A REVIEW OF THE WILLARD (SAN ANDRES) UNIT CO_2 INJECTION PROJECT

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ABSTRACT

The Willard Unit is located in the Wasson (San Andres) Field in Yoakum County, Texas. The reservoir is a layered dolomite with an average porosity of 8.5% and average permeability of 1.5 md. Secondary recovery by waterflooding has been in progress since 1965. Although secondary operations have been quite successful in the Willard Unit, a substantial amount of oil will be unrecoverable by waterflooding. A CO_2 miscible displacement project was conducted in the unit to investigate the applicability of this process for full-scale improved oil recovery.

The project consisted of two separate field tests to study the various operational and reservoir aspects of the CO_2 miscible process. The first of these consisted of eight adjacent CO_2 injection wells on regular waterflood spacing. Since this was the first effort to conduct a CO_2 miscible flood in this unit, this test was called Phase I. Water and CO_2 were injected alternately in Phase I from November, 1972, to February, 1975. This area was planned to provide insight into the extent of reservoir sweep problems that might occur in a regular-size pattern CO_2 flood. It would also provide an opportunity to investigate control measures if these problems arose. Additionally, information would be obtained on injection performance and operational procedures that could be used in planning a unit-wide flood. The second test was located and operated separately from Phase I and was called the Pilot. It consisted of four wells: an injector, logging observation well, pressure observation and sampling well, and pressure core well, all on close spacing. The Pilot was designed to allow a more detailed investigation of the reservoir flow behavior of CO_2 and water and to determine the reduction in waterflood residual oil levels due to CO_2 injection.

Phase I injection performance was good. The reservoir pressure was maintained above the minimum required for miscible displacement. Cumulative CO_2 injection was 3.8 BCF of CO_2, or 4.4% of the hydrocarbon pore volume. Some of the injected CO_2 was produced as a result of excessive CO_2 injection pressures, but this volume has totaled only 3% of the cumulative injection. There was no evidence of severe gravity segregation or areal sweep problems.

A complete analysis of the Pilot area has not been finalized. This project verified the concept of stratified flow in the reservoir and no significant gravity overriding of the CO_2 was observed. The pressure core project was very successful and the Pilot results suggest that additional oil displacement occurred as a result of the CO_2 injection.

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INTRODUCTION

Figure 1 shows the location of Willard Unit and Wasson Field in Yoakum and Gaines Counties of West Texas. The unit contains 13,130 productive acres which have been under waterflood since 1965. Production is from the Permian age San Andres dolomite at an average depth of 5200 ft. Gross pay thickness varies from 230 to 50 ft across the unit and the average porosity and permeability are 8.5% and 1.5 md, respectively. Unit oil production was less than 4000 BOPD before unitization in 1965 and peaked at 31,500 BOPD in 1974 under secondary recovery operations. Reference 1 provides a detailed discussion of the geological and reservoir characteristics of the Willard Unit.

Several characteristics of this project make it an attractive candidate for improved oil recovery by CO_2 miscible flooding: (1) Laboratory tests[2] on Willard reservoir fluid samples indicate that the miscible pressure for CO_2 is 1250 psi. Since the average reservoir pressure is around 2000 psi, a large volume of the reservoir could be swept above miscibility pressure. (2) Geological and reservoir engineering studies[1,3] have shown that this reservoir contains good porosity zones separated by dense intervals of a few inches to a few feet thick. This results in a layered or stratified reservoir where the low porosity zones present barriers to vertical flow and effectively maintain a preferred horizontal move-

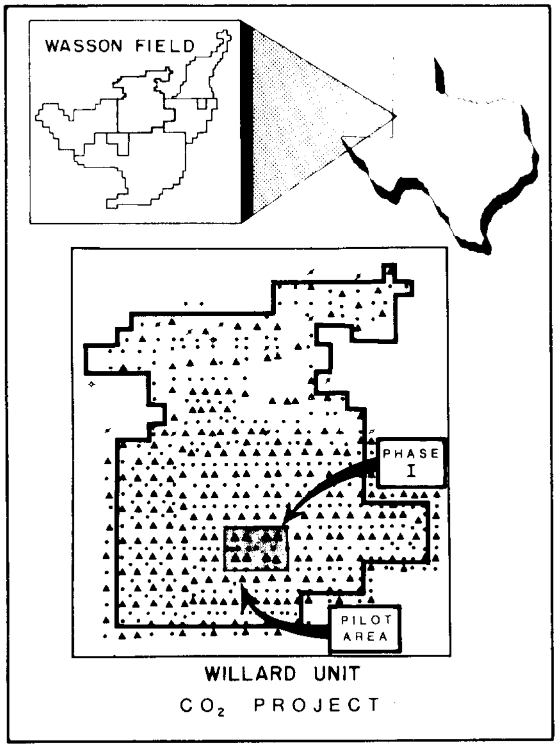

FIGURE 1 —LOCATION OF WILLARD UNIT CO_2 INJECTION PROJECT.

ment of fluids. The good and low porosity zones are correlative for several well distances. This situation should serve to restrict gravity segregation of the CO_2 moving interwell distances through the reservoir. (3) Waterflood performance indicates good conformance and if the mobility of a CO_2 slug can be controlled, good volumetric sweep could be achieved with a miscible flood. (4) Early laboratory investigations of Wasson San Andres cores indicate that waterflood residual oil saturations average in excess of 30% of the pore volume. This volume of oil represents a considerable target for additional recovery from the water-swept intervals. (5) To optimize secondary operations, portions of the unit where oil-in-place per acre is high have been drilled to an average spacing of 20 acres per well on a uniform pattern.

To investigate various operational and reservoir aspects of the process, two separate CO_2 injection field tests were conducted in the unit. In the first, eight adjacent water injection wells in the middle of the unit were converted for CO_2 injection to conduct a miscible flood with alternate CO_2 and water injection on the existing pattern spacing. The area of the unit containing the eight CO_2 injection wells was labeled "Phase I" since it was the first attempt to conduct a CO_2 miscible flood in this unit. Figure 1 shows the location of Phase I and Figure 2 is a detailed map of the area.

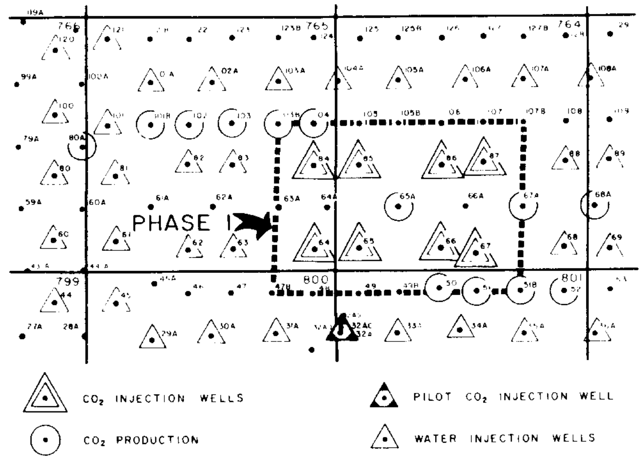

FIGURE 2 PHASE I AREA.

Phase I was located in the center of the unit where the reservoir properties are representative of the average for the unit. The area bounded by the producers surrounding the eight injectors contains approximately 425 acres with original oil-in-place ranging from 55 to 70 MSTBO/acre across the area. The area was sized to utilize a local source of CO_2. Phase I was planned for the following objectives:

1. Obtain operational experience with CO_2 injection.
2. Determine if alternate CO_2 and water injection can be conducted in this reservoir at adequate rates and at pressures necessary to maintain the reservoir above the CO_2 miscible pressure.
3. Gain insight into the extent of mobility control and CO_2 channeling problems.
4. Investigate control measures should CO_2 channeling occur.
5. In the long range, obtain a measure of the production performance and oil recovery to be expected from CO_2 flooding.

In actuality, the first four objectives were reasonably well satisified. CO_2 injection was discontinued as a result of an accident and the CO_2 slug was insufficient to effect any significant improvement in oil recovery.

The second test, called the Pilot, was located directly south of the Phase I area as shown in Figures 1 and 2. It consisted of four wells: injection well 32A, logging observation well 32AO, pressure observation and sampling well 32AS, and pressure core well 32AC. Figure 8 shows the relative locations of the Pilot wells.

The Pilot was conceived to provide a more thorough study of the CO_2 miscible process in this reservoir in a much shorter time than could be achieved in Phase I. Plans called for waterflooding the Pilot area followed by miscible flooding with alternate CO_2 and water injection under carefully controlled conditions. Water and CO_2 were injected in Well 32A. Fluid bank movement and saturation changes were traced by running compensated and pulsed neutron logs in Well 32A0. Well 32AS was used for pressure monitoring and fluid sampling to confirm changes observed in Well 32AO. Well 32AC was drilled following CO_2 injection to obtain pressure cores for quantitative measurements of oil, water, and CO_2 saturation levels. The Pilot was planned for the following objectives:

1. To provide another source for obtaining operational experience and injection performance data on alternate CO_2 and water injection.
2. To obtain data to develop a concept of reservoir stratification and to determine the extent of gravity segregation and crossflow within and between the different porous strata.
3. To obtain a measure of the magnitude of reduction in waterflood residual oil saturation caused by CO_2 miscible displacement in this reservoir.

The results of the Pilot will be used to develop a reservoir simulation model to allow CO_2 miscible flood performance predictions for the Willard Unit.

Source of the CO_2 for both tests was the acid gas effluent from the Wasson gas sweetening plant approximately three miles from Phase I. This gas was composed of approximately 95% CO_2, 4% H_2S, and traces of hydrocarbons. The gas was obtained at 1 to 2 psi and compressed to about 1600 to 1700 psi for injection.

Pressured CO_2 was delivered to the unit in a system completely independent of the water injection system. Manifolds at the wells allowed individual metering, flow control, and pressure and temperature monitoring of both fluids for cyclic injection.

PHASE I

Review

The eight injection wells were originally producers that were converted to water injection in an expansion program in 1969 and 1970. A line drive pattern was selected to take advantage of the fracture orientation, which runs approximately east-west in this reservoir. The producers and injectors were sand-fracture treated to increase throughput rates.

To optimize waterflood operations and prepare for CO_2 injection, completion intervals were checked to insure that the entire pay was open in all wells. Profile surveys were run in the injectors and innerstring casing jobs and remedial acidizing and fracturing treatments were performed[1] as necessary to provide good vertical coverage of injection fluids. Step-rate tests were conducted in the area to determine fracture extension pressures. Gas and water samples from the offsetting producers were analyzed to provide base data for monitoring water and CO_2 breakthrough. Since the gas to be injected contained hydrogen sulfide, laboratory core flood studies were conducted to determine the possible extent of wellbore damage resulting from sulfur deposition. The results indicated that this should not be a problem.

Specifications for the CO_2 flood called for injecting a CO_2 slug of at least 15% to 20% of a hydrocarbon pore volume (HCPV). Since CO_2 has a relatively low viscosity at reservoir conditions, the CO_2 would be injected with water in alternate, equal cycle volumes on a reservoir barrel basis. It was estimated that these conditions should promote equal frontal velocities of the CO_2 and water and thus control the mobility of the CO_2 slug.

An extensive surveillance and data collection program was outlined for Phase I to monitor performance. Daily CO_2 and water injection volume, pressure, and temperature for each injection well were taken to maintain injection balance and for accurate reservoir injection volume calculations. The casing-tubing annulus pressure of each injector was monitored for detection of wellbore communication. Injection profile surveys were run on the water cycles to check for plugged perforations, channeling, and changes in the vertical distribution of injected fluids.

Frequent (usually at least two per month) production tests were run on the offsetting producers. Monthly gas analyses were taken on these wells to check for production of injected CO_2. Periodic gas analyses were performed on the producers immediately outside of Phase I to check for migration of CO_2 to the surrounding area. Periodic water analyses were taken on the producers to monitor water breakthrough levels and scaling tendencies.

Injection History

CO_2 injection was initiated in November, 1972, into Wells 85 and 86. Initial rates averaged 800 to 1800 RVBD of CO_2 per well at wellhead pressures of 1600 to 1700 psi. Additional wells were placed on CO_2 injection until mid-June of 1973 as wellhead and injection manifold equipment became available.

Figure 3 is a graph of Phase I CO_2 injection performance. During 1973, total CO_2 injection averaged 2360 RVBD at 1566 psi wellhead pressure. During that year, a number of mechanical difficulties were encountered with the compressors and injection wells which resulted in considerable down time. As a result of these problems, some of the injection wells received disproportionate volumes of CO_2 at excessive wellhead pressures for short periods of time. Consequently, the reservoir fracture extention pressure was exceeded and resulted in production of injected CO_2 from the producing wells

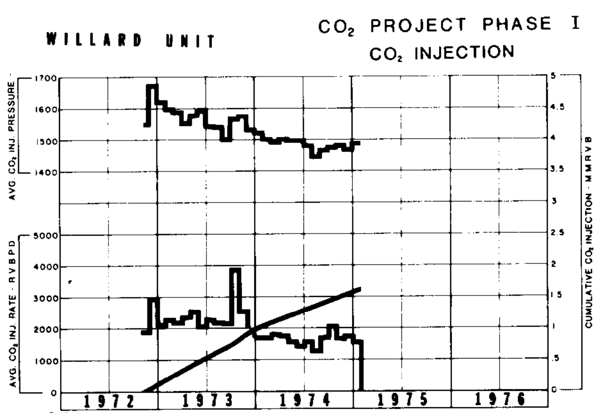

FIGURE 3— PHASE I CO_2 INJECTION.

along the fracture orientation. By 1974, most of the operational difficulties were resolved and injection rates and pressures were under close control. Total CO_2 injection in 1974 averaged 1620 RVBD at 1480 psi wellhead pressure.

CO_2 injection was discontinued in February, 1975, as a result of an accident. All the Phase I wells were placed on continuous water injection at that time. Table I summarizes the injection data by well for the project. Cumulative CO_2 injection was 3.8 BCF or 1.6 MMRVB resulting in a 4.4% HCPV CO_2 slug. Individual well CO_2 cumulatives ranged from 1.8% to 6.8% HCPV. These differences are due to varying injectivities, timing of conversion to CO_2, and the mechanical problems and down time experienced for each well.

TABLE 1—PHASE I INJECTION SUMMARY

WILLARD UNIT
CO_2 PROJECT—PHASE I
INJECTION DATA
2/1/75

WELL	DATE ON CO_2 INJECTION	CUMULATIVE CO_2 INJECTION MRVB	CUMULATIVE CO_2 INJECTION % HCPV
64	4-5-73	196.4	3.77
65	12-19-72	105.4	2.03
66	2-13-73	240.3	5.10
67	6-14-73	150.0	3.18
84	3-28-73	278.3	6.10
85	11-14-72	289.2	6.58
86	11-14-72	283.4	6.80
87	6-22-73	76.6	1.84
TOTALS		1,619.5	4.36

Injection Performance

Table 2 is a tabular comparison of the average injection rates and wellhead pressures of the eight Phase I injectors and eight immediate offsetting water injectors. These were calculated based on actual time of injection for each well. The table allows a comparison of the CO_2 and water injection performance for the CO_2 wells and an overall comparison of these to the offset water injectors. The sixteen wells all had comparable water injection histories to the time CO_2 injection was initiated. Cumulative injection to November 1, 1972, averaged 991 MBW per well in Phase I and 969 MBW per well in the offsets.

Overall, injection performance was very satisfactory. As a whole, the injection wells

TABLE 2—PHASE I INJECTION RATE AND PRESSURE PERFORMANCE
WILLARD UNIT
CO_2 PROJECT—PHASE I

INJECTION PERFORMANCE

AVERAGE INJECTION RATES AND SURFACE INJECTION PRESSURE

	Eight Phase I CO_2 Wells				Eight Offset H_2O Wells	
	H_2O		CO_2			
Year	Rate BWPD	Press PSI	Rate RVBD	Press PSI	Rate BWPD	Press PSI
1973	597	1115	709	1566	566	1131
1974	393	1108	396	1480	452	1189
1975	375	1261	—	—	418	1291

Cumulative water injection to 11-1-72

8 Phase I 7929 MBW (991 MBW/well)
8 Offsets 7754 MBW (969 MBW/well)

exhibited a decreasing input rate and increasing injection pressure over the period shown, reflective of continued waterflood fillup and reservoir pressure increase in this part of the unit. The Phase I injectors averaged 385 BWPD per well in 1974 and 1975 compared with 435 BWPD per well for the offset water injectors over this same period. Also, water injection pressures for the CO_2 wells were slightly lower than the offsets.

The 1973 average CO_2 injection rate was 709 RVBD compared with the average alternate water injection rate of 597 BWPD. This is a result of exceeding the fracture extension pressure in some wells while on CO_2 injection. The 1974 average CO_2 injection rate of 396 RVBD reflects the efforts to control and balance CO_2 injection in that year.

Injection pressure trends and transient pressure tests run in the area around Phase I indicate that the reservoir pressure was maintained around 2000 to 2500 psi. The profile surveys run in Phase I showed good conformance to the overall pay interval. Figure 4 shows results of a water injection survey run on Well 85. Small acid treatments were performed on three of the injectors using 15% HCl acid to open plugged perforations and increase permeability around the wellbore.

CO_2 Production

As mentioned in the previous section, some production of injected CO_2 has been experienced, apparently as a result of overpressuring while on

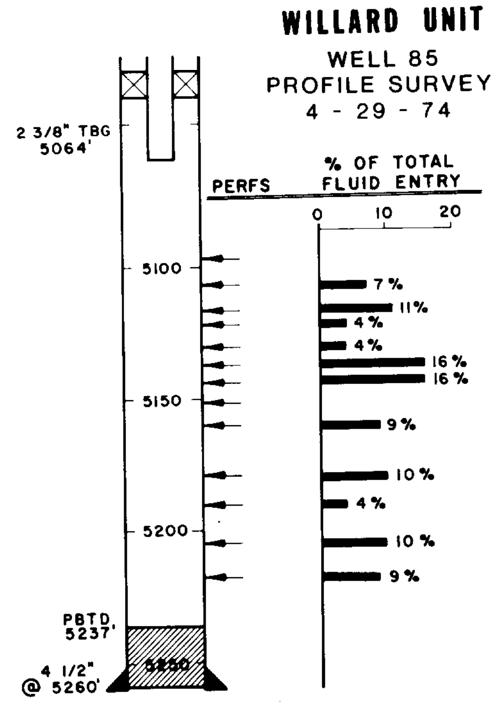

FIGURE 4—PHASE I WELL 85 WATER INJECTION PROFILE.

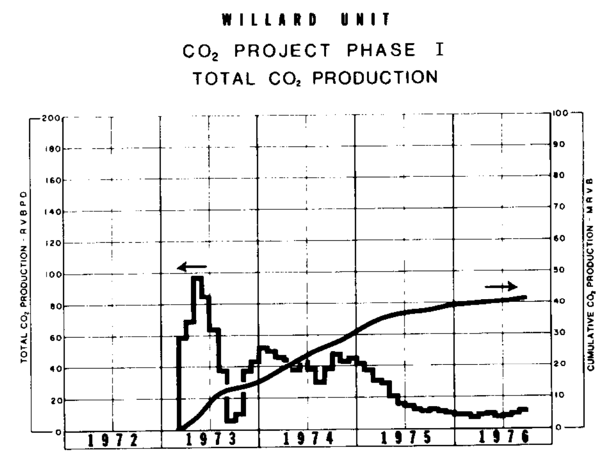

FIGURE 5—PHASE I TOTAL CO_2 PRODUCTION.

CO_2 injection. Figure 2 shows the wells that have produced CO_2 in excess of background levels, and Figure 5 is a graph of total CO_2 production from these wells.

CO_2 production was first observed in Wells 68A, 103B, and 104 in March, 1973, and in Well 67A in May, 1973. The peak total CO_2 rate from these wells was 100 RVBD or 4% of the CO_2 injection rate at that time. Injection Well 86 was suspected to be the source since it has a high CO_2 cumulative relative to the other injectors and had experienced injection rates in the range of 1000 to 1700 RVBD of CO_2

WILLARD UNIT

CO_2 PROJECT PHASE I

CO_2 PRODUCTION - WELLS 68 A & 103 B

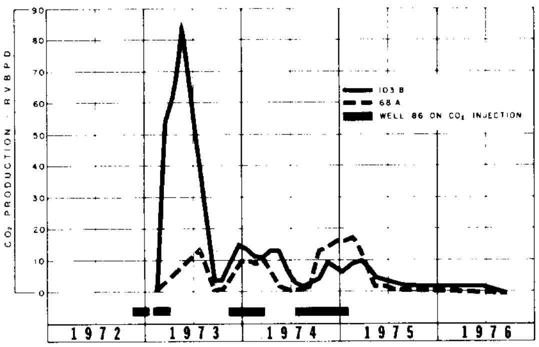

FIGURE 6—PHASE I WELLS 68A AND 103B CO_2 PRODUCTION.

shortly after conversion to CO_2 injection. Also, Wells 67A, 68A, and 103B offset Well 86 along a line running approximately N 113°E. Borehole televiewer measurements in Well 87 indicated this to be the induced fracture orientation in this area. Well 86 was placed on water injection at a rate of 400 BWPD in April, 1973, and the total CO_2 production dropped to 10 RVBD or 10% of the peak rate by September, 1973. Production from Wells 67A, 68A, and 103B has been controlled since that time by limiting CO_2 and water injection rates in Well 86 to around 500 RVBD. Figure 6 shows the CO_2 rate performance from Wells 68A and 103B relative to the CO_2 injection cycle periods in Well 86.

In October, 1973, injection rates over 1000 RVBD of CO_2 per well were experienced in other Phase I injectors as a result of testing at the compressor plant. CO_2 production was noted in several other offsetting producers along the fracture orientation. Total production rose to 50 RVBD of CO_2 in January, 1974. By this time most of the mechanical difficulties with the wells and compressor plant were solved and CO_2 and alternate water injection rates were balanced and controlled to 500 RVBD per well or below. CO_2 wellhead injection pressures were limited to 1500 psi or less. Production stabilized between 40 and 50 RVBD of CO_2 or 2.5% of the average 1974 injection rate.

A total of 13 offsetting producers have experienced CO_2 breakthrough. Cumulative production is 41 MRVB of injected CO_2 or only 2.5% of the total cumulative Phase I injection. Of this, 24 MRVB, or 59% of the total CO_2 production came from Wells 68A and 103B. Total CO_2 rate fell markedly following the termination of CO_2 injection and currently only 8 to 10 RVBD are being produced.

In summary, total CO_2 production is small relative to total injection. More than 97% of the cumulative CO_2 injection has been retained in the reservoir. The cyclic behavior of the CO_2 production with CO_2 and water injection cycling, and the orientation and distances of the producers relative to the CO_2 injectors all suggest the CO_2 flowed down induced fracture channels. This was controlled by lowering the CO_2 injection rates and pressures to balance with the alternate water injection. There is no evidence of unfavorable sweep conditions, even to CO_2 cumulatives in excess of 6% HCPV in some patterns. The high CO_2 retention and absence of CO_2 breakthrough associated with poor areal sweep are further indications that the reservoir pressure was maintained well above the minimum pressure required for miscible displacement.

Production Performance

The Phase I area was in the mid-range of waterflood maturity at the start of CO_2 injection. Cumulative water injection averaged about 1 MMBW per well, or 22% of the HCPV. The offsetting producers had experienced a gas-oil ratio decline and oil production increase and average

WILLARD UNIT

CO_2 PROJECT PHASE I

PRODUCTION PERFORMANCE

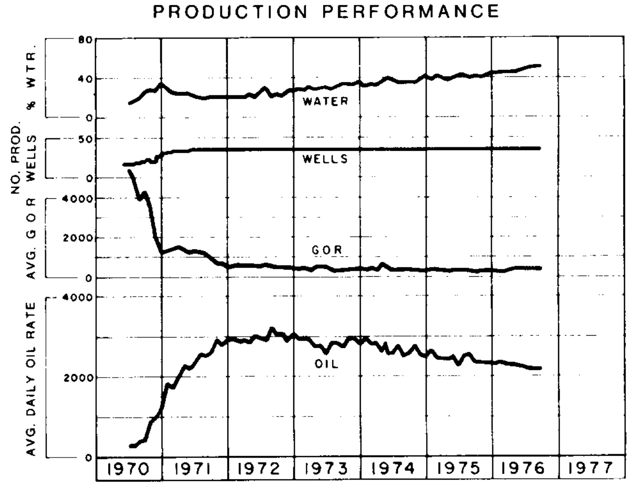

FIGURE 7—PHASE I PRODUCTION PERFORMANCE.

water cut was 27% of total fluid rate. Figure 7 shows the production performance of the producers adjacent to the Phase I injectors and the eight immediate offset water injection wells.

In principle, Phase I would have provided a measure of the additional oil recovery to be expected from CO_2 flooding. However, since less than 0.3 pore volumes of water had been injected before initiating CO_2 injection, the ultimate oil recovery from waterflooding would have to have been estimated rather than actually measured. Also, since the Phase I area was on regular waterflood pattern spacing, many years would have been required before the miscible flood would be sufficiently advanced to permit a thorough performance evaluation.

In actuality, less than a 5% HCPV slug of CO_2 was injected in Phase I. This was probably too small to noticeably affect oil rate and recovery performance. It is significant that no premature anomalous production behavior was noted that would point to extreme stratification or sweep problems. Also, the small amount of CO_2 production experienced in some wells has not caused any adverse effects on the hydrocarbon production or the scale or corrosion levels of the wells.

PILOT

Review

As discussed in the introduction, the Pilot was designed for a short term investigation of the factors influencing fluid flow behavior in this reservoir. The test included four wells: Well 32A, the CO_2 and water injector; Well 32AC, the pressure core well; Well 32AO, logging observation; and Well 32AS, pressure monitoring and fluid sampling.

The Pilot area was retained under solution gas drive for the purpose of the test. The waterflood had been expanded to areas of the unit surrounding the Pilot in 1969 and 1970. Well 32A, the CO_2 and water injector, and the two regular-spacing east and west offsets, Wells 31A and 33A, were not placed on water injection until the start of the Pilot in August, 1972. Wells 31A and 33A received no CO_2 injection but were used to balance fluid movement in the Pilot area. Well 32A was cased through the San Andres pay, selectively perforated and fracture treated with 15,000 gallons of fluid.

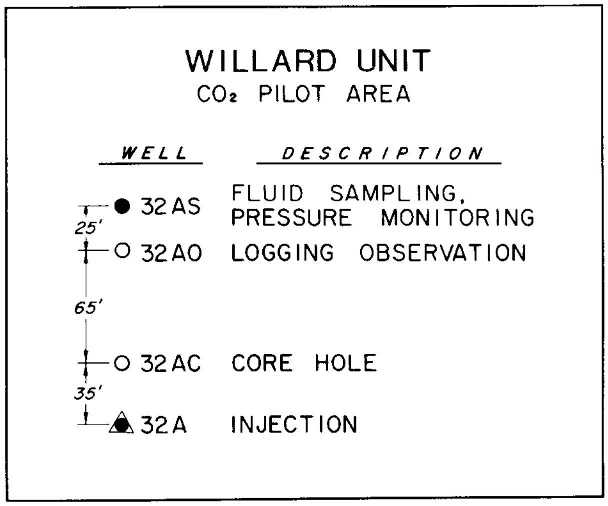

FIGURE 8—PILOT AREA.

Wells 32AO and 32AS were directionally drilled in the summer of 1972 to the approximate bottom hole locations relative to Well 32A shown on Figure 8. Both were conventionally cored and logged with open hole porosity and resistivity devices to allow a complete geological study of the area. Well 32AO was completed 100 ft from Well 32A with a liner through the pay and was not perforated. This permitted the use of compensated and pulsed neutron logs for estimates of gas and water saturation changes respectively using time lapse logging techniques.[4,5] Well 32AS was completed 25 ft from Well 32AO with a full casing string and selectively perforated over the same interval as Well 32A. This well was not sand fracture treated but was stimulated with very small-volume, low-rate acid jobs so as not to disturb the area around Well 32AO. Well 32AS was used for pressure observation and for sampling fluids moving near the well. As such, it was not intended to provide a representative production performance as in a pattern-type Pilot. Well 32AC was directionally drilled in April, 1976, about 35 ft from Well 32A and pressure cores were taken across the entire pay interval. A full program of open hole logs was run to compliment the pressure cores and aid in geological studies.

The data collection and surveillance program included the following:

1. Daily injection rate and temperature measurements at Well 32A. Injection rates were taken weekly on Wells 31A and 33A.
2. Continuous injection pressure measurements

on Wells 31A, 32A, and 33A and continuous casing pressure monitoring of Well 32A.

3. Compositional analyses of the water injected Well 32A and the produced water and gas from producers offsetting the Pilot area.
4. Periodic water injection profile surveys and pressure falloff tests on the three injection wells.
5. Monthly compensated and pulsed neutron logging in Well 32A0.
6. During the CO_2 flood, weekly bottom hole pressure measurements in Well 32AS when shut-in, and fluid level determinations when sampling.
7. Periodic production sampling from Well 32AS and analyses of produced fluids. This testing would be dictated by the results of the logs run in Well 32A0.

History

Water injection was initiated in August, 1972. Well 32A received Willard Unit produced water with salinity levels very close to the connate water salinity in the Pilot area. This was done to eliminate uncertainty in the time-lapse logging program. By December 15, 1973, 447 MBW had been injected in Well 32A and the log monitoring program indicated that the major porous intervals in the pay had been waterflooded. Production sampling at Well 32AS verified that the area had essentially been watered out.

CO_2 was injected in Well 32A from December 15, 1973 to February, 1975. During this time CO_2 and water were injected in alternate, equal reservoir volumes. The Bottom hole injection pressure was held as nearly as possible at the same level during the alternating CO_2 and water cycles to promote uniform entry of fluids across the entire interval. To February, 1975, a total of 87 MRVB of CO_2 and 75 MBW had been injected in Well 32A.

Well 32AC, the pressure core well, was completed in April, 1976, and will provide quantitative measurements of the reduction in waterflood residual oil levels resulting from the CO_2 injection. Nineteen cores totaling about 170 ft were taken over the entire pay interval. The coring project was very successful, with 18 of the 19 cores recovered under pressure. Reference No. 6 describes the operation of the pressure core program.

Results

Figure 9 shows the injection performance of Well 32A and the reservoir pressure as measured in Well 32AS for 1974. Injection performance of both fluids was very good. Injection rates were nearly constant at 400 BPD and surface injection pressures stabilized around 1300 psi for CO_2 and 800 psi for water. Pressure observations in Well 32AS showed that the reservoir pressure was maintained at 2100 to 2300 psi, which is well above the minimum miscibility level of 1250 psi. Injection profile surveys in Well 32A indicated excellent vertical conformance of the injected fluids.

Figure 10 illustrates the core air permeability and porosity profiles along with compensated and pulsed neutron log overlays from Well 32AO. The

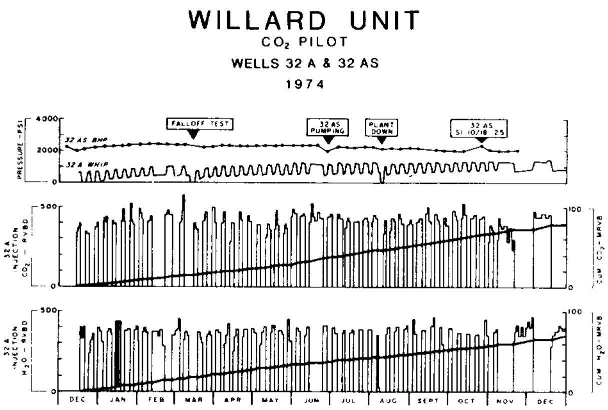

FIGURE 9—PILOT OBSERVATION WELL 32A0 CORE AND LOG DATA.

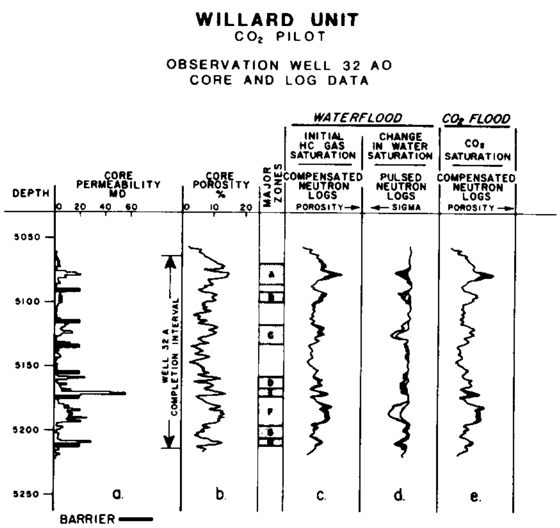

FIGURE 10—PILOT INJECTION AND PRESSURE HISTORY 1974.

permeability and porosity profiles, segments a and b of Figure 10, show that the formation can be characterized as a series of porous and permeable intervals that are separated by dense streaks that act as barriers to vertical fluid flow.

The compensated and pulsed neutron log exhibits, segments c and d on Figure 10, are overlays of logs run near the beginning and end of the waterflood portion of the test. The compensated neutron logs showed an initial gas saturation that was distributed fairly uniformly across the entire pay interval. This gas saturation was observed to disappear as it was displaced by water and dissolved by oil as the waterflood progressed. The pulsed neutron logs showed an increase in the water saturation levels of the major porous zones as these were watered out. The gas and water saturation changes are evidenced by the displacement in the logs as shown on Figure 10.

Compensated neutron logs run during the CO_2 flood showed the establishment of a CO_2 saturation in zones A and E as shown in segment e of Figure 10. There is also an indication of CO_2 in the thick F zone directly below the E zone. Sampling in Well 32AS confirmed the presence of injected CO_2 as indicated by the logs.

A complete evaluation of the Pilot logging program has not been finalized, but several points are apparant based on the preliminary results. The logs indicate excellent vertical conformance of injected fluids, confirming the results of profile surveys run in the injection well. No gross gravity segregation of either initial free gas or injected CO_2 was observed across the entire pay interval. This behavior supports the stratified flow concept where vertical barriers serve to restrict vertical migration of fluids. This condition should promote good vertical coverage of the pay under CO_2 miscible flooding. Finally, the CO_2 saturation displayed by the compensated neutron logs suggests that additional oil displacement has occurred as a result of the CO_2 injection.

A complete, quantitative study of the Pilot test will incorporate the results of both the time-lapse logging in Well 32AO and the pressure cores recovered from Well 32AC. Both of these are still in various stages of analysis and as such, much of the information to be gained is not as yet available.

When the log and pressure core data is fully evaluated, this information will be used to calibrate reservoir simulation models to permit prediction of the performance of CO_2 miscible flooding in the Willard Unit.

CONCLUSIONS

1. Alternate CO_2 and water injection performance of the Phase I injection wells was comparable to the water injection performance of the immediate offsetting water injectors. Phase I profile surveys showed that vertical conformance to the pay interval was good. The reservoir pressure was maintained above the minimum required for CO_2 miscible displacement.
2. Approximately 97% of the CO_2 injected in Phase I has been retained in the reservoir and there was no evidence of severe gravity segregation or areal sweep problems.
3. Of the total CO_2 injected in Phase I, 3% has been produced. This resulted from exceeding the fracture extention pressure for short periods of time in some injection wells while on CO_2 injection.
4. The CO_2 production in Phase I was effectively controlled by lowering the CO_2 injection rates and pressures to balance with the alternate water injection.
5. Less than a 5% HCPV total CO_2 slug was injected in Phase I. This volume was probably too small to noticeably affect oil rate and recovery performance. No premature or anomalous production behavior was noted that would point to extreme stratification or sweep problems.
6. Alternate CO_2 and water injection performance of the Pilot injection well was good. Injection rates were stable and pressure observations in Well 32AS showed that the reservoir pressure was maintained well above the CO_2 miscible pressure. Injection profile surveys in Well 32A and the logging program in Well 32A0 both indicate vertical conformance to the pay interval was excellent.
7. Pilot core data and the fluid flow behavior as observed with the logging program in Well

32A0 verify the concept of stratified flow in the reservoir. No significant gravity segregation of either initial free hydrocarbon gas or of injected CO_2 was observed.

8. The CO_2 saturation displayed by the compensated neutron logs run in the Pilot suggests that additional oil displacement has occurred as a result of the CO_2 injection. The pressure coring program in Well 32AC was very successful and will provide quantitative measurements of the reduction in waterflood residual oil levels resulting from the CO_2 injection.

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