DESIGN, OPERATION AND RESULTS OF GARBER CO_2 TERTIARY PILOT

Rajeshwar Kumar and Harold A. Weinland
ARCO Oil and Gas Company

ABSTRACT

ARCO Oil and Gas Company started work on a tertiary CO_2 Pilot in the Garber Field during early 1980. The purpose of the pilot was to investigate the CO_2 flooding of relatively shallow sands which were previously waterflooded to depletion. The pilot is in the Crews sand, a shallow Pennsylvanian sand, located at an average depth of 1950 ft. The main pilot is a 10.4 acres, normal 5-spot, which is enclosed by backup water injectors and outside producers. It was initially waterflooded to raise the reservoir pressure and to establish a base production curve. CO_2 injection started in late October 1981. In all, 27,000 tons of CO_2, representing 35% of HCPV within the effective area, was injected in this pilot. The response of the pilot has been very encouraging. It has already recovered over 70,000 STBO. Ultimate recovery should exceed 14% of the original oil in place within the effective area. The success of this pilot opens up possibilities for shallow reservoirs, which had not been seriously considered for CO_2 flooding.

FIELD HISTORY & PILOT BACKGROUND

The Garber CO_2 pilot is located in the Garber field, 14 miles east of Enid, Ok. (Fig. 1). This field was discovered by Sinclair Oil & Gas Company in 1916 and has produced from more than 22 different pays ranging in depth from 900 ft to 4500 ft. Since discovery it has produced in excess of 84 million STBO. Production from the Burlingame limestone located at an average depth of 2120 ft $\pm$ and the zones above was primarily under depletion drive until 1942. In that year limited gas injection for pressure maintenance was started. Waterflooding in this field began in 1948 on a pilot scale and proved very successful. Later, it was expanded fieldwide to cover most of the zones.

The CO_2 pilot is located on the T. F. Campbell lease, in the Crews sand, at an average depth of 1950 ft (Figs. 2 and 3). This sand was successfully waterflooded on this lease from 1951 to 1964. By 1969 the Crews sand production from this lease had dropped to only 3 BOPD and 130 BWPD. The lease was not producing any oil from the Crews sand when it was selected for CO_2 flooding. On this basis, it is concluded that the sand was depleted on this lease and any oil recovered by CO_2 flooding would be tertiary oil.

Work on this project started in 1980. Total number of wells needed for the project was 24 (Fig. 2). Only five of the existing wells were found useable as outside water injectors, the remaining 19 had to be newly drilled. In addition, 7 old wells were plugged and abandoned and 4 were replugged. The decision to replug 4 wells was made because these old holes had been plugged and abandoned without proper isolation of the zones, which could have resulted in possible loss of CO_2 to the shallower zones.

Initial individual daily oil production from the nine producers in the project area averaged less than 2 STB. The overall reservoir pressure in the project area varied from less than 200 psig to 400 psig. The average reservoir pressure was 220± psig. Water injection in the pilot area was started in last week of January, 1981 to pressure up the reservoir and also to establish a base curve for the oil production.

GEOLOGY

The Crews sandstone is of late Pennsylvanian age and consists of a heterogeneous succession of sandstones, shales and thin beds of limestone that appear to have been deposited in a deltaic and shallow marine environment. There is a great degree of lateral variation within the reservoir. Heterogeneities within the reservoir are attributed to lateral and vertical facies variation characteristic of a deltaic environment. Detailed examination of cores from the new wells revealed several components of deltaic environment. The pilot area appears to be a smaller deltaic lobe within a larger deltaic complex.

The thicker and more permeable and porous sandstone development occurs in the central part of the pilot and is oriented in a northeast-southwest direction. The elongated, thicker sand areas are interpreted to be distributary channel sandstones surrounded by delta front sandstones. The thinner sand areas represent interdistributary bay and pro delta deposits. Figure 4 is the gross sand isopach map for the Crews sand in the pilot area.

GARBER CO_2 PILOT PLANT FACILITIES

General layout of the CO_2 Central Plant is shown in Figure 5. These facilities include water injection equipment, well test equipment, production process equipment, CO_2 storage and injection facilities, and microprocessor data center. Garber is a non-unitized field and the pilot area includes three different leases; therefore each lease has separate production facilities.

Fiberglass lines were used in water injection system and individual carbon steel lines were used to carry CO_2 to four central CO_2 injection wells. Quintuplex horizontal pump equipped with 2 3/8-in. OD ceramic plungers was selected for water injection. The maximum injection pressure was maintained below 500 psig.

CO_2 Plant Facilities

The source of CO_2 for the pilot was a fertilizer plant near Enid. The liquid CO_2 was transported to the plant site in 20 ton refrigerated trucks and then transferred to two 50 ton storage tanks. The storage tanks were stainless steel, with dimensions of 8 ft 10-in. X 57 ft 9-in. These tanks were placed at an elevation of 6 ft from ground level to maintain a constant head on the system. Each tank was equipped with an 8-HP refrigeration unit, with controls set for start up at 315 psig and shut off at 294 psig. The refrigeration coils for these tanks are mounted inside the upper third part of the tank. The liquid CO_2 was kept at 300 psig and 0^oF.

CO_2 from the storage tanks was transferred by two centrifugal booster pumps to the suction side of two horizontal reciprocal triplex pumps at a pressure of 350 psi. The reciprocal pumps pumped 120 tons/day of liquid CO_2 at discharge pressures varying from 620 psi to 680 psi.

Each of these pumps had 1¼-in. OD stainless steel plungers with Colmonoy #6 hard coating to prevent scouring if debris were encountered in the liquid CO_2. The pumps had H.B. valves with 316 stainless steel seats and Delrin discs. Each plunger had two sets of packing with forward set (fluid end) comprised of 1¼-in. X 2-in. OD spring loaded pressure rings made of combination buna-N, duck and teflon material. The back set (power end) had 1¼-in. X 1 3/4-in. OD spring loaded pressure rings made of the same material. The packings on each plunger were lubricated by force feed pumps with refrigerant lubrication oil, which has a range of -40°F to 100°F.

Turbine meters were used for measuring total liquid CO_2 pumped and to each individual CO_2 injection well. The liquid CO_2 left the distribution manifold at 2°F to 3°F and was heated by electric line heaters at each CO_2 injector to prevent the formation of hydrates near the wellbore.

The electric line heater consisted of two 16 ft heater elements (Fig. 6). The line heater had a maximum operating temperature of 150°F. One electric heater element was able to heat the liquid CO_2 from 5°F to 58°F. Temperature of the injected CO_2 was maintained between 46°F to 58°F. All CO_2 lines, valves, check valves, and line heaters exposed to ambient temperature had 1-in. to 1½-in. insulation with metal covering.

CO_2/H_2O Typical Injection Well Hook Up

Figure 6 shows the typical fittings, connections, and equipment hook up for a CO_2/H_2O injection well. In addition, each well also had a cable for transmitting injection pressures and volumes to the central plant for display by digital meters. These data, along with the data from the well testers and the master meters for CO_2 and water were collected by a microprocessor unit. All of this data could be read at any company computer terminal via telephone and proved very useful in the monitoring of this pilot.

Figure 7 shows a schematic for a CO_2/H_2O injection well. These wells were equipped with duoline tubing and a Lynes inflatable packer. The bottom 500 ft of the casing was internally lined with cement and a post cure heat treated fiberglass liner inside the cement lining and bonded with cement mortar. The Lynes inflatable packer had a mandrel with an ID of 1.25-in. The mandrel was installed to get a better seal between the packer and casing. It was not a good choice as it prevented running of normal size tools for pressure, temperature and tracer surveys.

Water Injection Wells

The outside injection wells were equipped with standard 2 3/8-in. OD EUE IPC tubing and standard tension type packers. The IPC for tubing was 5 to 8 mils high baked Phenolic.

Well Test Equipment

The test units were 3 ft X 10 ft skid mounted horizontal vessels. They were equipped with two positive displacement meters for oil and water measurement and a turbine meter to measure the gas. Numerous problems were encountered with these units and, despite extensive work, they failed to operate satisfactorily. We now believe that test separators for CO_2 floods should be designed with sufficient retention time for CO_2 to separate[10] and also should have sufficient distance between the interfaces for proper operation of controllers. There was a tendency for scale build up on the turbine meter vanes and debris accumulation on the magnet, which resulted in erroneous measurement of the gas. Because of the tester malfunctions, the wells were tested individually by flowing them in frac tanks, and gas volumes were read from the orifice meter runs for each lease. The pneumatic-operated diverter valves were found to provide best service at flow line manifolds and were operated under 60 psig air/gas pressure.

Heater Treater Vessels

The heater treater units were 4 ft X 20 ft and operated properly at low production rates but malfunctioned when the water production increased beyond the design capacity. Free water knockouts were installed to keep the heater treaters operating properly. As the CO_2 production increased, formation of hydrates and ice in the dump valves and and the lines occurred, resulting in CO_2 entering the oil system. This problem was solved by installing electric heater tape wrapping, along with 1½-in. of insulation on lines and dump valves.

Safety Equipment

Air quality monitor heads were installed in the CO_2 plant area to sound an alarm whenever the oxygen content of the air became 19% or less. Normal oxygen content of the air is 21.6%$\pm$. For emergency use, portable Scott masks and masks with positive pressure regulators with air supply tanks were available. Portable CO_2 leak detector instrument was used to check for leaks at the central plant and the injection wells.

CHEMICAL TREATMENT FOR INJECTION AND PRODUCING WELLS

A regular chemical treatment for injection and producing wells was started very early in the pilot. Chemical treatment for producers consisted of one time application of heavy slow filming corrosion inhibitor, displaced with crude oil down the annulus. It was followed up with weekly treatments consisting of smaller volumes of fast filming corrosion inhibitor displaced with crude oil. These treatments minimized the corrosion of downhole equipment and tubing. The water for injection was treated continuously with 2 to 3 ppm of scale inhibitor. This treatment was successful in controlling calcium carbonate scale buildup in the injection system and injection wells. No injectivity problems have been experienced with the injectors, even after they were switched from CO_2 to water injection.

PRE-FLOOD RESERVOIR EVALUATION

Fresh cores were obtained from four of the five central pilot wells. One well was not cored due to a salt water flow from one of the shallow zones. The average porosity and permeability for the pilot area given in Table 1 and Figure 8 shows porosity and permeability distribution for the central pilot well.

Due to the commingled production from multiple pays, accurate determination of oil saturation by material balance was not possible. The best estimates for residual oil saturation by material balance was in 30%$\pm$ PV range. Core analysis using the end point method gave a residual oil saturation of $\pm$25% PV. Conventional core analysis also gave similar values. The residual oil saturation was also obtained by the log-inject-log method in T. F. Campbell No. 49. In the portion of the sand which took most of the injected water, the residual oil saturation was calculated to be 25% PV (Fig. 9).

Crude oil from the Crews sand is 46° to 47° API with a GOR of 14 SCF/STBO. Compositional analysis of separator crude recombined at reservoir conditions at the beginning of this pilot, is given in Table 2. The minimum miscibility pressure data for this oil and CO_2 are given in Fig. 10.

Tracer Test

Radioactive water and CO_2 tracer tests were conducted to verify interwell continuity and to identify any potential reservoir problems. Water tracers were injected after 3½ months of water injection. The producing wells were regularly sampled and tested to detect the breakthrough of various tracers. The results of the water tracers are shown in Fig. 11. No tracers from T. F. Campbell No. 43 were picked up in either Louisa Crews Nos. 35 or 36.

CO_2 INJECTION AND PRODUCTION RESPONSE

CO_2 injection in the pilot began on October 20, 1981. The gross daily injected CO_2 volumes varied between 110 and 120 tons/day. The amount of CO_2 going into each injector was based upon the hydrocarbon pore volume associated with it. This balance was carefully monitored throughout the period of CO_2 injection.

Up to the time of starting CO_2 injection, all the producing wells had been on pump. The results of CO_2 core flood studies that were done at this time indicated that if the reservoir pressure dropped below the minimum miscibility pressure, a very significant loss in the oil recovery would occur (Table 3). In order to maintain reservoir pressure, it was decided to put all the producers on natural flow. None of the wells had any problem in producing and they all remained flowing until October 19, 1983, when they were put on pump.

CO_2 tracers were injected in the four central injectors two weeks after the start of CO_2 injection. The results of these tracer tests are shown in Fig. 12.

Sulphur hexaflouride injected in T. F. Campbell No. 41 was detected in six of the producers before the CO_2 breakthrough. No tracers from T. F. Campbell No. 42 were detected in the center producer, T. F. Campbell No. 49, during the tracer testing period that continued through July 1, 1982. Tracer tests revealed the presence of a channel from T. F. Campbell No. 41 to T. F. Campbell No. 47. The presence of this channel had also been suspected from the earlier pulse tests.

The first CO_2 breakthrough, as expected, occurred in T. F. Campbell No. 47. No remedial operation was taken to correct this problem as it was believed that no risk was justified which could result in the loss of one of the CO_2 injectors or possibly increase the damage. Instead, the production was controlled from this well to minimize the loss of CO_2 . Ultimately, when the CO_2/oil ratio from this well became excessive, it was shut in. The CO_2 breakthrough times for the nine producers are shown in Table 4. On the whole, CO_2 breakthrough occurred long after the tracer breakthrough. In those wells that didn't produce much CO_2, no significant increase in oil production occurred. T. F. Campbell No. 52, which has not shown any CO_2 breakthrough thus far, hardly produced any additional oil, even though it was one of the better wells upon initial completion.

The effect of CO_2 injection on oil recovery was very dramatic. The center pilot well, which produced only a trace of oil during the water injection phase, reached a peak daily rate of 86 BOPD. The staggered CO_2 breakthrough in the producing wells also maintained the production from this pilot at fairly even rates, as can be seen from the pilot production curve (Fig. 13). The amount of CO_2 production from the pilot was quite low, averaging only 390 MCF/day during 1982 (Fig. 13).

The CO_2 requirements for this pilot are based upon the hydrocarbon pore volume (HCPV) inside the nine producers, which has been called effective area in this paper. The original design of the pilot was to inject only 25% HCPV of CO_2. It was to be in the form of a 7% HCPV straight CO_2 slug, followed by 1:1 WAG CO_2 injection. This design had been based upon initial simulation work which had indicated early CO_2 breakthrough due to severe gravity override. Once the CO_2 injection in the pilot started, no such problems were encountered. It was decided therefore to go with a straight CO_2 slug.

After 25% HCPV of CO_2 was injected, the oil production was still increasing and there were a number of producers which had yet to respond. It was decided that the CO_2 slug size should be increased to 35% HCPV. No decline trend for the oil production had been established even after that much CO_2 injection, but we had reached the optimum economic size for CO_2 slug size, and therefore the CO_2 injection was stopped.

After the CO_2 injection was stopped, the CO_2 injectors were converted to water injection, and the ongoing water injection was maintained in the outside injectors. The oil production did not show any drastic decline and stayed above the anticipated rates. No injectivity problems were experienced with the CO_2 injectors after the switchover.

To evaluate the CO_2 displacement in the reservoir, a pressure core was taken in T. F. Campbell No. 53. It is located 100 ft northeast of T. F. Campbell No. 43, one of the CO_2 injectors (Fig. 2). This well was pressure cored on October 9, 1982, after 127 days of post CO_2 water injection. The results of this core are shown in Fig. 14. As indicated on that figure, first core barrel lost pressure due to mechanical conditions, and in the third core barrel only 5 ft of core was recovered. The remaining portion of the sand in that core was accidentally ground down due to bit plugging. The portion of the second core which has good porosity and permeability shows a residual oil saturation varying from 7 to 10% PV.

By the middle of October 1983, the daily average oil production had declined to 50 BOPD with associated CO_2 production of 130 MCF/day. It was decided that no additional useful information would be gained by continuing to flow the wells. All the wells were put on pump October 19, 1983. This resulted in daily oil production increasing to an average of 70 BOPD with the associated CO_2 production increasing to 250 MCF/day.

DISCUSSION OF THE OIL RECOVERY

The Garber CO_2 pilot is still an ongoing pilot and the results are not final. However, the cumulative recovery as of January 1, 1984 is over 70,000 STBO, which represents 11% of the original oil in place within the effective area of the pilot. The recovery vs injection graph (Fig. 15) so far does not show any break in the curve. With the established trend, the ultimate oil recovery from this pilot should exceed 14% of the original oil in place within the effective area. The oil recovery from the central pilot itself so far has been less than the overall oil recovery from the effective area. As of January 1, 1984, the central pilot has recovered 16,600 STBO or 7.6% OOIP within the central pilot. The lower recovery from the central pilot is probably due to lack of support from one of the CO_2 injectors or to disproportionately small part of CO_2 going into the pilot area.

In this paper no explanation has been offered to identify the process by which the CO_2 has recovered the oil in this pilot. Because of the high oil recovery it is believed that miscibility between the CO_2 and oil was definitely achieved. A definite increase in the gravity of the oil was also observed. It increased from $46^o$to 47^o API to about $49^o$to 50^o API. It is also quite apparent that the characteristics of crude oil in this reservoir, high gravity and extremely low GOR, are ideally suited for CO_2 flooding. The reservoir heterogeneity also seems to have helped in controlling the gravity override and early CO_2 breakthrough problems.

CONCLUSIONS

1. The excellent oil recovery obtained in the Garber CO_2 Pilot demonstrates the feasibility of successful CO_2 flooding at depths less than 2000 ft, under similar reservoir conditions.

2. Good oil recovery is possible when the residual oil saturation is as low as 25% PV.

3. Reservoirs which have undergone successful waterflooding can be good candidates for CO_2 flooding, provided they meet other conditions for CO_2 flooding.

4. CO_2 breakthrough in a producing well was essential for oil response.

5. If the CO_2 is well contained, the benefit of injection will continue long after CO_2 injection has ceased.

6. The economics of CO_2 flooding fields like Garber can be attractive if large investments for redrilling of new wells and replugging of old wells are not required.

REFERENCES

1. Sneider, R. M., Tinker, C. N. & Mechel, L.D.: "Deltaic Environment Reservoir Types and Their Characteristics," J. Pet. Tech. (Nov. 1978) 1538-1546.

2. Holm, L.W.: "Status of CO_2 & Hydrocarbon Miscible Oil Recovery Methods," J. Pet. Tech. (Jan. 1976) 76-83.

3. Stalkup, F.I.: "Carbon Dioxide Miscible Flooding: Past, Present and Outlook for the Future," J. Pet. Tech. (Aug. 1978) 1102-1112.

4. Orr, F. M. and Taber, J. J.: "Displacement of Oil by Carbon Dioxide," U. S. Department of Energy Report DOE/ET/12082-9, May 1981.

5. Goodrich, J. H.: "Review and Analysis of Past and Ongoing Carbon Dioxide Injection Field Tests," Paper SPE/DOE 8832 presented at First Joint SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, Okla., April 20-23, 1980.

6. Graham, B. D., Bowe, J. F., Duane, N. C. and Warden, G. D.: "Design & Implementation of a Levelland Unit CO_2 Tertiary Pilot," Paper SPE/DOE 8831, presented at First Joint SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, Okla., April 20-23, 1980.

7. Watts, R. J., Conner, W. D., Wasson, J. A., and Yost II, A. B., "CO_2 Injection For Tertiary Oil Recovery, Granny's Creek Field, Clay County, West Virginia," Paper SPE/DOE 10693 presented at Third Joint SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, Okla. April 4-7, 1982.

8. Desch, J. B., Larsen, W. K., Lindsay, R. F., and Nettle, R. L.: "Enhanced Oil Recovery by CO_2 Miscible Displacement in the Little Knife Field, Billings County, North Dakota," Paper SPE/DOE 10696 presented at Third Joint SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, Okla. April 4-7, 1982.

9. "EOR Boosts Twofreds Oil Production," Oil & Gas Journal (Mar. 15, 1982) 34-36.

10. Roye Jr., J. E.: "Sizing Separators For CO_2 Flood Operations," Paper SPE 11164 presented at 57th Annual Fall Technical Conference & Exhibition of SPE held in New Orleans, La. Sept. 26-29, 1982.

11. Todd, R. M., Cobb, W. M. and McCarter, E. D.: "CO_2 Flood Performance Evaluation for the Cornell Unit, Wasson San Andres Field," J. Pet. Tech. (Oct. 1982) 2271-2282.

12. Stiles, L. H., Chiquito, R. M., George, C. J., and Long, L. D.: "Design and Operation of a CO_2 Tertiary Pilot: Means San Andres Unit," Paper SPE 11987 presented at SPE 58th Annual Technical Conference & Exhibition, San Francisco, CA, October 5-8, 1983.

13. Kumar, R., and Eibeck, J. N.: "CO_2 Flooding a Shallow Pennsylvanian Sand in Oklahoma, A Case History," Paper to be presented at Fourth SPE/DOE Symposium to be held in Tulsa, OK. April 15-18, 1984.

ACKNOWLEDGEMENTS

We thank the management of ARCO Oil and Gas Company for permission to publish this paper. The design, implementation and operation of this pilot involved many individuals from ARCO Oil and Gas Company and ARCO Production Research. We gratefully acknowledge the contribution and support of everyone involved with this project.

Table 1
Basic Reservoir Data

Formation	Crews Sandstone
Age	Upper Pennsylvanian
Depth, ft	1950
Depth Subsea, ft	-900
Formation Dip, Degrees	<5
Average Net Pay, ft	21.0
Average Porosity, % PV	17.0
Average Permeability, md	57
Initial Connate Water Saturation, % PV	30
Reservoir Temperature, F^o	95
Original Formation Volume Factor, RB/STB	1.2
Oil Gravity, ^{o}API	47
Oil Viscosity, cp	2.1
Pilot Area, Acres	10.4
Effective Project Area, Acres	38.3
Original Oil-in-Place in the Effective Area, STBO	620,000
Average Reservoir Pressure at the start of CO_2 injection, psig	1250
GOR at the start of CO_2 injection, SCF/STBO	14
Estimated Oil Saturation at the start of CO_2 injection	25-30%
Minimum Miscibility Pressure, psig	1075
CO_2 Formation Volume Factor @ 1250 psig & 95^{o}F, Res Bbls/MCF	.5546

Table 2
Hydrocarbon Analysis of Reservoir Oil*

Component	Mole Percent	Weight Percent
Carbon Dioxide	0.05	.02
Nitrogen	0.18	.06
Methane	1.34	.23
Ethane	0.38	.12
Propane	0.94	.44
iso-Butane	0.38	.23
n-Butane	1.48	.91
iso-Pentane	1.32	1.00
n-Pentane	2.49	1.89
Hexanes	9.60	8.71
Heptanes plus	81.84	86.39
	100.00	100.00

* Stock tank oil recombined at initial reservoir conditions
95^{o}F, 300 psig pressure
GOR 14 SCF/STBO

Table 3
Summary of Carbon Dioxide Core Flood Results
at Different Pressures

Core Sample No.	Initial Waterflood: Oil Saturation at start of waterflood % Pore Space	Initial Waterflood: Oil Saturation at end of waterflood % Pore Space	Pressure psi	Carbon Dioxide Flood: Oil Saturation at end of CO_2 flood % Pore Space	Final Water Flood: Oil Saturation at end of final waterflood % Pore Space
1	42.9	18.7	1000	17.2	15.1
2	60.9	26.9	1125	18.7	18.7
3	60.9	26.0	1200	4.8	1.0
4	50.9	22.6	1500	2.5	2.4

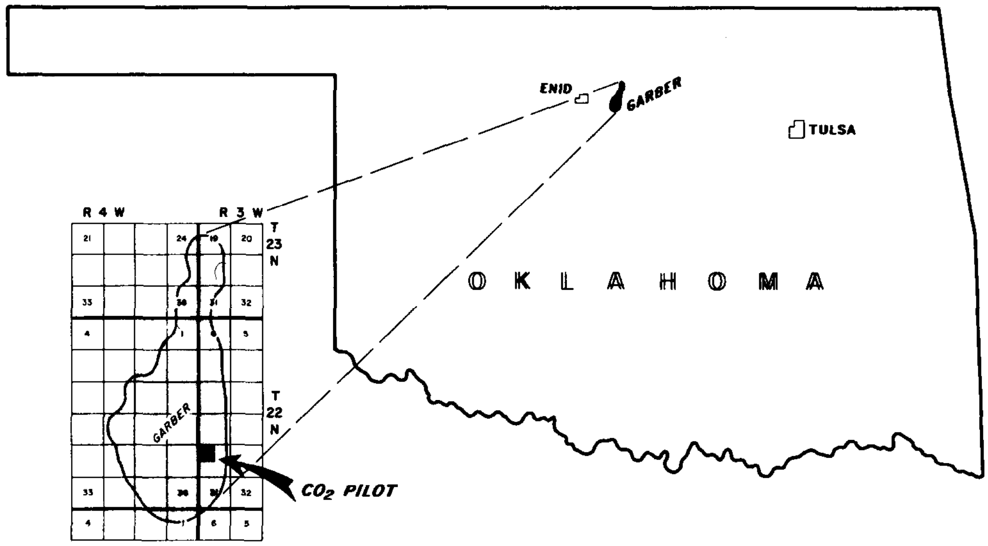


Figure 1 - Location map

Table 4

Lease Name/Well No.		CO_2 Breakthrough Dates	No. of Days to CO_2 Breakthrough
T. F. Campbell (North)	#47 *	11-18-81	29
"	48	4-23-82	185
T. F. Campbell (South)	49	1-29-82	101
"	50	12-18-81	59
"	51	4- 8-82	170
"	52	No CO_2 breakthrough	
Louisa Crews No.	34	3-30-83	526
"	35	11-15-82	391
"	36	3- 6-82	137

* T. F. Campbell No. 47 was S.I. on 5-8-82

CO_2 injection started on 10-20-1981 and ended on 6-22-1982.

(245 days of CO_2 injection)

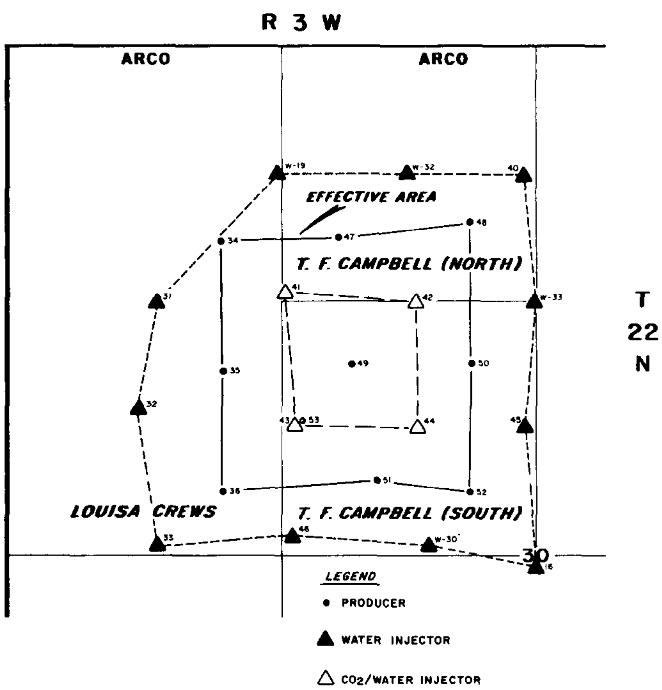


Figure 2 - Pilot well locations

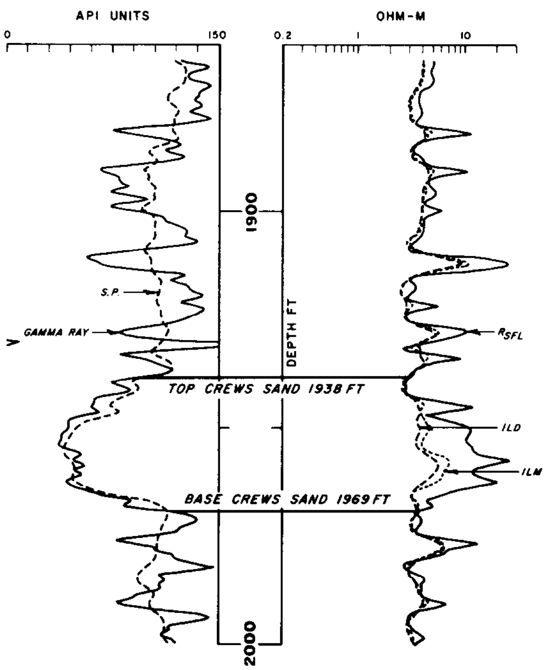


Figure 3 - Type log - Crews sand T. F. Campbell No. 48

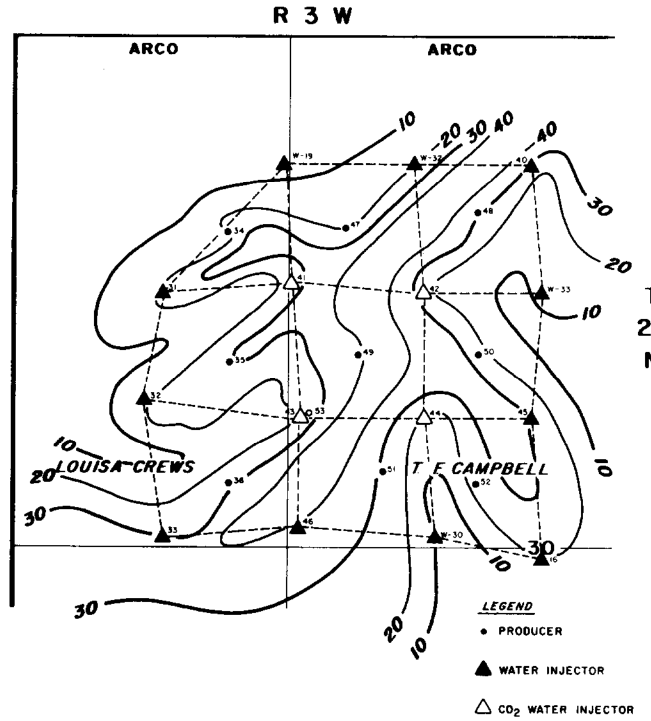


Figure 4 - Gross sand isopach - Crews sand

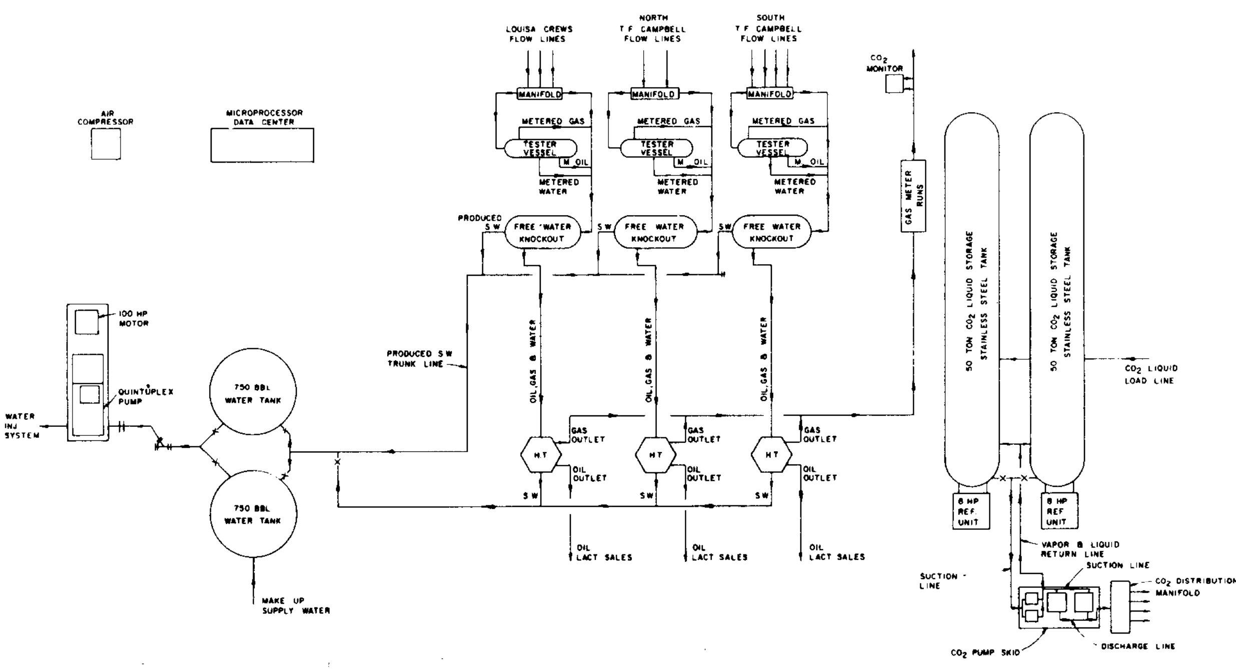
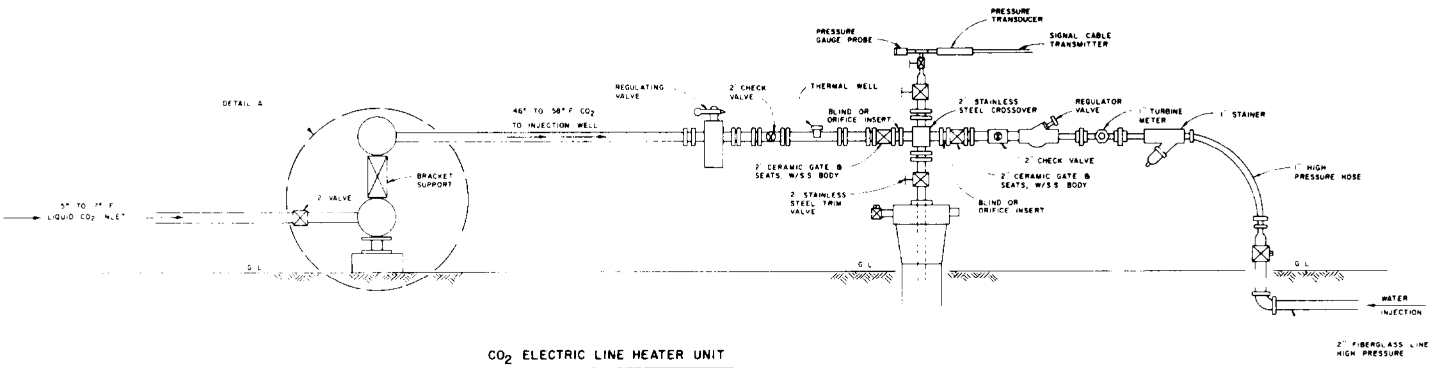


Figure 5 - Garber CO_2 Pilot Plant facilities



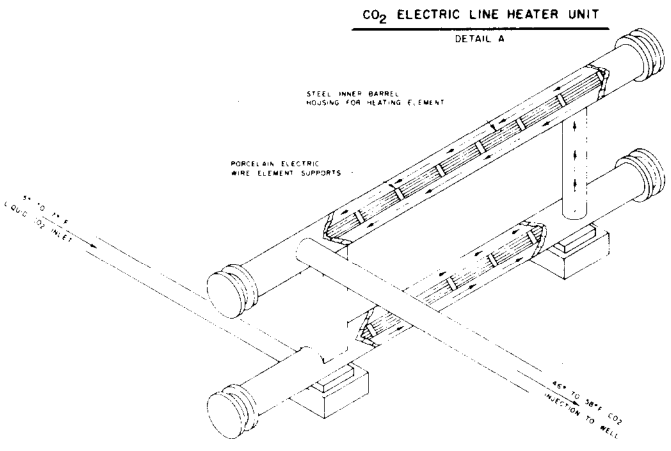


Figure 6 - Typical CO_2/water injection well hook up

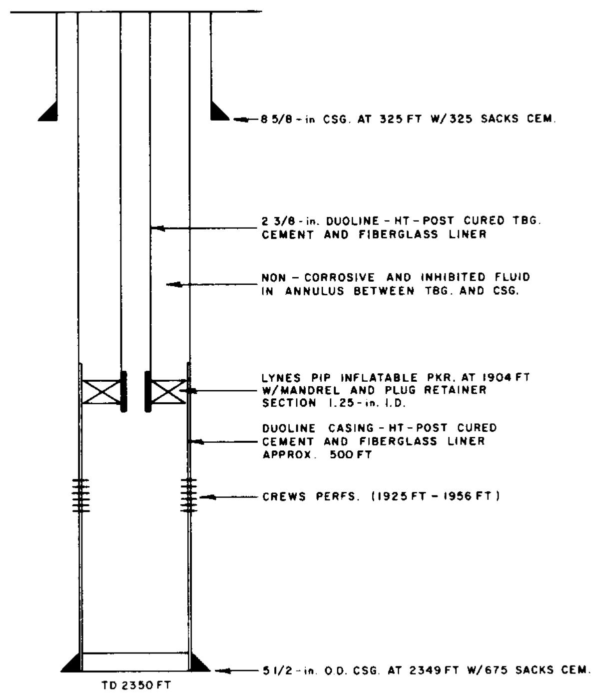


Figure 7 - CO_2/H_2O injection well schematic

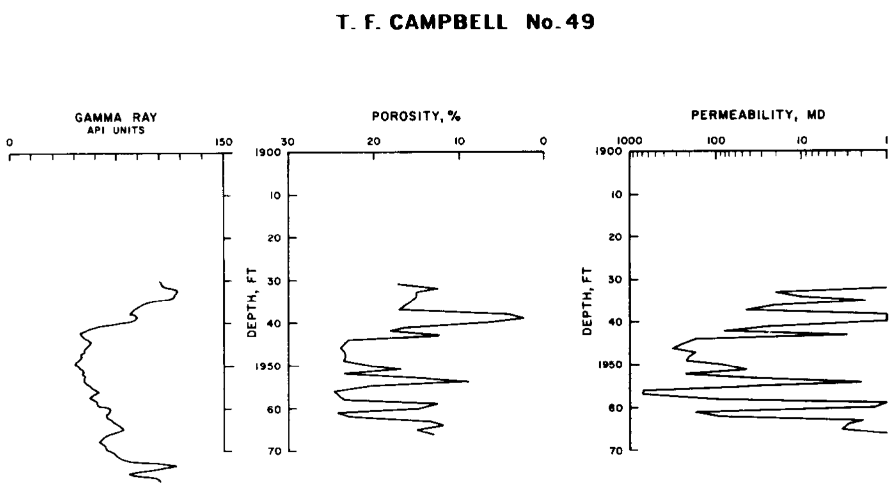


Figure 8 - Crews sand core data

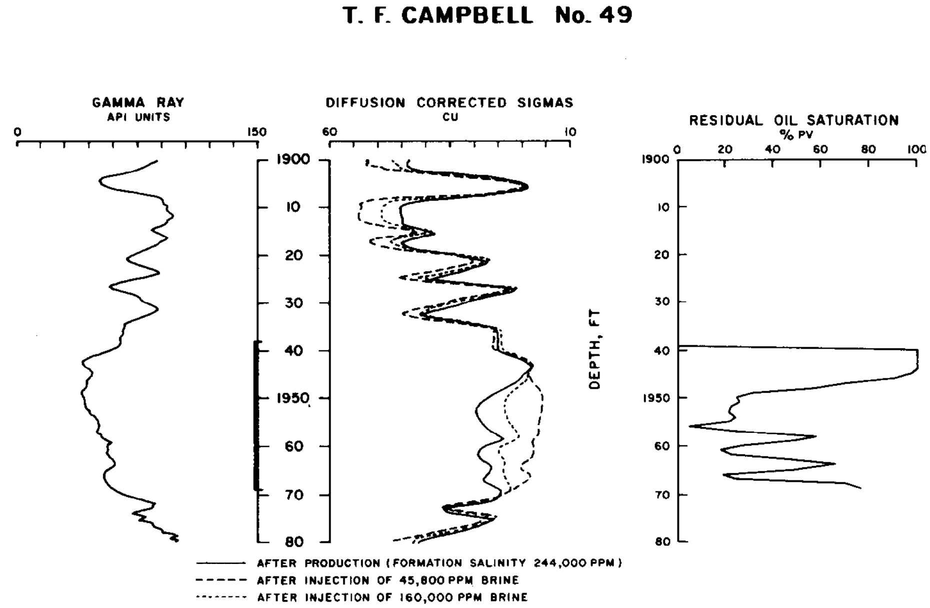


Figure 9 - Log-inject-log results

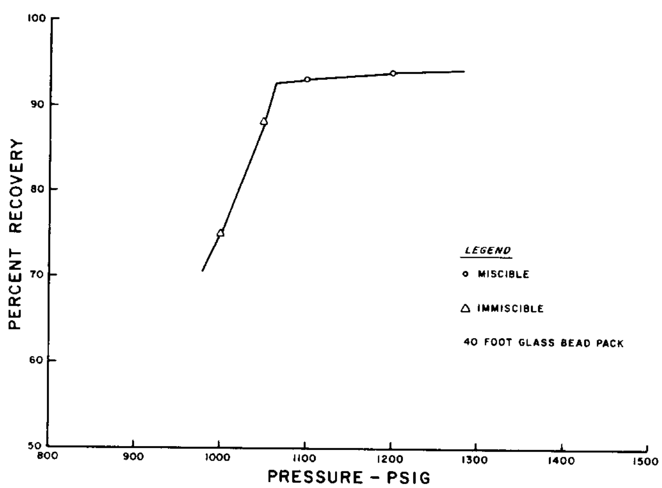


Figure 10 - Minimum miscibility pressure data

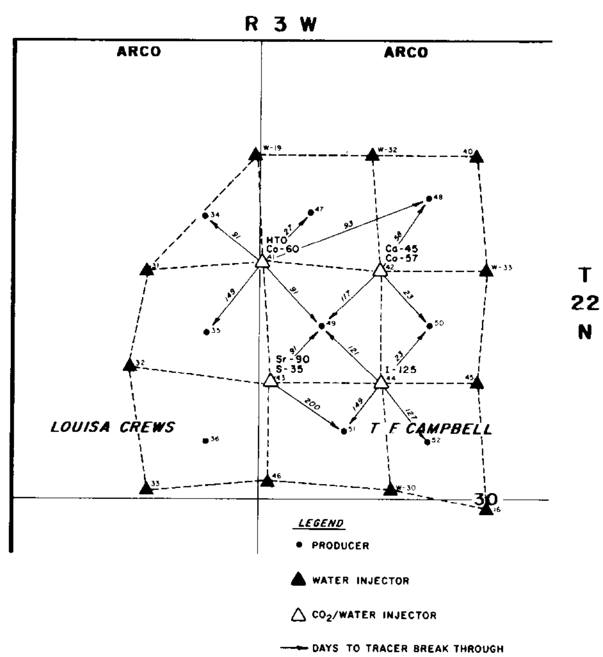


Figure 11 - Water tracers results

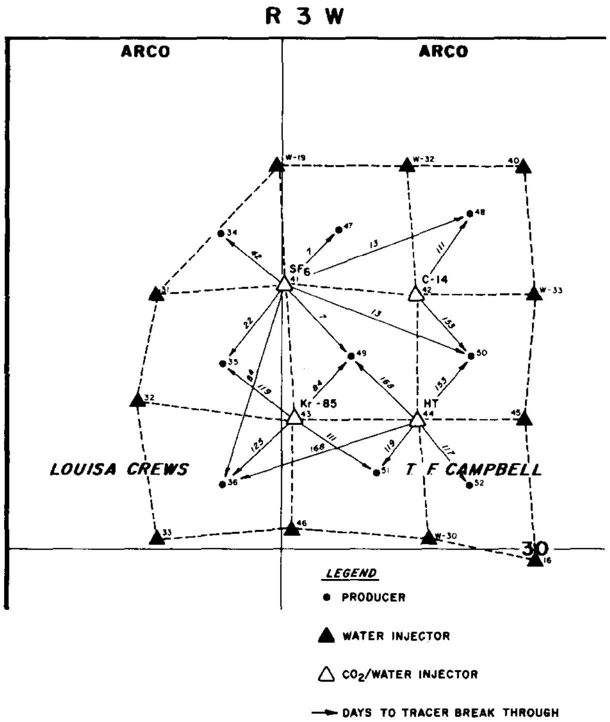


Figure 12 - CO_2 tracers results

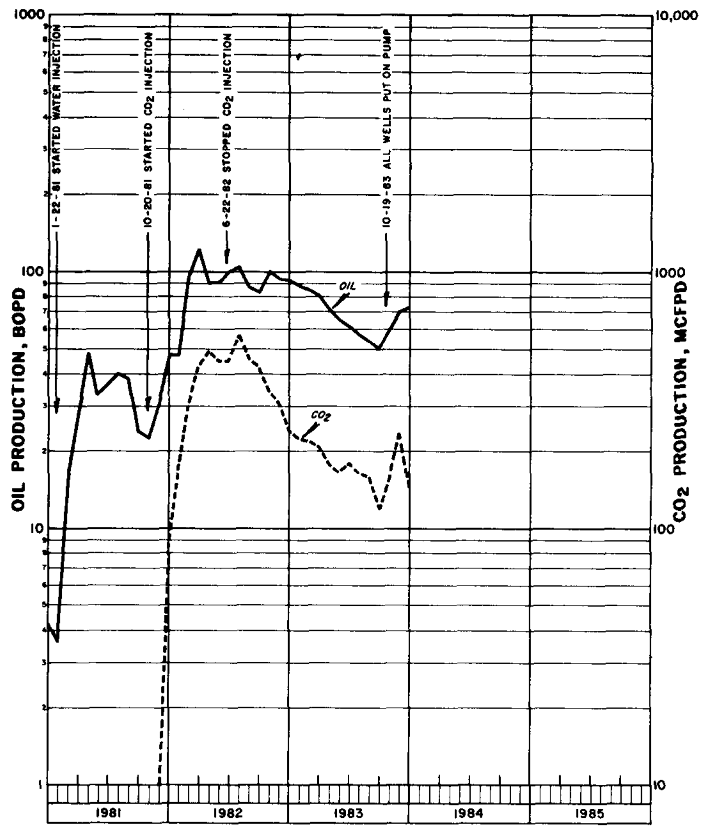


Figure 13 - Pilot production

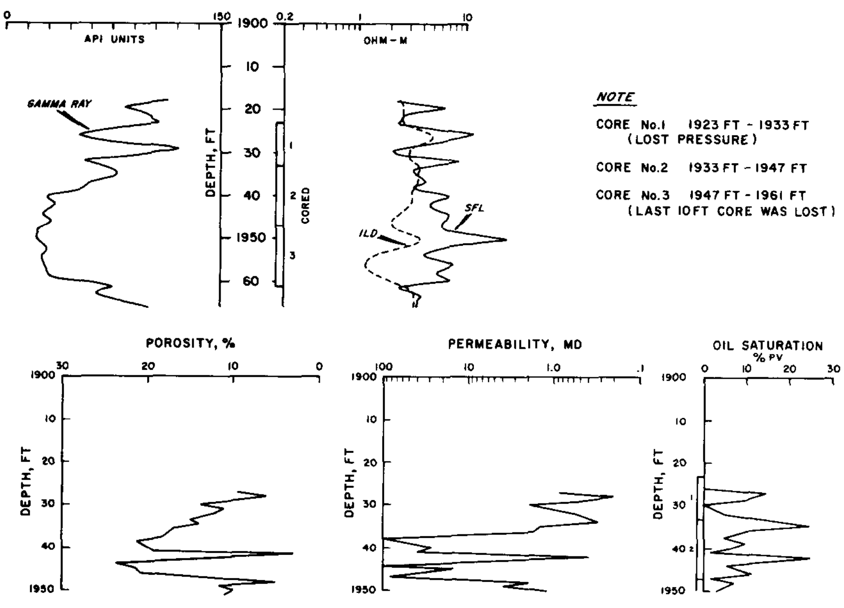


Figure 14 - Pressure core results

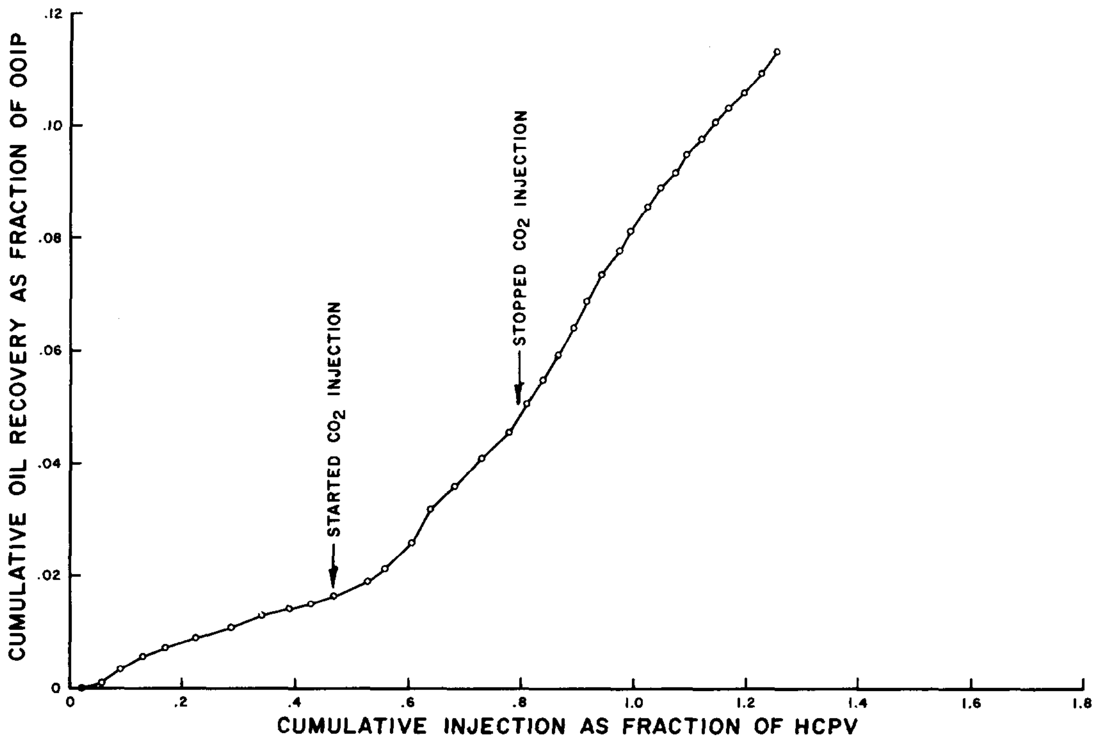


Figure 15 - Injection (CO_2 + water) vs recovery