FOSSIL ENERGY

DOE/BC/14991-14
(OSTI_ID: 2714)

DESIGN AND IMPLEMENTATION OF A CO2 FLOOD UTILIZING ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL INJECTION WELLS IN A SHALLOW SHELF CARBONATE APPROACHING WATERFLOOD DEPLETION

Annual Report
July 1, 1997 to June 30, 1998

By
Rex Owen
C.R. Robertson
K.J. Harpole
E.G. Durrett

January, 1999

Performed Under Contract No. DE-FC22-94BC14991

Phillips Petroleum Company
Odessa, Texas

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government.

This report has been reproduced directly from the best available copy.

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615) 576-8401.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161

DOE/BC/14991-14
Distribution Category UC-122

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

By
Rex Owen
C.R. Robertson
K.J. Harpole
E.G. Durrett

January 1999

Work Performed Under Contract DE-FC22-94BC14991

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Dan Ferguson, Technology Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by:
Phillips Petroleum Company
4001 Penbrook Street
Odessa, TX 79762

TABLE OF CONTENTS

Abstract v

Executive Summary vii

Introduction
- Summary of Project Objectives 1
- Summary of Field Details 1
- Project Description 2
- Summary of Progress 3

Discussion
- Background Information 5
- Task V: Field Demonstration 5
  - Testing of Horizontal Injection Wells 5
  - Drill Two Vertical WAG Leaseline Injectors 6
  - Drill Multiple Producing Wells 7
  - Convert Wells for Water Injection 7
  - Plug and Abandon Shut-in Wells 8
  - Workover or Recondition Existing Wells 8
  - Construct, Modify, and Upgrade Facilities 12
  - Purchase CO_2 and Operation of Recycle Compression 12
  - Evaluate Project Performance 13
- Task VI: Technology Transfer, Reporting, and Project Management 15

List of Figures 17

Figure 1 Comparison Actual Unit Performance vs. Model Forecast 21

Figure 2 Comparison of Simulation Model Forecast Gas Injection Rate vs. Actual Rates 22

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 (CO_2) injection in July 1996, several operationally related issues emerged within this reporting period. These include out of zone CO_2 injection, conformance methods, high reservoir pressure, and lack of injectivity and productivity.

Injection profile surveys in two recently drilled leaseline vertical wells, 6-26 and 6-27, indicated out-of-zone injection, requiring remediation. Conventional cement squeezes proved unsuccessful as an isolation technique, the use of foamed cement, however, improved in-zone injection.

Well No. 6-29 was drilled as a replacement for Well No. 6-01 in September 1997. Additional perforations were added to Well No. 6-29 to improve productivity. Two wells, 6-18 and 8-03, previously shut in, were converted to water injection during third quarter of 1997. Three wells, 2-16W, 6-01 and 6-12 were plugged and abandoned due to regulatory requirements associated with bad casing. Seventeen cleanouts and/or acid stimulations were conducted in 1997 to improve productivity in underperforming wells.

Horizontal injection Well No. 7C-11H was tested and profiled. Results suggested the majority of injectant entered the toe of the well into a fractured system, with probable high out-of-zone communication. Remedial action will be implemented before year end to resolve this issue.

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" CO_2 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. Other options, still being evaluated, are purchase and completion of off-lease water disposal in non-operated wells and transportation of produced water to nearby waterflood projects.

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; currently individual-well designed chemical treatments to remove scale/asphaltines/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 is the use of horizontal lateral jetting technology. Two wells 1-07 and 6-20 will be used to test this new technology, which if proven, will be used extensively in the project area for improving productivity and in-zone injectivity.

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 (CO_2) flood project utilizing advanced reservoir characterization and CO_2 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 CO_2 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 CO_2 water alternating gas (WAG) injection wells were drilled in December 1995. Two horizontal CO_2 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 CO_2 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 leaseline 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, currently individually-well designed chemical treatments to remove scale/asphaltines/paraffins have proven successful. If continued treatments are successful, they will be a more cost effective and long term method to ensure withdrawal rates are maintained.

High reservoir pressure is a concern for the project as it has limited CO_2 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 jetting technology. To reduce voidage replacement water production will require off lease, or, off reservoir disposal to reduce average reservoir pressure. Well 2-18 is therefore being evaluated as a water disposal well by deepening to the Canyon and/or Clearfork intervals. Other wells and water injection projects in the vicinity of South Cowden Unit are being evaluated for water disposal.

CO_2 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 CO_2 volumes are being efficiently utilised.

Cumulative CO_2 injected as of June 30, 1998, is estimated at 4,946,372 thousand standard cubic feet (Mscf) CO_2. The average daily CO_2 injection rate during June 1998 was 5.5 MMscf CO_2 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 (CO_2) flood project development approach for improving CO_2 flood project economics in shallow shelf carbonate (SSC) reservoirs.

Most of the incremental tertiary oil production from CO_2 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 CO_2 miscible flood projects implemented in SSC reservoirs account for over one-half of the total incremental oil production attributable to CO_2 miscible flooding in 1992 in the United States.

This project shall demonstrate the economic viability of the advanced technology of developing a CO_2 flood project utilizing multiple horizontal CO_2 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 CO_2 distribution system. It is anticipated that the proposed advanced technology will show improved CO_2 sweep efficiency and will significantly reduce the capital investment required to implement a CO_2 tertiary recovery project relative to conventional CO_2 flood pattern developments using vertical injection wells. This technology will be readily transferred to the domestic oil industry and should introduce CO_2 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 CO_2 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 20 months of CO_2 injection, the Unit is producing 448 barrels of oil per day (BOPD) with a water cut in excess of 94% from 49 active producers and 16 active injectors. For June 1998, the continued water injection prediction for oil rate, if no further development had occurred at South Cowden, was 260 BOPD. Approximately 190 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 CO_2 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 CO_2 flood project, utilizing advanced reservoir characterization and CO_2 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 CO_2 operations.

Standard methods of CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 project was completed in mid-July, 1996, with the initiation of CO_2 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, CO_2 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 leaseline 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 CO_2; 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 during March to early July. Additional recent treatments are awaiting well test information to identify their success.

Also under review, and scheduled to commence this summer are some new methods of improving productivity using horizontal lateral technology. If this proves successful the method will provide an extremely cost effective approach for improving offtake rates.

Monitoring of CO_2 response to date suggests areas where high CO_2 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 CO_2 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

DRILL, RE-ACTIVATE, AND CONVERT WELLS

Testing of Horizontal Injection Well No. 7C-11H (H-2)

Confirmation Profile Injection Log under Water Injection

A third injection profile was run during October 1997 to confirm identified losses in the toe of the well. Gamma ray and temperature logs confirmed major loss in two distinct intervals in the well's toe, at 6100-6110' and 6150-6180'. The log also indicated a possible internal diameter (I.D.) restriction at 5400'. This well was placed back on CO_2 injection following this survey. The information obtained from the injection profile logs will be used for implementation of mobility control measures during 1998. Options being evaluated including packers, crosslinked polymers, cement, foamed cement, monomers and sodium silicates.

Interference Test

During the drilling of leaseline cooperative injection Well No. 6-28W, oil shows were seen in drilling returns. When placed on production test during January 1997, however, the well produced 70% CO_2 from the gas stream. This gave concern CO_2 was by-passing reservoir rock through a suspected fracture system connected to the toe region of the injection Well 7C-11H. During February 1997 a tracer test was attempted to determine the source of the produced CO_2, but was inconclusive. Because of the east-west preferential fracturing direction, determined by micro-fracturing tests, there was additional concern CO_2 could originate from vertical injection Well 2-26W, almost 2000' to the west-northwest.

An interference test was therefore designed during early October to determine the origin of the produced CO_2. While injecting water into 7C-11H, pressure bombs were hung in the shut-in well No. 6-28.

Well No. 6-28 was shut-in at 8:00 a.m. on September 24, 1997. The gauge clock initiated at 9:53 a.m. October 2, 1997 (zero hours). Well No. 7C-11H was shut-in (for injection logging, discussed above) at 21:53 on October 2, 1997 (+12 hours (hrs) 10 minutes (mins)). At 8:03 am, October 4, 1997, 2-26W was shut-in (+46 hrs 15 mins). This well should have then been placed back on injection to confirm any interference detected during the shut-in periods, however, this was not done.

Pressures in 6-28 continued to build-up following shut-in of 7C-11H. Pressures, however, began falling-off approximately five hours after 2-26W was shut-in. The project team believed the test indicated strong pressure interference between 2-26W and 6-28, but was not confirmed by a final injection period on 2-26W.

An additional pulse test between wells 2-26 and 6-28 was undertaken in June 1998. 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 is still being analyzed to extract as much communication information as possible.

Drill two vertical WAG injectors along South Cowden Unit boundary - approved under Amendment No. A007 to the Cooperative Agreement for inclusion in Phase II funding

Vertical water alternating gas (WAG) injection Wells 6-26W and 6-27W commenced water injection during January, 1997. Water injection profile logs were run during February, 1997.

Well No. 6-26W injection profile survey indicated communication with an uphole water sand and a deeper reservoir interval. A workover was performed during April 1997 to conventionally squeeze the lower thief zone 4709'-4726' and cement squeeze the upper perforations at 4568'-4582'. Subsequent water injection profile surveys, during June 1997, indicated the upward channeling was successfully plugged, however, all the injected water was going out the bottom of the well.

During June 1997 a foamed cement job and reperforations across the E and upper F zones (4618'-4638') was performed to prevent out-of-zone injection. The job appeared successful. On September 19, 1997 a follow-up injection profile was obtained, at an injection rate of 424 BWPD at 400-psig surface injection pressure. Velocity calculations indicated eighty-three percent (83%) of the fluid entered the new perforations at 4618'-4638'. Eighteen percent (18%) of the fluid, however, was entering old perforations at 4631'-4637'. No flow was detected inside the pipe past 4642'.

Temperature logs indicated channeling up to 4580', and down below 4648', with approximately 70% of fluids leaving new perforations at 4618'-4628'. Although the

profile was not perfect, the foamed cement job was deemed a success and CO_2 injection commenced.

The injection profile survey for 6-27W indicated 50-60% of fluid entering the wellbore through the perforated interval 4746'-4748', which is perforated below the oil-water-contact at approximately -1800' subsea (ss). The injection survey also indicated limited water injection occurring above 4686'.

A foamed cement squeeze was performed on Well 6-27W in early August utilizing 300 sacks of "premium plus" cement foamed with 10 pound/gallon density. The cement was then drilled out, and the well reperforated at 4608'-4628'. The well was stimulated, and placed back on injection. A follow-up injection profile survey, during mid-September, determined the effectiveness of the foamed cement squeeze. The velocity shots indicated 82% of the fluid leaving the new perforated interval 4608'-4628', with 18% exiting the old perforations at 4631'-4635' and no flow inside the pipe past 4642'. Temperature logs indicated 70% entering through the new perforated interval, with 6% movement down to 4648' and an upward channel to 4580' (not out of the San Andres interval). Although not perfect, the profile indicated a correction of the out-of-zone injection, and the well was placed on CO_2 injection during October 1997.

Drill Multiple Producing Wells

Drill Production Well No. 6-29

South Cowden Unit (SCU) Well No. 6-29 was drilled to a total depth of 4808' during September 1997, with a plugback depth at approximately 4755'. This is a replacement well for Well No. 6-01, which had irreparable casing damage. The casing program consisted of 8-5/8" surface casing set at 1699', and 5-1/2" production casing to total depth (TD) 4805'. Well No. 6-29 was completed October 18, 1997, testing 8.5 barrels of oil per day (BOPD), 183 barrels of water per day (BWPD), 1.2 thousand cubic feet gas per day (MCFGD), and 9% carbon dioxide (CO_2), with fluid level at 27 joints. A shut-in bottomhole pressure (BHP) and buildup test measured BHP of 2233 pounds per square inch gauged (psig) recorded after a 72-hour shut-in. The pressure extrapolated to infinite shut in time is 2455 psig (P*).

Convert Two Wells for Water Injection

During third quarter, 1997, SCU Wells Nos. 6-18 and 8-03 were converted to water injection. The results are summarized below:

	---------BEFORE---------	----------AFTER----------
SCU 6-18	Shut-in	Injecting @ 248 BWPD and 480 psig
SCU 8-03	Shut-in	Injecting @ 300 BWPD and 680 psig.

Plug and Abandon Three Shut-in Wells (not included in DOE funding)

During third quarter 1997, SCU Wells Nos. 2-16W, 6-01 and 6-12W were plugged and abandoned due to regulatory requirements (bad casing).

Workover or Recondition Existing Wells

During third quarter 1997, fourteen wells were acid stimulated. The results follow:

	----------BEFORE--------			----------AFTER----------			
Well	BOPD	BWPD	MCFD	BOPD	BWPD	MCFD	Comments
SCU 2-01	20	107	0	41	217	7	
SCU 2-02	3	41	0	12	188	1	
SCU 2-08	3	38	0	13	147	3	
SCU 2-22	8	141	5	24	253	29	
SCU 2-25	30	167	5	30	207	6	
SCU 5-07	8	87	1	25	225	49	
SCU 6-02	12	105	1	9	150	47	
SCU 6-22	47	97	25	0	151	32	
SCU 7-02	2	43	0	11	70	28	
SCU 7-08	28	910	340	20	477	123	
SCU 7-09	3	55	0	5	220	0	
SCU 7-12	1	8	0	0	285	0	
SCU 7-13	14	30	0	9	1	5	
SCU 7-15	6	30	0	13	96	0	

Production for the project area increased by approximately 75 barrels of oil per day (BOPD) and 1500 barrels of water per day (BWPD) as a result of the total clean-out program, including Wells Nos. 7-01, 7-05, and 7-10, stimulated during second quarter 1997, which were discussed in the previous annual report.

Reduce Reservoir Pressure (not included in DOE funding)

Shut-in bottomhole pressure data in the SCU Project Area indicated reservoir pressure to be approximately 2300 psig, increasing to approximately 2600 psig in the Emmons Unit to the north. Bottom-hole pressure surveys in wells 6C-25H and 7C-11H, conducted during February 1998, indicated 2614 psig and 2632 psig @ reservoir datum of -1700 (4651 TVD).

Minimum miscibility pressure (MMP) is 1200 psig. The optimum reservoir pressure for SCU CO_2 flooding is estimated at 1800 psig. Lower reservoir pressures allow injected CO_2 to occupy more reservoir volume and contact more recoverable oil by increasing the narrow pressure margin between the fracture gradient and reservoir pressure.

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, as necessary to handle increased water injection capacity. This Subtask, however, was specifically excluded from funding by the DOE.

The Project team is in unanimous agreement additional water disposal in a lower San Andres interval would ultimately increase overall San Andres reservoir pressure, thus further contributing to the problem. The projects mentioned below are therefore recommended as an alternative to Subtask V.1.9 of Phase II of the South Cowden Unit DOE Project.

During March, 1997, the project team requested funds to deepen, complete and equip SCU Well No. 2-18 for use as a water disposal well. Approximately 8000 BWPD is produced in the Unit, and reinjected. Funds were requested to deepen the plugged and abandoned SCU Well No. 2-18, for disposal of up to 5000 BWPD outside the San Andres CO_2 target interval.

Well No. 2-18 is scheduled for deepening and completion in the Canyon and potentially the Clearfork intervals. The project team is currently reviewing the intervals and their use for water disposal, and awaiting partner approval.

Three additional wells in the vicinity of the South Cowden area are being reviewed for water disposal potential, as are the options to lay pipelines to other leases (both Phillips operated and non-operated), where water injection volumes are required.

Increase Throughput

The current main concern is the lack of productivity from wells. Small withdrawal rates from producers have reduced throughput throughout the reservoir, increasing average reservoir pressure and limiting CO_2 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 new chemical treatment was tested on SCU Well No. 7-08 on March 5, 1998. The system was designed to address paraffin/asphaltenes, calcium carbonate, and calcium sulfate in a single application. The expense work included a paraffin/asphaltene solvent, sulfate and carbonate remover, antisludge chemicals, and an iron reducing agent. The job was applied via the casing-tubing annulus. The well showed no increase in oil production following the treatment, but daily water production increased by over 100 BWPD.

A successful similar sampling, analysis and chemical treatment is now under way in the majority of producing wells. 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 treated wells improved producing rate, with an average liquid rate increase of 92%. All 7 wells have reached there "target" liquid rate, 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, and are awaiting additional well test data to provide feedback on their success.

Wells 5-07, 6-02, 6-19, 6-20, 6-24, 7-15 and 8-13 are scheduled for treatment before the end of July.

Another method of improving productivity has emerged within the last few months. New technology to create lateral boreholes in existing wellbores using coiled tubing and jetting technology has been developed. Three producing wells (7-13, 1-07 and another as yet undecided well) are scheduled to use this technology this summer. Productivity improvements from these wells will be closely monitored before further production and injection wells are scheduled to use this technique.

Well No. 6-29 had perforations added in the zone of interest followed by stimulation during July to improve throughput in the area south of 6-28.

Limiting surface injection pressure and reduced CO_2 injection

Instantaneous shut-down pressure (ISDP) data, obtained from wellwork during second and third quarters 1997 in Emmons and South Cowden Units, indicated the fracture gradient to be approximately .6 psi/ft. With this knowledge the team recommended surface injection pressures for water injection wells be limited to 650 psig and 1150 psig for CO_2 injection, within the project area. This would necessarily reduce the amount of CO_2 being purchased, and injected, but was thought would improve in zone CO_2 injection. The project team also recommended water injection wells surrounding the project area could exceed the recommended injection pressures to dispose of excess water in lower zones.

The field personnel implemented the above recommendations, reducing considerably the amount of CO_2 purchase. CO_2 volumes were reduced to minimum contract quantities of approximately 5 MMscfd, primarily being injected in the horizontal injection Wells Nos. 6C-25H and 7C-11H.

After reviewing the CO_2 injectivity for each well, in June 1998, injection rates were increased only in Well No. 6C-25H, as it was believed it was not injecting at its full capacity. Until further review the injection constraints will remain on injection wells.

Injectivity and Out Of Zone Injection

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 CO_2 wastage.

Since late 1997 surface pressures for water injection wells were limited to 650 psig and CO_2 injection wells to 1150 psig, to ensure injection below fracture pressures.

CO_2 injected volumes and surface pressures were closely monitored to observe injectivity. The table below summarises some of the individual CO_2 well injection rates.

	SCU 6C27	SCU 6C26	SCU 2C26	SCU 2C27	SCU 6C25H	SCU 7C11H	TOTAL	PREDICTED	PERCENTAGE
	Rate mcf/d	Rate mcf/d	Rate mcf/d	Rate mcf/d	Rate mcf/d	Rate mcf/d	Rate mcf/d	Rate mcf/d	PREDICTED
Aug-97	0	971	538	371	2883	2932	7695	11750	65.5
Sep-97	19	793	727	294	2718	686	5218	12000	43.5
Oct-97	999	896	935	387	3495	2797	9509	12000	79.2
Nov-97	986	874	946	554	3457	3452	10269	12000	85.6
Dec-97	482	441	481	184	2148	1690	5426	12000	45.2
Jan-98	136	397	290	1	1312	1116	3252	12250	26.5
Feb-98	85	621	354	0	1113	1140	3313	12250	27.0
Mar-98	33	631	316	0	1010	1190	3180	12250	26.0
Apr-98	20	1094	523	5	2347	2319	6273	12500	50.2
May-98	1	466	157	1	2476	2431	5532	12500	44.3
Jun-98	0	490	143	0	2547	2401	5581	12500	44.6

Actual injectivity has been reduced since limiting surface pressures, most noticeably in vertical wells. The main reason for this is the reduction of injection pressure, but there are two other 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 CO_2.

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 concern for vertical 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. If the lateral technology being implemented to improve productivity proves successful it maybe used for improving injectivity, coupled with conformance technology to isolate injectant in zone.

As a result of the cut back of surface injection pressures reduced volumes of CO_2 were required during the report period.

CONSTRUCT, MODIFY, AND UPGRADE FACILITIES FOR INJECTION AND PRODUCTION

Construct Injection Facilities

No changes were made to the injection facilities during the reporting period.

Modify or Upgrade Production Facilities

A second test separator was installed at the Satellite 6 location. The additional test separator will allow more frequent testing of producing wells.

Install Cathodic Protection

It has been determined that the cathodic protection system for protecting casing against external corrosion will not be beneficial. The activity has been eliminated.

Install Supervisory Control and Data Acquisition (SCADA) Equipment

During Second Quarter 1998 a new software package (Genesis) was configured and installed. The new software eliminated the reoccurring problems of measuring and controlling the amount of CO_2 injected into each well.

PURCHASE CO_2 AND OPERATION OF RECYCLE COMPRESSION

The total volumes injected in SCU injection wells for the reporting period were:

GAS INJECTION - Mscf of CO_2

	Jul 97	Aug 97	Sep 97	Oct 97	Nov 97
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	3,650,97	3,959,019

	Dec 97	Jan 98	Feb 98	Mar 98	Apr 98
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

GAS INJECTION – Mscf of CO_2 (CONT.)

	May 98	Jun 98
Monthly mcf	171,447	167,425
Daily Avg. mcf/d	5,531	5,581
Cumulative mcf	4,778,947	4,946,372

A summary of quarterly average production and injection follows:

	--------- PRODUCTION---------			--------- INJECTION ---------	
Quarter	BOPD	BWPD	MCFPD	BWIPD	MSCFPD CO2
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	7,066	974	7,066	3,248
2nd 1998	463	7,000	1,026	7,000	5,795

EVALUATE PROJECT PERFORMANCE

Update Performance Predictions and Re-evaluate Design Premises During the First 12 months of CO_2 Injection

The South Cowden full-field simulation model was updated to incorporate the exact project development and operating schedule as implemented project operations. The simulation model was adjusted to reflect the details of the actual locations, completions, and timing of newly drilled, reactivated, and recompleted wells in the CO_2 flood project area. No additional history matching changes were made to the simulation model reservoir description used in making the original project forecasts.

Figure 1 shows a comparison of actual Unit performance versus (vs.) model forecast performance under both the originally premised and actual project operation and implementation schedule. The original schedule premised that all new drilling, well work, facilities upgrades, etc. would be completed by July 1, 1996, CO_2 injection start date for the project. While all new wells were drilled and completed as scheduled, the actual startup of injection and production operations was delayed in some wells due to

well testing, conducting profile surveys, etc. Also, reactivation of several shut-in producers was delayed several months compared with the premised implementation plan due to logistical considerations. The productive capacity of several reactivated production wells was significantly less than was premised in the original forecasts (based on the capacity of each well prior to shut-in). These variances in project operations and the delays in the project implementation schedule compared with the originally premised development plan had an unexpectedly large impact on the CO_2 flood response.

Figure 2 shows the simulation model forecast gas injection rates in comparison with the actual measured CO_2 injection rates during project operations. The actual and forecast rates agree fairly well until late 1997 when the surface CO_2 injection pressures were limited to prevent out of zone injection.

Based on results of model forecasts versus (vs.) actual field performance, individual well responses, and injection profile data, remedial actions are being recommended to remedy suspected problems with injection profiles and inadequate production capacity in certain wells. Specific recommendations are planned for implementation during 1998 to stimulate selected wells and conduct additional conformance work to improve injection profiles in the CO_2 injection wells, particularly in the SCU horizontal injection Well 7C-11H.

As more data become available on the CO_2 production response in the South Cowden reservoir, further adjustments will be made to the simulation model reservoir description to match field performance and the CO_2 flood forecasts will be updated periodically. Based on these results, some adjustment of the reservoir management program may be advisable at South Cowden to optimize performance of the CO_2 project.

TASK VI TECHNOLOGY TRANSFER, REPORTING, AND PROJECT MANAGEMENT

Technology Transfer

Kimberly B. Dollens participated as a panelist and presented a paper entitled "Application of Horizontal Injection wells in the South Cowden Unit CO_2 Flood," at the 1997 Society of Petroleum Engineers (SPE) Horizontal Well Conference held in Midland, Texas, September 17 and 18, 1997.

Kimberly B. Dollens participated as a panelist and presenter in the 1997 SPE CO_2 Conference (Dec. 10-11, 1997) in Midland, Texas. The conference focused on actual case histories. The talk was entitled "Application of Horizontal Injection Wells in the South Cowden Unit CO_2 Flood". She also participated as a presenter in the 1998 Permian Basin Recovery Conference in Midland, Texas, on Thursday, March 26, 1998.

Kimberly B. Dollens submitted an abstract for a paper entitled "Field Implementation of a CO_2 Flood in a Small Waterflood-Depleted Carbonate Unit," for presentation at the 1998 Southwestern Petroleum Short Course in Lubbock, Texas, April 8-9, 1997. The proposed paper was co-authored by Ms. Dollens, Ken J. Harpole, and Larry Hallenbeck.

An abstract was submitted by T. F. McCoy, K. J. Harpole, and K. B. Dollens to the selection committee for the Sixth International Oil and Gas Conference and Exhibition in Beijing, China, on November 2-6, 1998. The abstract entitled "Transient Test Analysis Case History for Two Horizontal Miscible Gas Injection Wells". - This paper was accepted as an alternate paper, but will not be presented or included in proceedings.

A poster session entitled "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO_2 Flood, South Cowden Unit, West Texas" was presented by Craig Caldwell and Kimberly B. Dollens at the Permian Basin Section of the Society of Economic Paleontologists and Mineralogists' (SEPM) Permian Basin Core Workshop in Midland, Texas, on Thursday, February 26, 1998.

LIST OF FIGURES

Figure	Description
1	Comparison Actual Unit Performance vs. Model Forecast
2	Comparison of Simulation Model Forecast Gas Injection Rates vs. Actual Rates

FIGURES

Figure 1 - South Cowden Unit
Comparison Actual Unit Performance vs. Model Forecast

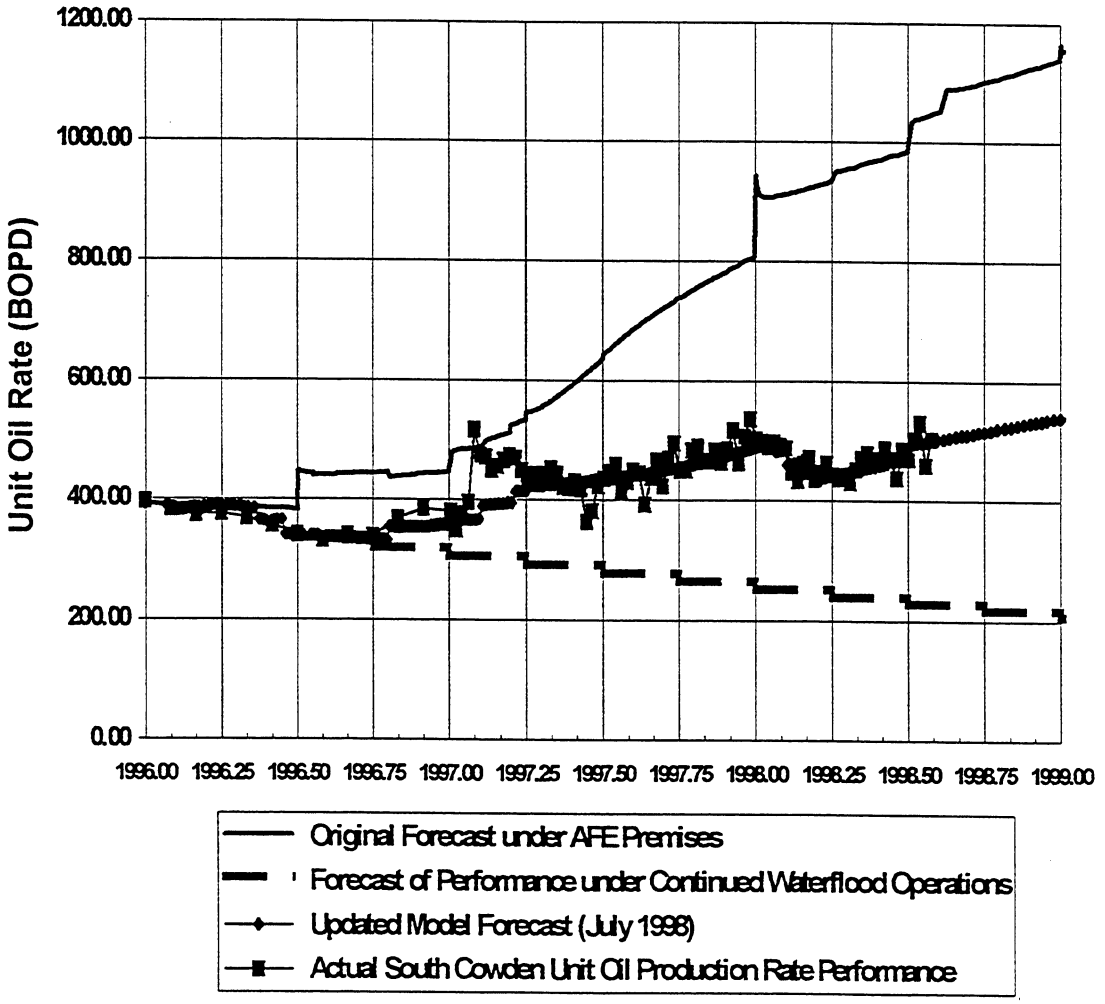
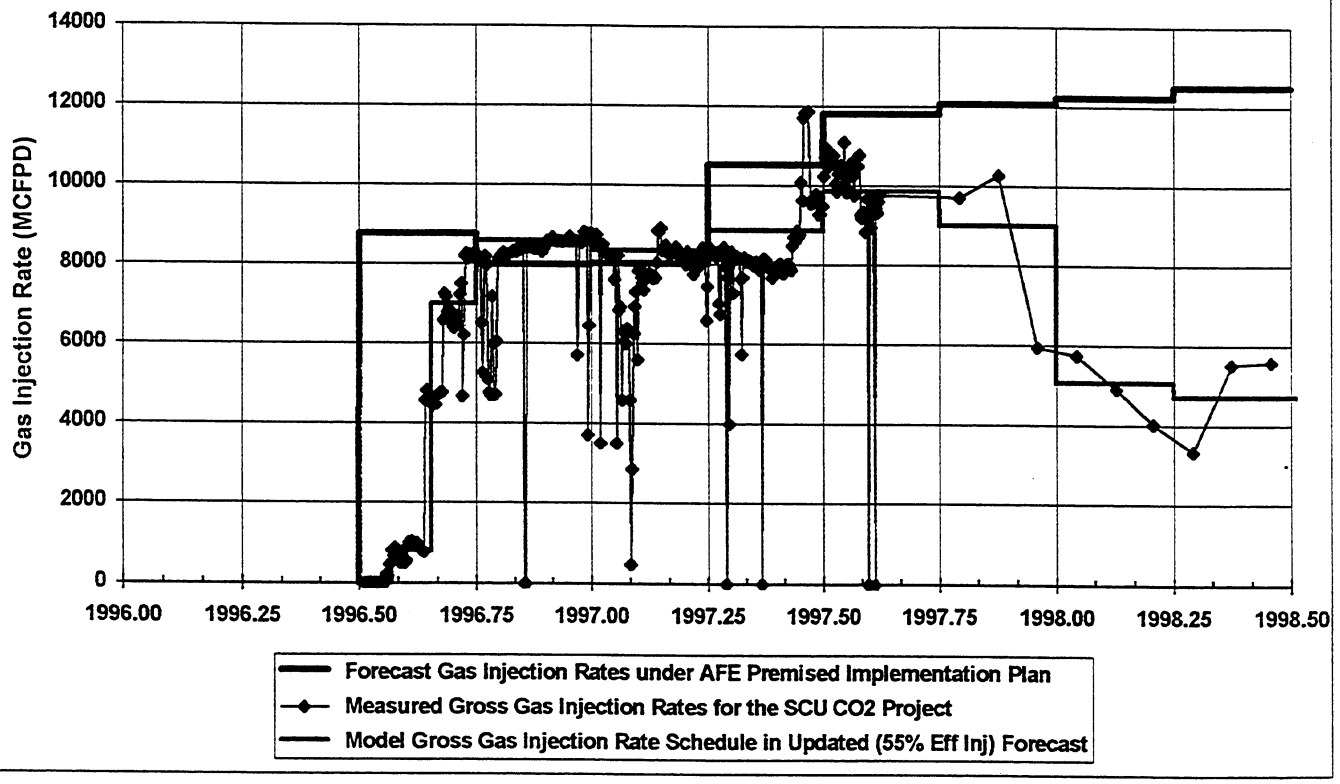
Figure 2 - South Cowden Unit
Comparison of Simulation Model Forecast Gas Injection Rates vs. Actual Rates