Advanced Reservoir Characterization in the Antelope Shale to Establish the Viability of CO₂
Enhanced Oil Recovery in California's Monterey Formation Siliceous Shales

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ABSTRACT

This report describes the evaluation, design, and implementation of a DOE funded CO₂ pilot project in the Lost Hills Field, Kern County, California.

The pilot consists of four inverted (injector-centered) 5-spot patterns covering approximately 10 acres, and is located in a portion of the field, which has been under waterflood since early 1992. The target reservoir for the CO₂ pilot is the Belridge Diatomite. The pilot location was selected based on geology, reservoir quality and reservoir performance during the waterflood. A CO₂ pilot was chosen, rather than full-field implementation, to investigate uncertainties associated with CO₂ utilization rate and premature CO₂ breakthrough, and overall uncertainty in the unproven CO₂ flood process in the San Joaquin Valley.

This report summarizes the methodology used in the project evaluation and design including construction of the geologic model, reservoir simulation and CO₂ flood predictions, facilities design, and well design and completion considerations. An actual CO₂ injectivity test was conducted in March 1999. The results of the injectivity test, which helped in the design of the pilot, are presented.

The reservoir management plan and future field potential are also discussed. CO₂ injection in the pilot is planned to commence in June of 2000. The methodology and technical analysis used to evaluate and design the Lost Hills CO₂ pilot are applicable to other potential San Joaquin Valley CO₂ floods.

EXECUTIVE SUMMARY

Introduction:

The primary objective of our project was to conduct advanced reservoir characterization and modeling studies in the Antelope Shale of the Buena Vista Hills Field. Work was subdivided into two phases or budget periods. The first phase of the project would focus on a variety of advanced reservoir characterization techniques to determine the production characteristics of the Antelope Shale reservoir. Reservoir models based on the results of the characterization work would then be used to evaluate how the reservoir would respond to enhanced oil recovery (EOR) processes such as of CO₂ flooding. The second phase of the project would be to implement and evaluate a CO₂ in the Buena Vista Hills Field. A successful project would demonstrate the economic viability and widespread applicability of CO₂ flooding in siliceous shale reservoirs of the San Joaquin Valley.

However, it was decided not to proceed with a Phase II field trial in Buena Vista Hills because of its very low oil saturation, lithologic heterogeneity and relatively few natural fractures in the siliceous shale reservoirs. Although Buena Vista Hills turned out to be a poor CO₂ EOR candidate, our reservoir characterization has demonstrated that under the right conditions, CO₂ is a viable enhanced recovery process for other siliceous shales. Therefore, the Phase II CO₂ pilot was moved to Lost Hills Field, about 30 miles north of Buena Vista Hills with the DOE's concurrence.

Lost Hills Field:

The target reservoir at Lost Hills is the Belridge Diatomite of the Monterey Formation. The Belridge Diatomite is a diatomaceous mudstone and is not present at Buena Vista Hills. The diatomite has high oil saturation (50%) and high porosity (45 - 70%), but its low permeability (<1 millidarcy) has led to low primary oil recovery (3 - 4% of OOIP). Due to the low primary recovery and large amount of remaining oil in place, Lost Hills presents an attractive target for EOR. In addition to the large resource base, there is technical and economic justification for CO₂ flooding that was developed through our reservoir characterization and simulation efforts. The oil response for four different recovery processes at Lost Hills at three different well spacings (2-1/2, 1-1/4, 5/8 acres) were evaluated:

- Primary (Hydraulically Fractured Wells)
- Waterflood
- Steamflood
- CO₂ Flood

Forecasts were then generated using Chevron proprietary reservoir simulation software. The results of this simulation are shown in Figure ES-1. One process, in particular, really does stand out. CO₂ flooding shows tremendous oil response relative to the other three processes, mainly due to improved injectivity. CO₂ injectivity is at least two to three times greater than that of water or steam at 2-1/2 acre spacing. The injection of CO₂ will also reduce reservoir oil viscosity and increase fluid expansion.

Figure ES-1. Comparison of various IOR processes at Lost Hills.

Preliminary economics for full-scale implementation of a CO₂ Flood in Lost Hills has identified several key uncertainties which will be evaluated as part of the pilot planning. The main economic uncertainties that can only be further evaluated by the pilot are oil response, and the corresponding CO₂ utilization required for such a response. The pilot has been designed and planned to significantly reduce the range of uncertainty for these two key items. Funding is also included in this project to further evaluate the feasibility and cost of local long-term CO₂ supplies. Since it is very unlikely that a CO₂ pipeline to California will be built anytime soon, success of a full-scale CO₂ flood will depend on utilization of CO₂ entrained in local produced gas and flue gas. Global warming and future world emission trading of CO₂ credits may drastically increase the availability and lower the cost of CO₂ in California. As part of project scoping the CO₂ Team will continue to track developments for global warming.

Background & Present Situation:

The Lost Hills Field, located 45 miles northwest of Bakersfield, California, was discovered in 1910. Reserves in the shallow sands, diatomite, and chert pools were developed using slotted liner completion techniques until the late 1970's. From the late 1970's to 1987, small volume hydrofracture completions were performed covering the entire Belridge Diatomite.

Advances in hydraulic fracturing technology in the late 1980's resulted in increased oil recovery that led to a more aggressive development program by Chevron. From 1987 to the present, high volume hydrofracture completions have been performed across the entire Belridge Diatomite and the Upper Brown Shale resulting in significant production increases. The Lost Hills Field is developed on a 5 acre (siliceous shale) to 1.25 acre (diatomite) well spacing. There are over 2.2 billion barrels of oil in place in the Belridge Diatomite in Lost

Hills. To date only 112 million barrels have been produced, or approximately 5% of the original oil in place (OOIP).

Chevron initiated a pilot diatomite waterflood project in December 1990 and began full-project development in April 1992. Since 1992, two hundred and eight 2-1/2 acre patterns have been put on water injection spanning parts of four sections (Sections 4, 5, 32 Fee, and 33). Since the initiation of first project water injection in April 1992, production has increased approximately 4,000 BOPD from 6,400 BOPD to the current rate of 10,400 BOPD.

Proposal:

Install a four-pattern, 2.5 acre pilot on Section 32 Fee to evaluate CO₂ flooding of the Lost Hills Diatomite. The scope of the pilot includes: remedial work to evaluate and upgrade the tubing and packers in the injectors, possible drilling of up to 4 replacement injectors, 3 observation wells, liquid CO₂ injection facilities, injection lines, dedicated gauging facilities, and extensive monitoring. It is anticipated that CO₂ injection could commence as early as June, 2000. The pilot will be evaluated for a period of 6 months to 2 years. Reservoir simulation predicts that oil response would not occur for several years. However, based on the results of the injectivity test, a quicker response time is now expected.

Objectives:

A CO₂ pilot will be installed in Section 32 Fee of the Lost Hills field to test the technical and economic viability of CO₂ flooding the low permeability diatomite resource. A full-scale CO₂ project is economically justified by an incremental analysis and comparison to the current base case waterflood. Incremental tertiary reserves are estimated to be 80 MMBOEG and are technically supported by reservoir simulation. However, the project is only marginally economic and considerable uncertainty exists in the magnitude of predicted CO₂ recoveries. Installing a pilot will provide us with an opportunity to gather and analyze the pertinent geologic, reservoir, and production data and gather facilities design information necessary to commit to a full-field project. In addition, the pilot capital and operating costs will take advantage of available DOE funding of nearly 2.7 million dollars.

Additional Objectives:

There following are additional objectives of the proposed CO₂ pilot:

- Gain information that could benefit other drive mechanisms in Diatomite such as:
  - Learn how injecting a gas (very low viscosity fluid) differs from injecting water into the diatomite in terms of fracture azimuth, injectivity, and areal and vertical sweep.
  - Mitigation measures for CO₂ breakthrough problems can be applied to other IOR operations.
  - Learn how much of the diatomite pay zone can effectively be processed. This knowledge can be applied to other IOR process designs.
  - Learn how to mitigate and/or control hydrofracture growth (vertically and areally).

- Potential Federal Regulations may make CO₂ a “free” commodity 5 to 10 years down the road. Injecting CO₂ may be used to offset emissions from other nearby Chevron facilities.

Risks:

The pilot has been design and planned to both minimize risk for the pilot and to better assess risk for the full-scale project. Some of the significant risks for the pilot and project are:

- Premature breakthrough of CO₂
- Oil response is not measured well
- Temporary loss of liquid CO₂ supply
- Excessive corrosion from gas high in CO₂ concentration

Facility Alternatives:

Since CO₂ equipment and purchases constitute the bulk of the expenditures for the pilot, several alternatives were considered. The primary strategies ended up being “Liquid CO₂” versus “Amine CO₂”. Liquid CO₂ is supplied from California refineries via truck while the “Amine CO₂” would involve the installation of an amine process CO₂ removal plant in Lost Hills (to remove CO₂ from produced gas that is 15% CO₂ by volume). Decision Analysis was used to determine the NPV for each alternative and the factors that could influence the final value. The analysis showed that liquid CO₂ is more economical for a pilot lasting less than 2 or 3 years.

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SECTION 1.

PRESENT SITUATION

1.1 GEOLOGY

Overview of Lost Hills Geology

Lost Hills Field was discovered in 1910 and is located 40 miles northwest of Bakersfield, CA (Figure 1.1-1). Productive intervals include Middle to Upper Miocene diatomite, chert, porcelanite, and siliceous shale, and Plio-Pleistocene sands. The field is situated along a northwest-southeast trending series of structural highs that begins with the Coalinga Anticline to the northwest and culminates with the Lost Hills Anticline to the southeast. This series of highs roughly parallels folds of similar age on the westside of the San Joaquin Valley. These folds are oriented nearly parallel to the trend of the San Andreas Fault to the west and approximately perpendicular to the direction of regional compression.

Lost Hills oil is trapped at the crest and along the southeast plunge of the anticline (Figures 1.1-2 - 4). In this portion of the field where the pilot will be located, the structural plunge varies from 2 to 6 degrees toward the southeast. Dips along the northeast flank average around 30 degrees while those on the southwest flank average around 15 to 20 degrees. This asymmetry in dips in the NE-SW direction is consistent with a fault-bend fold model. This model predicts that structural growth of the Lost Hills Anticline was initiated during latest Miocene time and that the resulting anticline is perched above a ramp thrust that is located around 13,000 feet below the surface. Numerous northeast-southwest trending normal faults with throws rarely exceeding 40 feet cut the Lost Hills structure. These faults do not appear to effect production.

The stratigraphy at Lost Hills is shown in Figures 1.1-3 and 1.1-5. The Monterey Formation is comprised of the Devilwater Shale, McLure Shale and Reef Ridge members. The Devilwater consists of shales and siliceous shales. It is slightly phosphatic. The McLure is subdivided into the McDonald Shale and the Antelope Shale. The McDonald consists of interbedded porcelanites and siliceous shales. It is also slightly phosphatic. The Antelope is comprised of finely laminated cherts and porcelanites. The uppermost member of the Monterey Formation is the Reef Ridge and it is subdivided into the Brown Shale and Belridge Diatomite. The Brown Shale is made up of interbedded siliceous shale, shale, and silt. The Belridge Diatomite consists of interbedded diatomaceous mudstone, fine-grained, argillaceous sands/silts, and porcelanite.

Based on regional studies of late Miocene paleogeography and paleobathymetry, the rocks of the Monterey Formation were deposited in a deep marine environment. In the San Joaquin Basin, the late Miocene environment was such that: water depths were bathyal (between 600 and 3,000 feet), cool water temperatures and upwelling in the upper 200 feet supported large diatom populations, and the deeper basin waters were oxygen poor. Two primary sedimentation processes were active in the basin at that time. First, hemipelagic sedimentation: the settling of diatom frustules and clay-sized particles onto the basin floor from the overlying water column. And second, turbidite sedimentation: the deposition of sand, silt, and clay-sized particles carried into the basin by density currents (usually originating along the basin margins).

This combination of environmental conditions and sedimentation processes led to the accumulation of thick deposits of organic-rich, laminated, diatomaceous sediments which occasionally are interrupted by thin-bedded, clastic-rich turbidite deposits. However, compared to the southwestern San Joaquin Basin, sandy turbidites at Lost Hills are not common. The Monterey Formation in the San Joaquin Basin differs from the coastal and offshore Monterey in that it is much more clastic rich.

The composition of the Monterey can be described in terms of three primary components: biogenic silica, clay, and silt/sand. As shown in Table 1.1-1, there is a fair amount of vertical compositional variation within the stratigraphic column at Lost Hills. The Devilwater contains 27% biogenic silica, 50% clay, and 23% silt/sand. The McDonald is slightly richer in biogenic silica, roughly comparable in clay, and slightly lower in silt/sand. The Antelope is very rich in biogenic silica, poor in clay, and poor in silt/sand. The Brown Shale is clay rich. The Belridge Diatomite has roughly equal amounts of biogenic silica, clay and silt/sand. The overlying Etchegoin Formation is rich in silt/sand and clay, and almost totally lacking in biogenic silica.

Table 1.1-1. Average rock compositions from Well 166, Section 32, T26S/R21E.

Rock Unit	Average. % Biogenic Silica	Average % Clay	Average % Silt/Sand	Number of Samples
Etchegoin	4	38	58	8
Belridge Diatomite	33	36	31	19
Brown Shale	26	47	27	28
Antelope Shale	61	18	21	14
McDonald Shale	34	47	19	24
Devilwater Shale	27	50	23	8

As hemipelagic and occasional turbidite deposits in the Lost Hills area were buried by the overlying Etchegoin and Tulare sediments, the diatomaceous sediments of the Monterey Formation gradually lithified into the highly porous (50-60% or more) but impermeable (0.1-10.0 millidarcy) rock termed diatomite. As discussed above, anywhere from 26% to 61% of this diatomite was composed of diatom frustules. Diatom frustules consist of a form of silica called opal-A, which is an unstructured mineral (essentially a solidified gel) usually containing 3-10% water. As this diatomite is buried deeper and reaches greater temperatures (40-50 degrees C), the opal-A material in the diatom frustule becomes unstable and undergoes a phase transition to opal-CT (Figures 1.1-6 - 7). This form of silica is more structured than opal-A and has released much of its water. Porosity is reduced to ~40%. At still greater depths and higher temperatures (80-90 degrees C), the opal-CT undergoes a final phase transition to a form of quartz with only a trace of water left. The Monterey Formation at Lost Hills is presently comprised of opal-A rocks at shallow depths ($\pm$ 2,300 feet or shallower), opal-CT rocks at intermediate depths ($\pm$ 2,300 to $\pm$ 4,300 feet), and quartz phase rocks below $\pm$ 4300 feet.

The exact temperatures at which the opal-A to opal-CT and opal-CT to quartz phase changes occur is governed by the amount of biogenic silica (diatoms) in the rock. Opal-A rocks rich in biogenic silica convert to opal-CT at lower temperatures (and therefore shallower depths)

than those poor in biogenic silica. Conversely, opal-CT rocks rich in biogenic silica convert to quartz phase at higher temperatures (and greater depths) than those poor in biogenic silica. For this reason, an interval of rocks whose laminations vary in their biogenic silica content create a transition zone of laminated phases near the phase transition temperature. The laminated phases in these transition zones (particularly where the laminae are thin) may be especially susceptible to natural fracturing, thereby enhancing system permeability. Volume reduction and water expulsion associated with the phase changes probably adds to the fracturing in these zones. In general, hydrocarbons are found in all three (opal-A, opal-CT, and quartz) phases. Also production is enhanced in the opal-A to opal-CT and, in particular, the opal-CT to quartz phase transition zones.

Geochemical analyses have demonstrated that Monterey Formation rocks in Lost Hills are typically composed of 1% to 6% total organics, making them fair to good hydrocarbon source rocks. Studies of kerogen maturation have shown that the Monterey rocks are immature (i.e., they have not been buried deep enough to generate oil) within the confines of the Lost Hills Field. However, studies of samples taken from down-flank wells indicate that these rocks are mostly mature in the syncline to the east of Lost Hills and possibly below the ramp thrust immediately beneath the Lost Hills Anticline. Because the Monterey Formation kerogens and the produced oils at Lost Hills have similar isotopic compositions, and because they contain similar concentrations of sulfur, it is believed that Lost Hills oil was sourced from the Monterey Formation itself.

Hydrocarbons migrated into the low permeability Monterey rocks at Lost Hills by way of faults, fractures and thin sands. Also the opal-A to opal-CT and opal-CT to quartz phase transition zones with their higher fracture density probably served as pathways for hydrocarbons to migrate from source beds down-structure to their ultimate resting place in the crest of the anticline.

In the McDonald Shale and Lower Brown Shale/Antelope Shale pools, hydrocarbons are confined fairly well within or immediately below the fractured opal-CT to quartz phase transition rocks. In the Upper Brown Shale, fracturing also helps to make it productive. Because the McDonald, Antelope, and Brown shales have such low matrix permeability, most of the oil produced from these rocks comes out of the fractures. In the Belridge Diatomite with its relatively higher matrix permeability, hydrocarbons have saturated the uppermost opal-CT, the opal-A to opal-CT transition, and most of the opal-A rocks. Most of the oil produced from the diatomite comes from the matrix. Lastly, some oil has even migrated into the overlying Etchegoin and Tulare Formations.

Pilot Location and Belridge Diatomite

The target reservoir for the CO₂ pilot in Lost Hills is the FF – L interval of the Belridge Diatomite (Figures 1.1-8 - 13). In the pilot area, the diatomite is in opal-A phase. The lower half of the Belridge Diatomite is comprised of approximately equal parts of biogenic silica (diatoms), silt/sand, and clay while the upper half is comprised mainly of silt/sand, clay, and minor biogenic silica. The diatomite is finely laminated. In general these laminations alternate between a more detritus rich lamina and a more diatomaceous rich lamina. The

laminations reflect cyclic variations in yearly runoff (detritus rich) and upwelling (diatomaceous rich).

Superimposed on this depositional cycling are the changes in relative sea level that occurred in the Upper Miocene. As sea level rose, diatomaceous rich deposits were deposited further up on the slope. As sea level fell, sandy diatomite deposits prograded down the slope. These fluctuations in sea level caused the larger scale deposition of sedimentary units of "clean" diatomite, "clayey" diatomite, and "sandy" diatomite. The diatomites were deposited under oxygen poor to anoxic conditions that could sustain only a limited sediment-dwelling fauna. Thus laminations are preserved in the diatomites. Meanwhile sandy diatomites were deposited under oxygen poor to oxygenated conditions. Sandy diatomites were originally deposited as interlaminated sands and clays but shortly after deposition were heavily bioturbated. Lastly, superimposed on the sea level changes was the overall progradation of the shelf, which resulted in the coarsening upward of the Belridge Diatomite, and the eventual filling in of the basin in the Pliocene.

As described above, the Belridge Diatomite is comprised of varying amounts of diatomaceous material, clay, and silt/sand. In Lost Hills, the Belridge Diatomite ranges in depth from 800 to 3,000 feet. Oil gravity ranges from 28 to 18 degrees API. Although porosity is very high (40 - 65%), permeability is very low (<1 - 10 millidarcies). Oil saturation ranges from 40% to 65% in opal-A and from 10% to 30% in opal-CT (Table 1.1-2).

Table 1.1-2. Comparison of rock types at the newly proposed pilot location (Lost Hills) and the original location (Buena Vista Hills).

Parameter	Lost Hills Pilot	Buena Vista Hills Pilot
Rock Unit	Belridge Diatomite	Upper Antelope Shale
Age	Uppermost Miocene	Upper Miocene
Depositional Environment	Hemipelagic; Progradational Slope	Hemipelagic-Turbidite; Basin
Rock Type	Diatomaceous Mudstone	Siliceous Shale
Silica Phase	Opal-A	Opal-CT
Percent Sand Beds	30%	5%
Sand Description	5-60 feet thick, fine-grained, argillaceous, bioturbated	<1 inch thick, fine-grained, non-bioturbated
Depth to Top of Unit	1,400 feet	4,200 feet
Thickness	700 feet	600 feet
Porosity	50%	29%
Permeability	0.1 - 10.0 millidarcies	<0.1 millidarcies
Oil Saturation	50%	14%

Development of the Lost Hills Field has evolved over the years. From 1910 to the late 1970's, slotted liner completions were used in the upper Belridge Diatomite. From the late 1970's to 1987, small volume hydrofrac completions were performed covering the entire Belridge Diatomite. From 1987 to the present, high volume hydrofrac completions have been performed across the entire Belridge Diatomite and the Upper Brown Shale. Since

1992 a portion of the diatomite has been under waterflood, and in 1998 a pilot steam-drive was started. The Lost Hills Field is developed on a 5 acre (siliceous shale) to 1.25 acre (diatomite) well spacing. Evaluations on closer well spacings are also in progress. There are over 2 billion barrels of oil in place in the Belridge Diatomite in Lost Hills. Due to the reservoir's low permeability less than 6% of this oil has been produced.

Natural Fractures and Thief Zones:

In general, all wells are hydraulically propped fractured in Lost Hills. Occasionally these hydraulic fractures intersect other existing producing wells causing them to sand-up, or increase water production if an injection well communicates with it. These are induced fractures. Hydraulic fractures intersecting existing wells can be the result of many factors. These include: 1) wells being in fracture alignment; 2) existing faults/fractures; and 3) localized areas of depletion due to production, or localized areas of re-pressurization from injection that cause the hydraulic fracture to propagate at an azimuth that is not in aligned with the natural stress field. In the case of the communication between the 12-8D and 11-8D during the CO₂ injectivity test, this most probably was the result of these two wells being in hydraulic fracture alignment.

Recent fracture analysis by D. Julander using Electrical Micro Imaging (EMI) logs, and log data from the OB-7 and 12-8D wells allows for observations to be made regarding the abundance of natural fractures and thief zones (Figures 1.1-14 - 15). The EMI from the CO₂ injectivity test well 12-8D is fairly representative of this part of the Lost Hills Field. It shows a fracture frequency between 1 and 3 fractures per 10 feet of vertical interval. This fracture frequency includes all observable fractures: open, closed (clay-filled), and fractures of undeterminable type (due to being poorly imaged).

With regards to thief zones, i.e., high permeability sands interbedded within the diatomite, there does not appear to be a large body of evidence to support this idea. Recent data from the nearby OB-7 well (1,160 feet SW of 12-8D) clearly exemplifies this. OB-7 was drilled and cored only 20 feet (perpendicular to fracture azimuth) from a water injection well (10-9W) that was drilled in 1994. Core PKS data clearly shows that the sandy diatomites from OB-7 do not have highly reduced oil saturations compared to the original injector. As stated above and illustrated in Figures 2.1-12 and 13, the sandy diatomites are clay rich and bioturbated. These features make it very difficult to behave as a thief zone. Also, the CO₂ injection profiles from 12-8D and 12-7W (Figure 1.1-16) also indicate that that CO₂ did not have a preference for the sandy diatomites.

In summary, while there are fractures and faults present in the diatomite, the reservoir should not be considered a highly fractured reservoir. However it should also be said that based on tiltmeter analysis of CO₂, water, and steam injectivity tests in Lost Hills, it appears that fractures and faults do play a role in the unpredictable distribution of low viscosity fluids at low injection rates. This is another reason why a pilot is necessary.

Figure 1.1-1. Location map of major oil fields in the southern San Joaquin Valley. Lost Hills Field is highlighted.

Figure 1.1-2. Productive limits of Belridge Diatomite follows trend of southeast plunge of the Lost Hills Anticline.

Pleist.	TULARE FM.				
Plio.	SAN JOAQUIN FM.				
	ETCHEGOIN FM.				C
Late Miocene	MONTEREY FORMATION	Reef Ridge	Belridge Diatomite	D	
				DD	
				E	
				EE	
				F	
				FF	
				G	
				GG	
				H	
				J	
				K	
				Brown Shale	
McLure Shale		Antelope Shale			
		McDonald Shale			
M. Mio.		Devilwater Shale			
	E. Mio.	TEMBLOR FM.			

Figure 1.1-3. Lost Hills stratigraphic column.

Figure 1.1-4. Lost Hills top Belridge Diatomite structure map. Contour interval 200 feet.

Figure 1.1-5. Generalized cross section along southeast plunge on Lost Hills. The Belridge Diatomite is the objective of the CO₂ pilot project.

Figure 1.1-6. SEM photomicrographs of opal-A frustule starting to convert to opal-CT (left), and frustule converted to opal-CT (right). 1,300X magnification.

Figure 1.1-7. Opal-A frustule initiating conversion to opal-CT (left), and a frustule after its conversion to opal-CT. SEM photomicrographs, 10,000X magnification.

Figure 1.1-8. Lost Hills CO₂ pilot base map. Structure contours on Top Belridge Diatomite.

Figure 1.1-9. Cross Sections through pilot area. CO₂ injection will be in the FF through L interval. Changes in interval thicknesses due to small faults. Predominant lithologies (end members) shown: "sandy" diatomite (half circles and dots), "clean" diatomite (ovals), and "clayey" diatomite (half circles).

Figure 1.1-10. Cross-sections of porosity, air permeability, and oil saturation of the C Point to Upper Brown Shale interval from W. Fong's 3D Earth Model. The view is SW-NE and the length extends across 4 patterns (one on either side of the pilot). The proposed CO₂ injection interval, FF - L, is highlighted. This is the same interval as the current waterflood.

Figure 1.1-11. Type log (12-8D) of Belridge Diatomite in the Lost Hills pilot location. 12-8D was used for injectivity test.

Figure 1.1-12. Slabbed core of laminated diatomite (left), and bioturbated sandy diatomite (right).

Figure 1.1-13. Thin section photomicrographs of a "clean" diatomite from the J Unit (left; 200X) and a "sandy diatomite from the GG Unit (right; 40X, unpolarized and polarized light). The J unit thin section shows diatoms and porosity in blue. The GG Unit shows "blotchy" sand and porosity due to bioturbation.

Figure 1.1-14. Halliburton Formation Tester measurements (upper curve) and fracture densities calculated from well 12-8D EMI log. Fracture data is from D. Julander.

Figure 1.1-15. Azimuths of natural fractures as measured from the OB-7 EMI log. The CO₂ pilot will target the F-L interval. Note the increase in fractures and change in fracture azimuth in the Upper Brown Shale versus the F-J and J-L intervals. The OB-7 is 600 feet to the southwest of the CO₂ pilot. Data is from D. Julander.

12-8D perf'd

12-7W frac'd

Figure 1.1-16. CO₂ injection profiles for the 12-8D and 12-7W wells. The tracks represent from left to right: gamma ray (25 – 75 API units), injection profiles, lithology, and resistivity (0 – 5 ohm m). The 12-8D shows the CO₂ injection profile (0-50%). The 12-7W shows, from left to right, profiles for water injection (after CO₂), two CO₂ profiles (higher and lower rate), and three earlier water injection profiles (1999, 1998, and 1996). The lithology track shows percentages, from left to right, of clay, sand/silt, and biogenic silica.

1.2 LOST HILLS CURRENT DEVELOPMENT

Lost Hills Primary Development:

The Lost Hills Field, located 45 miles northwest of Bakersfield, California, (see Figure 1.2-1) was discovered in 1910. Reserves in the shallow sands, diatomite, and chert pools (Figure 1.2-2) were developed using slotted liner completion techniques until the late 1970's. From the late 1970's to 1987, small volume hydrofracture completions were performed covering the entire Belridge Diatomite.

Figure 1.2-1. Lost Hills Field Location Map.

Figure 1.2-2. Lost Hills Field Regional Cross-Section.

Advances in hydraulic fracturing technology in the late 1980's resulted in increased oil recovery that led to a more aggressive development program by Chevron. From 1987 to the present, high volume hydrofracture completions have been performed across the entire Belridge Diatomite and the Upper Brown Shale resulting in significant production increases as shown in Figure 1.2-3. The Lost Hills Field is developed on a 5 acre (siliceous shale) to 1.25 acre (diatomite) well spacing. There are over 2.2 billion barrels of oil in place in the Belridge Diatomite in Lost Hills. To date only 112 million barrels have been produced, or approximately 5% of the original oil in place (OOIP).

Figure 1.2-3. Lost Hills Historical Primary Production.

Diatomite Waterflood Development:

Chevron initiated a pilot diatomite waterflood project in December 1990 and began full-project development in April 1992. Since 1992, two hundred and eight 2-1/2 acre patterns have been put on water injection spanning parts of four sections (Sections 4, 5, 32 Fee, and 33) as shown in Figure 1.2-4. The historical performance of the Lost Hills waterflood performance can be seen in Figure 1.2-5. Since the initiation of first project water injection in April 1992, production has increased approximately 4,000 BOPD from 6,400 BOPD to the current rate of 10,400 BOPD.

Figure 1.2-4. Lost Hills Waterflood Project Location Map.

Figure 1.2-5. Lost Hills Waterflood Performance.

In terms of recovery efficiency, Figure 1.2-6 compares the estimated primary and secondary (waterflood) recoveries for each of the 4 sections under waterflood to the original Lost Hills Waterflood GO-36 on a per pattern basis. The height of the bars in Figure 1.2-6 represent the average pattern OOIP. Estimated ultimate waterflood recovery from the Lost Hills diatomite is 8.1% of OOIP, which is considerably less than the original GO-36 estimate of 19.6% of OOIP.

Figure 1.2-6. Lost Hills Estimated Waterflood Reserves and Recovery Factors.

Infill Primary Pilot:

An infill primary pilot was initiated by Chevron in Section 32 U.S. in 1998 to test the economic viability of improving primary recovery (3 – 4 % of OOIP to date) by infill drilling from the current 2-1/2 acre development down to 1-1/4 acre spacing. A total of 11 infill producers have been or will be drilled and completed by the conclusion of the pilot test.

Infill Waterflood Pilot:

Installation of an infill waterflood pilot began in late 1998 by Chevron in Section 32 Fee to test the potential of waterflooding with 1-1/4 acre “direct line-drive” patterns compared to the current 2-1/2 acre “staggered” patterns. Plans call for 17 wells (6 injectors and 11 producers) to be drilled to determine if the current waterflood recovery can be accelerated, or better yet, if incremental waterflood reserves can be obtained by infill drilling.

Diatomite Steamflood Pilot:

Chevron initiated a diatomite steamflood/cyclic steam pilot in the southern portion of Section 29 in October 1998. The steamflood pilot consists of 7 injectors targeting the J – L “clean” diatomite intervals. A single pattern cyclic steam pilot consisting of 4 producers targeting the more permeable EE – F “sandy” diatomite was initiated concurrently. Both pilots are still under evaluation.

Horizontal Wells:

In 1997 Chevron began experimenting with horizontal wells to try to exploit the flanks of the field where vertical wells could not be economically justified due to the reduced oil column. Through September 1999, four horizontal wells have been drilled with mixed results. Figure 1.2-7 is a summary of the Lost Hills horizontal well performance to date.

Figure 1.2-7. Lost Hills Horizontal Well Performance.

SECTION 2.

PROPOSAL

2.1 CO₂ PILOT LOCATION

The proposed CO₂ Pilot will be located in the southeast quarter-section of Section 32, T.26S., R.21E. of the Lost Hills Field as shown in Figure 2.1-1. Plans are to install a four-pattern pilot. The pilot area is enlarged in Figure 2.1-2 showing the four existing waterflood patterns (10-8WA, 11-8WA, 12-7W, and 12-8W) which will be converted to CO₂ injection.

Figure 2.1-1. Lost Hills CO₂ Pilot Location Map.

Figure 2.1-2. Lost Hills CO₂ Pilot Pattern Map.

2.2 CO₂ INJECTIVITY TEST AND RESULTS

CO₂ injectivity tests were conducted in the Belridge Diatomite of the Monterey Formation in the Lost Hills Field from March 11, 1999 through April 16, 1999. The injection tests took place in two wells (Figure 2.2-1). The first well, 12-8D Section 32, is a new well that was drilled during late December 1998. This well had not been completed prior to the CO₂ injection test. The second well, 12-7W Section 32, is a waterflood injection well that was hydraulically propped fractured during mid-1996 and has been on continuous water injection since November 1996. A total of approximately 10 MMSCF of CO₂ was injected during the test. Figure 2.2-2 shows the injection rate and duration of the test.

Figure 2.2-1. Lost Hills CO₂ Pilot well location map. Injectivity tests were performed in 12-8D (non-hydraulically fractured well) and 12-7W (hydraulically fractured water injector). The map shows a preliminary 0.625 acre pilot design.

Figure 2.2-2. Injection versus time in the 12-8D and 12-7W wells.

Production Response:

Production from the 4 pattern producers (11-7B, 11-8D, 12-7, 12-8B) prior to the initiation of CO₂ injection was approximately 230 BOPD and 380 BWPD. Post CO₂ pattern production increased to a peak of 260 BOPD and 500 BWPD. Gas production rates were essentially unchanged as a result of the injection test. Figure 2.2-3 shows the gain in oil production that occurred as a result of CO₂ injection.

Oil production from 12-8D, was not included as part of the total pattern production. After injecting CO₂ in 12-8D, the well was hydraulically propped fractured and placed on production. Figure 2.2-4 contains the production history of 12-8D.

Surface Tiltmeter Mapping Results:

Surface tiltmeter mapping has been utilized in the Lost Hills field for over 10 years. There have been approximately 300 hydraulic fractures mapped during this time indicating an average fracture azimuth of N47°E ±10°. A surface tiltmeter array was employed during all CO₂ injections as well as during the hydraulic propped fracture treatment of well 12-8D. The tiltmeters saw strong signals. However, the tilt vector patterns induced by the CO₂ injections were quite complex, indicating a more complicated fracture geometry than just a single vertical fracture. For all of the CO₂ injections, the surface deformation tended to have a bowl shaped pattern, indicating multiple near-vertical fractures at azimuths very different from the field average. This bowl shaped surface deformation is quite different than that of a horizontal fracture.

Figure 2.2-3. Gain in oil production due to CO₂ injection.

Figure 2.2-4. Post CO₂ production data from 12-8D.

In well 12-8D the average propped hydraulic fracture azimuth was $N69^{\circ}E \pm 6^{\circ}$. This possibly indicates a local reorientation of the stress field. For the two CO_2 injection tests in 12-8D, and the first half of the CO_2 injection test in 12-7W, most of the injection resulted in two fractures. Of these two main fractures, the bulk of the fluid created fractures with an average azimuth of $N30^{\circ}E \pm 7^{\circ}$. That is an average rotation of about 40° to the North from the hydraulically propped fractures mapped in 12-8D. The majority of the remaining injected volume created either vertical or steeply dipping fractures that were oriented $N67^{\circ}W \pm 10^{\circ}$ and orthogonal to the main fracture system.

From Figure 2.2-5, it is clear that there was a strong possibility for the CO_2 from the 12-7W to communicate with adjacent wells 11-8D and 12-7. Gas analysis data confirmed that CO_2 was detected in both of these wells.

The second half of the 12-7W CO_2 injection was significantly different from the first half. After about $8 \frac{1}{2}$ days (half-way into the injection), all of the tiltmeters dramatically changed slope, with the biggest change seen on the East side of the well. It appears that after $8 \frac{1}{2}$ - 9 days, two events happened that might possibly be related. First, the main fracture from the first half of the injection communicated with well 12-7, as both the gas production and CO_2 concentration increased from a baseline of 20 MSCF/D at 20% CO_2 to nearly 50 MSCF/D at 45% CO_2 concentration. Once this primary fracture was in a "steady-state", the tiltmeters no longer detected significant growth in this fracture plane. Second, an orthogonal fracture began growing that is best fit with a single vertical fracture oriented at $N40^{\circ}W \pm 10^{\circ}$.

Tables 2.2-1 and 2.2-2 show the final results of the tiltmeter fracture mapping. Although the fracture system is difficult to completely resolve, the CO_2 injections certainly created more than a single vertical fracture. While most of the fluid was injected into vertical fractures oriented at or near $N30^{\circ}E$, there were also significant secondary fractures (also near-vertical fractures) at very different azimuth orientations, horizontal fracture components, and very likely significant shear slippage in the formation as well.

CO_2 injection is not likely to be maintained with simple reservoir matrix flow, as the rates will have to be extremely low. Nor is it likely to induce simple vertical fracture growth along the Lost Hills average maximum horizontal stress direction ($N50^{\circ}E$). Instead, injection will induce a more complicated, but not random, fracture system.

CO_2 Injection Profiling:

Injection profiling was done on each CO_2 injectivity test for well 12-8D prior to the well being hydraulically fractured. Additionally, CO_2 injection profiling was done at two different injection rates during the injection test into well 12-7W which was previously hydraulically propped fractured and on water injection since 1996. Figure 2.2-6 shows a fairly even distribution of CO_2 for both injection intervals in well 12-8D. It appears that CO_2 did not flow preferentially into zones of higher permeability.

Inasmuch as well 12-7W had been on water injection prior to CO₂ injection, a good comparison of water vs. CO₂ injection can be seen in Figure 2.2-7. Injection profiles indicate CO₂ entered zones where water injection was minimal.

Figure 2.2-5. Map showing hydraulically propped fracture azimuths from tiltmeter analysis.

Table 2.2-1. Tiltmeter fracture mapping results for CO₂ injections in Wells 12-8D and 12-7W.

Well	Inj.	Date	Volume Liquid Equiv. CO ₂ (BBL)	Average Injection Rate Liquid Equiv. CO ₂ (bpd)	Perf Interval (ft)	Azimuth	Dip	Volume % Component
12-8D	Inj. 1	3/10/99-3/17/99	867	123.85	1970-2120	N 32° E ± 8°	82° ± 6° down to the NW	55%
						N 67° W ± 10°	84° ± 7° down to the SW	45%
12-8D	Inj. 2	3/22/99-3/26/99	511	127.75	1760-1930	N 34° E ± 7°	84° ± 5° down to the NW	75%
						N 64° W ± 10°	Steeply dipping	25%
12-7W	Inj. 1 First Half	3/31/99-4/8/99	1027	120.8	1670-2140	N 23° E ± 7°	89° ± 6° down to the SE	75%
						N 69° W ± 10°	Steeply dipping	25%
12-7W	Inj. 1 Second Half	4/8/99-4/16/99	1027	120.8	1670-2140	N 40° W ± 10°	80° ± 10° down to the SW	N/A*

* This fracture has a significant shear displacement component

Table 2.2-2. Tiltmeter fracture mapping results for propped fracture treatments in Well 12-8D.

Well	Stage	Date	Volume (BBL)	Perf Interval (ft)	Azimuth	Dip	Volume % Horizontal Component
12-8D	1	4/28/99	660	2160-2320	N 62° E ± 5°	74° ± 4° down to the NW	39%**
12-8D	2	4/30/99	152	1970-2120	N 66° E ± 6°	70° ± 5° down to the NW	36%**
12-8D	3	4/30/99	812	1760-1930	N 72° E ± 4°	87° ± 3° down to the NW	56%**
12-8D	4	4/30/99	778	1500-1710	N 75° E ± 4°	75° ± 5° down to the SE	24%**

12-8D Peforated

12-7W Fractured

Figures: 2.2-6 and 2.2-7. Injection profile from CO₂ injection (pink bars) into 12-8D prior to prop fracture, shows fairly even distribution with no preference for CO₂ to enter into higher perm zones. CO₂ profiling from 12-7W shows CO₂ (pink bars) entering into zones not well covered by water injection (blue bars). 12-7W injection profiles in chronological order from right to left.

2.3 CO₂ PILOT EARTH MODEL

This section discusses the construction of a detailed earth model around the CO₂ pilot area at Lost Hills. The objective is to use the earth model to construct a reservoir flow simulation model in order to predict and analyze the future CO₂ pilot performance.

A detailed, full-field, reservoir characterization effort was completed last year by Chevron. Using this new data allows us to build better geologic models. Past simulation models were based on small, single pattern models with rather idealized fracture geometry. Although they have been adjusted to match averaged historical production, these models have significant confinement problems. A model covering a larger area has less confinement problems, and can better capture heterogeneity and fracture interference. In addition, an area-specific model is needed to carefully match the historical production (primary depletion and waterflood to date) in the pilot area.

Model Framework:

Chevron's G2/GoCad++ software was used in most of the earth modeling steps. The model covers 16 injector-centered patterns, as shown in Figure 2.3-1. The CO₂ pilot consists of the center four patterns. A 149-well group around the pilot area was extracted from the full field data. A total of 17 surfaces from the C-Pt. to 300 feet below the L-Pt. were used to confine the model, as listed in Figure 2.3-2. The total reservoir thickness is 1176'. The earth model has 25' × 5' areal grids, and 500 layers each about 2' thick. This results in a 10.3 MM grid model.

Figure 2.3-1. 16 pattern model outline. Pilot is in center 4 patterns.

Figure 2.3-2. Wells and 17 marker surfaces used in model construction.

Table 2.3-1 lists the marker surfaces incorporated in the model, and averaged properties for each layer. The total OOIP of this model is 73 MMSTB, including the 300' interval below the L-Pt.

Table 2.3-1. Markers and average interval properties.

Marker name	Avg. thickness (ft)	Avg. Porosity %	Avg. Air Perm (md)	Average S_o (%)
C-Pt.	127	44.4	8.5	30.7
D-Pt.	58	45.2	9.8	39.0
DD-Pt.	59	53.2	3.1	40.4
E-Pt.	36	50.7	3.1	40.1
E2 Sand Top	32	49.6	5.6	44.1
EE Top	55	46.3	7.4	44.8
F-Pt.	38	52.3	3.6	47.1
FF-Pt.	42	50.5	3.2	45.4
G-Pt.	48	49.4	2.9	44.2
G2 Sand Top	50	52.7	2.9	48.6
GG-Pt.	57	58.4	3.6	56.3
H-Pt.	56	51.3	3.6	50.8
H Sand Top	71	52.0	2.0	47.8
J-Pt.	81	54.0	1.6	49.4
K-Pt.	69	47.7	1.5	41.5
L-Pt. - 300' Below	300	43.2	0.53	24.9
Total or Average	1176	49.6	4.4	43.8

Geostatistics:

To populate the 3D volume, geostatistics was applied. A set of three logs, (PERM98, SO98 and PHI98) from the 149 wells, which correspond to calculated air permeability, oil saturation and porosity, respectively, were analyzed. Nested variograms can fit the data quite well. As shown in Table 2.3-2, each property can be modeled as a two level nested variogram. Model 1 is the short range, and Model 2 is the long range fit in feet. The Z, or vertical, range is normalized to the entire interval.

Table 2.3-2. Variogram Ranges

	X Range(ft)	Y Range (ft)	Z Range (ft)	Azimuth (degrees)
Oil Saturation				
Model 1 - Exponential	139	112	0.029	132
Model 2 - Gaussian	10000	6500	0.24	149
Porosity				
Model 1 - Exponential	374	284	0.019	149
Model 2 - Exponential	15000	7500	0.187	121
Ln of Permeability				
Model 1 - Exponential	327	249	0.025	19
Model 2 - Gaussian	20000	10000	0.63	149

Figures 2.3-3 to 2.3-5 show results of variogram fits. In each plot, the areal variogram fit, in four quadrants was plotted as four small windows on the left. The vertical variogram is shown as a single plot on the right. Model azimuth is plotted in the lower half.

Figure 2.3-3 Variogram fit for S_o .

Figure 2.3-4 Variogram fit for permeability.

Figure 2.3-5. Variogram fit for porosity.

Geostatistical Simulations:

A few different geostatistical options were tested. Earlier models were built by separate, independent *Sequential Gaussian Simulations (SGS)* of porosity, permeability and saturations. However, the resulting cross plot (e.g., S_o vs. porosity) and correlation value did not honor the input data. The R^2 can be either too high or too low, as shown in Table 2.4-3. A better way is to first perform a SGS on S_o , then perform a *Collocate Cokriging SGS (ColCok SGS)*, using the already simulated S_o as soft data. In performing the *ColCok SGS*, we adjusted the correlation coefficient input (for porosity or $\ln(\text{perm})$ vs. S_o) downwards to 0.2 – 0.3. After the *ColCok SGS* is done, we then compare the cross plot and R^2 , which is close to the original input, as summarized in the right column in Table 2.4-3.

Table 2.3-3. Different geostatistical options.

	Actual Well data Wells	Independent SGS	ColCok SGS
Porosity vs. S_o	0.55	0.66 (seed #1)	0.56
		0.44 (seed #2)	
$\ln(\text{perm})$ vs. S_o	0.49	0.41 (seed #1)	0.51
		0.40 (seed #2)	

Figure 2.3-6 shows simulated permeability (cross section) compared to well log values (cylinders). The values match quite well. Figure 2.3-7 shows the simulated porosity, permeability and oil saturation through the middle of the model. The location of the FF-Pt. and the L-Pt. surfaces are also shown.

Figure 2.3-6. Permeability cross-section. Figure 2.3-7. PKS cross-section.

2.4 CO₂ PILOT FLOW SIMULATION MODEL

The earth model was scaled up for reservoir flow simulation, this was also done in G2/Gocad++. Figure 2.4-1 compares porosity cross-sections of the original earth model, and a scaled up, 36 layer reservoir flow simulation model. The degree of scale-up is mostly determined by the size of the compositional model that can be run in a reasonable amount of time.

To model hydraulic fractures, thin planes of cells were added after scale-up (see Figure 2.4-1). The flow model allows for orthogonal sets of fractures originating from the injectors. This finally results in a 60,516 grid model for Chevron's *CHEARS* simulator. The model dimension is $41 \times 41 \times 36$. An 112,700 grid model with more vertical definition (67 layers) was also created.

Figure 2.4-1. Compare scale-up porosity.

Figure 2.4-2. Production & injection data.

Well completion and production data were imported into G2/Gocad++, as shown in Figure 2.4-2. The spheres indicate cumulative oil production to date. The diamonds indicate cumulative water injection to date. These were then output to *CHEARS* format for history matching. PVT data from well 11-8D was also incorporated into the model. For history matching purposes, the simulation model was run in black oil mode from 1949-1999. The pressure and saturation information will then be output to a compositional version of the same model for subsequent CO₂ injection predictions.

Figure 2.4-3 is a plot of production and injection rates for the wells in the sixteen pattern model. Wells that started producing in the 1950's were non-fractured wells. These wells produced until the late 1980's. From 1989 to current time, new hydraulically-fractured wells were gradually put on production. The Lost Hills waterflood commenced in the early 1990's. The history match was therefore made in two stages:

- (1) primary production period from 1949-1991 with no hydraulic fractures in the model .
- (2) primary + waterflood period from 1991-1999; with all new wells hydraulically fractured.

Figure 2.4-3. Historical production and injection performance since 1990.

Primary (or Pre-Frac) History Matching:

The result of the first stage history match is satisfactory. Figures 2.4-4 and 2.4-5 show the pressure and gas saturation in model by August 1992, respectively. Localized pressure depletion can be seen, and the pressure difference from top to the bottom of model is approximately 800 psia. Free gas saturation (2-3%) existed at this time, and the observed GOR (gas-oil ratio) reached 5000 scf/stb. The history match involve the following changes in original simulation properties:

- (a) increase original oil bubble point by 100 psia to 1315 psia, to better match initial GOR.
- (b) reduce critical gas saturation (S_{gc}) from 0.02 to 0.0 to improve GOR trend match.
- (c) reduce $S_{wir} = 0.97 * S_{wi}$ to allow for initial water production.

- Total liquid production (oil + water) vs. time for each well was used as input for the history matching runs.

Figure 2.4-4. Pressure distribution in model - 8/92.

Figure 2.4-5. Gas saturation in model - 8/92.

Figures 2.4-6 through 2.4-9 are plots of production history (shown as lines) compared to simulation results (shown as squares). Figures 2.4-6 and 2.4-8 shows good match of cumulative oil and water production from 1949 - 1991. By 1992, the predicted values are lower than historical values since the model wells still have no fractures, and the low permeability of the model cannot produce the actual rates. The GOR match is good. Again, by 1992, some water injection has taken place, resulting in a decrease in GOR. Water-Oil Ratio (WOR), however, is considered only fair.

Figure 2.4-6. Cumulative oil production match.

Figure 2.4-7. Gas-Oil Ratio history match.

Figure 2.4-8. Cumulative water production match.

Figure 2.4-9. Water-Oil Ratio history match.

Waterflooding (or Post-Frac) History Match:

The pressure and saturations of the pre-frac model at 1992 was output to construct a model with fractures at the newer wells. We assumed in the model, all the wells put on production after 1992 are hydraulically fractured in 1992. The history match was then continued. Results are currently being analyzed and will be presented in the first quarterly report of 2000.

2.5 CO₂ PILOT DESIGN

Objectives:

The proposed Lost Hills CO₂ Pilot was designed with the following goals and objectives in mind:

- Test the technical and economic viability of CO₂ flooding the low permeability Diatomite resource, which is one member of California's siliceous shale reservoirs of the Monterey Formation.
- Test the technical and economic viability of CO₂ flooding the Diatomite resource in a timely manner (3 years or less).
- Install a configuration that enhances the chance of process success (oil response).
- Install a configuration that minimizes the likelihood of premature CO₂ breakthrough.
- Provide an opportunity to gather and analyze reservoir, geologic, and production data and gather facilities design information necessary to commit to a full-field project.
- Install a CO₂ Pilot in Lost Hills safely, without incident, and in accordance with all county, state, and federal environmental rules and regulations.

With the foregoing objectives in mind, a four pattern (2.5 acre each) CO₂ pilot configuration was chosen as shown in Figure 2.5-1. This configuration confines one producer (11-8D) and reduces the risk of premature breakthrough that a 5/8 acre pilot configuration would likely incur.

Figure 2.5-1. Four 2.5 Acre Patterns Pilot Configuration.

Figure 2.6-1. Bottom hole injection pressure indicates a CO₂ injection gradient of 0.80 psi/ft at the top perforation.

Figure 2.6-2. Bottom hole injection pressure indicates a CO₂ injection pressure gradient of 0.88 psi/ft at the top perforation, above the DOG maximum limit of 0.8 psi/ft.

12-7W CO₂ Injection Test **L-FF pt markers (2140'-1670')**

Figure 2.6-3. Bottom hole injection pressure indicates a CO₂ injection gradient of 0.64 psi/ft at the top perforation, well below the DOG maximum injection gradient of 0.8 psi/ft.

2.6 DRILLING AND COMPLETION

Existing and New Producers:

All current CO₂ pilot pattern production wells are currently producing. At this time no additional pattern producers will need to be drilled. All future new, or replacement producers will need to be hydraulic fracture stimulated in 4-5 stages, from the Upper Brown Shale to the D pt. Marker. Based on the corrosion monitoring program, existing tubing and sucker rods may have to be replaced with corrosion resistant materials (internally coated tubing and/or externally coated continuous sucker rods).

Existing Injectors:

The existing four water flood injectors (12-7W, 12-8W, 11-8W, 11-8WA) will need to be pulled to install internally coated injection packers and tubulars. During this remedial work, the wells will be reconfigured from dual injection to single string injection. The probability of success during these injector conversions is extremely low, due to subsidence related casing restrictions. As of this writing, all four injectors have known casing restrictions and/or casing damage.

New Injectors:

Four new CO₂ injection wells may have to be drilled, based on the success of the injector conversions from will be drilled. These new injection wells will receive 7" casing, two propped fracture stages (Gpt-Jpt and Jpt-Lpt), and will be completed with a single, internally coated, injection string.

New Injector Completions:

Injection wells will have to be propped fractured to allow injection below the specified Division of Oil and Gas (D.O.G.) permit limit of 0.8 psi/ft as measured from the top perforation of the injection interval. Bottom hole pressure data from the CO₂ injection test conducted on non-fractured producer 12-8D Sec 32 Fee, indicated injection pressure gradients of 0.80 psi/ft (Figure 2.6-1) for the Jpt-Lpt interval, and 0.88 psi/ft (Figure 2.6-2) for the Gpt-Lpt interval. The CO₂ injection pressure gradient for well 12-7W, Sec 32 Fee (propped fractured water injector) was 0.64 psi/ft (Figure 2.6-3), well below the D.O.G maximum injection pressure limit of 0.8 psi/ft.

Data from the injectivity test indicates that single string injectors are adequate to achieve even CO₂ distribution across all injection intervals (Fpt-Lpt). Additionally, single string injectors are preferred over dual injectors from a surface rate and pressure control standpoint. Dual CO₂ injection wells will require twice the surface control and monitoring equipment as single string injectors. Lastly, injection tubulars and packers will have to internally coated for corrosion protection as a result of WAG (Water Alternating Gas) injection. The current injectors do not meet these requirements as none of the injection packers are internally coated and not all injectors have internally coated tubulars. Therefore the existing injectors will have to be mechanically reconfigured to accommodate CO₂ injection.

2.7 PILOT FACILITIES

Design Basis:

The facilities are being designed to support four 2.5 acre patterns with the following as the design basis:

- Four injection wells (existing water injectors) requiring a maximum pressure of 1200 psig. The equipment will be able to deliver a CO₂ rate as low as 100 mscfd per well, and as high as 500 MSCF/D per well. This range is based on the results of the recent injectivity test.
- Ten producing wells

A phased approach is being taken to establish early baseline data from the existing producing wells in the CO₂ pilot.

Phase 1 – New Gauging Facilities:

It should be noted that the existing gauge setting can handle and monitor the production associated with the pilot. However, if the pilot is sustained it would be advantageous to install the new gauge setting to improve metering accuracy and to minimize corrosion damage to existing facilities.

The new gauging facilities will start operating in late April or early May in order to establish good baseline production data prior to starting injection. They will be designed to handle and monitor the increased CO₂ production associated with the CO₂ pilot. The key objective of these facilities will be to isolate and handle the wet gases high in CO₂ to prevent excessive corrosion of the existing gathering system. The time lag between phase 1 and 2 facilities will be minimal (2 to 4 months). Since these gauging facilities will have salvage value to Chevron, regardless of the outcome of the pilot, it will be proposed that the DOE only pay 25% for this portion.

Some of the existing flow lines will be utilized for the producers, while others will be replaced with cement lined piping. Funding is included in this AFE to tie additional wells into the pilot dedicated gauge setting should they also experience CO₂ breakthrough outside the immediate pilot patterns. The facilities will include monitoring equipment, such as density meters and online corrosion monitors, to help detect CO₂ breakthrough.

Phase 2 - Injection Facilities:

The injection equipment will be leased and consist of; storage tanks, injection pumps, heaters, monitoring equipment, and injection lines. It will be very similar to the equipment utilized for the injectivity test but with a greater capacity. SCADA equipment will be installed to enable the existing infrastructure to gather and compile the data from the pilot.

2.8 PILOT AND PROJECT SCHEDULE

Pilot Schedule:

The pilot will be constructed and operated in phases, to establish reliable baseline production data. Phase 1, which includes the new metering facility will start-up in late April or early May. Phase 2, which includes the CO₂ and water injection systems will start-up in late June or early July. Construction and well drilling schedules are being closely monitored to look for ways to expedite installation of the pilot.

Critical path for the start-up of the pilot is the mechanical evaluation of the injectors and subsequent re-drills if necessary. To achieve injection by the second quarter it will be necessary to schedule a drilling rig for late in the first quarter of 2000. Drilling rig schedules will be juggled to accommodate the CO₂ pilot schedule.

Liquid CO₂ supply is also a major consideration in the pilot schedule. If the pilot starts prior to June of 2000 it may be subjected to periods of low CO₂ supply/curtailment. After June of 2000, BOC will have additional, more dependable, supplies from Chevron's El Segundo Refinery.

A plan has been developed to institute water alternating with gas (WAG) cycles as soon as there are indications of CO₂ breakthrough, for any individual pattern. Control techniques learned in the early stages of the pilot will be utilized and refined throughout the pilot duration.

The pilot duration could be as short as a few months (if breakthrough cannot be controlled), or as long as 2 to 3 years if sustained success is achieved.

As soon as the major economic uncertainties of oil production and associated CO₂ utilization are understood, the pilot will be terminated. At that time we will finalize the feasibility evaluation of expanding to a commercial CO₂ injection operation.

Commercial CO₂ Project Schedule:

Based on a strategy to utilize only the CO₂ that is locally obtainable, additional patterns can be installed and started roughly one year after approval to proceed is obtained. This is many years sooner than if we had to wait on an interstate CO₂ pipeline. The first 5 MMscfd of CO₂ is entrained in the Lost Hills produced gas and will be the easiest to deliver to the project. Additional CO₂ could be delivered 6 to 12 months thereafter.

If the CO₂ flood goes commercial, after a successful pilot, using just the local CO₂ supplies, it could be on line, with 10 to 30 patterns (depends on final design injection rate), as early as 2003. Additional expansion could take place every year, for several years thereafter, until the local supply is used up, or additional supplies come to the market.

2.9 FACILITY ALTERNATIVES

Pilot:

Since the CO₂ supply is the most significant cost for the pilot, Decision Analysis was used to determine the best method of supplying CO₂. The CO₂ Team held a framing session to list all possible methods of CO₂ delivery. Since CO₂ is entrained in the produced gas at Lost Hills the most likely choices came down to:

1. Use liquid CO₂ from trucks ("Liquid Strategy") or
2. Remove CO₂ from the Lost Hills gas ("Amine Strategy")

The base case Net Present Value (NPV) for the liquid strategy is higher than the amine strategy. The only exception to that is if the amine plant would have significant value after termination of the pilot. Unfortunately, this is not the case since the removal of CO₂ from our produced gas at Lost Hills does not result in gas sales price uplift and has no measurable merit above and beyond the pilot.

The duration of the pilot must approach 3 years for an amine CO₂ removal plant to be economic. The preliminary design for the CO₂ removal plant will proceed, should it be needed to supply a long-term, commercially viable source of CO₂.

Commercial CO₂ Project Alternatives:

The primary economic uncertainties are; a). The amount of oil production as a result of CO₂ injection and b). CO₂ utilization per BBL of incremental oil. Therefore, the alternatives for the project will focus on the most economical supply of CO₂ and the best way to utilize the limited supply.

2.10 DOE FUNDING PLAN AND EXPENDITURES

The U.S. Department of Energy (DOE) has made funds available to explore for ways to produce mature oil fields. This program is called the Class Program. In 1996 the DOE approved a Chevron proposal for a jointly funded study of CO₂ enhanced oil recovery in the Buena Vista Hills siliceous shale. After two years of study, it was determined that a CO₂ flood was not practical at Buena Vista Hills due to low oil saturation. However, core floods and reservoir simulation showed that a CO₂ flood of diatomite had technical merit. A revision of the original proposal was presented and approved by the DOE to move the pilot demonstration to the Belridge Diatomite at Lost Hills. Table 2.10-1 is a summary of the original DOE funding by budget period.

Table 2.10-1. Buena Vista Hills Field - Original DOE Funding by Budget Period.

	Period No. 1	Period No. 2	Total
DOE	\$2,334,048	\$2,515,406	\$4,849,454
Chevron	\$2,334,049	\$2,515,406	\$4,849,455
Total	\$4,668,097	\$5,030,812	\$9,698,909

Table 2.10-2 is a summary of actual pilot expenditures through December 31, 1999 and Table 2.10-3 is a summary of the total remaining DOE funds. As shown in the Table 2.10-3, a little over \$2.7 MM of DOE funding is available for the Lost Hills pilot in the future.

Table 2.10-2. Actual Pilot Expenditures Through December 31, 1999.

	Period No. 1	Period No. 2	Total
DOE	\$2,105,297	\$0	\$2,105,297
Chevron	\$2,105,297	\$0	\$2,105,297
Total	\$4,210,594	\$0	\$4,210,594

Table 2.10-3. Lost Hills CO₂ Pilot – Remaining DOE Funding.

	Period No. 1	Period No. 2	Total
DOE	\$228,751	\$2,515,406	\$2,744,157
Chevron	\$228,752	\$2,515,406	\$2,744,158
Total	\$457,503	\$5,030,812	\$5,488,315

As a condition of this funding, Chevron has agreed to make all findings of the pilot demonstration public. Thus Chevron is required to write topical reports, quarterly and annual reports, and a final project report. Also Chevron is required to publish papers and give oral presentations regarding the pilot. The funding plan was revised and submitted to the DOE in agreement with the Chevron approved funding plan. The original funding spreadsheet along with the proposed revisions are included in Appendix D. Generally, we now intend to use a significant amount of the DOE funding to offset the operating expense of purchasing CO₂. Table 2.10-4 is the forecasted DOE expenditure forecast for the Lost Hills CO₂ pilot and Figure 2.10-1 is a graphical representation of the same information.

Table 2.10-4. Year 2000 DOE Expenditure Forecast.

Through	This Period	Total Cumulative
1999	\$172,936	\$2,105,297
1 st Quarter - 2000	\$283,750	\$2,389,047
2 nd Quarter - 2000	\$853,063	\$3,242,110
3 rd Quarter - 2000	\$565,250	\$3,807,360
4 th Quarter - 2000	\$237,500	\$4,044,860

Figure 2.10-1. Future DOE Expenditure Forecast for Lost Hills CO₂ Pilot.

2.11 CO₂ SOURCES FOR LOST HILLS

CO₂ Source for Pilot:

As was discussed in "Facility Alternatives" it is more economic to supply a short lived pilot (less than 2 years in duration) with liquid CO₂ than by extracting it from the Lost Hills gas which contains 15% CO₂. As a result we have focused on getting the lowest, dependable source of liquid CO₂ possible. BOC Gases will supply the CO₂ and the associated storage/injection equipment for the pilot.

It is noted in the Risk Mitigation table that one of the pilot risks is that CO₂ will not be available for periods of up to several days. This is because the California CO₂ supply is limited, and will continue to be until BOC builds their CO₂ plant at Chevron's El Segundo refinery in the Spring/Summer of 2000. We plan to work closely with the vendor to monitor the CO₂ supply and to anticipate/mitigate problems.

CO₂ Source for Project:

The CO₂ Demand Study Group, made up of Oxy, Aera, and Chevron, was set up to determine the long-term demand for CO₂ in the San Joaquin Valley. The team has worked closely with companies such as Shell CO₂ and Ridgeway Oil to examine the feasibility of a CO₂ pipeline from Arizona or Colorado. Unfortunately, the cost for such a project would be between \$500 million and \$800 million, and require a sustained demand over 400 MMSCFD for at least 10 years. It is very unlikely that the combined demand of Aera, Oxy, and

Chevron would be that high in the foreseeable future. As a result, this project would depend on local CO₂ supplies and has been evaluated on that basis. The project would have limited initial growth due to the limited available supply. Some of the possible local CO₂ supplies are discussed below:

- **CO₂ from Lost Hills Produced Gas (4.5 to 6 MMSCFD):** Gas produced by Aera and Chevron in Lost Hills contains approximately 15% CO₂ and is processed locally at Aera's Four Star plant.
- **CO₂ from Cymric Casing Gas (1.5 to 2 MMSCFD):** Currently well vent gases, containing approximately 50% CO₂, are incinerated in steam generators in Cymric. If this CO₂ were removed from this casing gas it could be transported to Lost Hills via pipeline.
- **CO₂ from Produced Gas of Other Oil Companies (10 to 30 MMscfd in future):** Gas produced by other oil companies in the vicinity of Lost Hills is also relatively high in CO₂. Facilities could be installed to remove and transport this CO₂ to Lost Hills.
- **CO₂ from IC Engines (250 mscfd to 1 MMSCFD per engine):** Several IC engines are located within one-half mile of the CO₂ flood location. Other operators have utilized CO₂ from the exhaust of IC engines as an injectant supply. The bugs have not been worked out of this technology yet, but may be by the time the CO₂ flood would go commercial.

2.12 FIELD OPERATING STRATEGY

WAG Optimization:

Based on the injectivity test performed in April, 1999 we anticipate having to deal with quick breakthrough of CO₂. Therefore the operating strategy for the pilot centers around the need to control breakthrough individually for each pattern, on a moments notice.

The following table depicts the planned strategy for dealing with breakthrough:

Injectants	CO ₂ / Water Injection Rate	CO ₂ Injection Duration	Water Injection Duration	WAG Cycle Times	Synchronize Patterns ? (i.e. same injectant at all times?)
CO ₂ Alt. With Water	Start with low of 100 mscfd per well and work up to 500 mscfd max.	Inject until breakthrough is detected (breakthrough defined by detection of tracer gases in one producer)	Either: • Inject until desired HCPVSI is achieved or... • If there is a production kick we will "ride it out"	Continue with cycles until desired cumulative HCPVSI is achieved.	Control patterns individually - some may be in CO ₂ injection while others in water injection

As a result of trying the above strategies, we hope to arrive at the optimal process for controlling breakthrough while monitoring for an oil kick. As noted before, the above strategies will be tested before facilities to handle high CO₂ are installed. We are risking shutting down injection for a while but it reduces the capital investment risked up-front. If the cumulative CO₂ percentage for the area of the pilot stays low enough to avoid corrosion, injection will not be stopped to wait on facilities.

Monitoring:

Since the pilot is located near a gauge setting most, if not all, of the process data will be transmitted to the existing data acquisition system at the main processing plant where it will be compiled for analysis at desktop workstations.

Safety:

The pilot will be an expanded version of the injectivity test. We intend to utilize the safety plan and the subsequent lessons learned for the pilot. The key issues were safe delivery of the CO₂ and keeping Chevron personnel away from high-pressure injection lines. The

revised plan calls for the access road to be re-paved for the increased traffic. In addition, more visible signs will direct CO₂ delivery drivers to their destination

Manpower for Pilot:

The equipment requiring most of the attention will be the CO₂ storage vessels and the injection skid. A Contractor was on-site during all injection operations for the injectivity test. This would be cost prohibitive for the pilot, therefore automatic controls will be added to monitor critical process parameters and Chevron Operations personnel will be trained on how to check and operate/adjust the equipment (particularly the pumps). Generally, priming the CO₂ pumps after loss of flow is the most difficult operation. Injection will be continuous unless CO₂ monitoring indicates it should be stopped at which time operator intervention will be required to switch to water injection

In addition, significant manpower will be required to stay up to date on all the data necessary to properly evaluate success of the pilot. Contract labor will be used to gather and analyze oil and gas samples. Analysis of the data, with the intent of making WAG decisions, will be performed by the Production Engineer, in the field. Initially, these decisions will be made by consulting with the CO₂ Team members but should become more routine after a while.

2.13 PILOT MONITORING AND SURVEILLANCE

CO₂ Injection Monitoring Plan

In order to monitor the CO₂ pilot's performance, a comprehensive monitoring and surveillance program has been developed. Table 2.13-1 lists the types of data to be collected and its relevance.

Table 2.13-1. Pilot Monitoring and Surveillance.

Source	Data Collection		Data Evaluation & Evaluation	
	Type	Frequency	Presentation	Derived Information
Injection Wells	Tracer survey; Install flow meters w/ controllers @ each injector-header; Tiltmeters	Three months Daily	Logs; bubble plots & maps;	Injection profile; CO ₂ rate, pressure & temperature
		Once	Map	Hydraulic fracture azimuth
Fiberglass Cased Observation Wells	Cased hole resistivity; E-M survey Cross well seismic – (possible DOE funds)	Six months	Logs, charts & cross sections	Oil saturation changes CO ₂ sweep CO ₂ sweep
Steel Cased Observation Well	Pressure	Six months	Pressure plots	Formation pressure; Needed to determine hydrocarbon pore volumes of CO ₂ injected
Producing Wells	CO ₂ concentration in produced gas; Corrosion coupons;	Weekly	Rate, bubble & contour maps & plots	Performance updating; material balance; CO ₂ response; reservoir modeling
Casing Collection System	Gas composition	Daily	Pressure vs. oil rate plots	Energy balance; effect on casing pressure & oil production
Producing Wells: Incremental Oil, Gas & Water Production	Install new AWT dedicated to pilot wells	Every two days	Bubble & contour maps & plots Rate vs. Time plots HCPV _{SI} vs. Cum. Oil	Baseline production vs. actual production; Incremental gas production; Oil production vs. HC pore volumes injected
CO ₂ Utilization	CO ₂ injection rate vs. incremental production; CO ₂ quality % - blend in natural gas	Monthly	Injection rate vs. oil plots CO ₂ Utilization vs. Time	Meter CO ₂ injection rate and trend vs. oil produced – long term
CO ₂ Breakthrough	Detect when tracer gases arrive at producers	Daily	Gas composition plots	Online GC or frequent sampling with lab
Percent Recycle	Gas production composition	Monthly	Production plot % CO ₂ vs. Time Plot CO ₂ Injection & CO ₂ Production vs. Time	Sample & trend % CO ₂ at critical junctions of gas system – Section 3 compressor, Cahn 3 compressors, & Four Star gas plant sales point
Timing of Oil Response	Real time comparison of oil production vs. injection rates	Monthly	Production & injection vs. time plots	Pilot performance

We plan to drill 3 observation wells in April 2000. Two of these wells will be fiberglass-cased. We will run resistivity logs in these wells every six months to look for changes in oil saturation and vertical sweep. The third observation well will be steel cased and used for pressure observation.

An electro-magnetic (EM) survey is also planned for the fiberglass-cased wells. The advantage of EM is that while the resistivity logs only have a small radius of investigation around the wellbore, EM lets us see what is taking place between the wells. The two

fiberglass-cased observation wells will be located on either side of a CO₂ injector. Thus we should be able to image CO₂ areal sweep in the reservoir and monitor changes over time.

If any of the existing injectors needs replacement, then resistivity, gamma ray, neutron-density, and Electrical Micro Imaging (EMI) logs will be run. The EMI will be used to look for natural fractures.

SECTION 3.

TECHNOLOGY TRANSFER

3.1. TECHNOLOGY TRANSFER

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APPENDIX A
RESERVOIR FLUID STUDY

RESERVOIR FLUID STUDY

Introduction:

On March 8, 1999 a liquid and gas separator sample was taken from Well 11-8D in the CO₂ pilot area of the Lost Hills Field. The producing interval extended from 1202' to 2560' MD and covered the entire Belridge Diatomite. The reservoir pressure ranged between 313 – 640 psig, and averaged 475 psig. Bottomhole temperature reached 120°F with an average of approximately 108°F.

The separator liquid and separator gas sample from the subject well was sent to Core Laboratories in Carrollton, Texas for use in a reservoir fluid study to examine the effects of CO₂ injection into the reservoir. The following test and/or analyses were conducted:

Sample Composition:

The composition of the separator gas was determined using gas chromatography. The composition, along with the calculated properties of the separator gas, is presented on Table A-1. The composition of separator liquid was measured through a heptanes plus residual fraction using fractional distillation. The heptanes plus fraction was further analyzed by gas chromatography through triacontanes plus. The composition and density of the separator liquid can be found on Table A-2.

Reservoir Fluid Composition:

The separator gas and separator liquid were physically recombined to a gas/oil ratio (GOR) of 515 scf of primary separator gas per barrel of stock tank oil. The recombination values and calculated wellstream composition based upon GOR and separator product compositions can be found on Tables A-3 and A-4. The recombined separator products equilibrated at a target bubblepoint of 950 psig at 108°F in a PVT cell. The equilibrium gas phase was physically removed and the remaining equilibrium liquid was used as the "original reservoir fluid". The measured composition of the reservoir fluid is presented on Table A-5.

Pressure-Volume Relationship:

A portion of the reservoir fluid was charged to a high pressure, windowed cell heated to the reported reservoir temperature of 108°F. During the constant composition expansion at this temperature, a bubblepoint was observed at 930 psig. The results of the pressure-volume relations are presented on Table A-6.

Multi-Pressure Viscosity:

The viscosity of the reservoir fluid was measured over a wide range of pressures at 108°F in a rolling ball viscometer. The results of the viscosity measurements are presented in Figure A-1.

Separator (Shrinkage) Test:

A small portion of the reservoir fluid was subjected to a single-stage separator test to determine gas/oil ratio, stock tank oil gravity and formation volume factor. These data can be found on Table A-7.

Vapor/Liquid Equilibrium Experiment:

A mixture of 60 mole % CO₂ and 40 mole % reservoir fluid was prepared in a PVT cell for use in an equilibrium (K-value) experiment at 950 psig and 108°F. The equilibrium gas phase and equilibrium liquid phase were separately analyzed for volume, density and composition. A summary of the equilibrium products can be found on Table A-8. The compositions of the two phases are presented on Tables A-9 and A-10. An additional volume of the liquid phase was prepared and subsequently charged to a rolling ball viscometer for the purpose of measuring fluid viscosity versus pressure depletion at 108°F. This CO₂ swollen reservoir fluid viscosity can be found in Figure A-2.

Packed Column Displacements (Minimum Miscibility Pressure):

A series of packed column displacements were performed at 2000, 3000, and 5000 psig at 108°F in a forty-foot, Ottawa sand packed column using the reservoir fluid and pure CO₂. A summary of the displacements' recoveries at 1.2 pore volumes of gas injected is presented in Figure A-3. Minimum Miscibility Pressure, or MMP, is typically defined as the pressure at which 90% oil recovery occurs after 1.2 pore volumes of CO₂ gas injected. Analysis of Figure A-3 shows that this occurs at 5000 psig for the Lost Hills reservoir fluid.

Asphaltene Flocculation Experiments:

A 25 cc sample of reservoir fluid was placed in a high pressure PVT cell at an overburden pressure of 950 psig and reservoir temperature of 108°F. After reaching equilibrium, the sample was scanned using near-infrared (NIR) spectrophotometer to establish an absolute transmittance level for reference. Once the reference was established, the fluid was slowly mixed and maintained at 950 psig as pure CO₂ was added to the system. During CO₂ additions, scans in a near-infrared range of wavelengths from 1500 to 1700 nm were repeated at every cc increment of gas addition from 0 to 60cc (0 mole % to 207 mole % CO₂ added to reservoir fluid, respectively). Results of these NIR scans at reservoir temperature are presented in graphical form on Figure A-4. Following the gas addition, the system was equilibrated at 950 psig and 108°F and an additional reference scan performed. While mixing the cell contents, the system was slowly pressurized from 950 psig to 5100 psig. During this pressurization process, scans were performed at every 50-psig pressure increment. These data are also presented graphically in Figure A-4. Neither during the process of titrating the reservoir fluid with CO₂ nor subsequent pressurization of the system was an asphaltene onset observed.

Summary:

The results of the reservoir fluid study are encouraging for the proposed Lost Hills CO₂ pilot. Although the packed column displacement tests resulted in a Minimum Miscibility Pressure (MMP) of 5000 psig, there is still a significant benefit from CO₂ injection. Figure A-5 shows a comparison of the original reservoir fluid viscosity to the CO₂ swollen fluid viscosity as a function of pressure. Although the Lost Hills CO₂ flood will be operating well below MMP

and in the 500 – 1100 psig range, a fluid viscosity reduction in excess of 50% can still be achieved.

In addition, many CO₂ projects in West Texas and Colorado have been hampered with a severe asphaltene precipitation problem subsequent to commencing CO₂ injection. Analyses of the asphaltene flocculation experiments indicate that this will not be a problem with Lost Hills oil.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

COMPOSITION OF PRIMARY STAGE SEPARATOR GAS
(by Programmed-Temperature, Capillary Chromatography)

Component	Mol %	Plant Products (GPM)	Liquid Density (gm/cc)	MW
Hydrogen Sulfide	0.00			
Carbon Dioxide	26.70		0.8172	44.010
Nitrogen	0.02		0.8086	28.013
Methane	64.26		0.2997	16.043
Ethane	5.48	1.464	0.3562	30.070
Propane	0.71	0.195	0.5070	44.097
iso-Butane	0.92	0.301	0.5629	58.123
n-Butane	0.45	0.142	0.5840	58.123
iso-Pentane	0.46	0.168	0.6244	72.150
n-Pentane	0.21	0.076	0.6311	72.150
Hexanes	0.27	0.105	0.6850	84.0
Heptanes	0.35	0.147	0.7220	96.0
Octanes	0.12	0.055	0.7450	107
Nonanes	0.04	0.020	0.7640	121
Decanes	0.01	0.005	0.7780	134
Totals	100.00	2.678		

SAMPLING CONDITIONS

48 psig
72 °F

Gas Cylinder
DEN9009

Average Sample Properties

Critical Pressure, psia 771.4
Critical Temperature, °R 424.8
Average Molecular Weight 26.06
Calculated Gas Gravity (air = 1.000) .. 0.900

at 14.73 psia and 60 °F

Heating Value, Btu/scf dry gas*
Gross 877

Properties of Plus Fractions

Component	Mol %	Liquid Density (gm/cc)	Liquid API Gravity	MW
Heptanes plus	0.52	0.7326	61.5	101.2

Note: Component properties assigned from literature.

* ref: Gas Producers & Suppliers Association (GPSA) Engineering Data Book

Table A-1. Composition of Primary Stage Separator Gas.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

COMPOSITION OF PRIMARY STAGE SEPARATOR LIQUID
(by Low Temperature Distillation / Programmed-Temperature, Capillary Chromatography)

Component	Mol %	Wt %	Liquid Density (gm/cc)	MW
Hydrogen Sulfide	0.00	0.00		
Carbon Dioxide	0.49	0.08	0.8172	44.010
Nitrogen	0.00	0.00		
Methane	0.28	0.02	0.2997	16.043
Ethane	0.24	0.03	0.3562	30.070
Propane	0.11	0.02	0.5070	44.097
iso-Butane	0.25	0.05	0.5629	58.123
n-Butane	0.18	0.04	0.5840	58.123
iso-Pentane	0.53	0.14	0.6244	72.150
n-Pentane	0.42	0.11	0.6311	72.150
Hexanes	2.42	0.75	0.6850	84.0
Heptanes	7.50	2.67	0.7220	96.0
Octanes	9.91	3.93	0.7450	107
Nonanes	7.98	3.58	0.7640	121
Decanes	7.00	3.48	0.7780	134
Undecanes	5.44	2.97	0.7890	147
Dodecanes	4.81	2.87	0.8000	161
Tridecanes	4.48	2.91	0.8110	175
Tetradecanes	3.59	2.53	0.8220	190
Pentadecanes	3.16	2.41	0.8320	206
Hexadecanes	2.75	2.26	0.8390	222
Heptadecanes	2.59	2.28	0.8470	237
Octadecanes	2.74	2.55	0.8520	251
Nonadecanes	2.19	2.14	0.8570	263
Eicosanes	2.58	2.63	0.8620	275
Heneicosanes	1.86	2.01	0.8670	291
Docosanes	1.83	2.07	0.8720	305
Tricosanes	1.63	1.92	0.8770	318
Tetracosanes	1.69	2.07	0.8810	331
Pentacosanes	1.16	1.48	0.8850	345
Hexacosanes	1.09	1.45	0.8890	359
Heptacosanes	1.30	1.80	0.8930	374
Octacosanes	0.93	1.34	0.8960	388
Nonacosanes	1.29	1.92	0.8990	402
Triacosanes plus	15.58	43.49	1.1127	753
Totals	100.00	100.00		

SAMPLING CONDITIONS

48 psig
72 °F

Liquid Cylinder
226387D

Average Sample Properties

Average Molecular Weight 269.69
Calculated Density at 0 psig and 60 °F . 0.9245

Properties of Plus Fractions

Plus Fraction	Mol%	Wt%	Liquid Density (gm/cc)	Liquid API Gravity	MW
Heptanes plus	95.08	98.76	0.9296	20.6	280
Undecanes plus	62.69	85.10	0.9659	14.9	366
Pentadecanes plu:	44.37	73.82	0.9963	10.4	449
Eicosanes plus	30.94	62.18	1.0308	5.6	542
Pentacosanes plu:	21.35	51.48	1.0717	0.4	650
Triacosanes plus	15.58	43.49	1.1127	-4.5	753

Table A-2. Composition of Primary Stage Separator Liquid.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

WELLSTREAM RECOMBINATION CALCULATION
(based on field production data)

Conditions for Recombination Calculations

Primary Stage at 48 psig and 72 °F

Field Gas Rate Correction Factors -

Gas Gravity (air=1.000) ..... **
Gas Gravity Factor, Fg ..... **

Gas Deviation Factor, Z ..... **
Super Compressibility Factor, Fpv ..... **
Pressure Base, psia 14.730

Field Measured Rates and Ratios -

Primary Stage Gas Flow Rate, Mscf/D 34.00
Primary Stage Liquid Flow Rate, bbl/D 66.00
Primary Stage Gas / Oil Ratio, scf/S*bl 515.15

Recombination Rates and Ratios -

Primary Stage Gas Flow Rate, Mscf/D 34.00
Primary Stage Liquid Flow Rate, bbl/D 66.00
Primary Stage Gas / Oil Ratio, scf/bl 515.15

Laboratory Gas Rate Correction Factors -

Gas Gravity (air=1.000) 0.900
Gas Gravity Factor, Fg (not applied) 1.0542

Gas Deviation Factor*, Z 0.990
Supercompressibility Factor, Fpv (not applied) 1.0052
Pressure Base, psia 14.730

Laboratory Liquid Rate Correction Factors -

Liquid Volume Factor, S*bl/bl @ 60 °F ..... na
Bitumen, Sediment & Water (BS&W) Factor 1.000

Wellstream Recombination Ratio
mol/mol **1.1377**

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas), 1977, 8th Edition, Appendix II.

** Data not supplied to Core Laboratories

Table A-3. Wellstream Recombination Calculation.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

CALCULATED COMPOSITION OF WELLSTREAM

(from calculated recombination of separator products)

Component	Mol %	Wt%	Liquid Density (gm/cc)	MW
Hydrogen Sulfide	0.00	0.00		
Carbon Dioxide	14.44	4.54	0.8172	44.010
Nitrogen	0.01	0.00	0.8086	28.013
Methane	34.33	3.93	0.2997	16.043
Ethane	3.03	0.65	0.3562	30.070
Propane	0.43	0.14	0.5070	44.097
iso-Butane	0.61	0.25	0.5629	58.123
n-Butane	0.32	0.13	0.5840	58.123
iso-Pentane	0.49	0.25	0.6244	72.150
n-Pentane	0.31	0.16	0.6311	72.150
Hexanes	1.28	0.77	0.6850	84.0
Heptanes	3.69	2.53	0.7220	96.0
Octanes	4.70	3.59	0.7450	107
Nonanes	3.75	3.24	0.7640	121
Decanes	3.28	3.14	0.7780	134
Undecanes	2.54	2.67	0.7890	147
Dodecanes	2.25	2.59	0.8000	161
Tridecanes	2.10	2.62	0.8110	175
Tetradecanes	1.68	2.28	0.8220	190
Pentadecanes	1.48	2.18	0.8320	206
Hexadecanes	1.29	2.04	0.8390	222
Heptadecanes	1.21	2.05	0.8470	237
Octadecanes	1.28	2.29	0.8520	251
Nonadecanes	1.02	1.92	0.8570	263
Eicosanes	1.21	2.38	0.8620	275
Heneicosanes	0.87	1.81	0.8670	291
Docosanes	0.86	1.87	0.8720	305
Tricosanes	0.76	1.73	0.8770	318
Tetracosanes	0.79	1.87	0.8810	331
Pentacosanes	0.54	1.33	0.8850	345
Hexacosanes	0.51	1.31	0.8890	359
Heptacosanes	0.61	1.63	0.8930	374
Octacosanes	0.44	1.22	0.8960	388
Nonacosanes	0.60	1.72	0.8990	402
Triacosanes plus	7.29	39.17	1.1127	753
Totals	100.00	100.00		

RECOMBINATION CONDITIONS

48 psig
72 °F

Recombination Parameters

Primary Stage Gas / Oil Ratio, scf/bbl
at recombination conditions 515.15
Wellstream Recombination Ratio
moles gas / mole liquid 1.1377

Average Wellstream Properties

Average Molecular Weight 140.0
Calculated Density at 0 psig and 60 °F . 0.8383

Properties of Plus Fractions

Plus Fraction	Mol%	Wt%	Liquid Density (gm/cc)	Liquid API Gravity	MW
Heptanes plus	44.75	89.18	0.9291	20.7	279
Undecanes plus	29.33	76.68	0.9659	14.9	366
Pentadecanes plus	20.76	66.52	0.9963	10.4	449
Eicosanes plus	14.48	56.04	1.0308	5.6	542
Pentacosanes plus	9.99	46.38	1.0717	0.4	650
Triacosanes plus	7.29	39.17	1.1127	-4.5	753

Table A-4. Calculated Composition of Wellstream.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

COMPOSITION OF P_b ADJUSTED RESERVOIR FLUID*
(by Flash, Extended-Capillary Chromatography)

Component Name	Mol %	Wt %	Liquid Density (gm/cc)	MW					
Hydrogen Sulfide	0.00	0.00	0.8006	34.08	* Bubblepoint Adjusted to 930 psig at 108°F				
Carbon Dioxide	11.07	2.54	0.8172	44.01					
Nitrogen	0.00	0.00	0.8086	28.013					
Methane	16.17	1.35	0.2897	16.043					
Ethane	3.21	0.50	0.3562	30.07					
Propane	0.71	0.16	0.5070	44.097					
Iso-Butane	0.96	0.29	0.5629	58.123					
n-Butane	0.56	0.17	0.5840	58.123					
iso-Pentane	0.78	0.29	0.6244	72.15					
n-Pentane	0.48	0.18	0.6311	72.15					
Hexanes	1.59	0.70	0.6850	84	Total Sample Properties Molecular Weight ..... 192.04 Equivalent Liquid Density, gm/scc 0.8849				
Heptanes	5.80	2.90	0.7220	96					
Octanes	6.60	3.68	0.7450	107					
Nonanes	5.07	3.19	0.7640	121					
Decanes	4.53	3.16	0.7780	134					
Undecanes	3.46	2.65	0.7890	147					
Dodecanes	3.35	2.81	0.8000	161					
Tridecanes	3.19	2.91	0.8110	175					
Tetradecanes	2.58	2.55	0.8220	190					
Pentadecanes	2.28	2.45	0.8320	206					
Hexadecanes	1.90	2.20	0.8390	222					
Heptadecanes	1.83	2.26	0.8470	237					
Octadecanes	1.68	2.20	0.8520	251					
Nonadecanes	1.48	2.03	0.8570	263					
Eicosanes	1.47	2.10	0.8620	275					
Henelcosanes	1.22	1.84	0.8670	291					
Docosanes	1.21	1.92	0.8720	305					
Tricosanes	0.97	1.60	0.8770	318					
Tetracosanes	0.96	1.65	0.8810	331					
Pentacosanes	0.85	1.52	0.8850	345					
Hexacosanes	0.80	1.68	0.8890	359					
Heptacosanes	0.82	1.60	0.8930	374					
Octacosanes	0.79	1.59	0.8960	388					
Nonacosanes	0.89	1.86	0.8990	402					
Triacotanes plus	10.64	41.47	1.1074	748					
Totals	100.00	100.00							

Plus Fractions	Mol %	Wt %	Density	MW
Heptanes plus	64.47	93.82	0.9281	279
Undecanes plus	42.47	80.89	0.9641	366
Pentadecanes plus	29.89	69.97	0.9948	450
Eicosanes plus	20.72	58.83	1.0293	545
Pentacosanes plus	14.89	49.72	1.0648	641
Triacotanes plus	10.64	41.47	1.1074	748

Table A-5. Composition of P_b Adjusted Reservoir Fluid.

Chevron U.S.A. Production Company

Well 11-8D 32 Fee

RFL 990039

VOLUMETRIC DATA

(at 108 °F)

Saturation Pressure (P_{sat}) ..... 930 psig
 Density at P_{sat} ..... 0.8811 gm/cc
 Thermal Exp @ 5000 psig ..... 1.01954 V at 108 °F / V at 60 °F

AVERAGE SINGLE-PHASE COMPRESSIBILITIES

Pressure Range psig			Single-Phase Compressibility v/v/psi

5000	to	4500	4.64 E -6
4500	to	4000	4.73 E -6
4000	to	3500	4.84 E -6
3500	to	3000	4.96 E -6
3000	to	2500	5.11 E -6
2500	to	2000	5.30 E -6
2000	to	1500	5.56 E -6
1500	to	1000	5.92 E -6
1000	to	930	6.20 E -6

PRESSURE-VOLUME RELATIONS

(at 108 °F)

Pressure psig	Relative Volume (A)	Y-Function (B)	Density gm/cc

5000	0.9793		0.8997
4500	0.9816		0.8977
4000	0.9839		0.8955
3500	0.9863		0.8934
3000	0.9887		0.8912
2500	0.9912		0.8889
2000	0.9939		0.8865
1500	0.9966		0.8841
1400	0.9972		0.8836
1300	0.9978		0.8831
1200	0.9984		0.8825
1100	0.9990		0.8820
1000	0.9996		0.8815
b>930	1.0000		0.8811
929	1.0009	1.187	
928	1.0019	1.105	
927	1.0031	1.023	

(A) Relative Volume: V/V_{sat} or volume at indicated pressure per volume at saturation pressure.

(B) Where: Y: $\frac{(P_{sat} - P)}{(P_{abs}) * (V/V_{sat} - 1)}$

Table A-6. Pressure Volume Relations.

Figure A-1. Reservoir Fluid Viscosity from Well 11-8D.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

RESERVOIR FLUID SHRINKAGE ANALYSIS

Flash Conditions		Gas/Oil Ratio (scf/bbl) (A)	Gas/Oil Ratio (scf/STbbl) (B)	Stock Tank Oil Gravity at 60 °F (°API)	Liquid Shrinkage Factor (C)	Specific Gravity of Flashed Gas (Air=1.000)	Oil Phase Density (gm/cc)
psig	°F						
930	108						0.8811
0	68	214	214	21.7	.9064	1.056	0.9197
		Rsfb = 214					

(A) Cubic Feet of gas at 14.73 psia and 60 °F per barrel of oil at indicated pressure and temperature.

(B) Cubic Feet of gas at 14.73 psia and 60 °F per barrel of stock tank oil at 60 °F.

(C) Barrels of stock tank oil at 60 °F per barrel of oil at indicated pressure and temperature.

Table A-7. Reservoir Fluid Shrinkage Analysis.

Chevron U.S.A. Production Company

Well 11-8D 32 Fee

RFL 990039

INJECTION GAS / RESERVOIR FLUID EQUILIBRIUM

(Carbon Dioxide Added to Reservoir Fluid)

(at 108 °F)

**60 mole % Carbon Dioxide / 40 mole % Reservoir Fluid System
Equilibrated at 950 psig at 108°F**

Equilibrium Gas Phase:

57.26 volume % at 950 psig and 108°F

47.50 mole % at 950 psig and 108°F

0.1531 gm/cc at 950 psig and 108°F

0.680 Z-factor at 950 psig and 108°F

Equilibrium Liquid Phase:

42.74 volume % at 950 psig and 108°F

52.50 mole % at 950 psig and 108°F

0.8971 gm/cc at 950 psig and 108°F

Table A-8. Injection Gas / Reservoir Fluid Equilibrium.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

Composition of Equilibrium Gas Phase
(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	87.04		44.010	.8172
Nitrogen	0.02		28.013	.8086
Methane	10.45		16.043	.2997
Ethane	1.76	.470	30.070	.3562
Propane	0.17	.047	44.097	.5070
iso-Butane	0.16	.052	58.123	.5629
n-Butane	0.07	.022	58.123	.5840
iso-Pentane	0.06	.022	72.150	.6244
n-Pentane	0.03	.011	72.150	.6311
Hexanes	0.06	.023	84.000	.6850
Heptanes	0.10	.042	96.000	.7220
Octanes	0.05	.023	107.00	.7450
Nonanes	0.02	.010	121.00	.7640
Decanes	0.01	.005	134.00	.7780
Undecanes	Trace			
Dodecanes plus	Trace			
Totals	100.00	0.727		

Sampling Conditions

950 psig
108 °F

Sample Characteristics

Core Lab sample number 207

Critical Pressure (psia)	1018.2
Critical Temperature (°R)	528.4
Average Molecular Weight	41.03
Calculated Gas Gravity (air = 1.000)	1.417
Gas Gravity	
Factor, Fg	.8402
Super Compressibility Factor, Fpv	
at sampling conditions	1.2035
Gas Z-Factor	
at sampling conditions *	0.690

at 14.73 psia and 60 °F

Heating Value, Btu/scf dry gas	
Gross	165

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	0.18	103.9	0.737	60.3
Decanes plus	0.01	134.0	0.786	48.3

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas), 1977, 8th Edition, Appendix II.

Table A-9. Composition of Equilibrium Gas Phase.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

Composition of Equilibrium Liquid Phase
(by Flash/Extended Chromatography)

Component Name	Mol %	Wt %	Density (gm/cc)	MW
Hydrogen Sulfide	0.00	0.00	0.8006	34.08
Carbon Dioxide	44.53	12.54	0.8172	44.01
Nitrogen	0.00	0.00	0.8086	28.013
Methane	2.40	0.25	0.2997	16.043
Ethane	1.36	0.26	0.3562	30.07
Propane	0.31	0.09	0.5070	44.097
iso-Butane	0.52	0.19	0.5629	58.123
n-Butane	0.33	0.12	0.5840	58.123
iso-Pentane	0.47	0.22	0.6244	72.15
n-Pentane	0.32	0.15	0.6311	72.15
Hexanes	1.04	0.56	0.6850	84
Heptanes	3.69	2.39	0.7220	96
Octanes	4.45	3.05	0.7450	107
Nonanes	3.46	2.68	0.7640	121
Decanes	3.13	2.68	0.7780	134
Undecanes	2.50	2.35	0.7890	147
Dodecanes	2.29	2.36	0.8000	161
Tridecanes	2.29	2.57	0.8110	175
Tetradecanes	1.89	2.30	0.8220	190
Pentadecanes	1.71	2.26	0.8320	206
Hexadecanes	1.40	1.98	0.8390	222
Heptadecanes	1.23	1.87	0.8470	237
Octadecanes	1.16	1.86	0.8520	251
Nonadecanes	1.09	1.84	0.8570	263
Eicosanes	1.04	1.83	0.8620	275
Heneicosanes	0.97	1.80	0.8670	291
Docosanes	0.76	1.48	0.8720	305
Tricosanes	0.79	1.61	0.8770	318
Tetracosanes	0.59	1.26	0.8810	331
Pentacosanes	0.73	1.60	0.8850	345
Hexacosanes	0.52	1.19	0.8890	359
Heptacosanes	0.56	1.34	0.8930	374
Octacosanes	0.62	1.55	0.8960	388
Nonacosanes	0.55	1.42	0.8990	402
Triacosanes plus	11.10	40.35	1.0762	568
Totals	100.00	100.00		

Sampling Conditions

950 psig
108 °F

Total Sample Properties

Molecular Weight 156.27
Theoretical Liquid Density, gm/scc 0.8968

Plus Fractions	Mol %	Wt %	Density	MW
Hexanes plus	49.76	86.18	0.9238	271
Heptanes plus	48.72	85.62	0.9259	275
Decanes plus	36.92	77.50	0.9502	328
Pentadecanes plus	24.82	65.24	0.9851	411
Eicosanes plus	18.23	55.43	1.0150	475
Pentacosanes plus	14.08	47.45	1.0440	527
Triacosanes plus	11.10	40.35	1.0762	568

Table A-10. Composition of Equilibrium Liquid Phase.

Figure A-2. Viscosity of Equilibrium Liquid Phase or CO₂ Swollen Reservoir Fluid.

Figure A-3. Summary of Packed Column Displacement Tests.

Chevron U.S.A. Production Company
Well 11-8D 32 Fee
RFL 990039

Asphaltene Flocculation Experiment - NIR Scans
(From Near Infrared Spectroscopy Technique)
(at 108°F)

No Onset Detected

Figure A-4. Asphaltene Experiment

Figure A-5. Viscosity Comparison of Original Reservoir Fluid and CO₂ Swollen Fluid.

APPENDIX B

AVERAGE RESERVOIR PROPERTIES

Table B-1. Average Reservoir Properties for Lost Hills CO₂ Pilot.

Geologic Marker	Depth To Top		Average								
	VSS	Measured	Pressure (psig)	t (°F)	μ _o cp	h (ft)	k (md)	φ (%)	S _o (%)	S _w (%)	S _g (%)
C Pt.	837	1233	149	97	18.6	139	1.16	43.7	33.4	61.6	5.0
D Pt.	976	1372	234	100	17.1	61	1.44	43.7	41.5	53.4	5.1
DD Pt.	1037	1433	280	101	16.1	79	1.44	52.8	42.2	52.7	5.1
E Pt.	1116	1512	347	102	15.6	48	1.22	51.8	40.3	54.4	5.3
EE Pt.	1164	1560	393	103	14.9	81	1.22	42.8	43.0	51.7	5.3
F Pt.	1245	1641	479	105	14.4	25	0.71	55.0	47.4	47.5	5.1
FF Pt.	1270	1666	507	105	13.5	33	0.71	46.9	45.2	49.7	5.1
G Pt.	1303	1699	547	106	13.2	80	0.47	51.8	46.1	49.0	4.9
GG Pt.	1383	1779	651	107	12.9	62	0.47	60.0	60.9	34.2	4.9
H Pt.	1445	1841	741	108	11.9	46	0.45	53.1	57.9	38.8	3.3
BH Pt.	1491	1887	812	109	11.2	77	0.45	52.2	47.8	48.9	3.3
J Pt.	1568	1964	941	110	10.7	54	0.28	60.0	62.0	37.2	0.8
K Pt.	1622	2018	1039	111	9.8	130	0.29	56.6	55.9	43.6	0.5
L Pt.	1752	2148	1303	114	9.1	100	0.29	51.0	41.1	58.4	0.5
Average	1301	1697	622	106	13.5	73	0.64	51.0	46.4	50.0	3.6
Total						1015					

Figure B-1. Average RFT Pressure Data for Lost Hills CO₂ Pilot.

APPENDIX C

REVISED DOE SPENDING PLAN

Table C-1. CO₂ Pilot Cost Summary Spreadsheet

**Lost Hills DOE Project
Project Tasks and Budget**

Task Number and Name	Resources	Original Pilot Budget (12/98)	Revised Pilot Budget (10/99)	DOE SHARE (Note 1)	CHEVRON SHARE
A. Project Management, Reporting, & Technology Transfer					
A.1. Technology transfer throughout project (including Website)	CUSA/CPTC	\$ 45,000	\$ 40,000	\$ 20,000	\$ 20,000
A.2. DOE reporting throughout project	CUSA	\$ 10,000	\$ 10,000	\$ 5,000	\$ 5,000
A.3. Project management throughout project	CUSA	\$ 45,000	\$ -	\$ -	\$ -
Subtotal for A:		\$ 100,000	\$ 60,000	\$ 25,000	\$ 25,000
B. Prepare Proposal for DOE Phase II Funding - complete	CUSA	\$ -	\$ -	\$ -	\$ -
Subtotal for B:		\$ -	\$ -	\$ -	\$ -
C. Injectivity Testing (Wells 12-8D & 12-7W) - complete					
C.1. Complete Injectivity Well 12-8D	Complete				
C.2. Conduct Injectivity Test	CUSA				
C.3. Injectivity Test Evaluation/Report	CPTC				
C.4. Oil Geochemistry - Asphaltene Propensity	CPTC				
C.5. Revise/update simulation model with new data		Inject. Test Total Shown at bottom of page			
Subtotal for C:					
D. Preliminary Facility Design (Complete)	CUSA/TJ Cross	\$ -	\$ -	\$ -	\$ -
D.1. Generate & evaluate alternative pilot designs		\$ 10,000	\$ -	\$ -	\$ -
D.2. Draft process design		\$ -	\$ -	\$ -	\$ -
D.3. Review of Injectivity & Prelim. Design results w/Sponsors		\$ 20,000	\$ -	\$ -	\$ -
D.4. Finalize process design		\$ 10,000	\$ -	\$ -	\$ -
D.5. Prepare APCD permit application		\$ 5,000	\$ -	\$ -	\$ -
D.6. APCD permitting		\$ 5,000	\$ -	\$ -	\$ -
D.7. Set up pilot design team		\$ 100,000	\$ -	\$ -	\$ -
D.8. Prepare P&ID's and equipment specs		\$ 150,000	\$ -	\$ -	\$ -
Subtotal for D:		\$ 205,000	\$ -	\$ -	\$ -
E. Detailed Design Review	CUSA	\$ 5,000	\$ -	\$ -	\$ -
Subtotal for E:		\$ 5,000	\$ -	\$ -	\$ -
F. Detailed Facility Design & Equipment Purchases	CUSA/TJ Cross				
F.1. Long lead materials		\$ 1,200,000	\$ -	\$ -	\$ -
F.2. Detailed design - CO ₂ Injection Facilities		\$ 400,000	\$ 35,000	\$ 17,500	\$ 17,500
F.3. Detailed Design - Production & Gauging Facilities		\$ 120,000	\$ 45,000	\$ 22,500	\$ 22,500
Subtotal for F:		\$ 1,720,000	\$ 80,000	\$ 40,000	\$ 40,000
G. Implement Well Work	CUSA/Schlumberger				
G.1. Remediate 4 Injectors (Replaces "Drill Producers")		\$ 1,800,000	\$ 280,000	\$ 140,000	\$ 140,000
G.2. Drill & log pilot Injectors (4)		\$ 800,000	\$ 1,200,000	\$ 600,000	\$ 600,000
G.3. Drill, Log (including CTO for Baseline) 3 observation wells		\$ 140,000	\$ 400,000	\$ 200,000	\$ 200,000
Subtotal for G:		\$ 2,740,000	\$ 1,880,000	\$ 940,000	\$ 940,000
H. Construction of Facilities	J. E. Merit				
H.1. Install Well Gauging Facilities & CVR System - 75% Chevron		\$ 215,000	\$ 825,000	\$ 206,250	\$ 818,750
H.2. Install Remote Compression and Dehydration Facilities		\$ 750,000	\$ -	\$ -	\$ -
H.3. Install CO ₂ Injection Flowlines (includes infrastructure such as roads for CO ₂ trucks) - 75% Chevron		\$ 820,000	\$ 614,250	\$ 153,562.50	\$ 460,688
H.4. Install CO ₂ Injection Facilities (includes cost of removal and cancellation)		\$ 2,500,000	\$ 243,500	\$ 121,750	\$ 121,750
H.5. Safety Walkthrough & Punchlist		\$ 10,000	\$ -	\$ -	\$ -
Subtotal for H:		\$ 4,295,000	\$ 1,682,750	\$ 461,663	\$ 1,201,188

Table C-1. CO₂ Pilot Cost Summary Spreadsheet (continued)

**Lost Hills DOE Project
Project Tasks and Budget**

Task Number and Name	Resources	Original Pilot Budget (12/98)	Revised Pilot Budget (10/99)	DOE SHARE (Note 1)	CHEVRON SHARE
I. Pilot Start-up Activities	CUSA				
I.1. Start up production facilities		\$ 5,000	\$ -	\$ -	\$ -
I.2. Start-up CO ₂ Injection Facilities		\$ 25,000	\$ -	\$ -	\$ -
I.3. Initiate CO ₂ Injection with Permanent Supply		\$ 10,000	\$ -	\$ -	\$ -
Subtotal for I:		\$ 40,000	\$ -	\$ -	\$ -
J. Pilot Monitoring	CUSA				
Injector profiles		\$ 72,000	\$30,000	\$ 15,000	\$ 15,000
Cased-hole resistivity logging and analysis		\$ 60,000	\$20,000	\$ 10,000	\$ 10,000
Gas composition analysis		\$ 18,000	\$120,000	\$ 60,000	\$ 60,000
Interwell tracers (inject in injectors, sample producers)		\$ 48,000	\$40,000	\$ 20,000	\$ 20,000
Tiltmeter surveys		\$ 102,000	\$56,000	\$ 28,000	\$ 28,000
EM Survey		\$ 48,000	\$50,000	\$ 25,000	\$ 25,000
Cross-well seismic survey (LBL to Fund)			\$25,000	\$ 12,500	\$ 12,500
Static pressure surveys			\$12,000	\$ 6,000	\$ 6,000
Gas composition analysis			\$12,000	\$ 6,000	\$ 6,000
PVT Reservoir Fluid Sample and Analysis		\$ 120,000	\$15,000	\$ 7,500	\$ 7,500
Static pressure surveys		\$ 24,000	\$12,000	\$ 6,000	\$ 6,000
Corrosion coupons and probes		\$ -	\$38,000	\$ 18,000	\$ 18,000
Subtotal for J:		\$ 492,000	\$ 428,000	\$ 214,000	\$ 214,000
Pilot CAPEX Total:		\$ 9,542,000	\$ 4,120,750	\$ 1,700,563	\$ 2,420,188
Additional Funding for Design/Scoping of Long Term CO ₂ Supply:			\$ 250,000		\$ 250,000
CAPEX Total Including CO ₂ Project Scoping & Planning			\$ 4,370,750	\$ 1,700,563	\$ 2,670,188
K. CO₂ Injection Equipment & Purchases (MEJ: Expense Items)					
K.1 Rental of CO ₂ Injection Equipment & Start-up assistance	BOC or Air Liquide		\$ 277,000	\$ 138,500	\$ 138,500
K.2 Liquid CO ₂ Purchases (@ 1 MMscfd Injection rate) - Note 3			\$ 2,555,000	\$ 620,000	\$ 1,935,000
Expense Total:			\$ 2,832,000	\$ 758,500	\$ 2,073,500
Project Total Capital + Expense for 2 Years (\$)		\$ 9,542,000	\$ 6,952,750	\$ 2,459,063	\$ 4,743,688
DOE Expenditure Summary:					
Expenditures for Injectivity Test and Pilot Design (as of 10/1/99):			\$ 646,000	\$ 150,000	\$ 496,000
Carry In from "DOE Phase I":				\$ 97,896	
Original Phase II DOE Funding:				\$ 2,515,408	
Available Phase II DOE Funding (= Phase I Carry In + Phase II Funding):				\$ 2,613,302	
Projected Phase II DOE Expenditures				\$ 2,609,063	
Chevron Expenditure Summary:					
Chevron Capital Funding Requested for Pilot					\$ 2,670,188
Total Chevron Expense Funding Requested					\$ 2,073,500
Total New Chevron Funding (Capital + Expense) Requested					\$ 4,743,688
Total Phase II Expenditures (Including Injectivity Test)					\$ 5,424,688

Note 1: Task Costs to be split 50/50 unless noted otherwise

Note 2: Charge codes for each task will be provided at a later date

Note 3: CAPEX for wells may be less - In which case DOE funding would be used to purchase CO₂ (pending DOE approval)