proven Technology

CO_2 EOR is a well established EOR technique used in mature oil fields, usually after water flooding has been employed, to further enhance the recovery of oil. Currently more than 35 million tonnes of CO_2 are injected annually in oil fields throughout the United States.

Miscible CO_2 EOR processes are designed to inject CO_2 into reservoirs at high enough pressures to dissolve into the oil (the minimum miscibility pressure or "MMP"), but below pressures that would compromise the confining geologic seal. Above the MMP, CO_2 and crude oil are miscible, meaning they are capable of mixing in any ratio and becoming a single homogeneous solution. Due to the pressure gradient caused by the injection of the CO_2, the CO_2 will flow away from the injection well and become miscible with the reservoir oil. The resulting fluid has lower viscosity, enhanced mobility, and lower interfacial tension as compared to reservoir oil without dissolved CO_2. In effect, this process mobilizes and recovers oil that would otherwise be unrecoverable. Water injection is often alternated with CO_2 injection to sweep the miscible CO_2 /oil mixture to production wells and to control the movement of CO_2 through the reservoir.

1.3 Regulation of the Oxy CO_2 EOR Project

HECA has submitted an application to the California Energy Commission (CEC) for certification to authorize siting of the HECA Project. The CEC siting process requires the CEC to consider all potential significant impacts of the "whole of the project," which includes potentially significant impacts from the Oxy CO_2 EOR Project. To the extent that the CEC identifies potentially significant impacts relating to the Oxy CO_2 EOR Project, as it relates to the HECA Project, the CEC can specify additional project design features or mitigation measures that should be implemented by other agencies responsible for permitting the Oxy CO_2 EOR Project. Such additional requirements may include, for example, measuring, reporting and verification standards. This proposed MVR Plan seeks to inform the CEC's consideration of necessary and appropriate measuring, verification and reporting mitigation measures for the HECA project.

The Oxy CO_2 EOR Project will be implemented as part of the overall, ongoing OEHI operations in the EHU. The California Division of Oil, Gas and Geothermal Resources (DOGGR) is the agency responsible for issuing Class II Underground Injection Control (UIC) permits – under the California Public Resources Code and the federal Safe Drinking Water Act of 1974 – for OEHI operations in the EHU. DOGGR has issued permits for a variety of oil and gas production operations at the EHU in the past, including Class II UIC permits for injection wells used for gas pressurization, water flooding, polymer flooding, and a CO_2 EOR pilot project. OEHI will apply to DOGGR for Class II UIC permits for the Oxy CO_2 EOR Project. OEHI's application will provide information regarding its planned operations, including well design features, capacity calculations, operational injection volumes and pressures. In addition, all other necessary and appropriate permits and approvals for the Oxy CO_2 EOR Project (e.g., the Kern County Engineering, Survey and Permit Services Department, the San Joaquin Valley Unified Air Pollution Control District, and the California Department of Fish and Game) will be applied for and obtained in a timely matter.

The Oxy CO_2 EOR Project will be implemented in phases. In the initial phase, CO_2 will be injected in an eastern section of the Stevens reservoirs in the vicinity of the successful CO_2 EOR pilot project. As the Oxy Project progresses, new phases will expand the target injection zones in a westward direction. The Oxy CO_2 EOR Project is planned to begin operations once the HECA Project begins delivering captured CO_2 in about 2016. Due to DOGGR regulations that establish an automatic expiry for unused permits, OEHI does not anticipate applying for the first phase of UIC Class II permits until 2013 and will apply for additional permits as the Oxy Project progresses. In addition, filing for the permits closer to the time when CO_2 injection commences will ensure that the most recent and up-to-date well information and well status is reflected in the application.

1.4 The Oxy CO_2 EOR Project Will Result in CO_2 Sequestration

In the Oxy CO_2 EOR Project, CO_2 and hydrocarbon gas will be separated from the produced oil and water at the surface and re-injected into the target CO_2 injection zones using a closed-loop operating system so that recovered CO_2 is not released to the atmosphere. With each pass of the CO_2 stream through the oil reservoir, a significant portion of the injected CO_2 will become trapped in the reservoir; researchers from the University of Wyoming's Enhanced Oil Recovery Institute estimate that the amount trapped during each cycle can be roughly one third of the injected CO_2.[1] The balance of CO_2 will be recovered, recycled, and blended with additional CO_2 purchased from the HECA Project before being re-injected. Ultimately, all of the injected CO_2 (net of fugitive, operational, or other emissions as discussed later in this MRV Plan) will become trapped in the formation by structural and stratigraphic, residual CO_2, solubility and mineralization trapping mechanisms, and will be sequestered. Thus, sequestration is an inevitable consequence of EOR, and, for the purposes of this document, the term "sequestration" will be used interchangeably with the term "trapping."

1.5 Overview of the Monitoring, Reporting, and Verification (MRV) Plan

The MRV Plan is designed to:

- Identify and assess the risk of potential CO_2 leakage to the surface;
- Monitor to confirm injected CO_2 behaves as expected, including:

[1] EORI, University of Wyoming, "New Thinking," accessed online June 2010 at: http://eori.uwyo.edu/downloads/CO2_EOR.pdf.

    - Establish baselines against which changes can be measured
    - Monitoring surface sources
    - Monitoring subsurface CO_2
    - Respond to variances in expected performance

- Determine sequestration volumes using mass-balance methodology.

In addition, this MRV Plan includes procedures for data-quality assurance and quality control.

Geologic sequestration authorities note that proper site selection is the most important measure to mitigate the risk of atmospheric loss of CO_2 from geologic sequestration.[2] Accordingly, much of this MRV Plan is devoted to the analysis of the suitability of the EHOF for geologic sequestration.

As detailed in this MRV Plan, the site selected for the Oxy CO_2 EOR Project is very well suited for demonstrating sequestration of CO_2 injected for EOR. The positive attributes are summarized below.

- Excellent Site Characterization - The EHOF has been studied and documented extensively during its 100+ year history. It is one of the most fully characterized oil fields in the United States. OEHI has captured this characterization in a full-field simulation model of the planned operations. This model will be used to adjust the monitoring plans and operations as necessary.

- Insignificant Risk of Leakage - The target injection zones are located within a geologic structure that is known to have physically contained oil and natural gas for millions of years; there are no known natural features, such as transmissive faults and fractures, that penetrate the geologic seals that created the portion of the EHU that will be used for the Oxy CO_2 EOR Project; and, the operating history is well documented and does not indicate leakage from man-made pathways. Based on these characteristics, the potential risk of leakage resulting from future injection operations appears insignificant.

- Extensive Monitoring - The Oxy CO_2 EOR Project will be conducted in a small portion of the EHU that is surrounded by existing production wells. Some of the existing production wells surrounding the area of the Oxy CO_2 EOR Project will be designated to serve a secondary function – monitoring – becoming the core of an extensive monitoring network for the Oxy Project. In addition, OEHI has a sophisticated central control system that continuously monitors pressures and fluid composition throughout the EHU. Monitoring related to the Oxy CO_2 EOR Project will be designed to confirm that the injected CO_2 behaves as expected and will allow rapid detection of unexpected movement of injected CO_2. Unexpected

[2] "CO_2 Sequestration in Deep Sedimentary Formations," Benson, Sally M.; Cole, David R., Elements, Vol. 4, pp. 325-331 (Oct. 2008).

behavior will be responded to as appropriate. The monitoring data will be used to inform the full-field simulation model.

- Established Baselines - In addition to the modeling described above, OEHI has historical records indicating existing field pressures and CO_2 concentrations in produced fluids. OEHI will use this information to establish baselines that will be used to determine variances from normal conditions that might signify CO_2 leakage.

- Use of Mass-Balance Equations - All of the wells and facilities in the EHU are metered. OEHI intends to use data from the existing systems, additional data, and mass-balance equations to calculate the volumes of sequestered CO_2. OEHI will maintain records to verify those calculations.

2. Project Description

2.1 Background

The EHU is located 26 miles (42 kilometers) southwest of Bakersfield in western Kern County, California. The 48,000 acres of the EHU include land distributed across all or part of 81 sections as indicated in Figure 2.

The EHOF was originally developed as part of the federal Naval Petroleum Reserves. Today OEHI is the majority owner (78 percent) of the EHU and Chevron owns the remaining 22 percent. OEHI operates the EHU on behalf of Occidental Petroleum Corporation and Chevron.

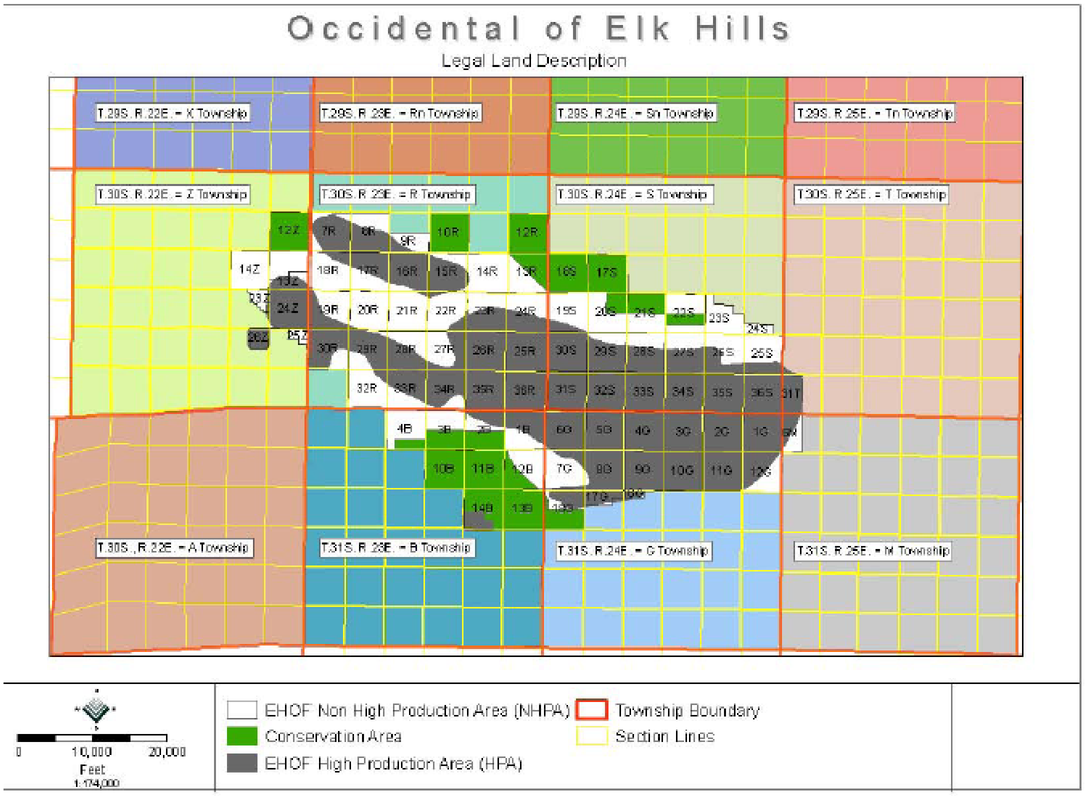

Figure 2 - EHOF Sections and Naming Convention

The EHOF has been well studied and provides a uniquely suited setting for large-scale geologic sequestration of CO_2. During its 100-year history, more than 6,000 wells have been drilled in the EHOF. The acquired data from these wells are contained in an extensive database that was transferred to OEHI when Elk Hills was acquired from the federal government in 1998. This database is the foundation for modeling the Oxy CO_2 EOR Project.

Occidental Petroleum Corporation is one of the largest and most respected CO_2 EOR operators in the world, operating 28 CO_2 EOR projects that include thousands of wells. This expertise will be utilized in planning and executing the Oxy CO_2 EOR Project.

2.2 Project Facilities and Equipment

The Oxy CO_2 EOR Project will be conducted in phases in the Stevens reservoirs with the requested permit area expanding over time to accommodate 20 years of CO_2 delivery. The first phase of operations will start in the eastern portion of the Stevens reservoirs in the structure marked “31S” (see Figure 3). Over time, the Oxy Project will expand westerly through this structure. Reservoirs within the structure marked “NWS” (Northwest Stevens) will also be used during the initial phase of the Oxy CO_2 EOR Project. Some of the NWS reservoirs are currently at a relatively low reservoir pressure compared to the 31S reservoirs and can accept CO_2 directly from HECA without additional compression. Including these reservoirs in the plan ensures that the Oxy CO_2 EOR Project can continue to accept CO_2 from HECA in the unlikely event of a temporary power failure or operational upset at the EHU which would affect injection into the higher pressured reservoirs.

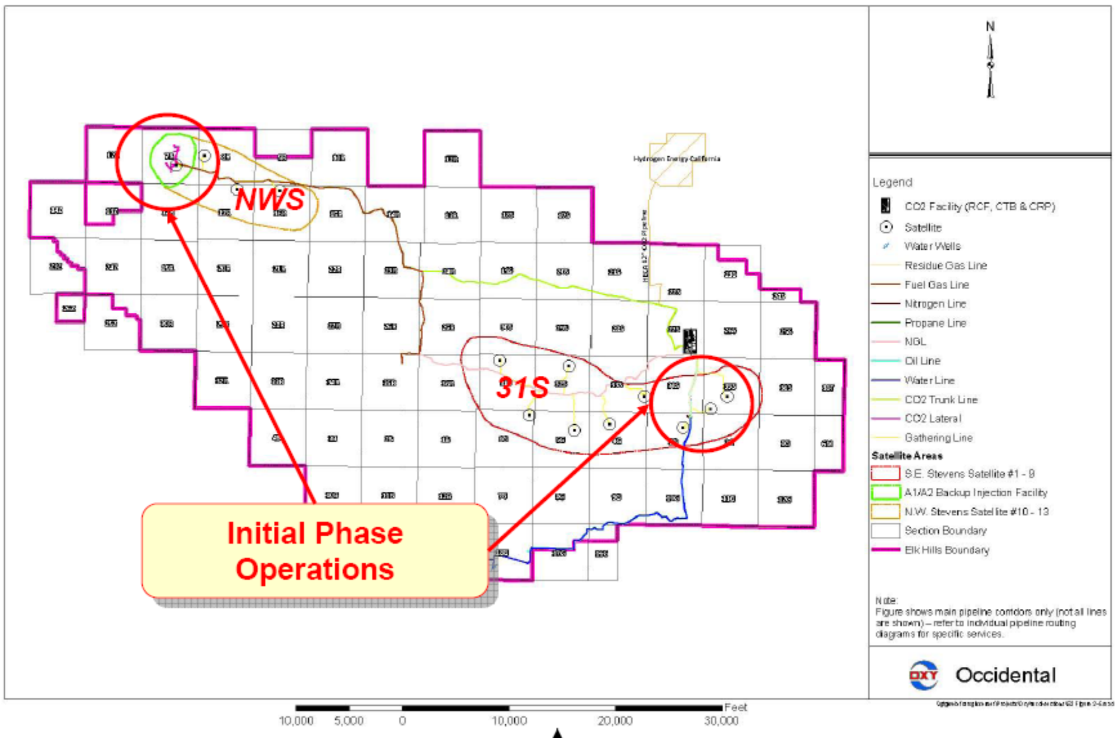

Figure 3 - Conceptual Plot Plan of Oxy CO_2 EOR Project

The Oxy CO_2 EOR Project is expected to receive an annual average rate of 107 million standard cubic feet per day (mmscfd) of CO_2 (approximately 2.2 million tonnes per year) from the proposed HECA Project. Figure 4 shows the conceptual process flow for the Oxy Project. OEHI will phase in process components and interconnecting systems to match the development of the Oxy CO_2 EOR Project over its life. Given the complexity of the system, this section provides a description of each of the component steps using Figure 4 as the base diagram.

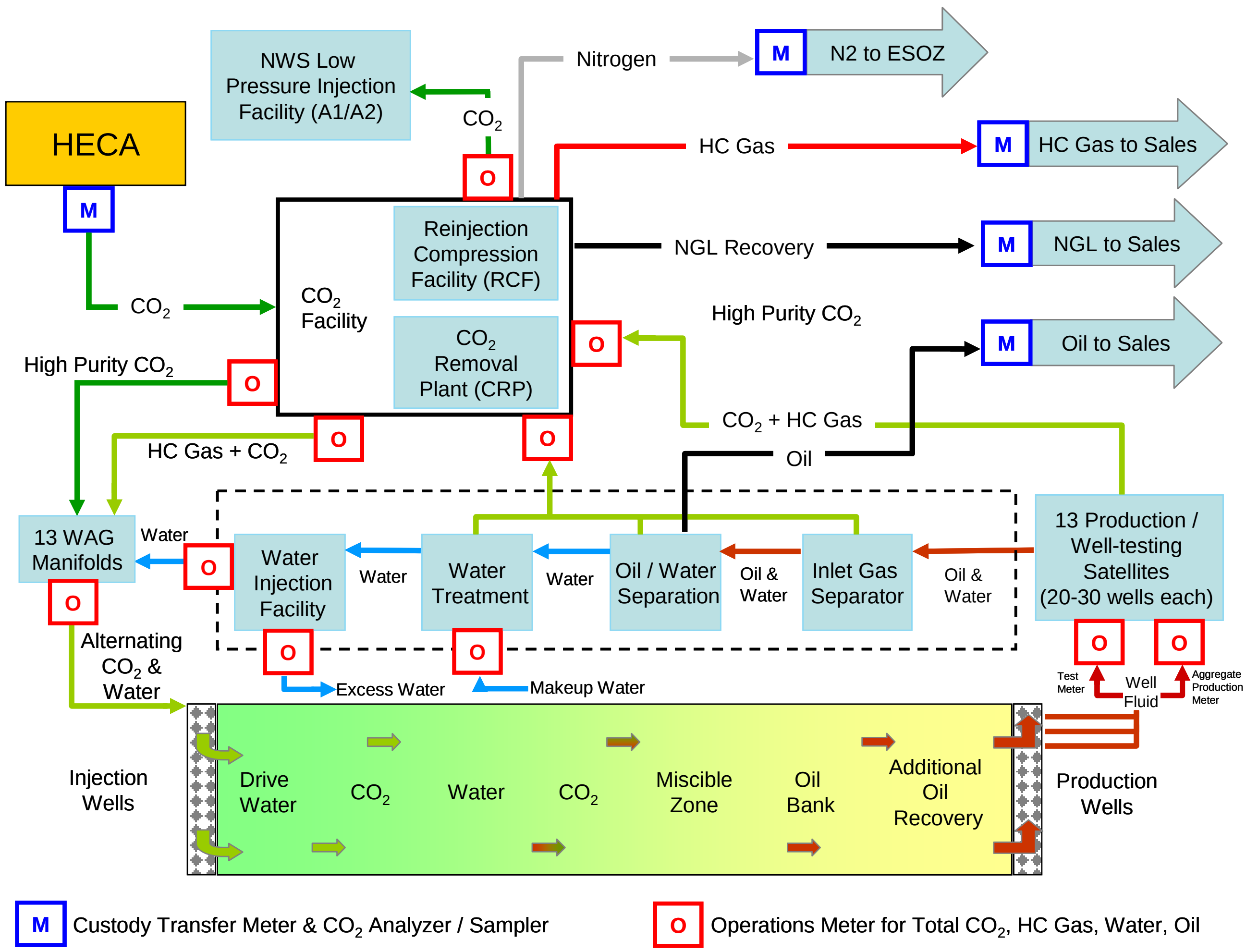

Figure 4 - Process Flow for Planned Oxy CO_2 EOR Project

1. Receiving CO_2 from HECA

The CO_2 will be compressed and delivered via pipeline to OEHI as depicted in Figure 5. Custody-transfer meters that will continuously monitor flow and CO_2 composition will be installed on both the HECA and OEHI sides of the delivery point.

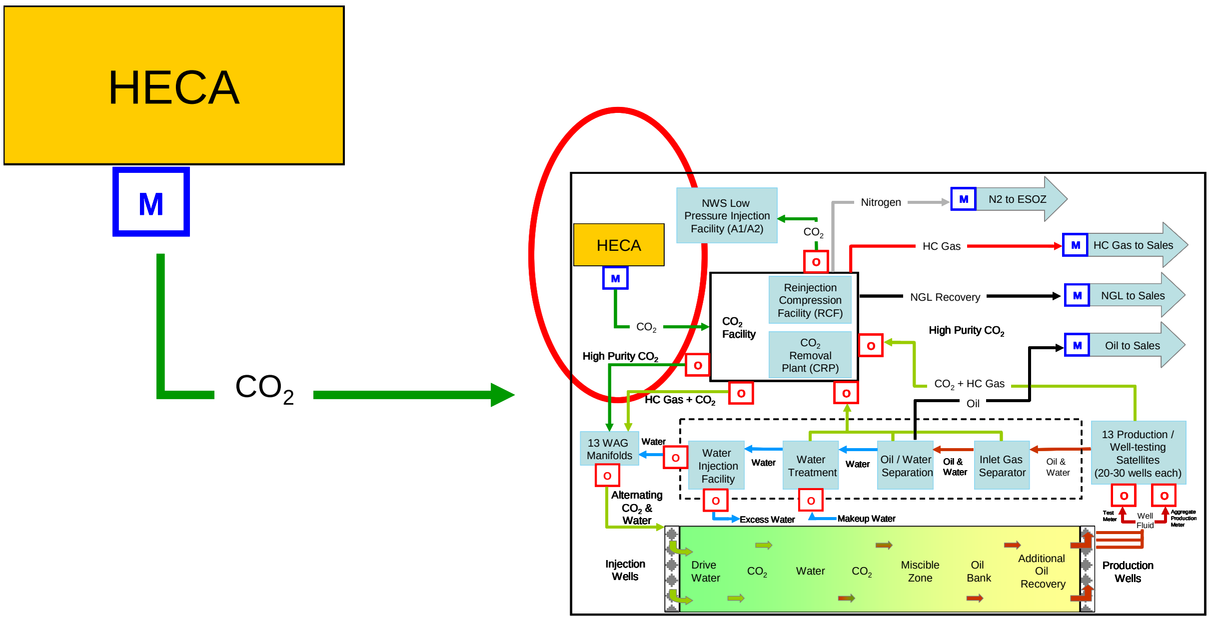

Figure 5 - CO_2 Pipeline from HECA

2. From the CO_2 Facility to the Injection Well

The CO_2 pipeline from the HECA plant terminates at the CO_2 Facility located in the upper center of Figure 6. Under normal operating conditions, CO_2 from the HECA plant is expected to meet typical specifications for common carrier CO_2 pipelines and will only need to be pumped from the CO_2 Facility to the injection wells.

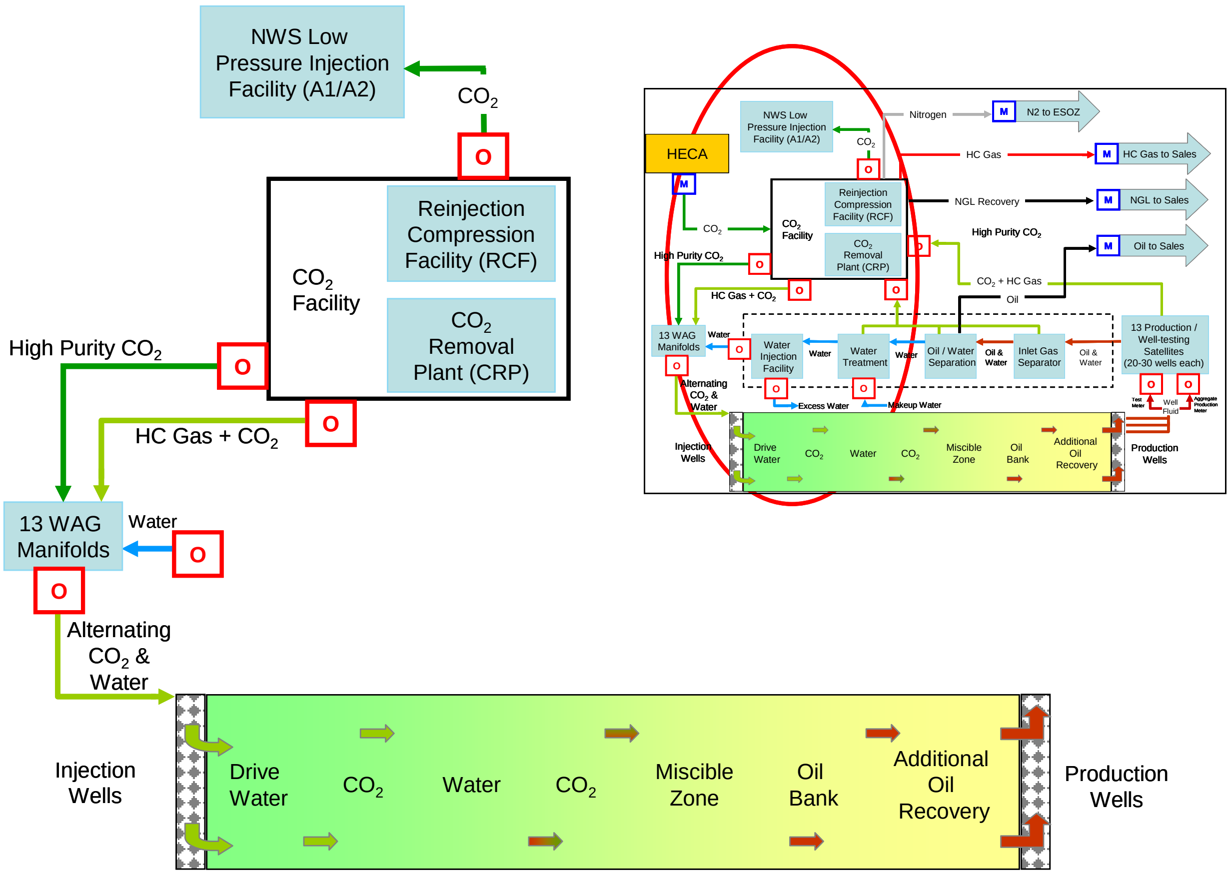

Figure 6 - CO_2 Transport from CO_2 Facility to Injection Wells

CO_2 that is recovered from the production wells is also brought to the CO_2 Facility. This is described in further detail after the following discussion about the production wells.

CO_2 is transported via pipeline either to the water alternating gas (WAG) manifolds located in the center left of Figure 6, or to the Low-Pressure Injection Facility (A1/A2) servicing the NWS structure and located in the very upper center of Figure 6. All CO_2 leaving the CO_2 Facility is tracked using operations meters to measure flow and either a continuous gas composition monitor or periodic gas sampling to determine CO_2 concentration.

A WAG manifold is a system that is capable of alternating the fluids going to the injection wells. In this case, the WAG manifold can alternate between water and CO_2 coming from the CO_2 Facility.

The injection wells will be placed in a pattern designed to optimize the recovery of oil. A typical well pattern consists of an injection well in the center and production wells located in a geometric pattern on the perimeter. For example, in a five-spot pattern, there would be four production wells spaced around a center injector, as if on the four corners of a square. Over the life of the Oxy CO_2 EOR Project, OEHI anticipates needing approximately 160 injection wells; these 160 injection wells are represented by the text and the image at the bottom of Figure 6.

An operations meter at the WAG manifold for each injector will be used to measure the volume of the injection fluid. OEHI will use the meter data from the CO_2 Facility and water injection facility to determine the total volume of injected CO_2 and water and will use the individual well data to allocate the total volumes to each well to report injection volumes to DOGGR. OEHI will also use this combination of data to monitor the performance of the EHOF and optimize operations.

The methodology described above is similar to the procedure OEHI currently uses to report water-flood data to DOGGR. It is a proven, practical approach where variances among readings from multiple operations meters (often dozens) are common. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will each have an effect on the meter reading. Many meters have some form of automatic adjustment for some of these factors, others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same volume of flow and gas composition.

3. Processing Produced Fluids – Part 1

Fluids recovered from the production wells will flow to one of 13 Production / Well-Testing Satellites (referred to as the satellite gathering stations) shown in the center right of Figure 7. Each satellite gathering station will be exclusively dedicated to the Oxy CO_2 EOR Project and service 20-30 production wells.

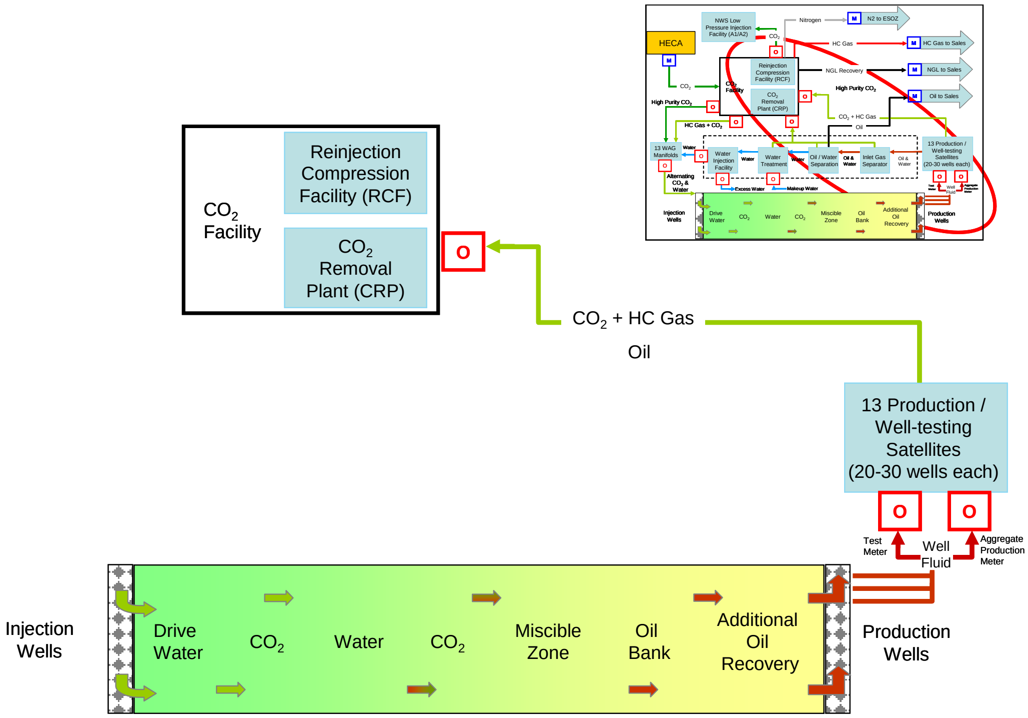

Figure 7 - Fluids Processing - Part 1

There are two operations meters at each satellite gathering station used to determine flow rates. One will be used to measure the aggregate volume of the produced fluid from all wells. A second meter will be used to measure the oil/water/gas rate of each production well on a rotating basis at least once a month. OEHI will use the total volume data gathered at each satellite gathering station and the results from each individual test of a production well to determine total produced volumes from each production well. This allocation will be reported to DOGGR. OEHI will also use this combination of data to monitor the performance of the Oxy CO_2 EOR Project and optimize operations.

At the satellite gathering stations, the produced fluid is separated into two streams: CO_2 mixed with hydrocarbon (HC) gas and CO_2 mixed with oil and water. This section will discuss the first stream, CO_2 mixed with HC gas; a discussion of the second stream follows.

From the satellite gathering station, a mixture of CO_2 and HC gas flows to the CO_2 Facility as seen in the upper center of Figure 7. The composition of CO_2 in the mixed flow stream will be measured at this point. The CO_2-rich gas will then flow through the Reinjection Compression Facility (RCF) to be dehydrated, compressed, blended with CO_2 purchased from the HECA Project, and sent back out for injection as depicted in Figure 6. As the volumes of recycled CO_2 increase over time, a CO_2 Removal Plant (CRP) may be constructed at the OEHI CO_2 Facility to separate CO_2 from the HC gas. The CO_2 from the CRP will be pumped and combined with the compressed CO_2-rich gas from the RCF and then combined with purchased CO_2 from the HECA Project before being sent back out for injection as depicted in Figure 6. When the CRP is in operation, HC gas will be sent to the sales pipeline.

4. Processing Produced Fluids – Part 2

As described above, all fluids recovered from the production wells will flow to one of 13 Production / Well-Testing Satellites shown again in the center right of Figure 8. This section describes what happens to the CO_2 mixed with oil and water.

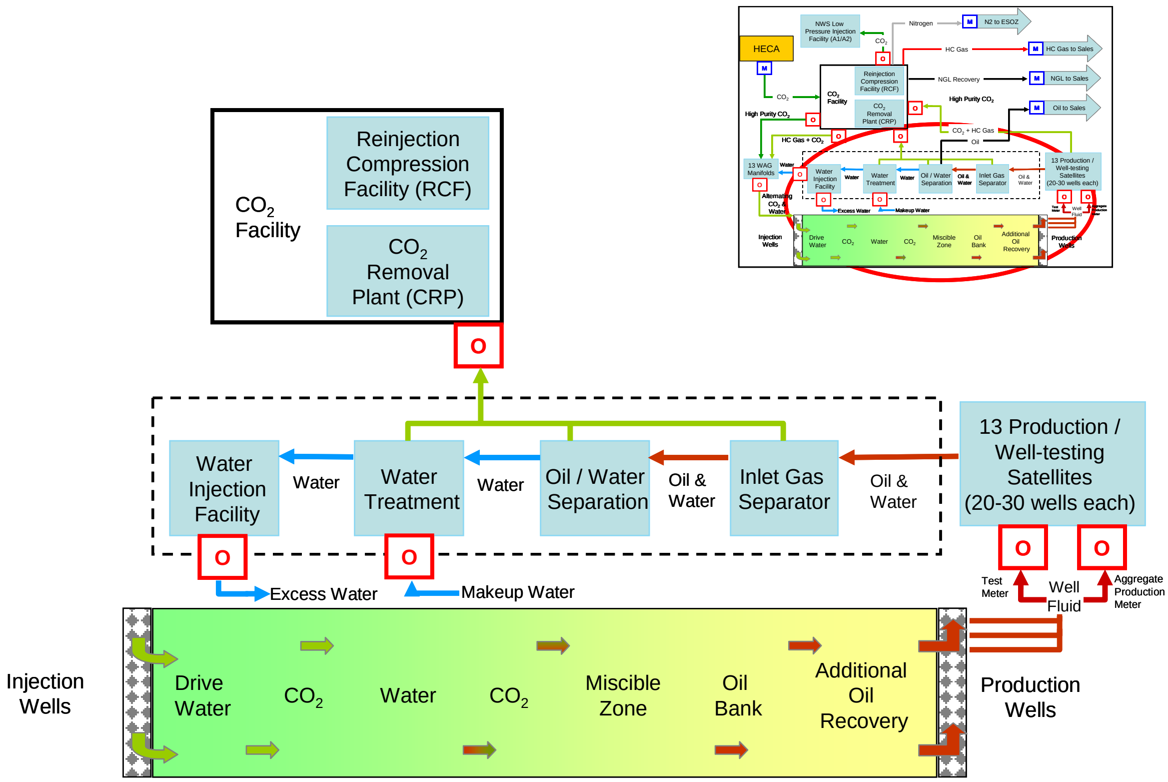

Figure 8 - Fluids Processing - Part 2

From the satellite gathering station, a mixture of oil and water with CO_2 will flow to the Central Tank Battery (CTB) as seen in the center of Figure 8. In the CTB the liquid will flow through a gas separator to remove CO_2-rich HC gas.

The remaining mixture will pass through an oil/water separation unit which will separate additional CO_2-rich HC gas, oil and water. The oil will be pumped to a commercial transfer point where the flow rate will be measured by a custody-transfer meter and where the stream will be sampled periodically to ensure that the oil meets the pipeline quality specifications.

The separated water will flow to a water-treatment unit where remaining CO_2-rich HC gas is separated. All of the CO_2-rich gas is collected and piped to the CO_2 Facility. An operations meter tracks the flow of the CO_2-rich gas entering the CO_2 Facility.

At the water treatment unit, additional water may be added from the make-up supply. An operations meter leading into the unit tracks water flow. Water will then flow to the water-injection facility. If there is excess water, the surplus will be sent to existing water-injection or disposal wells, the remainder will be sent to the WAG manifold as discussed in Figure 6. Operations meters at both of the outlets from the water-injection facility track flow.

5. Commercial Transfer of Certain Fluids

As discussed in reference to Figure 7, oil is pumped to an oil-shipment facility before custody is transferred to a commercial pipeline. Certain other fluids are similarly transferred as depicted in Figure 9.

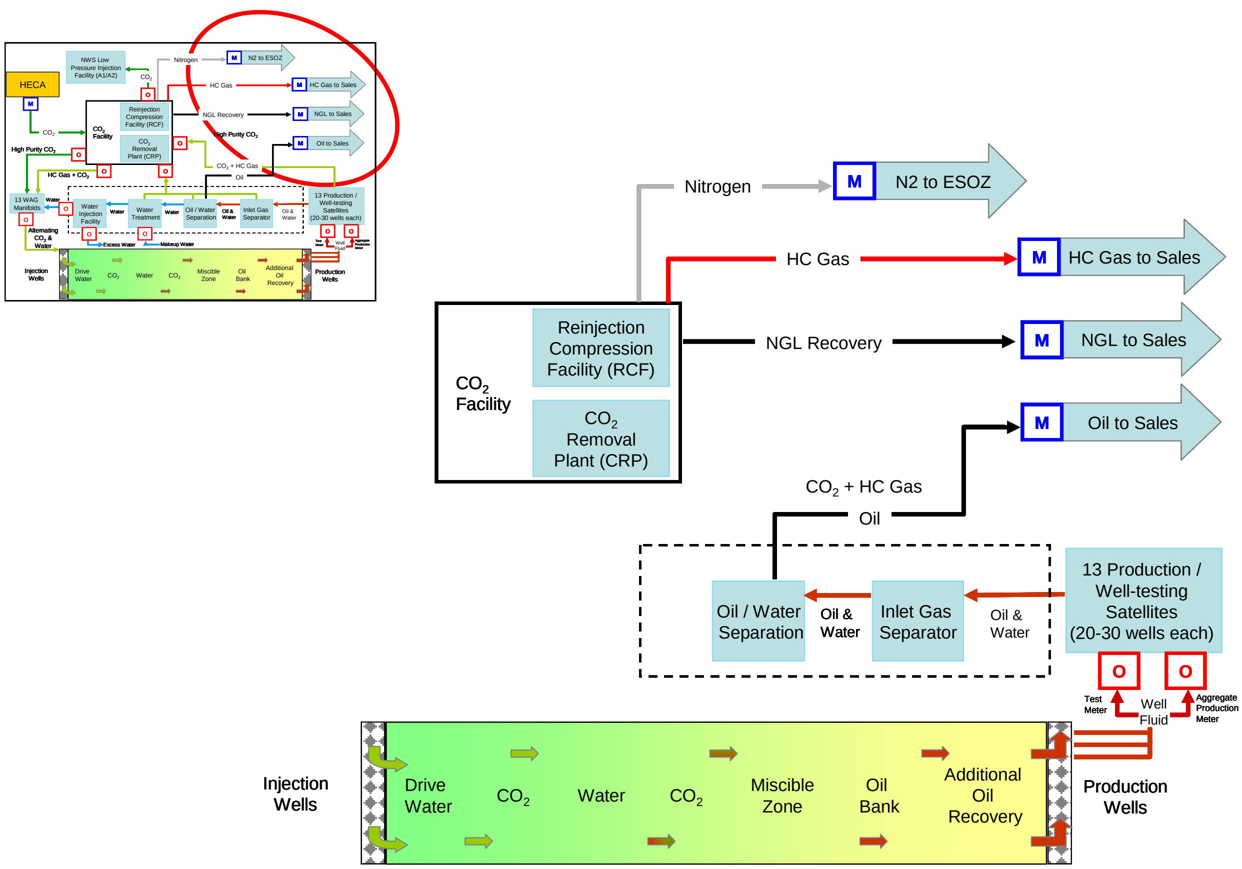

Figure 9 - Custody Transfer of Certain Fluids

Nitrogen gas, HC gas and liquid natural gas flow directly from the CO_2 Facility to pipelines where volumes and composition are determined for compliance with sales contracts and for financial accounting purposes.

3. Monitoring, Reporting and Verification

3.1 Assessment of Risk of Leakage

This section describes the site characteristics that make reservoirs on the 31S and NWS structures good sequestration candidates and discusses the assessment of potential leakage pathways.

3.1.1 Site Characteristics

The 31S and NWS structures are ideally suited for CO_2 EOR, and their characteristics have been carefully studied and documented. Exhibit A contains a selective list of such studies. This section reviews the results of that site characterization.

<u>Property Ownership and Land Use</u>

The EHU is located along the southwest edge of the San Joaquin Valley as indicated in Figure 1 above. The majority of land and associated mineral rights are owned by OEHI, and Chevron owns the remaining minority interest. The EHOF has been operated for more than 100 years as an oil and gas production facility. There are a number of communities, parklands, conservation areas, and natural features, such as the Kern River, located near the EHOF. The target injection zones are contained within the boundaries of the EHU, and it is expected that operation of the Oxy Project, like existing operations, will not disturb the nearby communities and sensitive areas. OEHI does not need to acquire any additional surface or subsurface property rights in order to operate the Oxy CO_2 EOR Project.

OEHI conducted a three-dimensional (3-D) seismic survey over approximately 400 square kilometers within the EHU from 1999-2000. This 3-D data was computer processed to allow for a highly accurate interpretation of the EHU's complex structure. New information gleaned from this 3-D seismic program and subsequent analysis has greatly aided the interpretation of the EHU's structural elements. Drilling, completion, and pumping innovations have been employed to manage the reservoir and maximize production throughout the field.

<u>EHOF Structure and Geology</u>

The EHOF produces oil and gas from several reservoirs that are vertically stacked and were formed in the Tertiary age (65 million to 2 million years ago). These reservoirs are comprised of layers of coarse-grained clastic rock in which there are multiple sublayers of shale. These layers have been folded and faulted, resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately

33 million to 5 million years ago (likely during the Oligocene and Miocene age[3]). The combination of multiple porous and permeable sandstone reservoirs interlayered with impermeable shale seals within the large anticlinal structure make the EHOF one of the most suitable locations for the extraction of hydrocarbons and the trapping of CO_2 in North America.

At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over 7 miles wide. With increasing depth, the structure sub-divides into three distinct anticlines, separated at depth by high-angle reverse faults. The anticlines are believed to have formed in a transpressional regime associated with formation of the San Andreas Fault, beginning in the Middle Miocene, which began approximately 16 million years ago (Callaway and Rennie Jr., 1991). The anticlines, labeled in Figure 10 as 29R, 31S and NWS, formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows.

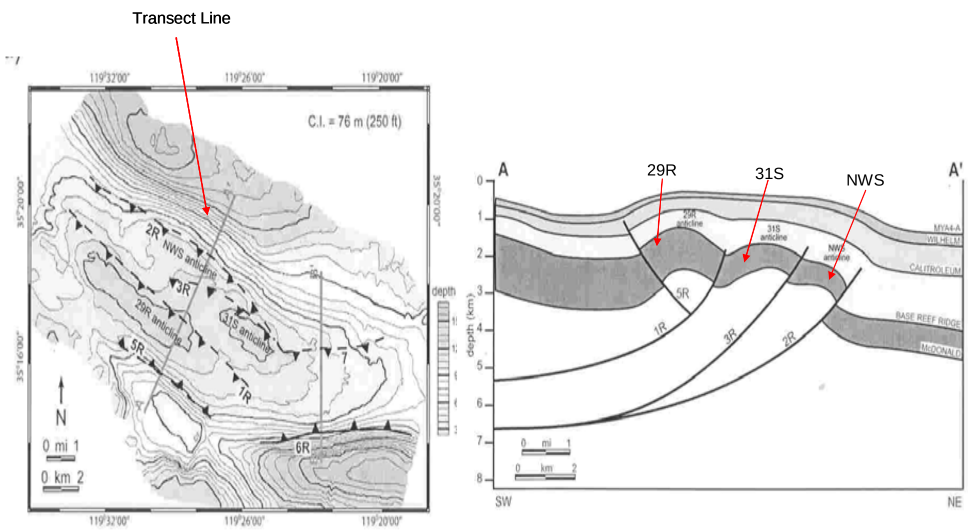

Figure 10 - (Left) EHOF Structure Contour Map Of Upper Pliocene Rocks Showing Faults And Location Of Cross Section A-A'; (Right) Cross Section A-A' Showing Structure Of EHOF Anticlines.[4]

To date, more than 6,000 wells have been drilled to various depths within the EHOF, creating an extensive library of information compiled within a comprehensive database. The deepest well in the field is the 934-29R, drilled to a total depth of 24,426 feet, bottoming in Mesozoic, Upper Cretaceous age (93 million to 65 million years ago) sediments. A schematic diagram of the EHOF area stratigraphy based on well 934-29R is presented in Figure 11.

[3] Zumberge, J. E., J. A. Russell and S. A Reid, 2005, Charging of Elk Hills reservoirs as determined by oil geochemistry, AAPG Bulletin, v. 89, no. 10, p. 1347-1371.

[4] Fiore, P. E., D. D. Pollard, W. R. Currin and D. M. Miner, 2007, Mechanical and stratigraphic constraints on the evolution of faulting at Elk Hills, California, AAPG Bulletin, v. 91, no. 3, p. 321-341.

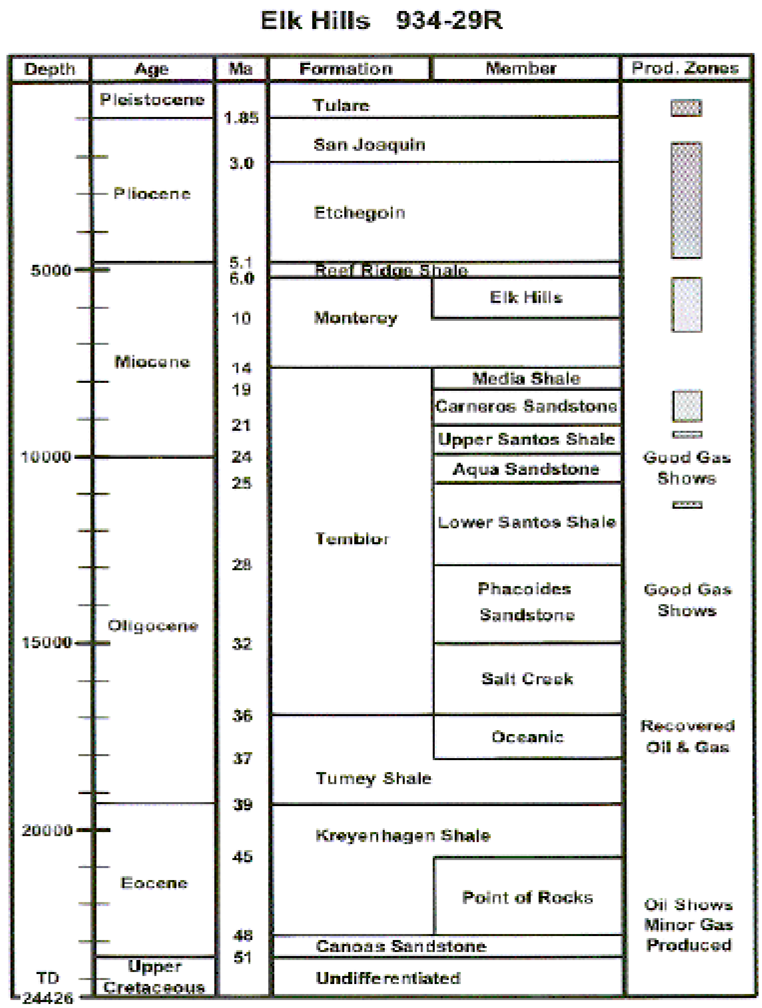

Figure 11 - EHOF Stratigraphy based on 934-29R Well

The oldest rocks observed in the field are Upper Cretaceous in age, but they are not productive. The Miocene-aged Carneros sandstone member of the Temblor Formation is the lower-most hydrocarbon producing interval in the field, although oil and gas shows have been recorded in deeper, older sediments. Above the Temblor is the Miocene-aged Monterey Formation. The Monterey is approximately 4,500 to 10,000 feet deep and includes the targeted portions of the Stevens reservoirs that produce from stratigraphic-structural traps on the three deep anticlines indicated in Figure 10. Within the upper Miocene is the Reef Ridge Shale, which is hard and siliceous (Nicholson, 1990) and acts as a stratigraphic trap keeping hydrocarbons sealed below.

Injection Zone

The Stevens reservoirs of the Monterey Formation are considered the best CO_2 EOR targets within the EHOF. They have been developed on 10 - 20 acre pattern spacing and have produced over 500 million barrels of oil to date. Pressure in one of the many sublayers within the Stevens reservoirs, the Main Body B (MBB), is near the MMP, indicating the MBB is an ideal initial candidate for CO_2 EOR.

The Stevens reservoirs are composed of stacked fining upward turbidite deposits composed of lenticular sheet sands, channels, and levee deposits within a submarine fan complex (Reid, 1990). They have porosities between 20 and 25 percent, permeabilities that average 150 millidarcy, and net reservoir thickness that can exceed 1,000 feet.

Unique oil-water contacts, pressures, and temperatures of the Stevens and the overlying Shallow Oil Zone (SOZ) reservoirs indicate that there are no transmissive faults across the Reef Ridge Shale. Additionally, concurrent development programs, including repressurization and depletion strategies, were employed without causing interference in either the SOZ or Stevens reservoirs. This vertical compartmentalization is attributed to not only the thickness of the Reef Ridge shale segregating the Stevens and SOZ reservoirs, but also the degree of transpression on the 31S structure throughout the Upper Miocene.

During 2005, OEHI conducted a four-month CO_2 EOR pilot project in the Stevens reservoirs. This pilot was designed to assess how much oil could be mobilized from the Stevens reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly that oil would be mobilized. Critical information was gained during this pilot, including that the injected CO_2 was contained within the Stevens reservoirs. The pilot also determined that the portions of the Stevens reservoirs selected for the Oxy CO_2 EOR Project are surrounded by, but isolated from, other hydrocarbon-producing reservoirs.

Seal Quality / Long-Term Stability of the Seal

As discussed above, the Stevens reservoirs include multiple sublayers contained within three geologic structures. The Reef Ridge Shale overlays this entire area and is the primary seal. There is substantial evidence that confirms the sealing characteristics of the Reef Ridge Shale, including:

- Physical rock characteristics of the Reef Ridge Shale,
- Fluid contacts and reservoir pressure depletion,
- Core analysis of the Reef Ridge Shale,
- Seismic control,
- Geochemical analysis, and
- Geomechanical analysis.

Physical Rock Characteristics of the Reef Ridge Shale

The characteristics of the Reef Ridge Shale make it an effective seal for containing injected CO_2. First among these characteristics is its areal extent; data from well penetration shows that it covers an area of the Stevens reservoirs much larger than the expected pore space that will be occupied by the injected CO_2. As shown in Figure 12, the Reef Ridge Shale is continuous across the 31S, 29R, and NWS structures.

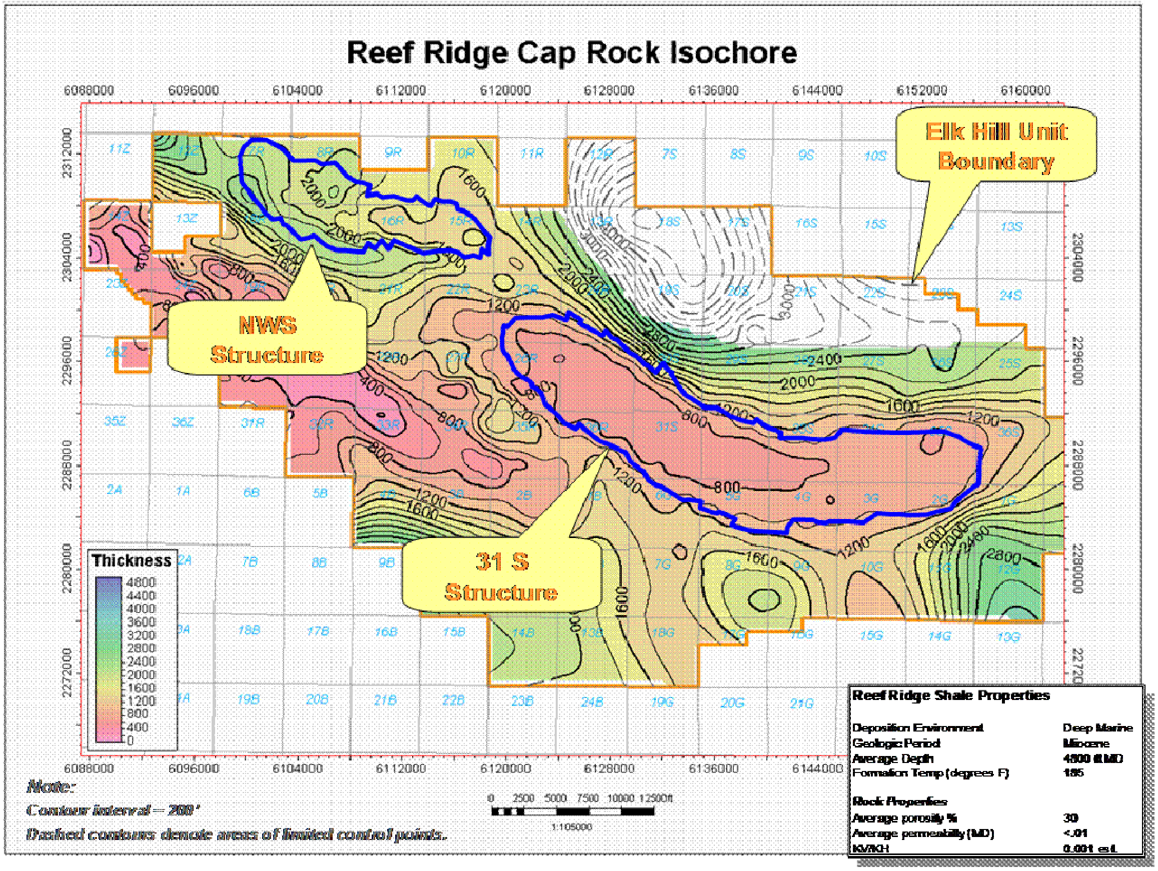

Figure 12 - Isochore Map of the EHOF

The continuity of the Reef Ridge can be further observed by the cross section in Figure 13 that indicates the location of the Reef Ridge Shale in two of these structures.

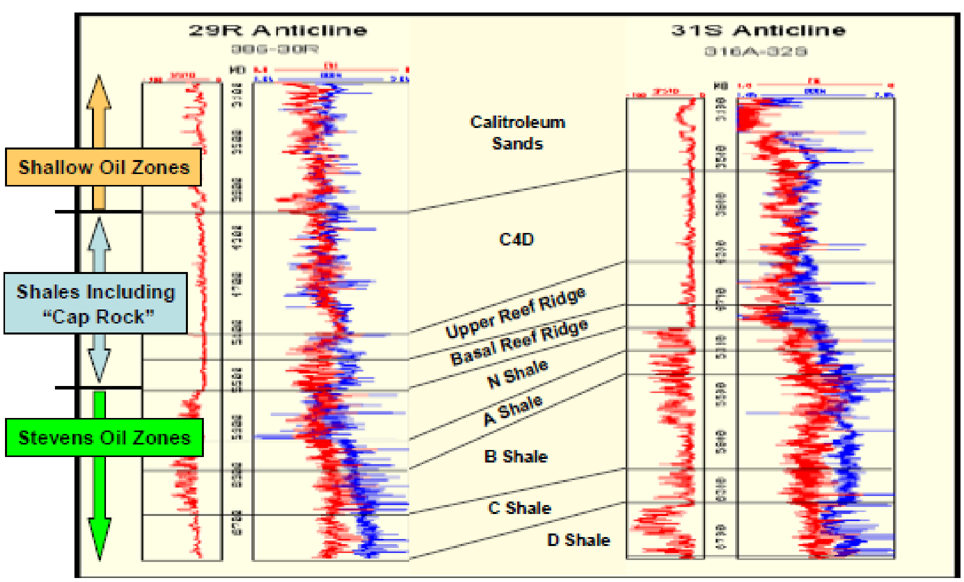

Figure 13 - Continuity of Reef Ridge Shale Anticlinal Structures

The isochore map in Figure 14 shows the thickness of the Reef Ridge Shale over the area planned for the initial phase of the Oxy CO_2 EOR Project. In Figure 14, as throughout the area planned for the entire 20-year injection period, the Reef Ridge is very thick, with a minimum thickness of 750 feet over the injection zones in the NWS and 31S structures. The contoured interval extends from the top of the Reef Ridge Shale to the top of the N Shale. Over the initially proposed permit area, the cap rock ranges from 750 to 1,400 feet in thickness.

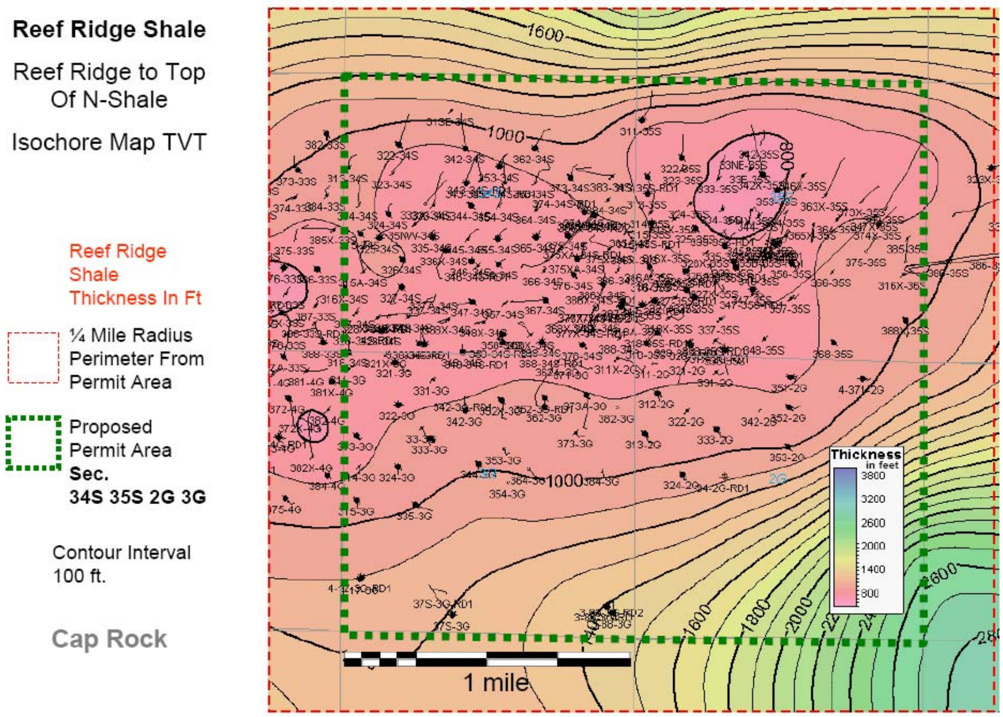

Figure 14 - Isochore Map of Reef Ridge Shale Interval

Water Flooding and Fluid Contacts Analysis

A program of secondary oil recovery using water flooding in the Stevens started in 1980. Water flooding is conducted under a set of Class II UIC permits issued by DOGGR. To date, more than 830 million barrels of water have been injected and there are approximately 150 active water-injection wells and 580 active oil and gas production wells. This process has yielded approximately 320 million barrels of oil. OEHI monitors the pressures and fluid composition in the wells surrounding the zone where the water flood is conducted. OEHI has not experienced any unplanned migration of the injected water beyond the Stevens reservoirs. This is confirmed by publicly-available production and pressure records.[5] The water-flood results provide a meaningful indicator that the planned CO_2 EOR injection zone is confined.

---

[5] Oil well production and injection records are publicly available on the DOGGR website: http://www.conservation.ca.gov/dog/Pages/Index.aspx. The user can select the menu option for "Online

OEHI also conducted an analysis of the potential fluid contacts between zones in the Stevens reservoirs and overlying SOZ reservoirs. The results indicate that the original oil/water contacts for the two reservoirs varied by over 3,000 feet, demonstrating that the reservoirs are not in communication. In addition, past development of each reservoir has created large pressure differentials across the Reef Ridge Shale. Considering the history of oil and gas production in the EHOF, the lack of fluid movement from areas of high pressure to areas of low pressure confirms the integrity and long-term stability of the seal.

Core Analysis

In 2000, Reef Ridge core samples were collected from the 31S structure. These core samples demonstrated two important features. First, X-ray diffraction of the core indicated that the most predominant secondary mineral is clay, which inhibits the Reef Ridge Shale's ability to fracture. Second, low permeability is verified by the absence of oil saturation. This data indicates that as zones below the Reef Ridge were being "charged" with hydrocarbons, the permeability of the Reef Ridge was sufficiently low to prevent hydrocarbon migration. The presence of the EHOF today indicates that this very thick, low-permeability interval has been an effective seal to hydrocarbons for millions of years. This conclusion is further evidenced by the results of geochemical analysis described below.

Seismic Control

The analysis of the 3-D seismic data provides further evidence of the sealing characteristics of the Reef Ridge Shale. A 3-D seismic survey was acquired from 1999 – 2000, and covered nearly 70 square miles in the EHU. The data has been processed using pre-stack depth migration which produces superior imaging in steeply dipping beds, such as on the flanks of the Stevens structures. Analysis of this data indicates that faults above and below the Reef Ridge Shale terminate before penetrating the seal.

OEHI has also reviewed the potential for naturally occurring seismic activity to propagate these faults and finds no evidence this has occurred. Since 1990, 129 naturally occurring earthquakes have been recorded with a magnitude greater than 3.0 within a 60-mile (100-km) radius of the EHOF. The vast majority of these have occurred along the White-Wolf fault, approximately 30 miles southeast of the EHOF (Southern California Earthquake Data Center web site). The EHOF is situated about 15 miles east of the San Andreas Fault.

From a longer-term perspective, the anticline structures in the EHOF developed over millions of years (since the middle Miocene) in response to regional shortening.[6] The Miocene Monterey Formation is the source rock for the oil reservoirs in the EHOF, and it

---

Production and Injection" to find the Elk Hills Field and the 31S wells. Within this database are records dating to the 1970s.

[6] Fiore, et al., 2007.

is thought that oil began moving into the reservoir early in the Pliocene at the same time as regional deformation began.[7] Although the area has undergone deformation since at least the early Pliocene (5 million years ago), the migrated oil has remained in place. This indicates that naturally occurring seismic activity throughout history has not compromised the sealing integrity of the Reef Ridge Shale.

Geochemical Analysis

Geochemical data provides additional evidence that there is vertical isolation between the Stevens and SOZ reservoirs, which lie above the Reef Ridge Shale. Zumberge, Russell and Reid documented geochemical data along with their analysis of 66 oil samples from the EHOF. Cluster analysis revealed five distinct oil families sourced from the Miocene Monterey Formation and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Stevens and SOZ oils among the other oil "families" identified suggests "minimal upsection, cross stratigraphic migration." The authors conclude by stating that hydrocarbon migration into the SOZ reservoirs is not the result of leakage (upward) from the older Miocene reservoirs.

Geomechanical Analysis

Geomechanical data about rock stress, rock strength, and fault stability has been incorporated into the full-field simulation model (see discussion below). This model will allow OEHI to assess the integrity of the Reef Ridge Shale under various injection-volume and pressure scenarios over extended periods of time.

Reservoir Simulation

Using the results of the CO_2-injection pilot test and other field and geologic data, OEHI is developing a full-field simulation model of the planned Oxy CO_2 EOR Project. The model will be used to determine the storage capacity of the 31S and NWS structures as well as volumes and pressures that could cause a breach of the Reef Ridge Shale or lateral spillover. The model will also be used to finalize the selection of monitoring wells and to predict CO_2 behavior. OEHI will update this model to reflect monitoring results. At least once a year, OEHI will determine if there is a material change in the full-field simulation model that would warrant a modification to the MRV Plan. OEHI will indicate the outcome of this assessment in its annual MRV Report.

Preliminary results from the full-field simulation model verify that the Reef Ridge Shale is a physical barrier, stabilizing the injected CO_2 volume shortly after injection ceases. Further, the simulation shows that some CO_2 mineralization will occur over 100 to 200 years. These results predict that, ultimately, all CO_2 injected during the life of the Oxy CO_2 EOR Project will remain permanently stored in the reservoir.

---

[7] Zumberge, et al., 2005.

Estimated Storage Volumes

Based on analysis of historic operating records from the Stevens reservoirs, OEHI estimates that there is sufficient voided pore space to accept the entire volume of CO_2 that will be purchased from HECA during the lifetime of the Oxy CO_2 EOR Project. This calculation is summarized in Table 1:

Table 1: Comparison of Planned CO_2 Purchase and Cumulative Void Space

	Volume in billion barrels of oil (bbo)
Total Stevens Reservoir Capacity (31S and NWS structures)	>7.5 bbo
Cumulative Net Fluid[8] Volume Produced	>1.3 bbo
Estimated volume[9] of 44 million tonnes CO_2	<1 bbo

Further, the EOR process relies on injecting CO_2 and producing more oil and gas. Over time, this will create new voided pore space. Table 2 illustrates this concept by showing how the estimate for "Cumulative Net Fluid Volume Produced" was derived based on operations that have occurred to date, including gas pressurization and water flooding.

Table 2: Calculation of Cumulative Void Space

	Volume in billion barrels of oil (bbo)
Cumulative Fluid Produced	>3.4 bbo
Cumulative Fluid Injected	<2.1 bbo
Cumulative Net Fluid Volume Produced (void space)	>1.3 bbo

Existing Wells Within The Field / Existing Area Of Review

More than 6,000 wells have been drilled in the EHOF throughout its history. There are detailed records describing the location and status of these wells in the existing OEHI and DOGGR permit databases.

[8] Includes oil, gas, and water.

[9] This volume is calculated using the following conversion factor: 1,900 ft^3 of CO_2 at standard conditions equals 1 reservoir barrel of CO_2 at 4,000 psia and 210 degrees F.

Wells in the Stevens

Approximately 1,231 wells penetrate the Stevens reservoirs. Currently 1,021 active wells penetrate the Reef Ridge Shale in the 31S structure; 128 wells are permitted by DOGGR as UIC Class II injection wells and 749 wells are permitted by DOGGR as production wells. In addition, there are 144 wells that can be both producers and injectors at the completion level within different reservoirs, or have been “plugged and abandoned” in one reservoir, but are active in another, or have changed well type. There are 178 inactive injection and production wells, 22 injection and production wells that have been “plugged and abandoned” according to regulatory requirements, and 10 wells that are shut in. The following two tables indicate depth and completion dates for these wells.

Table 3: Depths of Stevens Wells

Number of Wells	True Vertical Depth Subsea (TVDSS)
174	1,500 – 4,999 feet
321	5,000 – 5,999 feet
352	6,000 - 6,999 feet
144	7,000 – 7,999 feet
143	8,000 – 8,999 feet
97	9,000 feet or greater

The majority of the Stevens wells were completed since 1980 as indicated in the following table.

Table 4: Completion Dates for Stevens Wells

Number of Wells	Completion Date
718	After 1980
284	1960 - 1979
229	Before 1960

As part of the permit process for the existing wells, OEHI documented the status of all other wells penetrating the Reef Ridge Shale and demonstrated that those wells were properly maintained and closed as appropriate. OEHI will make the same kind of demonstration in applying for necessary permits for the Oxy CO_2 EOR Project.

Wells in the SOZ

Approximately 1,140 wells are located within the ¼-mile radius beyond the CO_2 EOR area which do not penetrate the Reef Ridge Shale. OEHI will document the status of these wells and demonstrate that they will not create a leakage pathway in the permit application(s) for the Oxy CO_2 EOR Project.

3.1.2 Identification of Potential Leakage Pathways

The EHOF has been studied and documented extensively during its more than 100-year history. It is one of the most fully characterized oil fields in the United States. OEHI has determined, based on a careful assessment of the potential leakage pathways, that, other than de minimis losses from surface equipment and pipelines, there are no identified leakage pathways that would result in significant loss of CO_2 to the atmosphere. The site has an excellent seal that persists across the entire EHOF; there are no known natural features, such as transmissive faults and fractures, that penetrate the Stevens seal interval; the operating history is well documented and does not indicate man-made leakage pathways resulting from past production activities; and, the potential risk of leakage resulting from unidentified pathways can be mitigated. A detailed discussion of potential leakage pathways from the Stevens reservoirs follows.

Faults, Fractures

After reviewing geologic, geomechanical, geochemical, seismic, operating and other evidence, OEHI has concluded that there are no known transmissive faults or fractures that transect the Reef Ridge Shale interval.

Regarding the possibility of pressure-induced fractures or shear, there is a large difference between MMP and fracture pressure throughout the target reservoir. For example, in the southeast nose of the 31S structure, lab tests indicate an MMP of approximately 3,000 psi, and observed fracture stimulation experience reveals a fracture pressure of approximately 5,000 psi at this location. This pressure difference of roughly 2,000 psi is significant and ensures that OEHI can safely achieve miscibility pressure without reaching a pressure and rate in the reservoir that would compromise the Reef Ridge Shale. It should be noted that UIC permits specifically prohibit operating at pressures that could compromise the overlying seal. The Oxy Project is expected to be permitted at pressures consistent with the foregoing.

The potential risk of propagating a fracture through the sealing zone can be fully mitigated by controlling injection pressure. This approach is currently employed in the existing water-flood operations, where permits specify a maximum injection pressure (0.8 psi per foot of depth measured from the top perforation) and require the operator to conduct a rate/pressure test to justify any sustained injection pressures greater than the specified maximum.

Injection pressure is easy to measure and the control system at OEHI can perform automatic shutdown well in advance of an over-pressure situation. For instance, each injection well is equipped with a flowrate meter and pressure indicators on the casing and tubing. The outputs from the meters and pressure indicators are monitored continuously, and alarms are set to notify control-center personnel if a certain threshold is reached. Control-center personnel determine if the alarm can be resolved by field technicians, or, if necessary, can have the well shut down immediately. All equipment and controls conform to the requirements of the American Petroleum Institute (API) Recommended Practices for Petroleum Equipment and Operations as well as applicable California regulations (i.e., California Code of Regulations, Title 14 Natural Resources, Division 2 Department of Conservation, Chapter 4 Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 1 Onshore Well Regulations, Article 3 Requirements, §1722 - §1724.10 and Subchapter 2 Environmental Protection, Article 3 Requirements, §1750 - §1779). Accordingly, methods for measuring and preventing over pressure are well developed and robust.

Natural and Induced Seismic Activity

Natural seismicity of magnitude 3 to 6 is not likely to impact field operations and is highly unlikely to lead to leakage of any injected CO_2 from the EHOF. This assessment is based on decades of historical data for earthquake effects on wells in oil and gas operations in Southern California. It is also based on the geological setting of the EHOF, which is in relatively soft and shallow sediments (approximately 6,000 feet below ground surface). Most major earthquakes with a magnitude 6 and above in California occur at depths of 6 miles or more in brittle basement rock. In contrast, the proposed injection zones at EHU are less than 2 miles deep in relatively soft sandstone. The strength of seismic waves decreases with distance; therefore, the large separation between any major earthquake source and the injection reservoirs would help prevent well damage.[10]

With respect to natural seismic events, abundant historical data and information indicate that such events do not constitute a significant threat of leakage. The southern San Joaquin Valley area has been a prolific oil and gas producing region for more than 100 years with about 70 medium-to-very-large-scale oil and gas fields. There are more than 58,000 deep production and injection wells in Kern and Inyo counties. These existing wells have experienced decades of seismic activity with no dangerous release of gas, oil or water to the surface during earthquakes. This is primarily due to the fact that metal casings on wells deform or bend but do not break under seismic strains.

It is notable that the nearby Los Angeles Basin contains more than 24,000 production and injection wells and is even more seismically active than the Southern San Joaquin Basin. From 1998 to 2008, over 400 earthquakes greater than magnitude 3.0 were recorded within 100 miles of Los Angeles, whereas less than 200 earthquakes greater than magnitude 3.0 were recorded within 100 miles of the EHOF (Southern California Earthquake Data Center). The Los Angeles Basin contains more than 80 oil and gas fields and several natural gas storage fields. During the operational life of these wells, the Los Angeles Basin has experienced more than 20 major earthquakes (greater than magnitude 6), some directly adjacent to major gas fields and natural gas storage fields, with no damaging release of gas to the surface.

[10] Foxall, W., and S.J. Friedmann, 2008. Frequently asked questions about carbon sequestration and earthquakes. Lawrence Livermore National Laboratory, Doc No. LLNL-BR-408445. 3 pp.

The risk of induced seismicity from CO_2 EOR is highly unlikely. A regional seismicity study was conducted in 2008 for the EHOF by Terralog Technologies.[11] The study found: "Injection operations have in fact induced small scale seismicity at a limited number of oil and gas fields around the world, including some in California (most notably the Geysers geothermal operations). While there is no history of induced seismicity at Elk Hills, the possibility can not be completely ruled out. Any such induced seismicity events would likely be less than magnitude 4, considering the geologic setting, areal extent and depth of proposed operations, and anticipated pressure and stress changes. Seismic events on the order of magnitude 3 to 4 would be felt in the local area but should not cause structural damage to facilities and buildings. Peak ground acceleration from such events should be on the order of 0.01g, well within seismic building code standards for the area. This is also at least an order of magnitude smaller than anticipated natural seismicity hazards for the area."

Existing Well Bores

During the course of permitting gas- and water-injection wells for the past 10 years, OEHI has demonstrated to DOGGR that existing well bores do not pose a threat of leakage from existing oil-production operations. OEHI continues to maintain all well bores in a manner that prevents creation of a leakage pathway from the targeted portions of the Stevens reservoirs to overlying intervals or to the surface by mechanical-integrity testing of injection wells, proper construction of production wells, and demonstration of well integrity at closure. OEHI will continue to monitor operational data in the SOZ and will undertake appropriate actions as necessary. OEHI will comply with or exceed API standards and California regulatory requirements (i.e., California Code of Regulations, Title 14 Natural Resources, Division 2 Department of Conservation, Chapter 4 Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 1 Onshore Well Regulations, Article 3 Requirements, §1722 - §1724.10 and Subchapter 2 Environmental Protection, Article 3 Requirements, §1750 - §1779). As a result, existing well bores pose an insignificant risk of leakage.

Previous Operations

OEHI has measured the pressure differential between the SOZ and the Stevens reservoirs. This differential is significant. In one set of measurements, the pressure in the SOZ ranges between 0.03-0.05 pounds per square inch / total vertical depth (psi/TVD) and the pressure in the Stevens ranges from 0.43-0.55 psi/TVD. These two reservoirs are separated by a vertical depth of approximately 1,400 feet. This pressure differential between the two zones, coupled with an operating history showing no fluid communication between the zones, indicates that previous operations have not compromised the Reef Ridge Shale's ability to serve as an adequate seal.

[11] Terralog Technologies USA, Inc, Potential for Induced Seismicity From CO_2 Injection Operations at Elk Hills, 2008.

Pipeline / Surface Equipment

The facilities and pipelines of the Oxy CO_2 EOR Project will utilize materials of construction and control processes and that are common to new CO_2 EOR projects in the oil and gas industry. Operating and maintenance practices will follow industry requirements. Facilities will be designed to follow the elements of process safety management specified in OSHA's Occupational Safety and Health Standard 29 CFR 1910.119. The CO_2 supply line from HECA to OEHI will cross underneath the California aqueduct and will comply with all applicable laws. Other field pipelines will comply with California Code of Regulations, Title 8. The unique and centralized automation and control system currently in use at the EHU will facilitate excellent operational control over the Oxy CO_2 EOR Project and ensure the safety and reliability of the facilities. Maintenance programs and mechanical integrity practices will be developed and followed to contribute to the reliability of the facilities. Reliability and availability studies, equipment and spare part philosophy and process-hazards analysis will be performed in Front End Engineering and Design (FEED) and detailed engineering stages to identify other options to maintain facility reliability.

Overfill Through Lateral Spillpoints

There are no reasonable injection scenarios that would lead to overfilling the reservoir with CO_2 to cause a horizontal spillover. Several factors, including the physical characteristics of the 31S and NWS structures and the small volume of CO_2 to be injected (Table 1), support this conclusion. Since: (i) the oil bearing strata that contain recoverable oil – which represent the target injection zones – are above the free-water levels (i.e., the depth below which there is no residual oil saturation), and (ii) the lateral spillpoints in the 31S and NWS structures lie below the free-water level, no economic EOR case exists to support injection of CO_2 at depths that are proximate to the lateral spillpoints.

Further, the Oxy Project will produce roughly the same volume of fluids as it injects, creating additional voidage during operations. The volume of CO_2 to be injected over the 20-year life of the Oxy CO_2 EOR Project is approximately 3 percent of the reservoir pore volume above the free-water levels illustrated in Figure 15. Therefore, the small injection volume relative to the storage capacity and the production of fluids during projected EOR operations render the risk of overfill through lateral spillpoints insignificant.

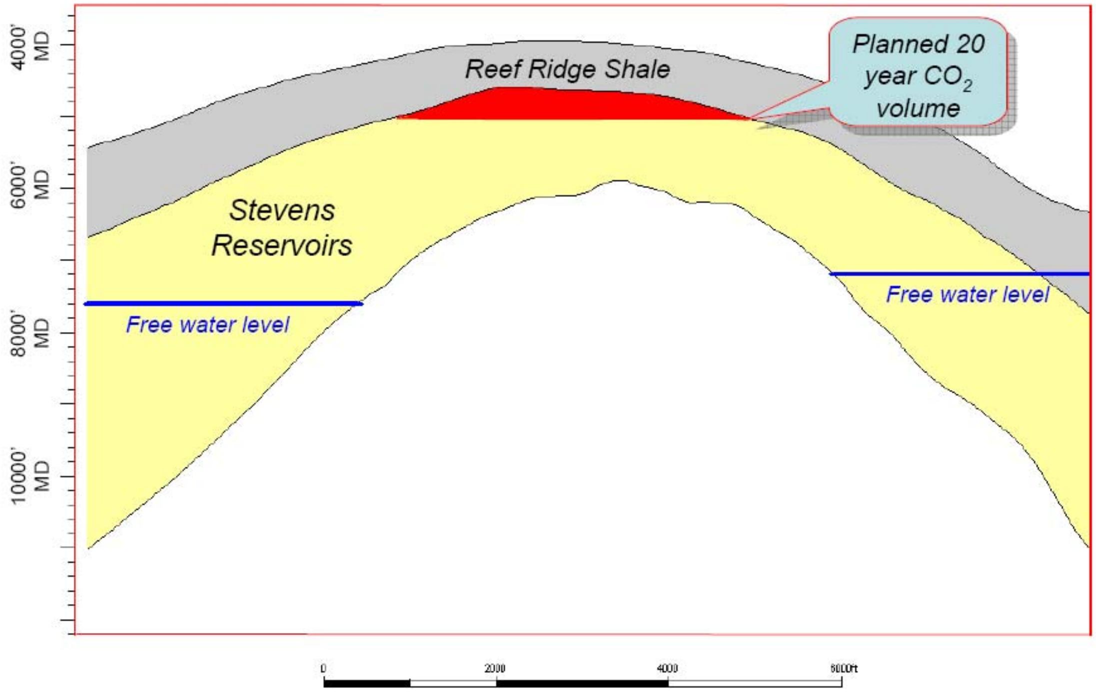

Figure 15 - Magnified View of Stevens Cross Section Showing Representative Magnitude of Total Expected Volume of Injected CO_2

Dissolution of CO_2 into Formation Fluid and Subsequent Migration

CO_2 will be injected in a super-critical state, and a small portion of the injected CO_2 will dissolve into the formation fluid. Some studies show that brine saturated with CO_2 may be heavier than brine which is not saturated with CO_2. Theoretically, this could lead to a potential leakage pathway if enough CO_2 dissolves into the formation fluid, is carried in that fluid to a location with different pressures, and then is released out of the formation fluid in an area where there is not an overlying physical barrier. Based on a review of existing data, OEHI believes this is not a likely pathway for leakage from the Stevens. For the reasons discussed above, overfill through lateral spillpoints is highly unlikely. Furthermore, evidence suggests that the formation fluid in the anticlinal structures is isolated by the compression faults that formed them. Consequently, during production, no influx of formation fluid has been seen and the injection volume is not expected to be sufficient enough to induce an outward flow of formation fluids past these spillpoints.

Drilling Through the CO_2 Area

Several regulations and guidelines specifically address zonal isolation during well construction. These regulations and guidelines are intended to ensure that existing wellbores pose no significant risk of leakage.

- Surface casing strings require a sufficient volume of cement to be pumped into the casing well-bore annulus so that the entire annulus is filled to surface.
- A minimum of 500 lineal feet of cement is required above any hydrocarbon zone in an intermediate or production casing string, which further provides zonal isolation.
- In cases where a liner is run and cemented, DOGGR requires that a negative lap test be performed after cementing and prior to completion to ensure hydraulic isolation between the production zone and any overlying zones.
- The DOGGR can direct OEHI to run a cement bond log (CBL) to evaluate the degree of zonal isolation in the cemented annulus prior to completion. If the CBL indicates a possible lack of isolation, remedial cementing work can be performed to improve isolation.

All of OEHI's well-construction processes strictly follow both DOGGR regulatory requirements and Oxy drilling standards. All OEHI well designs are approved by DOGGR, and a drilling permit is issued prior to commencement of any drilling operations.

3.1.3 Summary of the Leakage Risk Assessment

Various potential leakage pathways have been identified in this section. The structure and stratigraphy of the EHOF is ideally suited for the injection and trapping of CO_2. The stratigraphy within the CO_2 injection zones is porous and permeable and can be very thick, providing an excellent EOR target and ample capacity for long-term CO_2 sequestration. Between the surface and the Stevens reservoirs, naturally occurring dense and thick overlying shales exist, which serve as excellent seals that have proven capable of containing fluids and gases for millions of years. While faults are present within the EHOF, these faults are non-transmissive through the Reef Ridge Shale as indicated by variable oil-water contacts, pressures and temperatures within individual Stevens reservoirs. Furthermore, there are several productive horizons above the proposed injection zone, and evidence shows that the hydrocarbons in these shallow zones are not the result of vertical migration. In summary, based on a careful assessment of the potential leakage pathways, OEHI has determined that there are no identified leakage pathways that would result in significant loss of CO_2 to the atmosphere.

3.2 Monitoring Program

OEHI operations are centrally monitored and controlled by an extensive and sophisticated system (Consolidated Control Facility or CCF). The CCF is used to make operational control decisions on a continuous basis throughout the EHU to assure the safety of field operations and to comply with monitoring and reporting requirements in current permits.

As part of its ongoing operations at the EHU, OEHI collects flow, pressure, and gas composition data in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow OEHI response and reporting protocols when the system delivers notifications that data exceed statistically acceptable boundaries. The data can be accessed for immediate analysis throughout the EHU.

The CCF will be used to collect and analyze data from the Oxy CO_2 EOR Project. Figure 4 (repeated here again as Figure 16 for convenience) identifies the meters that will be used to evaluate, monitor, and report on the CO_2 flood as described in Section 4.1 below. A similar system is already installed throughout the EHU, and specific wells monitored by this system will be used to detect unanticipated CO_2 migration or leakage as described in Section 4.2 below.

OEHI also has a database of pressure, flow and gas composition data collected for nearly 100 years. These data will be used to develop a trend analysis to demonstrate the following baselines:

- Levels of naturally occurring CO_2 in the 31S and NWS structures as a function of reservoir pressure; and
- Levels of naturally occurring CO_2 in the SOZ as a function of reservoir pressure.

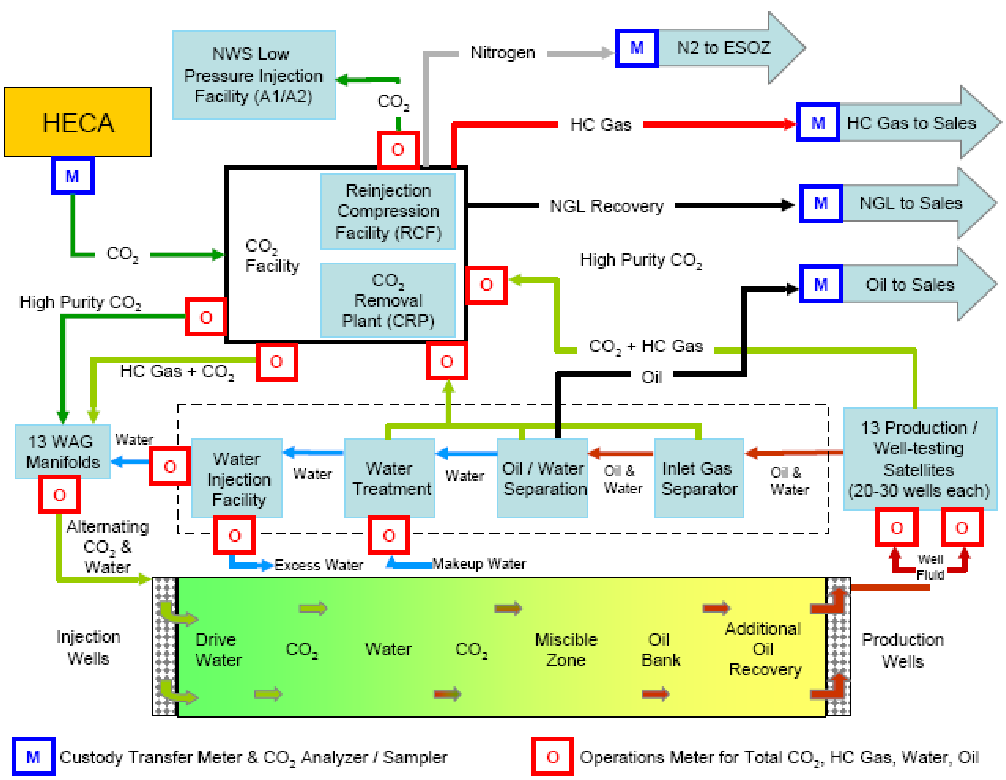

Figure 16 - Process Flow of Oxy CO_2 EOR Project, Indicating Meters

3.2.1 Monitoring Surface Sources

OEHI uses different meters for specific purposes. These meters fall into two primary categories: custody-transfer meters and operations meters.

As indicated in Figure 16, OEHI intends to operate custody-transfer meters at the point at which custody of the CO_2 from HECA is transferred to OEHI and also at the points at which custody of oil, liquid natural gas, HC gas and nitrogen gas is transferred from OEHI to another party. Custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling. All such data will be recorded. OEHI's metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained according to best practices, operated continuously and will feed data directly to the CCF. Further, custody-transfer meters are calibrated by a third party. These custody meters provide the most accurate way to measure mass flows.

Most process streams that move throughout the EHU are multi-component or multi-phase, with varying CO_2 compositions, as indicated in Figure 16. For these streams, flow rate is the most important control parameter. OEHI uses operations meters to determine the volumetric flow rates of these various process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. OEHI also uses operations meters – comparing aggregate data to individual meter data – to provide a cross-check on actual operational performance. As noted earlier in Section 2, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Consequently, developing a CO_2 mass balance on multi-phase, multi-component process streams is better accomplished using custody-transfer meters instead of operations meters.[12]

CO_2 Received at the Site

Meters will be used on both sides of the custody-transfer point to continuously measure the amount and composition of CO_2 received at the CO_2 Facility from HECA. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as currently promulgated by the API and the AGA).

[12] The level of precision and accuracy for the in-field process control meters currently satisfies the requirements for reporting in existing UIC permits. In the current permits for the water-flood operations, OEHI is required to use operations meters that are commercially available. While these meters are also very accurate, it is important to note that there is some variance between most commercial meters (on the order of 1-5%). OEHI maintains and calibrates the operations meters.

Injection

Under its existing Class II UIC permits, OEHI is required to report volumes of fluids injected. OEHI will allocate aggregate injected volume from data collected at the meters going into the CO_2 Facility (the custody-transfer meter and the two meters measuring recycled CO_2 from the production wells) to individual wells based on a ratio established by reviewing individual injection volume data as measured by in-field operations meters.

Production

The DOGGR requires OEHI to report volumes of produced fluids (oil, water, and produced gas). There are two operations meters at each satellite gathering station used to determine flow rates. One will be used to measure the aggregate volume of the produced fluid from all wells. A second meter will be used to measure the oil/water/gas rate of each production well on a rotating basis at least once a month. OEHI will use the total volume data gathered at each satellite gathering station and the results from each individual test of a production well to determine total produced volumes from each production well. This is the same approach OEHI uses in reporting produced volumes under existing DOGGR requirements.

Fugitives and Vented CO_2

Although the U.S. Environmental Protection Agency (EPA) proposed rules for GHG reporting at petroleum and natural-gas systems and CO_2-injection facilities have not been finalized, OEHI anticipates reporting on fugitive and vented CO_2 emissions for the EHU under 40 CFR Part 98, Subparts W and RR of the Mandatory Reporting of GHGs Rule, as applicable. OEHI intends to indicate which portions of the elements reported under Subpart W pertain to the Oxy CO_2 EOR Project and will report those with the annual MRV Report. Under the proposed EPA rules, OEHI would report the total fugitive CO_2 and methane (CH4) emissions from the following source types, as they apply to the Oxy Project:

- For onshore petroleum and natural-gas production: fugitive emissions from valves, connectors, open-ended lines, pressure-relief valves, compressor-starter gas vents, pumps, flanges, and other fugitive sources (such as instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services);

- For onshore natural-gas processing: fugitive emissions from valves, connectors, open-ended lines, pressure-relief valves, meters, and centrifugal compressor dry seals; and

- For onshore natural-gas transmission compression: fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure-relief valves, orifice meters, other meters, regulators, and open-ended lines.

3.2.2 Monitoring Subsurface CO_2

OEHI has assessed the following potential leakage pathways: faults and fractures, existing well bores, pipeline/surface equipment, overfill through lateral spillpoints, and migration of dissolved CO_2 into formation fluid.

The planned volume of CO_2 injection is small in comparison to the size of the available pore space in the Stevens. As demonstrated in Tables 1 and 2, the cumulative voided volume of 1.3 billion barrels is already larger than the 1 billion barrels of volume from the full 20 years of planned CO_2 injection. Fluids removed during production will further increase voided volume. OEHI currently has adequate capacity without being dependent on future production. Nonetheless, OEHI has designed a monitoring program that will focus first on detecting unanticipated migration of the CO_2 and, second, if such migration is detected, determining if leakage of CO_2 to the surface is occurring.

It is important to recognize that the Oxy CO_2 EOR Project will be conducted in an active and very productive oil field and is very much like the existing water-flood project – it is a process to enhance the recovery of existing oil that would otherwise be left stranded. It is OEHI's current practice to continuously monitor the performance of EHU's producing oil reservoirs for differences between expected and observed performance and movement of fluids (and this practice will continue for the Oxy Project). Any difference tends to indicate inefficiencies in oil-production operations, and addressing them quickly leads to improved interpretation of the subsurface and incremental changes to operations that improve performance. OEHI investigates wells or surface equipment to address such differences. For the same reasons, during the Oxy CO_2 EOR Project, OEHI will have a strong interest in ensuring that the CO_2 is being used as effectively as possible, since it will be purchasing CO_2 from HECA.

Based on this assessment, OEHI intends to implement all of the following separate measures to detect any leakage that might arise.

1. Monitoring Wells

OEHI will continuously monitor wellhead and annular pressure in certain production wells (monitoring wells) completed in the SOZ above and directly adjacent to the areas being injected with CO_2. OEHI will determine fluid composition, specifically the amount of naturally occurring or background CO_2 in these monitoring wells, at least once a year. OEHI will sample at least one well per section above and adjacent to the target injection zones where CO_2 is actively being injected to obtain representative fluid composition data. This composition data will be supplemented by downhole pressure and temperature data where available. Further, the aggregate SOZ production will be monitored continuously for CO_2 composition. As indicated in Section 4.3 below, OEHI will establish baselines for pressure and fluid composition for each identified monitoring well. OEHI will develop a control chart filter (pre-programmed variances based on a statistical analysis of the reservoir simulation and injection plan) that will automatically notify technicians in the CCF of material changes in monitored results. If such a change is noted, OEHI's first response will be to ensure that the data is accurate; its second response will be to initiate additional testing and inspection to determine the cause of the change. OEHI will address such change and remedy it as appropriate. If a change indicates CO_2 leakage into the SOZ, OEHI will report the condition and the response action to DOGGR as quickly as practicable but at least within 30 days. OEHI will describe any material changes and describe how they were addressed in the annual MRV Report.

2. Visual Inspection

When CO_2 leaks or is vented at the surface, it decompresses, rapidly cooling and forming vapor and ice, a process which is both noisy and easily visible. Along with daily computer surveillance, OEHI will perform daily facility inspections and weekly well-site inspections. If a leak is detected, the leaking system will be immediately isolated, depressurized, and repaired. Any maintenance requirements will be logged, planned, and scheduled using OEHI's Computerized Maintenance Management System (CMMS). OEHI will describe in its annual MRV Report any leaks found in the surface equipment and how they were addressed and will include an estimate of the CO_2 loss. Records of visual logs will be made available for inspection by DOGGR representatives upon request.

3. Monitor CO_2 Injection

OEHI will develop an injection and production performance plan for the Oxy CO_2 EOR Project based on the full-field reservoir simulation. This plan will provide a projection of the rate and volume of CO_2 injection as well as the rate and volume of fluid production. OEHI will develop a control chart filter that will automatically notify technicians in the CCF of any material variances between the projected and monitored results in the Oxy CO_2 EOR Project. If such a variance is noted, OEHI's first response will be to ensure that the data is accurate; its second response will be to conduct additional testing and inspection to determine the cause of the variance. OEHI will address such variance and remedy it as appropriate. If a variance indicates CO_2 migration from the Stevens reservoirs, OEHI will report the condition and the response action to DOGGR as quickly as practicable but at least within 30 days. OEHI will describe any material variances and how they were addressed in the annual MRV Report.

3.3 Determining Sequestration Volumes

3.3.1 Mass Balance Methodology

OEHI proposes to calculate the total mass of sequestered CO_2 on an annual basis using the following mass-balance equation (all terms are in mass). Mass calculations will be determined as set forth in the subsections below.

CO_2 sequestered = CO_2 transferred to OEHI – CO_2 measured at the custody-transfer points in products sold offsite – CO_2 emitted through leakage – fugitive and vented CO_2 associated with injection and production.

3.3.2 Mass of CO2 Transferred to OEHI

OEHI anticipates reporting CO_2 on a mass basis in the annual MRV Report. Accordingly, the total volumetric gas rate (volume per unit of time) will be measured utilizing meters and electronic flow-measurement devices at the point of custody transfer. The CO_2 volumetric rate will be calculated by multiplying the total gas volumetric rate by the CO_2 volumetric composition.[13] The CO_2 volumetric rate will be converted to mass rate and reported as metric tonnes for MRV purposes.

3.3.3 Mass of CO2 in Sales Products Transferred Offsite

The total volumetric rate of CO_2 in sales products (oil, HC, NGL) transferred offsite will be measured utilizing meters and electronic flow-measurement devices at each point of custody transfer. The CO_2 volumetric rate will be calculated by multiplying the total volumetric rate by the CO_2 composition. The CO_2 volumetric rate will be converted to mass rate and reported as metric tonnes for MRV purposes.

3.3.4 Mass of Fugitive or Vented CO_2

OEHI will report the mass of fugitive and vented CO_2 for the entire EHU under Subpart W of EPA's GHG Reporting Rule. OEHI will allocate a portion of this CO_2 to the Oxy

[13] OEHI will use a combination of gas-composition monitors and gas sampling to determine CO_2 concentrations at all monitoring-system meters identified in Figure 4. Final design and selection of gas-composition monitors will be performed during detailed engineering. Various CO_2 analyzer technologies are currently used in CO_2 operations, including gas chromatographs and infrared CO_2 analyzers. Process-gas samples will be taken and sent to a laboratory, where the composition of the gas will be determined.

CO_2 EOR Project based on an assessment of the current CO_2 injection operations, including the number of wells.

3.3.5 Mass of CO_2 Emitted Through Leakage

OEHI will calculate and report the total annual mass of CO_2 emitted from leakage to the surface using an approach that is tailored to specific leakage events, if they arise. Generally, OEHI is prepared to address the potential for leakage in a variety of settings. Estimates of the amount leaked will depend on the nature of the equipment and efforts to estimate the duration and concentration of the leak.

Generally, this process would entail using best engineering principles, emission factors or direct measurement. Given that such leakage would be an extraordinary event, OEHI cannot predict in advance which approach will be appropriate in various scenarios. In the event leakage occurs, OEHI will disclose the methods used to estimate or measure the volume leaked when DOGGR is notified of the leak (either within 30 days or in an annual MRV Report).

3.3.6 Internal Cross-Check on Mass-Balance Equation

OEHI proposes to cross-check the results of the sequestration mass balance described above by a calculation based on data from the in-field operations flow meters, corrected for any fugitive or vented CO_2 . Similar to the methods used to derive well production and injection data for reporting to DOGGR, OEHI will calculate a mass of CO_2 injected by summing the product of flow and CO_2 concentration at the meters going into the CO_2 Facility. OEHI intends to allocate the mass of CO_2 injected to each injection well based on the ratios established from the individual well-injection data.

OEHI will calculate the mass of CO_2 produced by summing the product of flow and CO_2 measured at the meters going into the CO_2 Facility from the production wells and measured at the custody-transfer meters for fluids leaving the EHU. This will include the sum of mass from the individual test-well separators as well as the multi-well gathering stations. OEHI intends to allocate the mass of CO_2 produced to each production well based on the ratios established from the individual well tests which are conducted at least once a month for each well.

4. Monitoring Quality Assurance / Quality Control

4.1 Data Handling

OEHI will maintain onsite, for at least seven years or as required by permit, a complete record of the parameters used in calculating sequestered CO_2 as indicated in this MRV Plan. These data will be collected as generated and aggregated as required for reporting purposes. Among the data will be volumetric flow rates, pressures, temperature, gas compositions and any other data used in calculating sequestrated CO_2.

4.2 Missing Data Procedures

In the event data cannot be collected according to plan, OEHI will determine the length of specific periods where data was unavailable, e.g., during periods of maintenance or equipment failure, and will use the following procedures to supply data for those periods.

(1) The quantity of new CO_2 transferred onto the EHU from HECA will be estimated using the quantity of new CO_2 flow based on OEHI's check meter.

(2) For all CO_2 except for new CO_2 transferred onto the EHU, the quantity of CO_2 metered will be estimated using the quantity of CO_2 metered from the nearest previous time period (at similar conditions).

(3) CO_2 concentration values will be estimated using a concentration value from the nearest previous time period.

(4) For fugitive or vented CO_2 emissions from surface equipment at the facility, values will be estimated using methods specified in Subpart W of the GHG Reporting Rule.

4.3 Reporting and Recordkeeping

OEHI will develop the annual MRV Report and will store the records to validate that report for a period of at least seven years.

4.4 Monitoring System Maintenance and Calibration

For custody-transfer meters, OEHI's maintenance and calibration protocols will follow the prevailing industry standard(s) promulgated by the API and the AGA. OEHI will operate flow meters as specified in the UIC Class II permits that are issued for injection operations. OEHI will comply with the maintenance requirements for these meters. Any updates to applicable UIC Class II permit requirements or regulations will be incorporated into this MRV Plan when they are finalized. All flow meters will be operated continuously except for periods in which routine maintenance will be conducted.

4.5 MRV Plan Adjustments

OEHI will maintain and update the MRV Plan as needed. Each year, OEHI will file a statement with the annual MRV Report indicating that it has reviewed the monitoring and operational data. Such review will document any data or information that is relevant to a decision on whether to revise the MRV Plan. If an update is warranted or required it will be submitted to DOGGR.

EXHIBIT A

1. Walker, T., Kerns, S., Scott, D., White, P., Harkrider, J., Miller, C., Singh, T.: 2002, “*Fracture Stimulation Optimization in the Redevelopment of a Mature Waterflood, Elk Hills, California*”, SPE 76723-MS, SPE West.Regional/AAPG Pac Sec. Joint Mtg., 20-22 May, Anchorage, Alaska, 22 pp.
2. Sullwold, H.H.: 1961, “*Turbidites in Oil Exploration*”. in Peterson, J.A. and Osmond, J.C., Geometry of Sandstone Bodies, A Symposium, 45th Annual Meeting AAPG. P. 63-81.
3. Bandy, O.L. and Arnal, R.E.: 1969, “*Middle Tertiary Basin Development, San Joaquin Valley, California*”, Bull. Geol. Soc. Amer., v. 80, p. 783-820.
4. Macpherson, B.A.: 1978, “*Sedimentation and trapping mechanism in upper Miocene Stevens and older turbidite fans of southern San Joaquin Valley, California*”, AAPG Bulletin, v. 62, p. 2243.
5. Webb, G.W.: 1977, “*Stevens and earlier Miocene turbidite sandstones, southern San Joaquin Valley, California*”, AAPG Bulletin, v. 65, p. 438-465.
6. Harding, T.P.: 1976, “*Tectonic significance and hydrocarbon trapping consequences of sequential folding synchronous with San Andreas faulting, San Joaquin Valley, California*”, AAPG Bulletin, v. 60, p. 356.
7. California Dept. of Conservation, Division of Oil, Gas and Geothermal Resources: 1998, “California Oil and Gas Fields”, v. 1, p. xii.
8. Harrison, C.P. and Graham, S.A.: 1999 “*Upper Miocene Stevens Sandstone, San Joaquin Basin, California: Reinterpretation of a petroliferous, sand-rich, deep-sea depositional system*”, AAPG Bulletin, v. 83, p. 898-924.
9. Scott, R.M.: 1979, “*Facies Analysis of the Deep Water Stevens Sandstones, Southern San Joaquin Valley, California; A Core Study*”, Cities Service Co. (internal publication) Technical Report #71, Contrib. G79-01, 152 pp
10. Scott, R.M. and Tillman, R.W.: 1981, “*Stevens sandstone (Miocene), San Joaquin Basin, California*”, in C.T. Seimers, R.W. Tillman, and C.R. Williamson, eds., Deep Water Clastic Sediments: a Core Workshop: SEPM Core Workshop No. 2, San Francisco, CA, p. 116-248.
11. Lamb, M.A., Anderson, K.S., Graham, S.A.: 2003, “*Stratigraphic Architecture of a Sand-rich, Deep-sea Depositional System: The Stevens Sandstone, San Joaquin Basin, California*”, Pacific Section AAPG, Pub. MP-47, 64 pp.
12. Reid, S.A.: 1990, “*Trapping characteristics of upper Miocene turbidite deposits, Elk Hills Field, Kern County, California*”, in J.G. Kuespert and S.A. Reid, eds., Structure, stratigraphy and hydrocarbon occurrences of the San Joaquin basin, California: Pacific Section, SEPM, Book 64, p. 141-156.
13. Lowe, D.R.: 2004, “*Deep-Water Sandstones: Submarine Canyon to Basin Plain, Western California*”, Pacific Section AAPG, Pub. GB-79, 79 pp.
14. Tillman, R.W.: 1976, “*Deep Water Sedimentation*”, p. S1-S14; In. Cities Service Co. (internal publication) Geol. Contrib. No. 27, G76-17, 205 pp.