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A REVIEW OF THE WEST SUSSEX UNIT CO_2 FLOOD PROJECT

By
Dwight L. Dauben

November 1988

Performed Under Contract No. AC19-85BC10830

K&A Technology
Tulsa, Oklahoma

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SUMMARY

Conoco, Inc. conducted a miscible CO_2 pilot flood in the Shannon Formation of the West Sussex Unit, Johnson County, Wyoming. The unit is located in the western edge of the Powder River Basin and consists of a highly faulted anticlinal structure in which hydrocarbons are trapped. The field has been extensively depleted through primary recovery operations and by a successful waterflood. The purpose of the pilot project was to determine if CO_2 flooding will recover sufficient quantities of tertiary oil to be economic.

The CO_2 pilot consisted of a four-spot, with three producers and a single injector. Carbon dioxide was delivered in liquid form by transport trucks from a distance of 175 miles and successfully injected into the reservoir. It was estimated by Conoco that the CO_2 flood produced an incremental oil recovery of 16,000 barrels, requiring 12.9 MCF of CO_2 per barrel of oil produced. The project was considered successful by Conoco and potentially economic if expanded. An expansion would require the construction of a pipeline to deliver CO_2 to West Sussex, as well as to other fields in the Powder River Basin.

Our review indicates that the project was well designed and implemented. The project yielded an oil recovery response. However, questions have been raised as to the relative contributions of CO_2 and water injection on the oil recovery response. Although the reservoir had been extensively waterflooded, pockets of oil were likely bypassed due to the presence of the numerous faults and to large permeability contrasts within the formation. The installation of the CO_2 pilot may have produced some secondary recovery responses as a consequence of the smaller pattern and different flooding direction. The selection of the pattern type may have influenced the production response since the producers are strongly influenced by operations outside of the pilot.

The project is considered to have potential for expansion. However, the prospects are hampered by the lack of a nearby CO_2 source. This project, as well as others, points out the need to develop CO_2 resources on a local basis using advanced design processing and available energy resources such as natural gas, coal, and lignite.

INTRODUCTION

The West Sussex Field is located in the western edge of the Powder River Basin, in Johnson County, Wyoming. This field was discovered in 1951 with the completion of a well in the Shannon Formation. The field consists of an anticlinal structure, contained by a major fault which extends approximately seven miles. The structure is characterized by a series of normal or oblique-slip faults which branch off the main fault system and divide the field into several discrete blocks. The Shannon Formation is a shaly marine sandstone of Late Cretaceous age. Conoco operates the West Sussex Unit (Figure 1), which occupies the southwestern four miles of the structure. Texaco operates the three-mile long Dugout Creek Unit in the northwestern portion of the field. Table 1 lists the basic reservoir properties of the field and the pilot.

A pilot waterflood was installed in the West Sussex Unit in 1955, and a full scale waterflood began in 1959. Seven water injection wells were drilled downstructure within the aquifer, forming a peripheral flood pattern. Upstructure producers were converted to injectors upon flood out to sweep greater portions of the individual fault blocks. Patterns were generally developed on about 20-acre spacing and became more random with time.

Table 2 summarizes the recovery projections for primary and secondary recovery operations. As shown, the projected recovery from primary and secondary recovery operations was about 44 percent of the original oil-in-place. The unit was nearing the end of its economic life and was considered a good candidate for the CO_2 project.

The West Sussex test was conducted under the Tertiary Incentive Crude Oil Program for a specific enhanced oil recovery technique. K&A Technology is evaluating many of the EOR projects conducted under the Cost/Shared and the Tertiary Incentive programs under a contract with the DOE. The evaluations are made available to the public.

The purposes of this report are to independently evaluate the performance of this project, to determine how the project could have been improved using advancements in technology, and finally, to define critical areas of research that are needed to further develop the technology.

The primary sources of information used for this evaluation are from References 1 and 2. Reference 1 provides a good review of the project and its performance. This report summarizes the key points from that paper and evaluates the design and performance of the project.

PROJECT DESIGN

The pilot area was selected using the criteria that (1) the project will be evaluated principally by "oil-in-the-tank", and (2) watered-out producers will be used to permit easy identification of tertiary oil. The intent was to avoid observation wells (which contribute significantly to costs) and to avoid the use of miniature well patterns. Selection of a suitable pattern area was difficult due to the highly faulted nature of the field. An initial pilot area was rejected after drilling a new injector and discovering it was not in communication with three existing producers. The pattern ultimately selected is shown in Figure 1. This pattern was selected after determining that the three producing wells were in communication with each other, based upon pressure pulse tests. Well 114 was drilled as the pilot injector.

A miscible flood simulator was used to develop operating guidelines for the injection and withdrawal from the pattern and to predict tertiary oil recovery. One constraint was the availability of liquid CO_2, which came from Conoco's plant in the McCallum Field, Jackson County, Colorado. Producing rates were specified to achieve pattern balancing and to optimize oil recovery. The simulations predicted a recovery of 19,500 barrels from the pilot, which was about 25 percent of the remaining oil-in-place (or about 9.6 percent of the original oil-in-place). A CO_2 slug volume of 30 percent pore volume was assumed, with a computed CO_2 utilization of 10.6 MSCF per barrel of oil recovered. Table 3 lists the predicted and actual recoveries achieved in the pilot.

Slim tube tests using 95 percent purity CO_2 indicated the minimum miscibility pressure to be in the range of 1,500 to 1,600 psi. The reservoir pressure at pilot initiation was about 2,150 psi, indicating that miscible displacement could be achieved.

PILOT IMPLEMENTATION

West Sussex Well 114 was drilled as the pilot injector. Logs from this well indicated an oil saturation of about 28 percent, which was near the waterflood residual level. Production tests conducted in Wells 13 and 19 indicated oil cuts of about 1.5 percent; whereas, Well 53 (a former injector) was flowing essentially 100 percent water.

Water was injected into Well 114 beginning on July 31, 1982, to establish stabilized flow conditions and to better understand the reservoir prior to CO_2 injection. A 10 Curie tritiated water tracer slug was injected on August 6, 1982, and offset producers were periodically monitored for the tracer. Tracer breakthrough occurred in Well 19 after about three weeks, and in Well 13 after about seven months. Tracer was never observed in any significant quantity in Well 53. Produced fluids were also analyzed for iron content as a corrosion indicator and for the presence of CO_2.

The liquid CO_2 used in the pilot was obtained from a liquification plant in the McCallum Field in Jackson County, Colorado. The CO_2 was transported 175 miles by refrigerated tank trucks, maintained at a temperature of 0°F and a pressure of 300 psia. The CO_2 was delivered over a ten month period beginning December 21, 1982. No problems were encountered in delivery, but the reduced plant capacity during the summer months resulted in lower injectivity during that period (Figure 2).

PROJECT PERFORMANCE

Figure 3 shows the total production from the pilot. The combined production rose to about 33 barrels of oil per day (BOPD) in September 1983, but declined to 13 BOPD by December 1983. The decreased oil production was apparently due to wellbore plugging from paraffins. Several operational changes were implemented at this point to improve performance, including:

1. Increased injection rate, to encourage a response in Well 53. A step rate test indicated that the new rate would not exceed the pressure parting level.

2. Increased production rate from Well 53, while still maintaining an overall consistent injection-withdrawal balance.

3. Stimulation of the three producers with hot oil to cut the paraffin deposits. The total production increased substantially to 79 BOPD. Production thereafter declined steadily, as shown in Figure 3.

Figure 7 shows the oil production response in Well 19. An apparent increase in oil cut occurred about one month after CO_2 injection began. The early response corresponds with the early breakthrough of the previously injected tracer. Figure 5 shows the oil production in Well 13. Oil response occurred about six months after CO_2 injection, which also corresponds with the tracer breakthrough time. There appeared to be virtually no response in Well 53.

Several possible explanations were offered by the operator for the lack of response in Well 53, including:

1. Well conversions. The well was originally drilled as a producer, later converted to an injector, and then converted back to a producer for the pilot. This history of conversions may have produced high water saturations around the well, which contributed to the lack of response.

2. Extraneous water. The possibility was raised that extraneous water may be entering the wellbore by behind-the-pipe channeling from another zone or by communication from outside of the pattern.

3. Gravity effects. Gravity effects tend to move the injected CO_2 toward Wells 19 and 13 since those wells are updip with respect to Well 53.

4. Low sweep efficiency. It is possible that the CO_2 may have contacted a smaller than anticipated volume of the reservoir in the vicinity of Well 53.

Corrosion problems appeared to be minimal. Although CO_2 broke through early in Well 19, there appeared to be no corrosion-related problems. Iron from produced water remained low throughout the pilot, indicating that severe corrosion problems were not occurring. Well 19 did have a minor tubing leak, which is not unusual in Shannon waterfloods.

Injectivity was satisfactory throughout the pilot operation. There were concerns that the injection of liquid CO_2 (at 0°F) could lead to the freezing of water in the annulus with consequent damage to the casing. To minimize this risk, the upper 160 feet of water in the annulus was removed and replaced by nitrogen. A downhole temperature survey conducted near the end of CO_2 injection indicated that there was no evidence of casing damage.

Paraffin problems were handled by hot oil treatments. It is possible that the buildup of paraffins on the tubing helped to minimize corrosion problems.

The ultimate tertiary oil recovery was estimated to be about 16,000 barrels, divided equally between Wells 13 and 19. Essentially no tertiary oil was attributed to Well 53. This recovery level compares with 19,500 barrels which had been predicted as shown in Table 3. The ultimate CO_2 utilization was estimated to be 12.9 MCF per barrel of oil recovered.

About 20 percent of the injected CO_2 was produced. The volumetric sweep efficiency was computed to be 52 percent, by assuming that the oil saturation in the contacted area was reduced to 10 percent. The assumption of a 10% residual saturation was considered reasonable, but was not supported by any field measurements.

The operator considered that the project was successful and could be expanded given an adequate supply of CO_2. A pipeline would be required for a commercial operation. A large supply of CO_2 exists in the LaBarge Field in southwest Wyoming. Although the size of the West Sussex Field does not justify a separate line, there are numerous other fields in the Powder River Basin which could potentially be flooded with CO_2. The justification for such a pipeline is strongly dependent upon the price of oil.

PROJECT EVALUATION

This discussion provides our evaluation of the design and performance of the CO_2 pilot in the West Sussex Unit. Recommendations are made on improvements.

DESIGN

In general, the project was well designed and executed. The following are some of the key elements of the design.

1. Suitability of the Reservoir. The reservoir appears to be a suitable candidate for CO_2 flooding. The reservoir pressure was well above the minimum miscibility level as a result of extensive water injection. Thus, there is little doubt that miscibility conditions were achieved. The waterflood was successful, indicating that injected CO_2 should contact a sufficient volume of the reservoir. An adequate residual oil saturation existed in the reservoir after waterflooding (28 percent), providing an ample target for tertiary oil recovery. The major question concerning the viability of CO_2 flooding is reservoir heterogeneity. The reservoir is known to contain large permeability contrasts (Dykstra-Parsons permeability variation factor of 0.9) and to be highly faulted (Figure 1). Although the waterflood was successful, the CO_2 might sweep much less of the reservoir than the waterflood due to gravity effects, the more limited volumes injected and the lower fluid viscosities.

2. Selection of the Pilot Area. Selection of a suitable site was a problem due to the numerous faults and permeability contrasts. An initial site was rejected after discovering communication problems between the injector and producers. The waterflood was less affected by faults due to the use of multiple, down-dip injectors

to form a phderpheral flood pattern. Even with this pattern, however, it is likely that pockets of oil were bypassed during the waterflood.

The pattern ultimately selected was considered to be sufficiently uniform, based upon pressure pulse tests conducted between the producing wells. As later determined, however, very poor communication existed between the injector and Well 53. Adequate communication existed between the injector and the other two producers.

3. Pattern Selection. The pilot pattern was a four-spot (Figure 1) consisting of one injector and three producers. The advantage of such a pattern is that a minimum amount of CO_2 is required to test the process. This was a major consideration due to the limited supply of CO_2 and the transportation expenses. The major disadvantage is that the producers are subject to influences outside the pattern. The operator sought to minimize off-pattern influences by maintaining an injection/withdrawal of approximately 1 throughout the project. It was also reasoned that any oil recovered would be a result of the CO_2 injection since oil cuts were extremely low from the on-going waterflood operation. Tracers were also injected to better define the reservoir characteristics and to help determine if fluids were being confined to the pattern.

Regional pressure gradients also influence the pilot operation. Although reservoir pressure data were not provided, it is likely that a regional pressure gradient existed in the reservoir in the down-dip to up-dip direction. This would be expected from the large-scale down-dip water injection operation. It could be expected that these regional pressure gradients would greatly influence the pilot producers since only one CO_2 injection well was used. In particular, communication of the CO_2 injector (Well 114) with the most down-dip producer (Well 53) might be difficult because of the prevailing reservoir pressure gradient.

The presumption that all produced oil can be attributed to CO_2 injection may not be valid. As earlier indicated, the waterflood operation may have bypassed oil due to the faults and other heterogeneities within the reservoir. It is possible that the CO_2 pilot might generate a secondary oil recovery response due to the smaller pattern and to the different flooding direction. The five months of water injection prior to CO_2 injection may not have been sufficient to determine which portion of the oil response was due to the water or to the CO_2.

4. <u>Pilot Evaluation Procedures</u>. Initially, pressure pulse tests were conducted between the producers to establish continuity. This information provided sufficient data about the reservoir continuity to justify the drilling of the injection well. These pressure pulse tests proved to be worthwhile in assessing the suitability of a particular pilot location. Various other EOR projects have experienced serious interpretation problems due to questions of reservoir continuity.

Operating guidelines were established to help confine the CO_2 to the pattern area and to improve interpretation of the final results. An injection/withdrawal ratio of approximately 1 was designed for the pilot. Efforts were made to maintain the designed injection/withdrawal at a constant level in spite of periodic changes in the oil producing rates. Without maintaining a constant injection/withdrawal ratio, the pilot would be subject to varying influences from conditions outside the pilot.

Water was injected for a period of about five months before CO_2 injection began to establish baseline waterflood conditions. Tritiated water was also injected to determine if any adverse channeling occurred and to aid in the interpretation of oil recovery response from the CO_2 injection. These procedures proved to be very worthwhile in evaluating the project.

The principal means for evaluating performance is the amount of oil produced. There were no monitor wells to collect samples from or to monitor saturation or pressure changes. The basic strategy used for evaluation of the pilot is sound, except for the possible influences of the pilot pattern on secondary recovery performance.

PILOT PERFORMANCE

The reported incremental oil recovery for the pilot is about 16,000 barrels, with half coming from Well 13 and the remaining oil from Well 19. Almost no response was observed in Well 53. Figure 3 shows the response from the pilot. Figures 5 and 7 show comparable data for Wells 13 and 19, respectively.

Increased oil cuts were observed in Well 19 about one month after the injection of CO_2 (Figure 7). This compares with about three weeks breakthrough time for the tracer injection.

Increased oil cuts were reported for Well 13 about six months after CO_2 injection (Figure 5). This corresponds to about seven months for tracer breakthrough into the well.

The assignment that all of the incremental oil came from CO_2 injection is questioned for the following reasons:

1. A considerable amount of the CO_2 probably left the pattern area. Recovery computations from the produced tracer data from Wells 13 and 19 indicate that about 41 percent of the injected tracer was recovered (refer to Table 4). Since an injection/withdrawal ratio of approximately 1 was maintained throughout the project, this suggests that much of the produced fluids originated from outside of the pilot. The tracer data indicate that most of the injected CO_2 went outside of the pattern. This could occur if there were strong regional pressure gradients.

2. Analysis of the produced fluids does not show clearly discernible response due to the CO_2 injection. As shown in Figure 3, the total pilot production was trending upward before response to CO_2 injection was expected. The early response may have been due to water injection. The response in Well 19 does indicate an increase in oil production rates at about the expected time (Figure 7). However, no readily distinct CO_2 response was observed in Well 13 (Figure 5). As earlier discussed, the sharp production increases observed in early 1984 were due to workovers which removed paraffins. These data indicate that water should have been injected for a longer period of time to establish a clear baseline of performance. With the existing data, it is difficult to identify the relative contributions of water and CO_2 injection.

3. Oil recovery from the individual wells does not correspond with the level expected from tracer analysis. Table 4 shows the relationship of oil and tracer recovery. In EOR projects, there is a general correspondence of oil recovery and tracer recovery, since the injected EOR fluids follow the approximate path of the tracer through the reservoir. There should be a general correspondence providing that oil saturations are similar within the respective areas of the reservoir. As shown in Table 4, Wells 13 and 19 each recovered about 50 percent of the total oil. This compares with about 30 percent tracer recovery in Well 13, and 70 percent tracer recovery in Well 19. These comparisons suggest that a portion of the oil recovered in Well 13 was due to water injection.

4. The very early breakthrough of injected fluids into Well 19 (tracer and CO_2) suggests that significant channeling was occurring between the injector and producer. This represents an unfavorable condition since much of the injected CO_2 was being circulated through a small portion of the reservoir and was not available to contact oil saturation in the matrix.

5. As shown in Figure 10, about 20 percent of the injected CO_2 was produced. It is difficult to make quantitative conclusions from

this information. Qualitatively, the CO_2 can be lost by several mechanisms, including flow outside of the pattern, trapped as a distinct gas phase, or absorbed within oil or water.

Collectively, it is very difficult to determine the relative amounts of oil that were produced by the CO_2 and by water injection. The tracer data in particular suggests that part of the response was due to water injection.

OPERATIONS

No major operational problems were encountered during the pilot project. CO_2 related corrosion problems were minimal, possibly due to paraffin deposition on the metal surfaces. Annular wellbore freezing occurred during the injection of liquid CO_2, but there was no evidence of casing damage.

The major operational concern was the delivery of liquid CO_2 from a plant located 175 miles away. Delivery was limited during the summer, which necessitated the reduction of CO_2 injection. It is not thought that this action affected performance, since the corresponding production well rates were also reduced.

The pattern was selected to conserve the limited CO_2 supply. If a more plentiful supply had been available, a more definitive evaluation could have been made by using multiple CO_2 injection wells.

EXPANSION PLANS

The operator concluded that sufficient oil was recovered to consider an expansion. The key elements are the availability and price of CO_2 and the price of oil. Expansion would require the delivery of large volumes of CO_2 by pipeline. The most feasible source may be from the LaBarge Field located in southwest Wyoming.

A key factor to be considered in project expansion is the amount of oil recovered in the pilot. The project clearly demonstrated that incremental oil was recovered. However, questions are raised as to the relative amounts of oil that can be attributed to CO_2 and to water injection. It would not be important to know the relative contributions, provided that an expanded operation would yield comparable total oil recoveries. However, uncertainties may develop since the previous water injection may have swept other areas more (or less) than in the present pilot area. Without knowing the quantity of oil displaced by the CO_2, uncertainties will exist on the recoveries that could be expected in a project expansion.

CONCLUSIONS

1. A well-defined production response occurred from the pilot operation.

2. The operator reports that 16,000 barrels of incremental oil was recovered from the pilot, representing 7.8 percent of the original oil-in-place.

3. A portion of the observed oil recovery response may be due to immiscible displacement from water injection, for the following reasons:

   a. Flooding on a smaller acreage pattern. Although producers were essentially watered-out, oil may have been bypassed in the larger pattern waterflood due to the numerous faults and large permeability contrasts known to exist in the reservoir.

   b. Relative recoveries of oil and tracer. The relative amounts of oil recovered at each of the producers do not correspond with the relative amounts of tracer recovered at those wells. General correspondence would be expected if the initial oil saturations within the respective area are at a similar level.

4. Producing wells appeared to be strongly influenced by conditions outside of the pilot, based upon the low total recovery of tracer in the producing wells. The evidence is that the single injector could not strongly control fluid production at the three offset wells in spite of pattern balancing designed to confine the fluid within the pilot area. Regional pressure gradients imposed by the earlier waterflood was probably responsible for the fluid drift.

RECOMMENDATIONS

Recommendations are offered with the knowledge that "hindsight is better than foresight" and that there have been advancements in the applications of EOR technology.

The one major area where the project could have been improved was in the pattern selection. It is recognized that such a pattern may have been imposed by the limited volumes of CO_2 available. Where feasible, a pattern utilizing multiple injection wells is recommended. This will improve the ability to interpret performance. The use of patterns involving a single injection well should be avoided where possible. Such patterns are strongly influenced by conditions outside of the pilot area, particularly where strong directional pressure gradients may exist.

RECOMMENDATIONS FOR FUTURE RESEARCH

This project points out a major problem in the implemention of CO_2 flooding technology. This problem relates to CO_2 supply. For West Sussex, the supply was limited and it was necessary to transport liquid CO_2 for 175 miles. Even if the project is considered to be successful, major financial commitments and considerable delays are required to build a pipeline to the point of use. All of these factors tend to limit applications to areas such as West Texas where a large supply of CO_2 is available.

Technology is needed for developing CO_2 resources closer to potential sources of application. The goal should be to develop CO_2 as the primary source, and not a by-product as for an ammonia or fertilizer plant. It should be possible to use basic energy sources such as natural gas, coal, or lignite to produce the CO_2. An example of a process requiring further technical and economic evaluation is a cogeneration plant in which oxygen (from an air separator unit) is combusted with natural gas to produce CO_2 and steam.

TABLE 1

WEST SUSSEX UNIT
BASIC RESERVOIR DATA

Productive Area, acres	1,532
Depth, feet	3,000
Average Net Effective Pay, feet	22
Average Porosity, percent	19.5
Average Permeability, md	28.5
Dykstra-Parsons Permeability Variation Factor	.9
Connate Water Saturation, percent	27
Initial Oil Saturation, percent	73
Initial Reservoir Pressure, psig	1,273
Bubble Point Pressure, psig	888
Reservoir Pressure at Start of Waterflood, psig	350
Reservoir Pressure at Start of CO_2 Injection, psig	2,150
Reservoir Temperature, °F	104
Initial Oil Formation Volume Factor, bbls/STB	1.143
Original Oil-In-Place, MMBO	33.2
Oil Gravity, °API	39
Oil Viscosity at Original Conditions, cp	1.37
Initial Solution Gas-Oil Ratio, SCF/STB	284
Average Oil Saturation at Waterflood Inception, percent	60.3
Residual Oil Saturation to Water Injection, percent	28
Pilot Properties	
Pilot Size, acres	9.6
Remaining Oil-In-Place Before Pilot Initiation, STB	78,000
Total CO_2 Injected, MMSCF	206

TABLE 2

PRIMARY AND SECONDARY RECOVERY PERFORMANCE FROM THE WEST SUSSEX UNIT

Primary Oil Recovery, MMSTB	6
Secondary Oil Recovery, MMSTB (10/85)	8
Primary and Secondary Recovery, percent original oil-in-place (10/85)	42
Cumulative Water Injection, MM bbls (10/85)	58.7
Total Water Injection Rate for 12 Injectors, BWD (10/85)	2,000
Total Oil Production Rate for 27 Wells, BOPD (10/85)	200
Total Water Production Rate From 27 Wells, BWPD (10/85)	2,800
Ultimate Primary and Secondary Recovery Performance, MMBO	14.4
Ultimate Recovery From Primary and Secondary Recovery, percent	44

<u>TABLE 3</u>

<u>TERTIARY RECOVERY PERFORMANCE</u>

	PREDICTED	ACTUAL
Oil Recovered, STB	19,500	16,000
Oil Recovered, Percent of Remaining OIP	25	20.5
Oil Recovered, Percent of Initial OIP	9.6	7.8
CO_2 Utilization, MSCF/STB	10.6	12.9

TABLE 4

OIL RECOVERY AND TRACER PERFORMANCE

	Predicted Oil Recovery, bbls	Actual Oil Recovery, bbls	Tracer Recovery, Percent Injected*	Comparative Recovery, Percent of Recovery	
				Oil	Tracer
Well 13		8,000	12.5	50	30
Well 19		8,000	28.5	50	70
Well 53		-	-	-	-
Total	19,500	16,000	41.0	100	100

* Projected estimate through 1986.

FIGURE 1

DETAIL MAP OF THE WEST SUSSEX UNIT

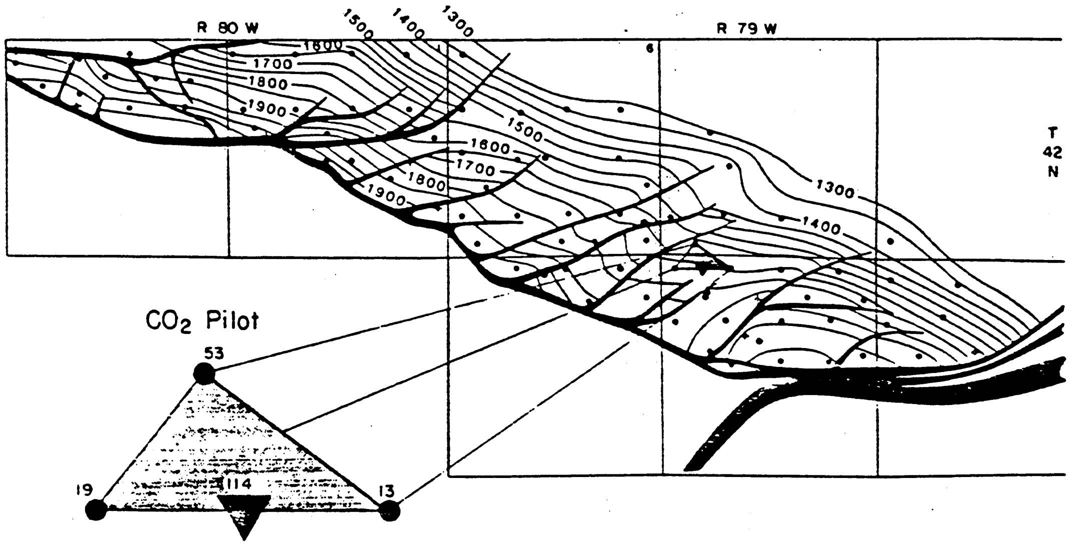
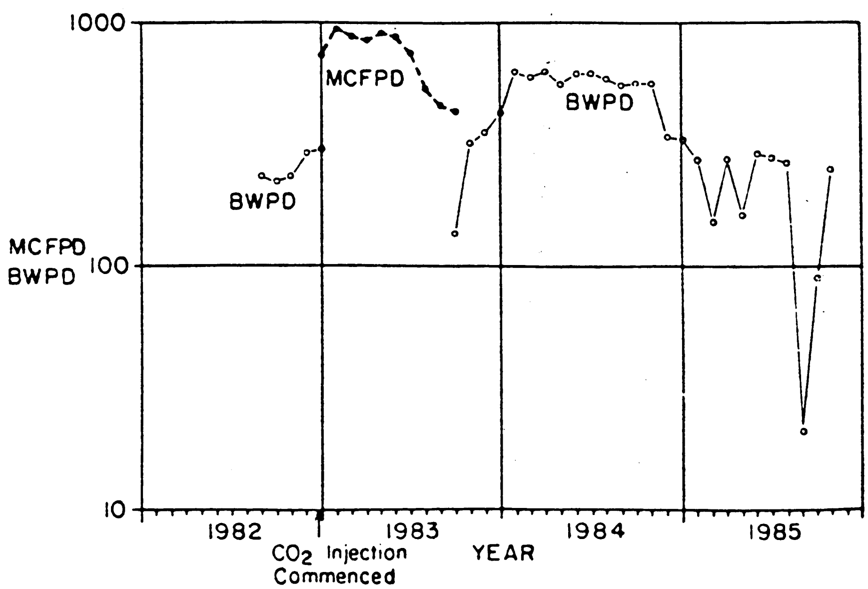


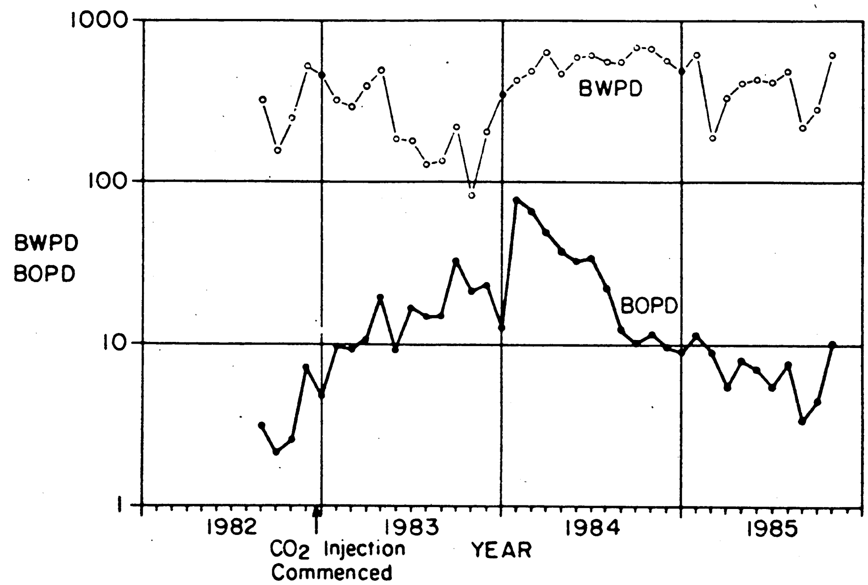
FIGURE 2

PILOT WATER AND CO_2 INJECTION HISTORY



<u>FIGURE 3</u>

PILOT OIL AND WATER PRODUCTION HISTORY



<u>FIGURE 4</u>

PILOT WELL NO. 13 - CO_2 AND TRACER PRODUCTION

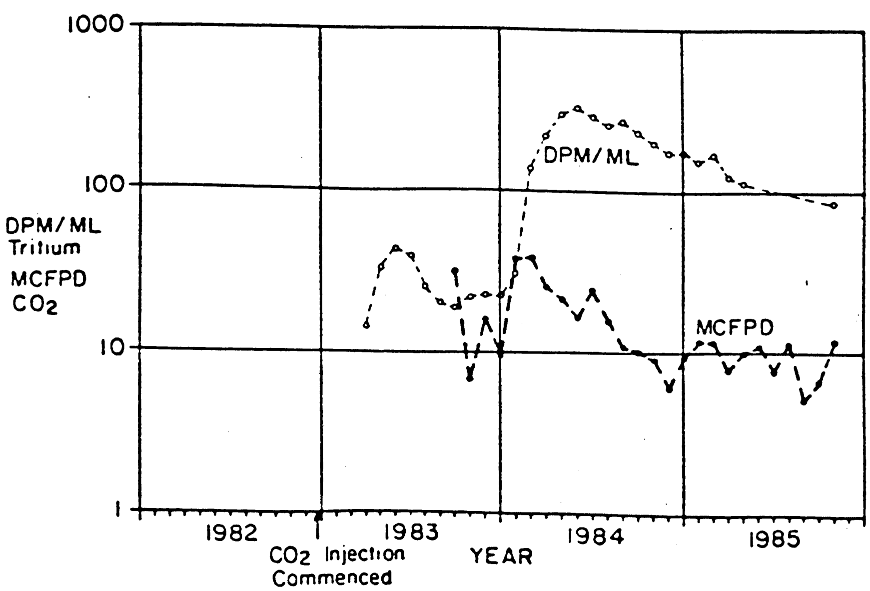


FIGURE 5

PILOT WELL NO. 13 - OIL AND WATER PRODUCTION

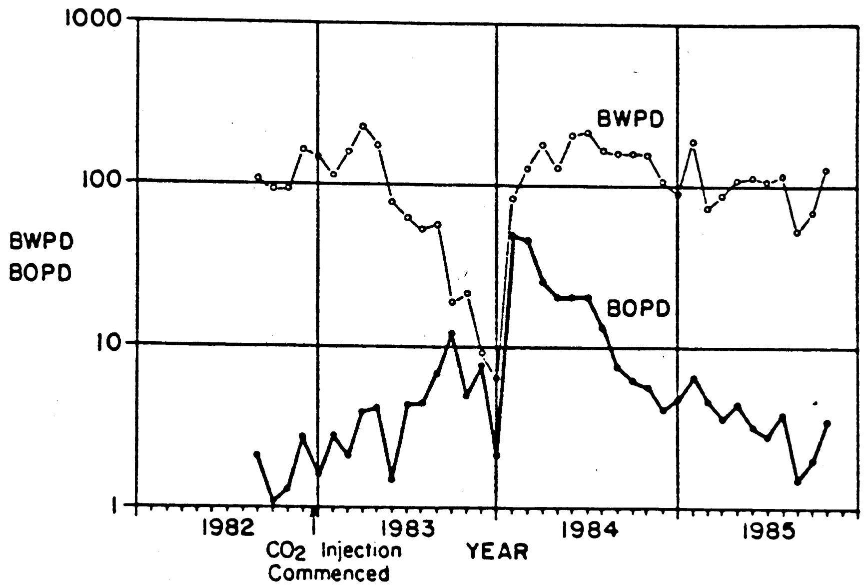


FIGURE 6

PILOT WELL NO. 19 - CO_2 AND TRACER PRODUCTION

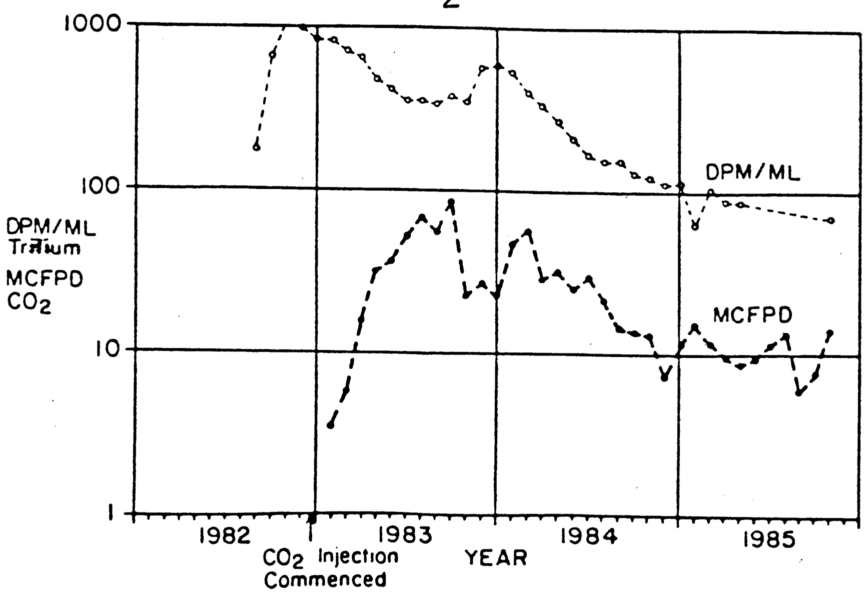


FIGURE 7

PILOT WELL NO. 19 - OIL AND WATER PRODUCTION

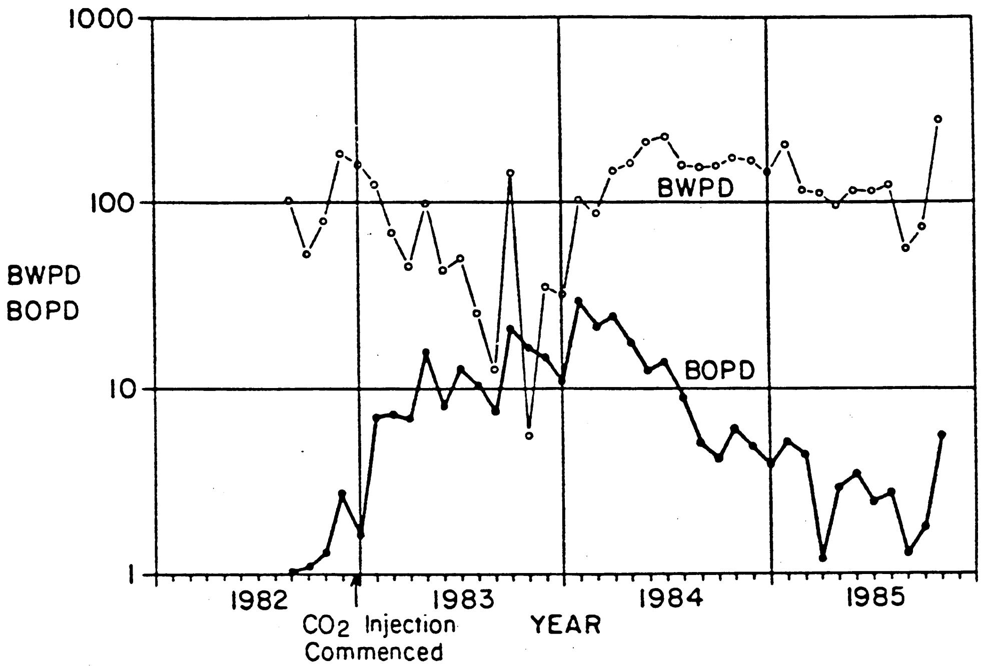


FIGURE 8

PILOT WELL NO. 53 - CO_2 AND TRACER PRODUCTION

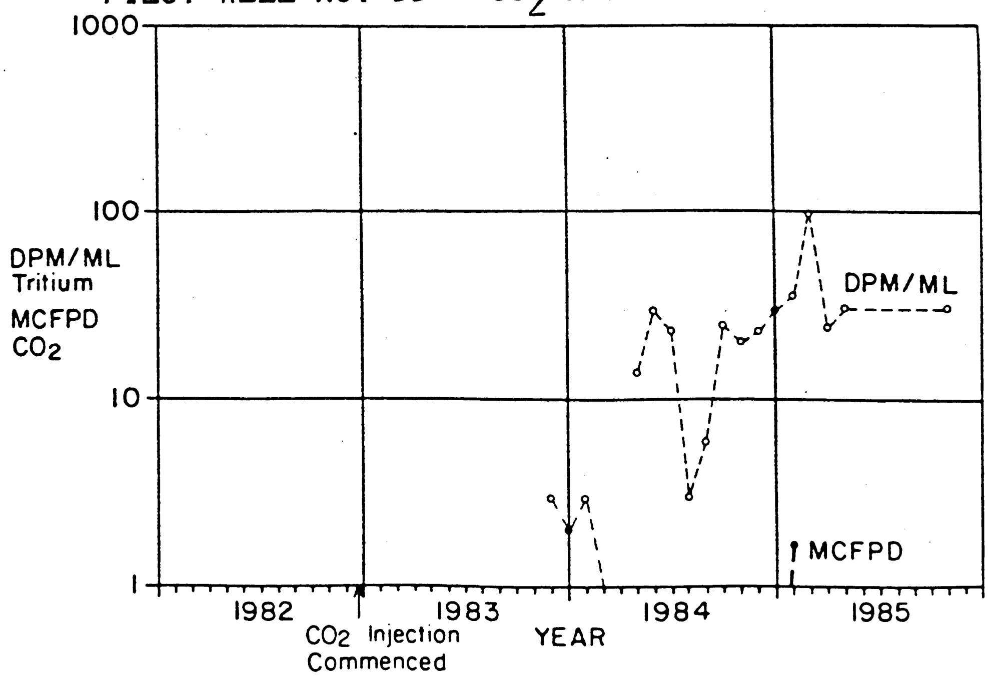


FIGURE 9

PILOT WELL NO. 53 - OIL AND WATER PRODUCTION

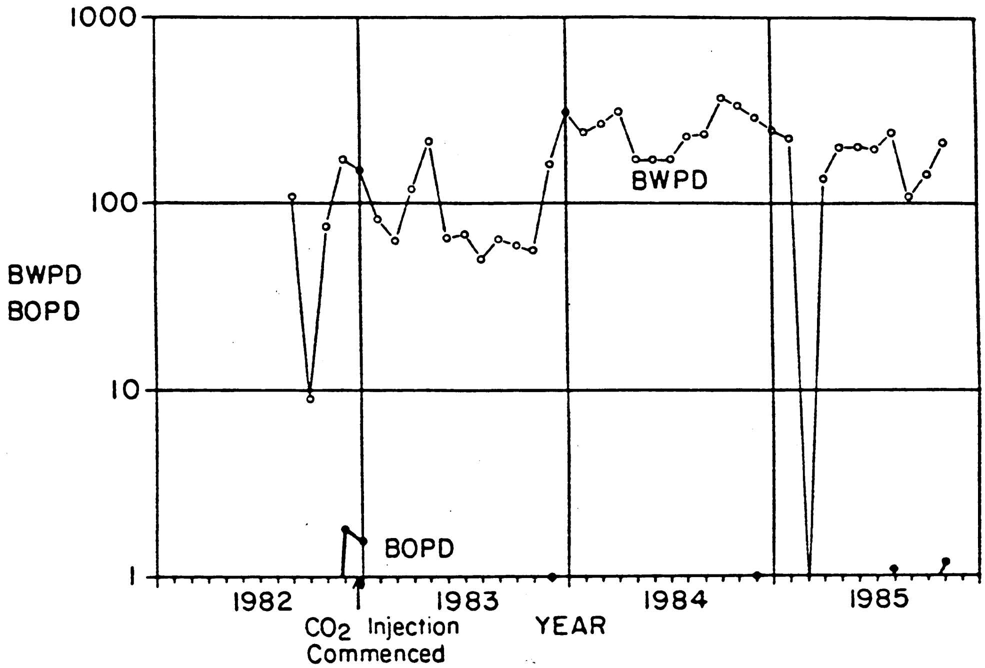
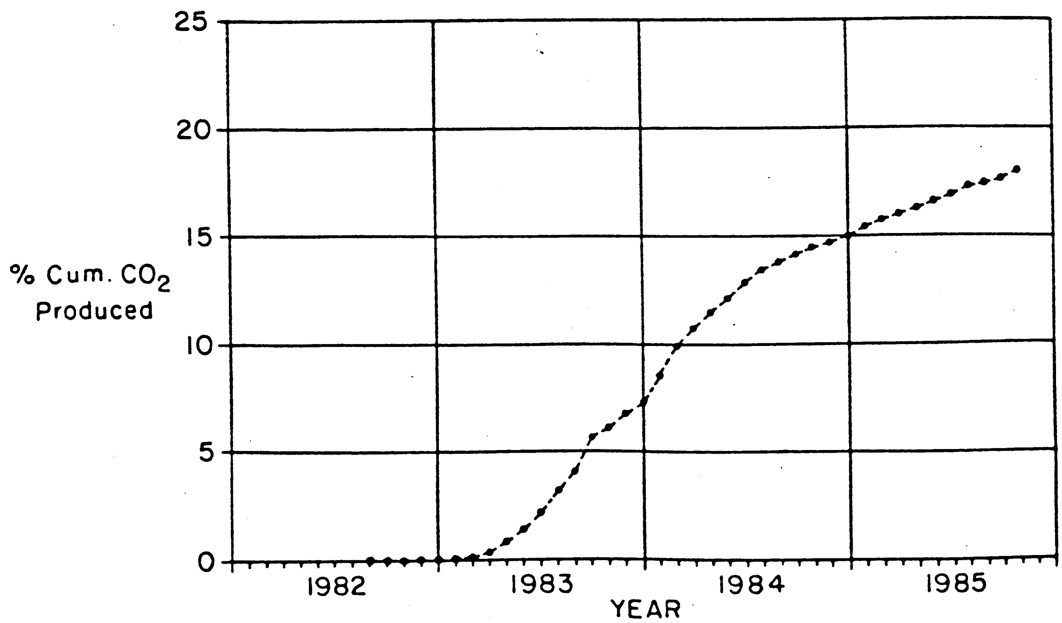


FIGURE 10

PRODUCED PILOT CO_2 AS A PERCENT OF INJECTED CO_2



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2. SF 385, information supplied to DOE as a self-certifiable EOR process.

★ U.S. GPO:1988 661-023/80050