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Design and Implementation of a CO₂ Flood Utilizing Advanced Reservoir Characterization and
Horizontal Injection Wells In a Shallow Shelf Carbonate Approaching Waterflood Depletion

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ABSTRACT

Work reported in this document covers tasks in Budget Phase II. The principle task in Budget Phase II is Field Demonstration.

Since starting carbon dioxide (CO₂) injection in July 1996, several operationally related issues emerged within this reporting period. These include out of zone CO₂ injection, conformance methods, high reservoir pressure, and lack of injectivity and productivity.

Interference tests were conducted between Well Nos. 6-28, 7C-11H and 2-26 after evidence of high connectivity between 6-28 and an "unknown" CO₂ injector, thought to be either 7C-11H or 2-26. An initial test in October 1997 suggested Well Nos. 6-28 and 2-26 were in communication through a fracture system. A subsequent test in June 1998 suggested this communication was not as apparent.

Reservoir pressure is deemed to be too high. Off lease/reservoir disposal options were identified to lower voidage replacement and reservoir pressure. Deepening of Well No. 2-18 to dispose of produced water in Canyon/Clearfork intervals was identified as the optimum method. This well was deepened August 1998 and has averaged 1793 barrels of water per day (BW/D) injection.

Performance monitoring to-date has identified the majority of producing wells are underperforming their anticipated withdrawal rates. Although acid stimulations during 1997 improved productivity, they were somewhat short lived. A longer-term solution was needed; individual-well designed chemical treatments to remove scale/asphaltenes/paraffins have proven very successful in improving withdrawal rates. If continued treatments are successful, they will be a more cost effective and long-term method to ensure withdrawal rates are maintained.

Other methods for improving withdrawal are being evaluated. The newest of which was the use of horizontal lateral jetting technology. Three wells 1-07, 6-23 and 7-13 were used to test this new technology in October 1998. Currently the technology is still under evaluation and we await further technological improvements before further use is made.

Other alternatives for improving injection/productivity are being evaluated. Use of deeper penetrating perforating techniques, lanced perforating and short radius drilling are being considered.

EXECUTIVE SUMMARY

In June of 1994, Phillips Petroleum Company received a financial award from the Department of Energy (DOE) to conduct a project in the South Cowden Unit (SCU) in Ector County, Texas. The project purpose is to design an optimum carbon dioxide (CO₂) flood project utilizing advanced reservoir characterization and CO₂ horizontal injection wells, demonstrate the performance of this project in the field and transfer the information to the public so it can be used to avoid premature abandonment of other fields.

The producibility problem in the unit is that it is a mature waterflood with a water cut exceeding 95%. Oil must be mobilized through the use of a miscible or near-miscible fluid in order to recover significant additional reserves. Also, because the unit is relatively small, it does not have the benefit of economies of scale inherent in the very large-scale projects, which have historically produced most of the CO₂ project oil. Thus, new and innovative methods are required to reduce the investment and operating costs.

Two primary methods to be used in this work to accomplish improved economics are the use of reservoir characterization to restrict the flood to the high quality rock in the unit and the use of horizontal injection wells to cut investment and operating costs through centralization.

The project consists of two budget phases. Budget Phase I started in June 1994 and ended late June 1996. During this phase the Reservoir Analysis and Characterization Task and the Advanced Technology Definition Task were completed. Completion of these tasks enabled the project to be designed, evaluated, and an Authority for Expenditure (AFE) for project implementation to be generated and submitted to the working interest owners for approval. Budget Phase II consists of the implementation and execution of the project in the field. Phase II will terminate in January of 2001.

Budget Phase II commenced with the drilling of the third reservoir characterization well (RC-3) during November and December, 1995. Two vertical CO₂ water alternating gas (WAG) injection wells were drilled in December 1995. Two horizontal CO₂ WAG injection wells were drilled and completed during March and April, 1996. These wells were designed to mechanically optimize well injection performance and useful well life. Two additional production wells were also drilled and completed in late 1995. These wells were needed to drain areas of the field offsetting the proposed horizontal injection wells, replacing old wells that had been previously plugged and abandoned.

Additional early Phase II work commenced during the first half of 1996 included petrographic core studies on specific cores obtained during the drilling of the third Reservoir Characterization Well (RC-3).

Phase II work continued with initiation of CO₂ injection in the two vertical WAG injection wells during July 1996, and the two horizontal WAG injection wells in August 1996, at a rate of approximately 8.0 million standard cubic feet per day (MMscfd) within the SCU

project area. Three additional lease line WAG injection wells were drilled and completed along the north boundary with the Emmons Unit. Injection profile problems were identified during early 1997 in two of these wells. Subsequent foamed cement isolation techniques during 1997 reduced out-of zone injection in these wells.

Two additional production wells, 7-13 and 7-15, were drilled during 1996. The first as a replacement well and the second to tighten well spacing in an important area of the Unit. An additional replacement Well No. 6-29 was drilled in September 1997, to replace Well No. 6-01, which had irreparable casing damage. Two shut in producing wells, 6-18 and 8-03, were converted to water injection during third quarter 1997. Three wells, 2-16W, 6-01 and 6-12, were plugged and abandoned due to regulatory requirements associated with bad casing.

Interference tests between wells 7C-11H, 6-28 and 2-26 during October 1997 indicated over communication, due to fracturing, between wells 6-28 and 2-26. A subsequent test during June 1998 indicated little or no communication between these wells.

Performance monitoring to-date identified the majority of producing wells are underperforming their anticipated withdrawal rates. Although acid stimulations during 1997 improved productivity, they were somewhat short lived. A longer-term solution was needed, individually-well designed chemical treatments to remove scale, asphaltines, and paraffins have proven successful.

High reservoir pressure is a concern for the project as it has limited CO₂ injectivity. To lower reservoir pressure, improving withdrawal rates has become of utmost priority with various solutions currently being evaluated: chemical treatments, perforations, stimulation and horizontal lateral technology. To reduce voidage replacement water production will require off lease, or, off reservoir disposal to reduce average reservoir pressure. Well 2-18 was drilled as a water disposal well by deepening to the Canyon and/or Clearfork intervals and has averaged 1793 barrels of water per day (BW/D) to-date..

CO₂ injection pressures were cut back in late 1997 to reduce pressures below fracture initiation pressure. It was believed significant out of zone injection was caused by the initial overpressuring during the early months of injection. Technologies are currently being evaluated to ensure both in-zone injection and improvement of injectivity to ensure CO₂ volumes are being efficiently utilised.

Cumulative CO₂ injected as of June 1999, is estimated at 6,961,811 thousand standard cubic feet (Mscf) CO₂. The average daily CO₂ injection rate during June 1999 was 4.7 MMscf CO₂ per day.

INTRODUCTION

Summary of Project Objectives

The principal objective of this project is to demonstrate the economic viability and widespread applicability of an innovative reservoir management and carbon dioxide (CO₂) flood project development approach for improving CO₂ flood project economics in shallow shelf carbonate (SSC) reservoirs.

Most of the incremental tertiary oil production from CO₂ projects in SSC reservoirs to date has come from a few, very large-scale projects where the sizable economies of scale inherent in this type of development can greatly improve project economics. In fact, the five largest CO₂ miscible flood projects implemented in SSC reservoirs account for over one-half of the total incremental oil production attributable to CO₂ miscible flooding in 1992 in the United States.

This project shall demonstrate the economic viability of the advanced technology of developing a CO₂ flood project utilizing multiple horizontal CO₂ injection wells drilled in several directions from a central location. The use of several horizontal injection wells drilled from a centralized location will reduce the number and cost of new injection wells, wellheads, and equipment; allow concentration of the surface reinjection facilities; and minimize the costs associated with CO₂ distribution system. It is anticipated that the proposed advanced technology will show improved CO₂ sweep efficiency and will significantly reduce the capital investment required to implement a CO₂ tertiary recovery project relative to conventional CO₂ flood pattern developments using vertical injection wells. This technology will be readily transferred to the domestic oil industry and should introduce CO₂ flooding as an economically viable technology option for smaller SSC reservoirs and for independent operators.

Summary of Field Details

The South Cowden Unit (SCU) is located in Ector County, Texas and produces primarily from the Grayburg and San Andres Formations of Permian Age. These formations were deposited in shallow carbonate shelf environments along the eastern margin of the Central Basin Platform. The primary target for CO₂ flood development under the proposed project is a 150-200 foot gross interval within the San Andres located at an average depth of approximately 4550 feet. The original oil in place (OOIP) for the South Cowden Unit is estimated to be less than 180 million barrels. The field was discovered in 1940 and unitized for secondary recovery operations beginning in 1965.

After approximately 36 months of CO₂ injection, the Unit is producing 455 barrels of oil per day (BOPD) with a water cut in excess of 93% from 49 active producers and 16 active injectors. For June 1999, the continued water injection prediction for oil rate, if no further

development had occurred at South Cowden, was 225 BOPD. Approximately 230 BOPD of incremental production is deemed to be a result of the implementation of the additional South Cowden development. Ultimate recovery for primary plus secondary is estimated at just over 35 million stock-tank barrels of oil (STBO), or approximately 20 percent of original oil in place (OOIP). Tertiary oil resulting from the CO₂ project is estimated at 12 million stock-tank barrels (STB), or 8% within the project area.

Project Description

The purpose of this project is to demonstrate the economic viability and widespread applicability of an innovative management plan for a CO₂ flood project, utilizing advanced reservoir characterization and CO₂ horizontal injection wells. The South Cowden Unit (SCU) is an example of a very mature waterflood, rapidly approaching its economic limit. Past waterflood performance was considered good; however, field average water cut at the project start-up exceeded 95 percent, leaving tertiary recovery as the only remaining prospect for extending the field life and recovering the remaining oil. Advanced reservoir characterization has been used to define the best areas within the field, which are likely to perform well under CO₂ operations.

Standard methods of CO₂ flooding are not viable under the current oil price scenario due to the limited aerial extent of SCU. Standard methods include the traditional fully-confined nine- or five-spot patterns. In the case of SCU, a feasibility study was completed in which the field was CO₂ flooded with 20-acre five-spots (assumed because of the existing well configuration). The feasibility study indicated that South Cowden Unit was an excellent technical CO₂ flood candidate; however, the large capital investment required restricted its economic viability. New and innovative methods were required to reduce the overall investment required to improve the economic viability. These new methods, however, carried additional risk.

The innovative approach chosen for the study was to CO₂ flood the South Cowden Unit with multiple horizontal injection wells from a centralized location. Preliminary studies indicated that significant investment cost reduction could be realized through lower overall drilling costs (fewer wells) and reduced surface injection line requirements, and operating costs reductions could be obtained through a reduction in re-injection costs. Improved sweep efficiency from the horizontal injection wells are expected to result in increased oil recoveries. Increased technical risks inherent in the project include the injection distribution along the horizontal section of the horizontal well and overall vertical coverage within the given horizontal well. Contingency plans for dealing with the technical risks were also developed. Advanced reservoir characterization has been essential in optimizing the final project design. At the conclusion of the project, a complete methodology for economical tertiary flooding of small SSC reservoirs will be established, allowing other operators to implement similar strategies for their own fields.

Summary of Progress

A CO₂ flood project for the South Cowden Unit (SCU) has been designed, evaluated, proposed to the working interest owners, approved for field implementation and fully implemented. Full-field implementation of the CO₂ project was completed in mid-July, 1996, with the initiation of CO₂ injection in the two vertical injectors.

Work on the project was initiated in June of 1994 with the Reservoir Analysis and Characterization Task, which were used to develop a three-dimensional (3-D) geologic reservoir description. An adequate reservoir description was assembled in early 1995 to initiate simulation studies for project design and performance forecasting.

The second major step in the process was defining the Advanced Technology Definition Task. This task was divided into seven subtasks, including Special Laboratory Studies; Screening Studies to Identify Suitable Gelled Polymers for Profile Modification; Advanced Geostatistical Studies; Reservoir Simulation for Project Design and Performance Forecasting; Design of the Horizontal Well Scheme and the Final Project Development Plan; Design of Upgrades and/or Additions to Production, Water Injection, CO₂ Injection, Compression, Water Disposal, Automation, Electrical and Cathodic Protection Facilities; and Investment Cost Forecast, Operating Cost Forecast and generation of the Authority for Expenditure (AFE). This AFE was approved and field implementation of the project (Budget Phase II) began in late October of 1995. From late October, 1995, through June 30, 1996, work included in Budget Phase I was being finished-up while implementation work included in Budget Phase II was being done.

Work on Budget Phase II was defined into two tasks: Field Demonstration and Technology Transfer, Reporting, and Project Management Activities for Budget Phase II. Field Demonstration during the current reporting period encompasses the project implementation subtasks, including injection testing and injection initiation in horizontal injection Wells Nos. 6C-11H and 7C-11H along with vertical injection Wells Nos. 2-26W and 2-27W; the drilling and testing of three additional lease line WAG injection wells and two production wells; the conversion of three wells for water injection; the reactivation of seven shut-in wells for production; the remediation of six existing production wells; the purchase of CO₂; the operation of the recycle compression and injection facilities; and the monitoring of project performance. Technology transfer, reporting and project management related to Budget Phase II primarily include the media opportunities related to the project start-up celebration, preparation of technical papers, and participation in industry events and the 1997 Department of Energy (DOE) project review.

Monitoring of project performance to date has revealed several concerns, which are currently being addressed. The main concern being the lack of productivity from wells. This appears to be caused by a combination of scale/asphaltine/paraffin build up in wells. Cleanouts and acid stimulations during 1997 proved moderately successful in treating this problem, but did not provide a long term solution. More success has been achieved with a

chemical treatment programme specifically designed for each well after analysis of fluids and solids being produced at surface. These “designer” chemical treatments have proven successful on all wells treated.

Monitoring of CO₂ response to date suggests areas where high CO₂ injectivity, which is in-zone, are providing the best response from surrounding producing wells. Other areas of the field are currently suffering from poor injectivity due to high reservoir pressure and potentially large out of zone CO₂ injection. The immediate forward management plan for South Cowden is to improve these problems with some innovative and cost effective technologies.

DISCUSSION

Background Information

Budget Phase Two consists of Tasks V-VI as defined in the Revised Statement of Work (RSOW). The RSOW contains fourteen primary subtasks in Task V, some of which were initiated in the past reporting period, and some of which will be reported on in this annual report. Task VI contains six primary subtasks, including Technology Transfer, Reporting, and Project Management Activities related to Budget Phase Two.

PHASE II

TASK V FIELD DEMONSTRATION

Reduce Reservoir Pressure (not included in DOE funding)

Subtask V.1.9 of the Revised Statement of Work included funds for the deepening of water injection wells inside the Unit boundary, to the lower San Andres, to handle increased water injection capacity. This subtask, however, was specifically excluded from Department of Energy (DOE) funding.

South Cowden Well No. 2-18 was scheduled to be deepened and completed in the Canyon and potentially the Clearfork intervals for use as a water disposal well. This well was successfully deepened to the Lower Clearfork interval between August 15 and September 9, 1998 and then perforated and acidized in the Canyon/Cisco and Lower Clearfork intervals on September 14.

Initial injection rates were 2600 barrels of water per day (bw/d) at 640 pounds per square inch gauged (psig) surface injection pressure. Average injection rate and pressure, for the reporting period, were 1793 bw/d and 651 psig. Figure 1 shows historical injection rates and surface pressures for this well.

Increase Throughput

The main concern at South Cowden is the lack of productivity from wells. The lack of withdrawal rates from producing wells has reduced throughput throughout the reservoir, increasing average reservoir pressure and limiting carbon dioxide (CO₂) injection.

Lack of productivity is caused, in the majority of wells, by an increase in effective skin factor due to build up of scale and heavy end hydrocarbons in the wellbore. A sampling, analysis and chemical treatment was undertaken in producing wells to improve productivity. This commenced in March 1998 with wells 2-25 and 7-08, followed by treatments in June and early July in wells 2-02, 6-17, 7-01, 7-02, and 7-09. All wells improved producing rate, with an average rate increase for the seven wells of 92%. All

seven wells have reached there "target" liquid rate, which are rates we would expect with no significant skin damage.

Wells 2-01, 2-17, 2-22, 6-14, 8-02 and 8-19 were treated between July 15 and 20. Of these six wells, five wells responded to the treatment and four wells reached their target rate.

Wells 5-07, 6-02, 6-19, 6-20, 6-24, 7-15 and 8-13 were scheduled for treatment before the end of July 1998. The two wells treated showed response to treatment and reached their target rate. The other five wells were not treated as improvements in off-take rate were observed, and no treatment was deemed necessary. From these early successes continued chemical treatments have occurred throughout the year.

Well No. 6-29 was scheduled to add perforations in the zone of interest, followed by a stimulation during July 1998, to improve throughput in the area south of well 6-28. This was successfully undertaken on July 23. The perforations and acid stimulation increased the off-take rate from 17 to 120 barrels of fluid per day (bf/d)

Another method of improving productivity emerged during 1998. New technology to create lateral boreholes in existing wellbores using coiled tubing and jetting technology has been developed. Three producing wells (1-07, 6-23 and 7-13) were jetted during October 1998. Productivity improvements from these wells were closely monitored. The technology is still under evaluation and we await improvements from the companies developing the technology is used on other wells.

We are currently looking at alternatives for re-stimulation that can improve injectivity/productivity without the use of stimulation above fracture pressures. These include: (1) use of Halliburton's Stimtube/Stingun/Powerperf technology followed by matrix acid stimulation, (2) lanced perforating and (3) use of short radius drilling. A candidate well No. 6-24 was initially identified to attempt to quantify re-stimulation techniques and their effect on injectivity/productivity. Due to the high pressures at the well, however, it would prove to be too expensive to work on this well to attempt to use these technologies. Wells 6-23 or 6-29 are currently being looked as alternative candidates.

Core samples from 6-24, from various zones in the San Andres, were tested for acid solubility and reaction time at various temperatures. This revealed carbonate intervals with high anhydrite content or intervals with high clastic content tended to have slow reaction times when compared to low anhydrite carbonates. For example, upper layers in the E zone (high anhydrite content) and the interval between the C and D zones (high clastic content) had lower reaction time when compared to the low anhydrite content C zone. Sensitivities to acid treatment temperature revealed reaction times for high anhydrite content intervals could be improved by raising treatment temperature, whereas low

anhydrite or high clastic content intervals reaction time was not effected by treatment temperature. The results of these lab tests are important for two reasons.

- 1) Any acid stimulation performed above fracture pressure, which would allow communication to low anhydrite content intervals, will preferentially react with those low anhydrite intervals. Therefore, any acid stimulation performed on an interval perforated in the target E zone, which had to be performed above fracture pressure, would allow open communication to lower intervals. Most noticeably this would be in the high permeability (low anhydrite) grainstone interval, which is normally below the oil water contact.
- 2) To improve acid reaction times and solubility of the rock where there is a higher anhydrite content it can be heated at surface.

In addition to the stimulation techniques described above, costs estimates are being prepared to drill short radius wells from existing wellbores. A service company from Houston has been contacted to perform this service.

Injectivity and Out Of Zone Injection

Surface injection pressures were maintained below reservoir fracture pressures throughout the year.

Injection profile surveys in vertical injection wells indicated significant out of zone injection into the highly transmissible, and water wet, "A" zone or "Grainstone", the lowest zone in the reservoir. Injecting above fracture pressures initiated fracturing downward into the Grainstone, causing CO₂ wastage.

Surface pressures for water injection wells were therefore limited to 650 psig, and CO₂ injection wells to 1150 psig, to ensure injection below fracture pressures, starting in late 1997.

Injected volumes and surface pressures were closely monitored to observe injectivity. The table below summarizes some of the individual CO₂ well injection rates.

Individual CO2 Injection Rates

	SCU 6C27	SCU 6C26	SCU 2C26	SCU 2C27	SCU 6C-25H	SCU 7C-11H
	<u>Rate Mcf/D</u>	<u>Rate Mcf/D</u>	<u>Rate Mcf/D</u>	<u>Rate Mcf/D</u>	<u>Rate Mcf/D</u>	<u>Rate Mcf/D</u>
Sep-97	19	793	727	294	2,718	686
Oct-97	999	896	935	387	3,495	2,797
Nov-97	986	874	946	554	3,457	3,452
Dec-97	482	441	481	184	2,148	1,690

Jan-98	136	397	290	1	1,312	1,116
Feb-98	85	621	354	0	1,113	1,140
Mar-98	33	631	316	0	1,010	1,190
Apr-98	20	1,059	523	5	2,347	2,319
May-98	1	466	157	1	2,476	2,431
Jun-98	0	490	143	0	2,547	2,401
Jul-98	22	409	476	303	3,542	1,766
Aug-98	45	0	565	351	3,790	1,920
Sep-98	80	0	625	458	3,768	1,971
Oct-98	86	350	656	434	3,692	2,224
Nov-98	134	581	1,057	0	3,686	2,437
Dec-98	15	377	229	0	2,543	1,502
Jan-99	1	206	102	0	2,536	1,451
Feb-99	5	209	94	0	2,525	1,455
Mar-99	23	209	329	203	2,518	1,106
Apr-99	23	212	390	111	2,568	1,082
May-99	22	226	196	2	2,565	1,045
Jun-99	0	235	13	36	3,271	1,140

Actual injection rates have therefore reduced since limiting surface pressures, most noticeably in vertical wells.

There are two reasons for poor injection rates:

- 1) High reservoir pressure in the zone of interest causing lack of pressure differential between well bore and reservoir, reducing the wells capacity to inject CO₂.
- 2) Lack of injectivity, due either to skin damage or poorer reservoir quality than anticipated.

As discussed above, high reservoir pressure is caused by lack of throughput within the project area and lack of off lease produced water disposal. Methods for improving throughput and productivity were discussed above.

Lack of injectivity is of more concern for vertical injection wells. Continued monitoring of injection volumes and pressures for these wells will determine if further intervention work or methods to improve injectivity will be required. It is anticipated, however, injection volumes will increase once throughput and reservoir pressures improve.

As a result of the cut back of surface injection pressures reduced volumes of CO₂ were required during the report period.

Horizontal injection well 7C-11H has out of zone injection in the toe of the well, which was determined after logging and fall off tests. Methods being evaluated to isolate this

section of the well include packers, crosslinked polymers, cement, foamed cement, monomers and sodium silicates. These methods have been reviewed in detail with Phillips and service companies, but no ideal solution for isolation has been realized, either because of high risk or expense. The best producing oil well 7-01 has been receiving support from the toe of 7C-11H, and it was deemed to risky and expensive at the current time to risk losing this well.

Indications from previous gas tracer studies indicated possible direct communication path from well 7C-11H to vertical lease line well 6-28, which had significant CO₂ production while on test. To try and resolve this concern a dye injection test is planned for 7C-11H. This will involve conversion to water injection while a batch of fluorescent dye is added. Monitoring of wells surrounding 7C-11H will determine if such direct communication paths exist. This activity is planned for 3rd quarter 1999.

During December 1998 low crude prices dictated a cut back of CO₂ purchases to the lease. Overall CO₂ injection was therefore reduced from 7.9 MMSCF/D to 4.7 MMSCF/D in December 1998. Average CO₂ purchases were maintained at an average of 4.4 MMSCF/D from December 1998 to June 1999.

Purchase CO₂ and Operation of Recycle Compression Facilities

The CO₂ recycle compression facilities have been in continuous operation during the reporting period.

Gas injection volumes for the four SCU injection wells and the three co-operative lease line injection wells are reported below. These volumes have been updated and corrected from previous reports.

South Cowden Unit Gas (CO₂) Injection

	<u>Jul-97</u>	<u>Aug-97</u>	<u>Sep-97</u>	<u>Oct-97</u>	<u>Nov-97</u>
Monthly Mcf	309,844	255,958	157,118	294,766	308,048
Daily Avg mcf/d	9,995	8,257	5,237	9,509	10,268
Cumulative Mcf	2,943,129	3,199,087	3,356,205	3,650,971	3,959,019
	<u>Dec-97</u>	<u>Jan-98</u>	<u>Feb-98</u>	<u>Mar-98</u>	<u>Apr-98</u>
Monthly Mcf	168,149	100,782	92,772	98,593	188,185
Daily Avg mcf/d	5,424	3,251	3,313	3,180	6,273
Cumulative Mcf	4,127,168	4,227,950	4,320,722	4,419,315	4,607,500

	<u>May-98</u>	<u>Jun-98</u>	<u>Jul-98</u>	<u>Aug-98</u>	<u>Sep-98</u>
Monthly Mcf	171,447	167,425	202,031	206,799	207,030
Daily Avg mcf/d	5,531	5,581	6,517	6,671	6,901
Cumulative Mcf	4,778,947	4,946,372	5,148,403	5,355,202	5,562,232

	<u>Oct-98</u>	<u>Nov-98</u>	<u>Dec-98</u>	<u>Jan-99</u>	<u>Feb-99</u>
Monthly Mcf	230,705	236,839	144,641	133,140	120,056
Daily Avg mcf/d	7,442	7,895	4,666	4,295	4,288
Cumulative Mcf	5,792,937	6,029,776	6,174,417	6,307,557	6,427,613

	<u>Mar-99</u>	<u>Apr-99</u>	<u>May-99</u>	<u>Jun-99</u>
Monthly Mcf	136,002	131,614	125,738	140,844
Daily Avg mcf/d	4,387	4,387	4,056	4,695
Cumulative Mcf	6,563,615	6,695,229	6,820,967	6,961,811

Unit Production

A summary of quarterly average daily production and injection follows:

SCU Unit Average Daily Production and Injection

<u>Quarter</u>	<u>PRODUCTION</u>			<u>INJECTION</u>			
	<u>BOPD</u>	<u>BWPD</u>	<u>MCFD</u>	<u>SCU Unit</u> <u>Wtr Inj.</u> <u>BWIPD</u>	<u>SCU</u> <u>2D18</u> <u>BWDPD</u>	<u>Total Unit</u> <u>Wtr Inj</u> <u>BWDP</u>	<u>MCSF/D</u> <u>CO2</u>
1st 1996	383	3,944	90	3,944			0
2nd 1996	356	3,528	89	3,528			0
3rd 1996	337	4,303	91	4,622			3,667
4th 1996	376	4,928	102	4,928			8,579
1st 1997	443	6,110	612	6,110			8,123
2nd 1997	425	6,466	929	6,466			8,584
3rd 1997	446	6,498	1,114	6,498			7,830
4th 1997	487	8,624	1,504	8,624			8,400
1st 1998	463	7,065	974	7,066			3,248
2nd 1998	457	6,999	1,026	7,000			5,795
3rd 1998	495	6,826	1,822	6,827			6,696
4th 1998	511	6,691	2,188	5,302	1,389	6,692	6,668
1st 1999	483	6,378	1,992	4,797	1,582	6,379	4,323
2nd 1999	456	5,984	1,413	4,432	1,553	5,985	4,379

Monitor Project Performance

Close monitoring of production data has shown the area around horizontal injection well 6C-25H has the best response to CO₂ to date. Suggesting areas where a) zonal isolation of injected CO₂ into the zone of interest, and b) high injectivity are possible will have the greatest benefit from CO₂ injection.

Well 6C-25H was drilled horizontally into the zone of interest, and has no indications of out of zone injection, unlike its twin well 7C-11H, where a fracture system is taking the majority of injected gas. The well is also capable of high injection rates, compared to other wells in the field, typically over 3 MMSCF/D at the injection constraint of 1150 psig surface pressure.

Other areas of the field, such as around vertical injection well 2-27, suggest CO₂ has less response to nearby wells. Well 2-22 appears to have earliest CO₂ breakthrough, suggesting the highest transmissibility between the pair. Other wells surrounding 2-27 have shown little indication of CO₂ response.

Response from nearby wells to the toe of 7C-11H suggest they are also responding to CO₂, so some percentage of the injected CO₂ must be entering the zone of interest, the majority, however, entering the fracture system and out of zone.

Interference Testing

An additional pulse test between wells 2-26 and 6-28 was undertaken in June 1998. This was to confirm an October, 1997 pulse test between the two wells that suggested communication, and 2-26 as the source of early breakthrough seen at well 6-28.

The June test, however, gave a conflicting response, suggesting no definite communication between these wells. With the lowering of injection pressures in well 2-26, from late 1997 onwards, the communication path seen during the October pulse test may have been eliminated. The data suggested the fractured system had healed up due to the lowering of surface injection pressures.

LIST OF FIGURES

<u>Figure</u>	<u>Description</u>
1	Historical Injection Rates and Surface Pressures of Well 2-18

FIGURES

SCU 2-18 Disposal Well

Figure 1
Historical Injection Rates and Surface Pressure