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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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By
Kirk Czirr

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Philips Petroleum Company
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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

By
Kirk Czirr

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

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

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

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OBJECTIVE

The first project objective is to utilize reservoir characterization and advanced technologies to optimize the design of a carbon dioxide (CO₂) project for the South Cowden Unit (SCU) located in Ector County, Texas. The SCU is a mature, relatively small, shallow shelf carbonate unit nearing waterflood depletion. The second project objective is to demonstrate the performance and economic viability of the project in the field. All work during the fourth quarter falls within the demonstration project.

SUMMARY OF TECHNICAL PROGRESS

BUDGET PHASE II

TASK V FIELD DEMONSTRATION

Drill Production Well No. 6-29

South Cowden Unit (SCU) Well No. 6-29, drilled during September, 1997, was completed October 18, 1997, testing 8.5 BOPD, 183 BWPD, 1.2 MCFG, 9% CO₂, with fluid level at 27 joints. A shut-in bottomhole pressure and buildup test was run with a bottom hole pressure of 2233 pounds per square inch gauged (psig) recorded for a 72-hour shut-in. The pressure extrapolated to infinite shut in time is 2455 psig (P*).

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 Nos. 6-26W and 6-27W were placed on water injection during January, 1997. Injection profile logs were run while the wells were on water injection during February, 1997. Injection profile conformance work utilizing foamed cement was completed on Well No. 6-26W during third quarter, 1997. However, additional work remained during fourth quarter for Well No. 6-27W.

The injection log run on Well 6-27W indicated 50-60% of the injection volume was leaving the wellbore through the perforated interval 4746'-4748', which had been 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 was reperforated at 4608'-4628'. The well was stimulated, and placed back on water injection. A follow-up injection profile survey was run during mid-September to determine the effectiveness of the foamed cement squeeze. The velocity shots indicated 82% of the fluid leaving in the new perfed interval 4608'-4628', with 18% exiting the old perfs at 4631'-4635' and no flow inside the pipe past 4642'. The temperatures indicated 70% loss 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 CO₂ injection during early October.

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

Confirmation Profile Injection Log under Water Injection

A third injection profile was run on Well No. 7C-11H on October 2nd and 3rd while under water injection, to confirm the identified loss in the toe while under water injection. The gamma ray and temperature logs confirmed major loss in two distinct intervals in the toe of the well, 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 CO₂ injection following this survey. The information obtained from the injection profile logs will be used for implementation of mobility control measures during 1998, particularly in light of the results of the latest log on Well No. 7C-11H.

Interference Test

As detailed in previous reports, during the drilling of lease line cooperative injection Well No. 6-28W, oil shows were seen in the drilling returns; however, when placed on a production test during late January, 1997, the well produced 70% CO₂ cut in the produced gas. This gave concern that the CO₂ was by-passing contact with reservoir rock through the suspected fracture system in the toe region of the northwesterly horizontal injection Well No. 7C-11H. During February, 1997, a tracer test was attempted to determine the source of the produced CO₂, but was not conclusive. Because of the east-west preferential fracturing direction determined by micro-fracturing tests, there was additional concern that the CO₂ could, instead, be originating from vertical injection Well No. 2-26W, almost 2000' to the west-northwest.

An interference test was therefore run during early October to determine the origin of the produced CO₂. While injecting water into horizontal injection Well No. 7C-11H, pressure bombs were hung in shut-in Well 6-28, with gauges set to record for at least seventy-two (72) hours, initiated a few hours prior to shutting-in Well No. 7C-11H. Well 6-28 was shut-in at 8:00 on September 24, 1997; the clock on the gauge was initiated at 9:52 that day. Well No. 7C-11H was shut-in at 21:53 on October 2, 1997, for the injection logging operations detailed above. At 8:03 on October 4, 1997, Well No. 2-26W was shut-in. This well should have then been placed back on injection to confirm any interference detected during the shut-in periods; however, it was not done.

The pressures in Well 6-28 continued to build-up following shut-in of Well 7C-11H; however, the pressures began falling-off approximately five hours after Well No. 2-26W was shut-in. The project team believes the test indicated strong pressure interference between Well No. 2-26W and Well No. 6-28, but this was not confirmed by a final flow period on Well No. 2-26W. This interference test may be rerun during 1998 to confirm the source of the CO₂ production in Well No. 6-28.

Purchase CO₂ and Operation of Recycle Compression Facilities

The CO₂ recycle compression facilities have been in continuous operation during fourth quarter.

Gas injection volumes for the four SCU injection well and the three cooperative lease line injection wells for the fourth quarter (along with third quarter volumes) are reported below:

GAS INJECTION

	Jul 97	Aug 97	Sep 97	Oct 97	Nov 97	Dec 97
Monthly -mcf	252,308	208,448	132,748	295,125	312,344	181,053
Daily Average-mcfpd	5,605	6,804	6,605	9,520	10,411	5,840
Cumulative-mcf	2,859,131	3,067,579	3,200,327	3,495,452	3,807,796	3,988,849

Unit Production

By late December, sustained oil production had increased approximately 150 barrels of oil per day (BOPD) total, with 75 BOPD as a result of the CO₂ injection in the near vicinity of the horizontal injection wells, and the remaining 75 BOPD as a result of the earlier stimulation program. The project team recognizes that production in the following quarter may decline as a result of decreased CO₂ injection, as overall pressures will begin to level-out and decline. A summary of quarterly average production and injection follows:

Qtr	-----PRODUCTION-----			-----INJECTION-----	
	BOPD	BWPD	MCFD	BWIPD	MSCFPD CQ
1st 1996	375	3861	88	4520	0
2nd 1996	356	3526	89	4208	0
3rd 1996	337	4301	91	4144	3623
4th 1996	375	4907	105	4900	8674
1st 1997	442	5837	611	5837	8111
2nd 1997	425	6462	929	5710	8293
3rd 1997	445	6408	1110	6335	6451
4th 1997	479	*	1316	5014	8571

- * Phillips Petroleum Company instituted a new production reporting system, as some previously-reported volumes such as water production appear to be erroneous. Correct water injection volumes for fourth quarter will be included in the upcoming first quarter, 1998, report.

Monitor Project Performance

As the CO₂ project progressed this year, several key problem areas were identified for resolution. These problem areas can be summarized as : (1) high reservoir pressure, (2) narrow margin between reservoir pressure and parting pressure, and (3) out-of-zone injection problems.

The reservoir pressure in the project area is estimated at 2300 pounds per square in gauged (psig), with much higher pressures to the north in the Emmons Unit (estimated at 2600 psig), and lower pressures to the south along the project area boundary. For this reason, the CO₂ preferentially is traveling to the south of the horizontal Well No. 7C-11H, with initial oil response and CO₂ breakthrough occurring primarily in that region. The project team is currently reviewing various alternatives for moving produced water off-lease for disposal outside of the Project area, in an effort to reduce overall system pressures. The reduction of overall reservoir pressure will also increase the efficiency of the injected CO₂, as the same amount of CO₂ will occupy more space, thus contact more oil under lower pressures.

Instantaneous shut-down pressure (ISDP) data obtained from the wellwork during second and third quarters in both the Emmons Unit and South Cowden Unit indicates the frac gradient to be approximately .6 psi/ft. With this knowledge the team recommended that the surface injection pressures for the water injection wells be limited to 650 psig for any water injection within the project area, and 1150 psig for CO₂ injection. This would necessarily reduce the amount of CO₂ being purchased, as well as injected, but would better insure the purchased CO₂ was in fact being efficiently utilized. For the time being, the water injection wells surrounding the project area would be allowed to exceed these recommended injection pressures to dispose of excess water in the lower zones.

The field personnel implemented the above recommendations, which reduced considerably the amount of purchased gas required. However, it also changed the mix of the injected CO₂ with the contaminated produced gas, thus the fluid head and resulting maximum surface injection pressures. Pressure surveys with gradient stops are planned for January in order to determine guideline pressures under current mixing conditions. As a result of the changes, the purchased CO₂ 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.

The out-of-zone injection problem is also believed to be exacerbated by the high reservoir pressure; for this reason, further conformance control work, including foamed cement squeezes and monomer/polymer work will be delayed until after the reservoir pressure has been reduced by a couple of hundred pounds.

TASK VI TECHNOLOGY TRANSFER, REPORTING, AND PROJECT MANAGEMENT

Technology Transfer

Kimberly B. Dollens participated as a panelist and presenter in the 1997 SPE CO₂ 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~~ Flood".

Kimberly B. Dollens submitted an abstract for a paper entitled "Field Implementation of a CO₂ 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 will be co-authored by Ms. Dollens, Ken J. Harpole, and Larry Hallenbeck.

An abstract has been submitted by T. F. McCoy, K. J. Harpole, and K. B. Dollens to the selection committee for the SPE Sixth International Oil and Gas Conference and Exhibition in Beijing, China, on November 2-6, 1998. The abstract is entitled "Transient Test Analysis Case History for Two Horizontal Miscible Gas Injection Wells".