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Steamflooding after Steam Soak - Effect of Water Saturation Build-up on Oil Recovery

By

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ABSTRACT

In heavy oil recovery, cyclic steam stimulation is frequently followed with steamflooding, in order to increase the ultimate recovery. It is wellknown that in the cyclic stimulation phase, a large proportion of the injected condensate is retained in the formation. In view of this, two questions arise: First, how does such water saturation build-up affect oil recovery in the subsequent steamflood? And, secondly, how should the steam injection wells be located with respect to the high water saturation regions in order to maximize oil recovery?

The present study attempts to answer the above two questions principally on the basis of an experimental investigation, which was supplemented by selected simulations. The experimental phase utilized a two-dimensional reservoir model, with simulated adjacent formations. High water saturations were created in four configurations: around the injection well, around the production well, around both wells, and in the center of the pattern. It is shown that, depending on the steamflooding scheme employed, any of these situations may obtain in the field. Forty-five experimental runs were conducted, using several different oils. The theoretical phase employed a steamflood simulator, which permitted changes in the areal fluid saturation distributions.

Results of the studies showed that the presence of water saturation build-up near the wellbore may influence the steamflood oil recovery, the magnitude of the effect being dependent on oil viscosity. Thus, the effect is appreciable for low viscosity oils, becoming less pronounced for higher viscosities. It was found that a high water saturation in the vicinity of both the injection and production wells is likely to be unfavorable, and should be avoided in steamflood development. In all cases studied, the water saturation build-up was more injurious to oil recovery in the case of high, rather than low initial oil saturations. In both cases, the oil recovery decreased as the water zone size increased.

One phase of the experimental study was designed to determine whether the retained water is dispersed throughout the formation, or it simply creates a high water saturation zone immediately around the wellbore. Results of the experimental study indicate that the latter situation is more probable. However, in actual field tests, this may not be so. Implications of such a situation are discussed.

References and illustratons at end of paper.

INTRODUCTION

Cyclic steam stimulation is a well-established method for the recovery of heavy oils, and has been tested under a wide variety of conditions. Even though the oil production rates after the soak period are usually high, the subsequent rapid decline in rates leads to a rather low ultimate oil recovery, perhaps 6-15% of the oil in the affected area. As a result, in many cases, in the U.S. and in Canada, cyclic steam stimulation is followed with a continuous steamflood, in order to recover a major portion of the remaining oil. Since over half of the water injected as steam is retained in the formation, the question arises whether the water saturation build-up is likely to lower the recovery efficiency of a subsequent steamflood. [Table 1 gives water retention figures for a number of reported field tests. Other data are given in (1)]. The present work attempts to investigate this question principally on the basis of an experimental investigation. Several steamflood simulations were also carried out to obtain the general trends for heavy oils, with viscosities much higher than those employed in the experiments. The effect of high water saturation regions was studied for four different configurations of such regions in relation to the injection and production wells, in order to determine which configuration is desirable from the standpoint of steamflood oil recovery. Lastly, the likelihood of creating high water saturation zones was considered in the light of field observations.

EXPERIMENTAL APPARATUS AND MATERIALS

The experimental apparatus used comprised of the porous medium and the underlying formation, the fluid injection and production system, and the temperature measuring set-up.

The porous medium consisted of a rectangular steel box packed with 90 mesh glass beads, having inside dimensions of 12.5 in x 12.5 in x 1.5 in. The pore volume of the pack was 1700 cc, giving a porosity of 44.5%, and the permeability was 10.90 darcies. The model was designed to simulate the quadrant of a five-spot pattern. The upper surface of the model was insulated to represent an adiabatic boundary, while the lower surface was in contact with a medium grain, dry sand pack, to simulate the underlying formations. Figure 1 depicts a cross-sectional view of the model assembly.

A heat-resistant rubber sheet was placed on top of the box, and the steel cover plate was bolted on it. The space between the plate and the rubber sheet was pressurized by a high boiling oil, by means of a pump, so that the porous pack was under a confining pressure higher than the pore pressure, thus eliminating any tendency to steam channeling.

The bottom of the steel box was provided with 33 threaded holes, 20 of which were used to install thermocouples, and 13 were used to install wells. Six of the wells were meant for injection and production, saturation, and clean-out operations, three wells were provided at equal radial distances from each of the diagonally opposed main injection and production wells, and one well was installed at the center of the model. These latter seven wells were employed for creating high water saturation regions as the need arose. All of the wells were constructed of bronze tubing 5/16-in diameter. perforated with 1/16-in diameter holes, completely covered with 270 mesh stainless steel screen.

Fluids were injected using two mini-pumps, having a maximum capacity of 2,200 cc/hr, and passed through 3μ Millipore filters to prevent plugging of the well screens.

An electrode-type boiler, rated at 650 psig and 201,000 Btu/hr was used to supply 95 percent quality steam. It was connected to the injection well by heavily insulated stainless steel tubing. A steam trap was incorporated in the line.

The produced effluent passed through a coil-type condenser, equipped with a back pressure regulator, pressurized with nitrogen. The regulator was used to control the pressure drop across the model, which was measured by a mercury manometer. Figure 2 shows the layout of the apparatus used.

Five refined oils were used in the experiments, with viscosities ranging from 3.81 to 150 centipoises. One of the oils was a mixture, which was employed to check the results for an intermediate viscosity. Table 2 gives the physical properties of the oils used.

EXPERIMENTAL PROCEDURE

To simulate the pre-soaked conditions during a steamflood, it was required to create high water saturation zones around the selected well or wells, pertaining to one of the cases shown in Fig. 3. Four cases were considered: high water saturation around the injection well (HWSAIW), high water saturation around the production well (HWSAPW), high water saturation around injection and production wells (HWSAIPW), and high water saturation around the center well (HWSACW). In addition, base runs involving no high water saturation zones were also conducted. In the following, "soaking" will be taken to imply "creating a high water saturation region around the well in question". Notice that such high saturations were created by injection of predetermined volumes of cold water into appropriate wells, and so there were no high temperature gradients which would normally accompany such zones in actual field tests. Volumes of 250, 500, and 750 cc of water were employed for "soaking" purposes in various runs.

A part from the four different high water saturation configurations shown in Fig. 3, steamfloods were carried out at an initially residual oil, or irreducible water saturation. In a typical run, the steam was allowed to enter the model at a pressure of 18-21 psig, and flow through the model under a 90 mmHg differential pressure, which was maintained constant by means of the back pressure regulator and the steam bleed valve.

During the runs, the steam front was traced by measuring the temperature distribution in the model. Steam breakthrough was determined by checking the temperature of the production well, which varied from 265-270°F. Most of the runs were terminated at steam breakthrough, however, several runs were continued up to the point of zero oil production to obtain the "ultimate recovery".

After each run, the model was completely closed, and allowed to cool, following which the fill-up volume was determined, which gave the average steam injection rate.

DISCUSSION OF RESULTS

Tables 3 to 7 summarize the experimental data for the 45 runs conducted. Figures 4 to 9 show typical production histories for the lowest (figs. 4 to 6) and the highest viscosity (Figs. 7 to 9) oils used. Only two of the four water saturation configurations tested are shown.

Possible Situations Encountered in Steamflooding After Steam Stimulation

As mentioned above, after subjecting an oilfield to cyclic steam stimulation, it is frequently desirable to conduct a steamflood to enhance oil recovery. Assuming that the cyclic stimulation is carried out on a pattern basis, the situation shown in the upper left of Fig. 3 will obtain. In converting this pattern to a steamflood, the most likely situation will be the one where the existing wells are used for both the injection and production of fluids, giving rise to the HWSAIPW case. However, if the original spacing of the steam stimulation wells is too large, additional wells may be drilled, and depending on the choice of the pattern size and injection and production wells, one of the situations depicted in Fig. 3 may obtain; still other possibilities can be visualized. In view of the desirability of using only the existing wells in the steamflooding operations, the case HWSAIPW was more thoroughly studied for the effect on oil recovery.

Role of Oil Viscosity

On the whole, it was found that the effect of a given type of high water saturation zone on oil recovery becomes smaller as the oil viscosity is increased, over the viscosity range considered in this work. Simulations, mentioned below, seem to support this observation for much higher oil viscosities. Tables 3 to 6, for each of the four oils tested, show that as the oil viscosity increased, the differences in the individual values of oil recovery by the steamflood (Column 12) became smaller. The results are plotted in Figs. 10 and 11, for initial irreducible water and residual oil saturations, respectively, in the porous medium. The curves shown are least squares fits. The most significant aspect of the curves is that, in both figures, the vertical spread of the points decreases with an increase in oil viscosity, again indicating that the effect of high water saturation zones on oil recovery decreases with an increase in oil viscosity. Also, it can be seen from Figs. 10 and 11 that oil recovery tends to increase with oil viscosity, regardless of the type of water saturation zone involved.

More specifically, consider the runs involving Drakeol 35, the most viscous oil employed. Figure 7 shows the base run (irreducible water) production history, the steamflood (breakthrough) recovery being 64.00%. Figures 8 and 9 show similar production histories for HWSAIW and HWSAIPW cases, with recoveries of 59.80 and 54.40%, respectively. For residual water initially in the porous medium, the steamflood recoveries were 37.60, 36.17, and 35.54%, respectively, for the three cases considered (Runs 34, 35 and 36; Table 6). In both instances, the recovery values are fairly close to each other.

In contrast to the above, consider now the runs involving the least viscous oil Soltrol-170. Figures 4, 5, and 6 show production histories for the base run, and for the HWSAIW and HWSAIPW cases, respectively, for irreducible water saturation initially in the porous medium. The steamflood recoveries were 68.00, 37.20, and 62.00%, respectively. In the residual oil saturation case, the recoveries were 23.50, 20.40, and 9.77%, respectively (Runs 6, 7, and 10; Table 3). Recoveries for other water saturation zone configurations, listed in Table 3, reflect considerable variations.

The experimental results showed that in those cases where the high water saturation zone was located at the production well, as also in residual oil type runs, the initial production consisted of water only, with the oil cut increasing to a large value at the breakthrough of the oil bank. For example, in Run 33 (Fig. 8), the water cut decreased from 96.0% to 54.8%, leveling off to an average of 75.0%. A comparison of the breakthrough and ultimate steamflood recoveries for this run (54.4 and 71.2%), with the values for the base run (64.0 and 83.0%) (Run 31) shows that the high water saturation zone adversely affected the steamflood recovery.

It may be noted that in the residual oil case, the breakthrough steamflood recoveries did not differ very much (35.54% for Run 36 vs. 37.6% for Run 34), for the water saturation zones considered, however, the ultimate recoveries for the two runs showed a significant difference (62.8% vs. 73.47%). Thus, it would seem that the magnitude of the effect of a given type of high water saturation build-up on oil recovery not only depends on the oil viscosity, but also on the initial oil saturation.

With reference to the oil recovery data given in Tables 3 to 7, it should be noted that the combined "soak" and steamflood oil recoveries, reduced to the initial oil basis, still come out to be less than the straight steamflood recovery (for the base run).

Effect of the Type of Water Saturation Zone on Oil Recovery

Tables 3 to 6 show that the steamflood performance was governed by the configuration of the high water saturation zones with regard to injection and production wells. In runs involving Soltrol-170, the HWSAIW case appeared to affect the steam breakthrough recovery most for the irreducible water saturation type runs (e.g. 37.20% for Run 2 compared to 68.0% for Run 1; Figs. 5 and 4). In the residual oil type runs, recovery was lowest for the HWSAIPW case (9.77% in Run 10). The steam breakthrough times for the former runs did not show a definite trend, whereas in the residual oil type runs, they did not differ appreciably.

In the cases of Drakeol 15 and 33, the HWSACW situation gave the lowest steamflood recoveries in the irreducible water type runs.

Only HWSAIW and HWSAIPW cases were considered for the 150 cp viscosity Drakeol 35. Both for irreducible water and residual oil types the HWSAIW gave the lowest recoveries, being 54.40% (Run 32) and 35.54% (Run 35), respectively, compared to the respective base run oil recoveries of 64.00% (Run 31) and 37.60% (Run 34).

Effect of the Size and Location of the High Water Saturation on Oil Recovery

While in most of the runs conducted (Tables 3 to 6) the volume of the water injected for "soaking" was 500 cc, in selected runs (Table 7), additional volumes of 250 and 750 cc were employed, in order to study the effect of the magnitude of water saturation on steamflood recovery.

Results given in Table 7 show that an increase in the water saturation generally led to a decrease in the steamflood oil recovery. The relative decrease became less pronounced as the water saturation increased. This is attributed to the attainment of the maximum water saturation in the "soaked" regions. Figure 12 shows plots of steamflood recovery as a function of water injected, for the HWSAIPW case, for the four oils tested. A decrease in oil recovery is evident in all cases.

Regarding the location of the high water saturation zones in the runs conducted, the "soaking" period fluid production indicated that such regions were in the immediate vicinity of the well "soaked". Thus, the injected water did not disperse throughout the porous medium. The steamflood fluid production, for cases where the production well was "soaked", substantiated this conclusion. However, this need not be the case in actual field operations, especially where the oil viscosities are high, as discussed below.

Experimental Errors and Reproducibility of Results

The variations in the initial oil saturation for different types of runs, using the same oil, caused difficulties in correlating the results with the base runs. For example, when using Drakeol 33, the initial oil saturation varied from 60.60 to 66.45%. The tubing connecting the thirteen wells used in the experiments retained some fluid during the experiments. This, together with the possibility of air entrapment, in spite of the care taken to avoid any entry of air into the core, and less than complete cleaning of the core after the runs might be some of the factors that caused variations in the oil saturation values.

Inherent errors involved in thermocouples and the temperature indicators might have caused the recorded temperatures to deviate by about ± 5°F. The thermocouples situated near the walls of the steel box showed temperature readings higher than expected because of the rapid heating of the steel walls due to conduction. The boundary on the top of the steel box was not completely adiabatic because of the limitations of the insulation material used.

Errors in the volume measurements might be of the order of ± 1%. Some uncertainty was involved in the determination of fill-up volumes, which led to the determination of only average steam injection rates.

Several runs were repeated to check the reproducibility of the results, and fairly good agreement was obtained. The predictability of the runs for the HWSAIPW case was checked by using a 125 cp oil (Run 45). Considering the above errors the agreement with the general trend was fair.

Heat conduction in the walls of the steel box used, and the consequent heating of the porous pack, was numerically investigated. The equation of heat conduction in a three-dimensional heterogeneous system was solved, for both stationary and moving heat (steam) fronts. The simulation took into account the thickness of the steel box walls, top, and bottom, as well as the porous pack, via a variable grid. Results showed that during the time of a typical experimental run (1.5 hours), heat conduction in the steel may increase the local porous pack temperatures by as much as 30° F adjacent to the front, and by 18-20°F at the diagonally opposed far end. In view of this, the steamflood sweep patterns obtained may be in error and are not reported here. Also, the effective oil viscosities in the run would be lower than those indicated in Table 2, as a result of conduction heating.

Numerical Steamflood Simulations

In order to study the water saturation build-up effects on oil recovery for very viscous oils, a two-dimensional steamflood simulator was employed. Water injection in the injection well as in the experiments, was simulated prior to the steamflood. Oil viscosities of 5,000 and 50,000 centipoises (at 72°F) were considered. The viscosities were assumed to decrease to 5 and 50 centipoises, respectively, at 500° F. Results of the simulations for five-spot pattern sizes of 10 and 20 acres are summarized in Table 8. It is seen that the effect of an initial water saturation increase on subsequent steamflood recovery becomes smaller as the oil viscosity and/or pattern size increases. Also, it should be mentioned that in these simulations the injected water did not form a high water saturation zone in the vicinity of the injection well. Rather, it was dispersed, as one would expect on the basis of the very high mobility ratio involved. The disposition of the retained water would, of course, depend on the reservoir and fluid characteristics in specific instances.

Validity and Limitations of the Results

On the basis of the experimental results and the computations reported here, one might conclude that high water saturation regions existing prior to a steamflood would lower the oil recovery by a certain amount as compared to a straight steamflood. The loss of recovery seems to decrease with an increase in the in-place oil viscosity. However, two factors must be taken into account in interpreting the results of this study. First, the field situation as regards cyclic steam stimulation may be considerably different from the simple picture assumed here. In a manner of speaking, steam stimulation can be looked upon as a "thermal fracturing" process, in that the steam usually penetrates a relatively thin zone. Formation fracturing may occur, as the injection pressures in field tests tend to indicate. As a result, the retained water may be spread over a much greater volume than one would surmise on the basis of uniform advance of steam over the entire reservoir thickness. As a matter of fact, in the latter case, only water would be produced in the production phase. Probably, the simulation results are more representative of the actual situation in this regard.

Secondly, the present study does not take into account the increase in the formation temperature as a result of cyclic stimulation. In fact, the study is confined to saturation effects only. Increase in formation temperature, as a result of cyclic stimulation is a valuable effect from the standpoint of the subsequent steamflood, since formation pressure depletion and oil viscosity decrease help to lower resistance to flow, in particular, in the production wells. Also, the increase steam injectivity may more than offset any adverse features of water saturation build-up.

It may be noted that in many instances, cyclic stimulation of producing wells is highly desirable in conjunction with a steam flood or an in situ combustion operation [e.g. (4)].

The present study gives certain findings for a limited set of conditions. Field interpretation of these results must take into account the above-mentioned effects.

CONCLUSIONS

Within the framework of the present investigation, the following conclusions may be drawn:

1. The present of high water saturation

regions in the vicinities of injection and/or production wells, or in the center of the flow pattern, would lead to a decrease in the steamflood oil recovery, as compared to a steamflood in the absence of such regions. The presence of high water saturation regions around both the injection and production wells seems to be more unfavorable.

2. The above-mentioned decrease in steamflood recovery due to high water saturation regions depends on oil viscosity; it is appreciable for low viscosity oils, but becomes insignificant for highly viscous oils.

3. The presence of high water saturation regions was more detrimental when the initial oil saturation was high (irreducible water saturation) than in the case of a water flooded porous medium.

4. The steamflood oil recovery decreased with an increase in the water saturation in the water zones.

5. The decrease in recovery due to water saturation build-up, if significant, should be weighed against the decrease in the flow resistance which may permit higher steam injection and oil production rates in the steamflood following the cyclic stimulation.

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TABLE 1 - WATER RETENTION DATA FOR SELECTED STEAM STIMULATION TESTS

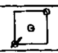
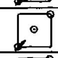
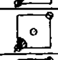
	Field	Cycle No.	Cum. Steam Injected, Bbl Water	Cum. Oil Produced, Bbl	Cum. Water Produced, Bbl	S_o %	Water Retention, % Water Injected as Steam	Ref.
1.	Tia Juana, W. Venezuela	1,2,3	6,746,000	20,270,000	1,800,000	80	73.2	2
2.	Kern River, California	1	16,073	10,661	8,037	80	50.0	3
3.	Oxnard, California	1	22,839	5,153	1,904	80	91.5	4
4.	"	2	14,756	13,192	4,538	80	69.2	4
5.	"	3	7,500	11,497	5,575	80	25.7	4
6.	"	4	10,671	13,125	9,187	80	14.0	4

TABLE 2 - PROPERTIES OF THE FLUIDS USED

Hydrocarbon Name	Abbreviated Name	Specific Gravity at 80°F	Viscosity at 80°F	Viscosity at 212°F	Refractive Index at 80°F	Boiling Range
Soltrol 170	S-170	0.7440	3.81	0.37	1.4294	424-460
Drakeol 15	D-15	0.7850	50.50	5.72	1.4723	660-920
Drakeol 33	D-33	0.8225	100.00	7.04	1.4780	-
Drakeol 35	D-35	0.8308	150.00	8.67	1.4795	-
Mixture[a]	D-33+35	0.8267	125.00	7.08	1.4780	-

[a]Drakeol 33 and Drakeol 35 each 50 percent.

TABLE 3 - SOLTROL 170 RUNS

Run No.	Type of Oil	Type of Run	Estim. Position of H.W.S.	Vol. of Water Used to Soak cc	ΔP mm Hg	Steam Inlet Pres. psig	Steam Injec Rate cc/min	IOIP % PV	OIIAS % PV	Recov. from Soak % IOIP	Recov. by Steam-Flood % OIPAS	Ult. Recov. % OIPAS	Time to Steam B.T. min	Res. Oil Sat. After B.T. %PV
1	S-170	Ir. W.		--	90	20	18.60	66.50	66.50	--	68.00	*	32	21.23
2	S-170	Ir. W.		500	90	20	12.22	72.00	68.00	5.63	37.20	*	27	44.70
3	S-170	Ir. W.		500	90	20	29.27	72.00	65.10	9.54	50.00	*	37	29.40
4	S-170	Ir. W.		500	90	20	12.48	70.15	46.60	30.90	46.91	*	45	24.60
5	S-170	Ir. W.		500**	90	20	10.84	70.00	49.80	49.80	62.00	*	46	18.80
6	S-170	Res. Oil		--	90	20	10.70	15.30	15.30	--	23.50	*	36	11.81
7	S-170	Res. Oil		500	90	20	19.10	19.70	19.40	3.22	20.40	*	39	15.65
8	S-170	Res. Oil		500	90	20	16.50	16.50	14.20	13.10	17.35	*	37	12.35
9	S-170	Res. Oil		500	90	20	13.22	16.60	16.00	3.54	11.78	*	36	14.70
10	S-170	Res. Oil		500**	90	20	14.33	16.45	15.05	8.57	9.77	*	37	15.00

* Not determined. ** Per well. IOIP=Initial oil in place. OIPAS=Oil in place after soak. HWS=High water satn.

TABLE 4 - DRAKEOL 15 RUNS

Run No.	Type of Oil	Type of Run	Estim. Position of H.W.S.	Vol. of Water Used to Soak cc	ΔP mm Hg	Steam Inlet Pres. psig	Steam Injec. Rate cc/min	IOIP % PV	OIPAS % PV	Recov. from Soak % IOIP	Recov. by Steam-flood % OIPAS	Ult. Recov. % OIPAS	Time to Steam B.T. min	Res. Oil Sat. After B.T. %PV
11	D-15	Ir. W.		--	180	20	31.00	78.25	72.28	--	73.45	*	23	21.00
12	D-15	Ir. W.		500	120	20	21.28	79.00	71.00	8.30	51.50	*	50	34.70
13	D-15	Ir. W.		500	160	20	23.60	77.50	69.00	8.50	53.50	*	20	32.00
14	D-15	Ir. W.		500	200	20	31.56	76.50	54.80	35.40	40.60	*	16	32.60
15	D-15	Ir. W.		500**	90	20	12.35	76.00	62.95	17.10	53.12	*	81	26.95
16	D-15	Res. Oil		--	90	20	10.20	30.60	30.60	--	34.80	*	53	19.95
17	D-15	Res. Oil		500	90	20	9.74	30.20	29.00	3.90	32.00	*	58	19.35
18	D-15	Res. Oil		500	90	20	12.04	27.05	25.30	2.54	17.60	*	48	17.60
19	D-15	Res. Oil		500	90	20	9.30	26.00	25.85	0.68	25.20	*	67	18.80
20	D-15	Res. Oil		500**	90	20	9.70	27.00	24.25	11.10	26.20	*	70	19.35

* Not determined. ** Per well. IOIP=Initial oil in place. OIPAS=Oil in place after soak. HWS=High water satn.

TABLE 5 - DRAKEOL 33 RUNS

Run No.	Type of Oil	Type of Run	Estim. Position of H.W.S.	Vol. of Water Used to Soak cc	ΔP mm Hg	Steam Inlet Pres. psig	Steam Injec. Rate cc/min	IOIP % PV	OIPAS % PV	Recov. from Soak % IOIP	Recov. by Steam-flood % OIPAS	Ult. Recov. % OIPAS	Time to Steam B.T. min	Res. Oil Sat. After B.T. %PV
21	D-33	Ir. W.		--	90	20.00	7.75	60.60	60.60	--	69.00	*	80	18.75
22	D-33	Ir. W.		500	90	20.00	8.64	64.70	60.60	6.36	58.50	*	78	25.20
23	D-33	Ir. W.		500	90	18.50	7.71	66.45	57.25	8.58	66.38	*	125	19.45
24	D-33	Ir. W.		500	90	19.00	8.75	63.00	46.50	26.20	56.60	*	109	20.10
25	D-33	Ir. W.		500**	90	20.00	10.79	65.75	52.00	21.00	60.23	*	115	20.60
26	D-33	Res. Oil		--	90	19.00	9.31	24.50	24.50	--	51.75	97.48	83	11.80
27	D-33	Res. Oil		500	90	20.00	9.20	24.00	23.60	1.4[illegible]	50.40	*	90	12.23
28	D-33	Res. Oil		500	90	19.00	9.61	22.90	21.29	6.82	55.56	*	9[illegible]	11.15
29	D-33	Res. Oil		500	90	19.50	8.47	27.90	27.16	2.74	43.50	*	86	16.10
30	D-33	Res. Oil		500**	90	19.00	10.20	27.30	24.05	12.05	44.25	*	85	16.55

* Not determined. ** Per well. IOIP=Initial oil in place. OIPAS=Oil in place after soak. HWS=High water satn.

TABLE 6 - DRAKEOL 35 RUNS

Run No.	Type of Oil	Type of Run	Estim. Position of H.W.S.	Vol. of Water Used to Soak cc	ΔP mm Hg	Steam Inlet Pres. psig	Steam Injec. Rate cc/min	IOIP % PV	OIPAS % PV	Recov. from Soak % IOIP	Recov. by Steam-flood % OIPAS	Ult. Recov. % OIPAS	Time to Steam B.T. min	Res. Oil Sat. After B.T. % PV
31	D-35	Ir. W.		--	90	20.50	9.15	61.83	61.83	--	64.00	83.00	103	22.84
32	D-35	Ir. W.		500	90	20.00	9.05	66.75	58.20	14.55	59.81	76.43	132	20.90
33	D-35	Ir. W.		500**	90	19.50	8.13	70.47	53.41	17.35	54.40	71.75	131	26.40
34	D-35	Res. Oil		--	90	20.00	10.70	32.00	32.00	--	37.60	73.47	99	20.00
35	D-35	Res. Oil		500**	90	20.00	13.27	32.90	32.70	0.715	36.17	77.50	72	21.00
36	D-35	Res. Oil		500	90	20.00	15.60	34.08	32.80	3.80	35.54	62.80	73	21.20

* Not determined. ** Per well. IOIP=Initial oil in place. OIPAS=Oil in place after soak. HWS=High water satn.

TABLE 7 - [illegible]

Run No.	Type of Oil	Type of Run	Estim. Position of H W.S.	Vol of Water Used to Soak cc	ΔP mm Hg	Steam Inlet Pres. psig	Steam Injec Rate cc/min	IOIP % PV	OIPAS % PV	Recov. from Soak % IOIP	Recov by Steam-flood % OIPAS	Ult. Recov. % OIPAS	Time to Steam B.T. min	Res. Oil Sat. After B.T. % PV
1	S-170	Ir. W.		--	90	20.00	18.60	66.50	66.50	--	68.00	*	32	21.23
37	S-170	Ir. W.		250**	90	19.50	9.45	67.48	56.00	17.18	69.13	91.72	71	17.30
5	S-170	Ir. W.		500**	90	20.00	10.89	70.00	49.80	49.80	62.00	*	46	18.80
38	S-170	Ir. W.		750**	90	20.00	9.39	68.25	49.25	27.87	61.60	69.24	50	18.90
[illegible]	D-15	Ir. W.		--	90	20.00	31.00	78.25	78.25	--	73.45	*	23	21.00
39	D-15	Ir. W.		250**	90	19.50	10.13	62.48	52.00	16.61	59.75	78.00	77	21.00
[illegible]	D-15	Ir. W.		500**	90	20.00	12.35	76.00	6[illegible].95	[illegible]	53.12	*	81	26.95
[illegible]	D-15	Ir. W.		750**	90	18.50	10.25	75.00	59.57	20.[illegible]	[illegible]	62.[illegible]	69	34.30
[illegible]	D-[illegible]	Ir. W.		--	90	20.[illegible]	[illegible].75	6[illegible].60	60.60	--	69.00	*	[illegible]	18.75
[illegible]1	D-[illegible]	Ir. W.		250*	90	[illegible]	[illegible]	73.00	[illegible]	[illegible]	[illegible]	[illegible]	129	24.00
25	D-33	Ir. W.		500**	90	20.00	10.79	65.75	52.00	21.00	51.75	97.48	83	20.60
42	D-33	Ir. W.		750**	90	19.00	9.63	70.31	58.09	17.30	51.60	65.50	124	28.10
[illegible]	D-35	Ir. W.		--	90	20.50	9.14	61.83	61.83	--	64.00	83.00	103	22.84
43	D-35	Ir. W.		250**	90	19.00	8.51	66.50	55.75	16.96	55.59	75.10	86	24.72
[illegible]	D-35	Ir. W.		500**	90	19.50	8.13	70.4[illegible]	5[illegible]	17.35	5[illegible].40	71.[illegible]5	131	26.40
44	D-35	Ir. W.		750**	90	19.00	9.26	6[illegible].75	49.76	19.60	46.00	68.75	70	26.85
45	D-33 + 35	Ir. W.		500**	90	20.00	9.92	7[illegible]	60.00	20.60	52.[illegible]	75.3[illegible]	96	28.55

* Not determined. ** Per well. IOIP=Initial oil in place. OIPAS=Oil in place after soak. HWS=High water satn.

TABLE [illegible]

	10-acre pattern 5,000 cp Oil	10-acre pattern 50,000 cp Oil	20-acre pattern 5,000 cp Oil	20-acre pattern 50,000 cp Oil
Oil recovery by steamflooding after "soaking"	16.0	11.3	16.2	9.1
Oil recovery by steamflooding without "soaking"	19.6	14.7	17.7	11.0

Notes: Data assumed were: steam pressure 2000 psia; initial oil saturation 82%; formation thickness 55 ft; formation porosity 33%; permeability 2.5 darcies; in all cases 48,000 bbl of water were used for "soaking", which represent 3.41% pore volume of the 10-acre pattern.

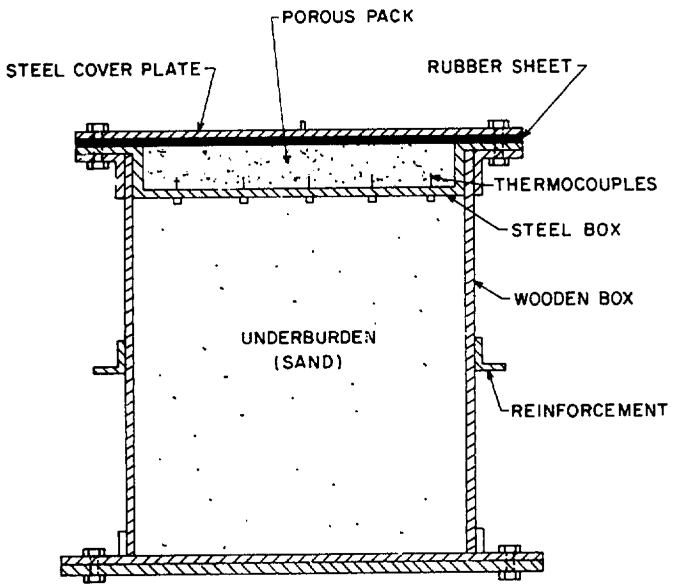


Fig. 1 - Sectional view of the model assembly.

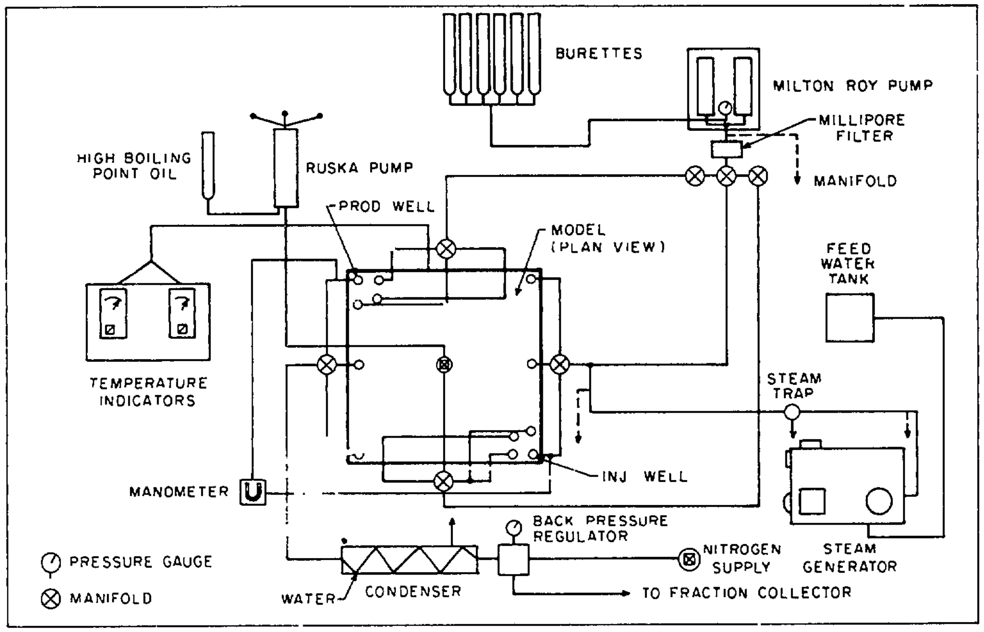


Fig. 2 - Experimental apparatus.

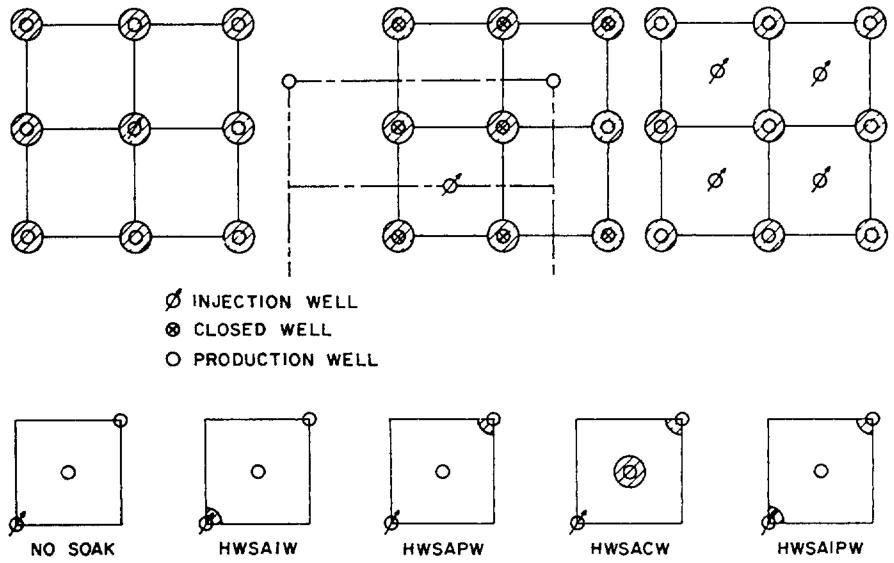


Fig. 3 - Possible configurations of high water saturation zones prior to a steamflood, in a cyclically stimulated field.

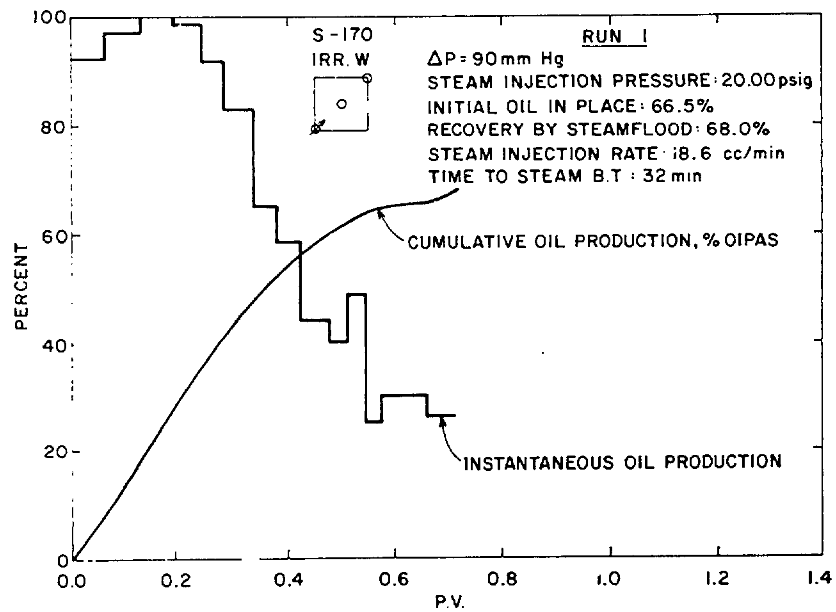
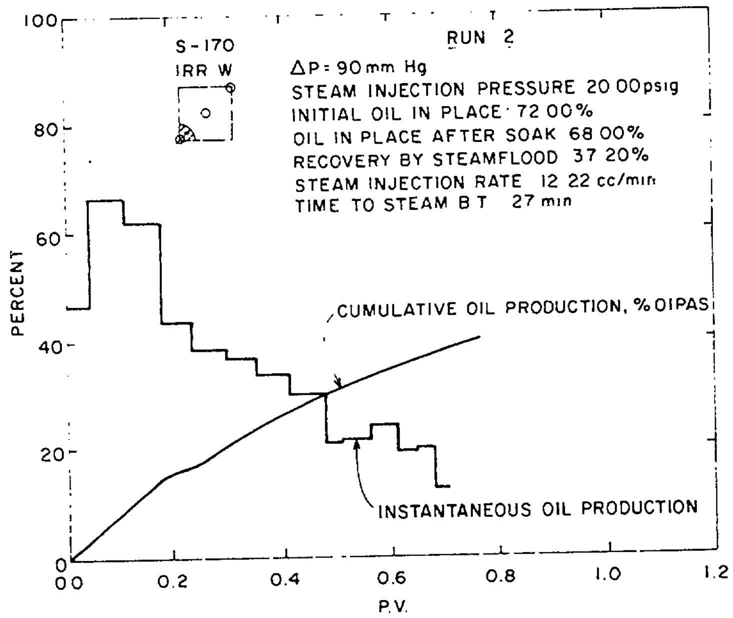
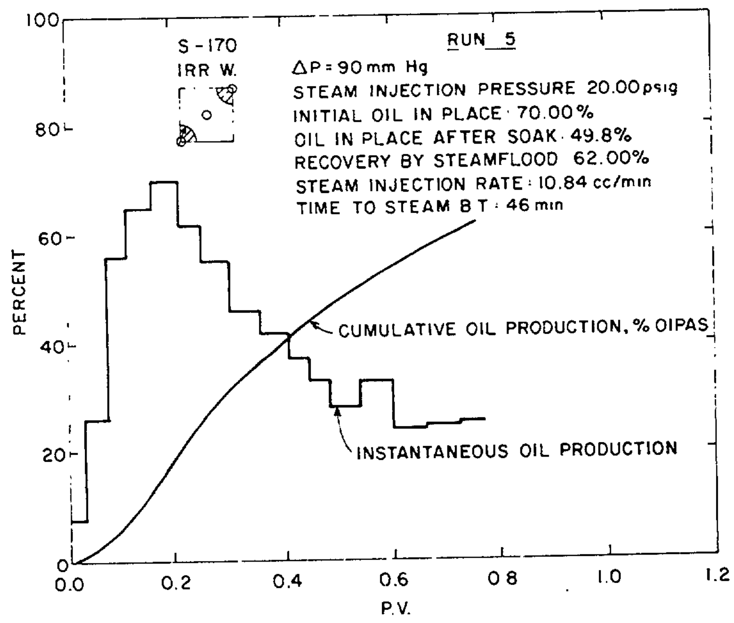


Fig. 4 - Production history for Run 1 (Soltrol-170).



[illegible] (Coltrol-1[illegible]).



[illegible] - Production History for Run 5 (Coltrol-170).

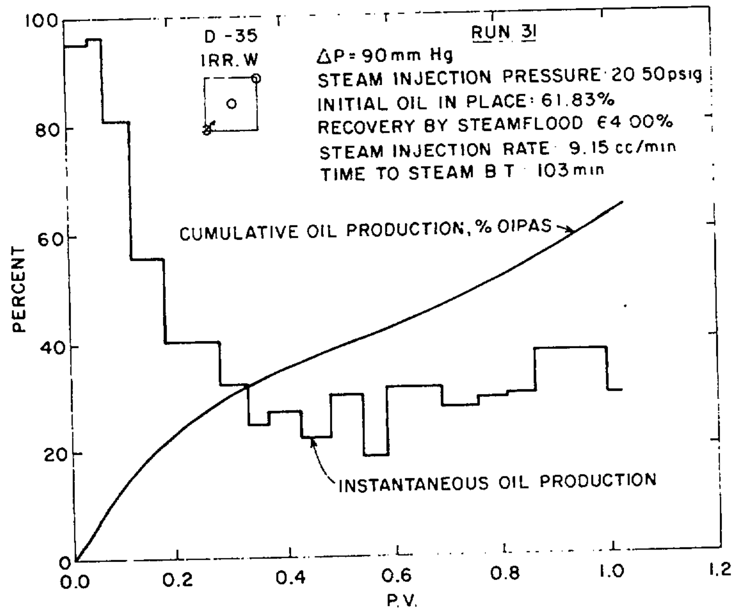
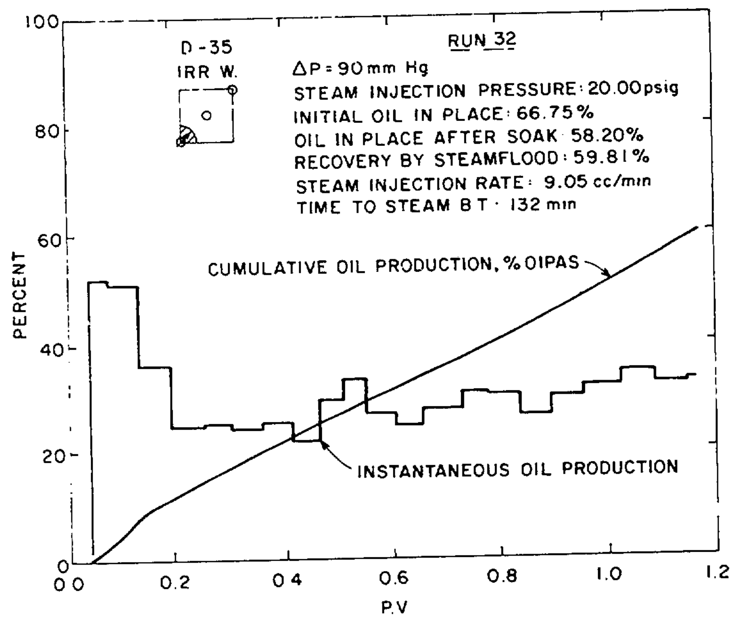
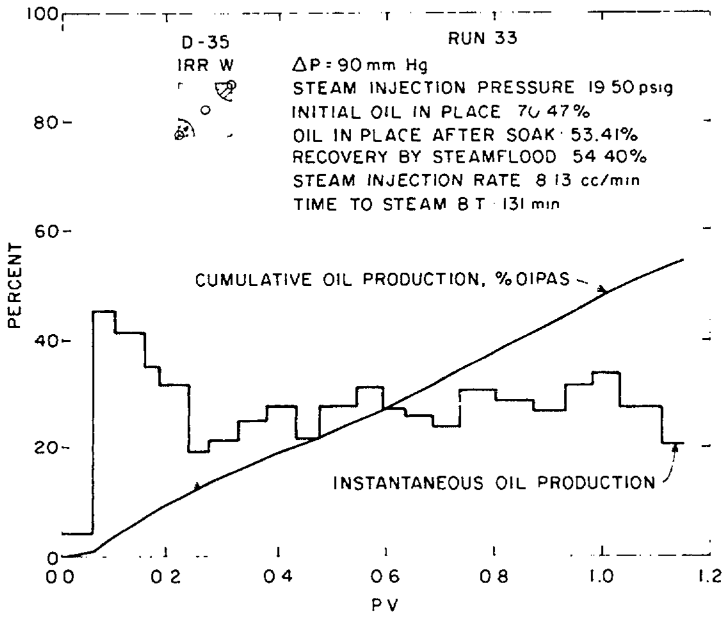


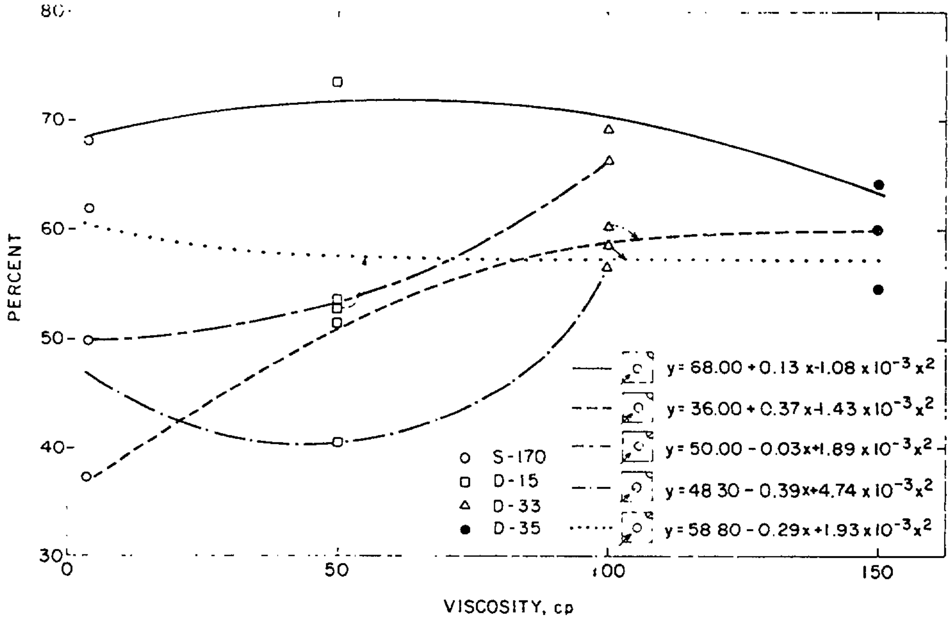
Fig. 7 - Production History for Run 31 ([illegible]).



[illegible] for Run 32 ([illegible]col-35).



[illegible]



... for all irreducible water type runs.

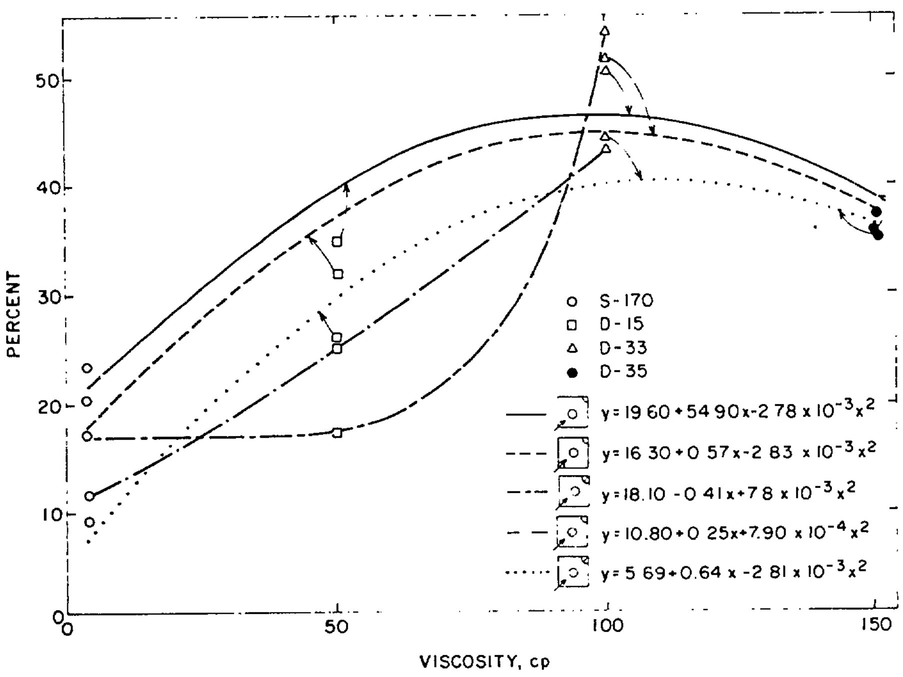


Fig. 11 - Steamflood recovery vs oil viscosity, for all residual oil type runs.

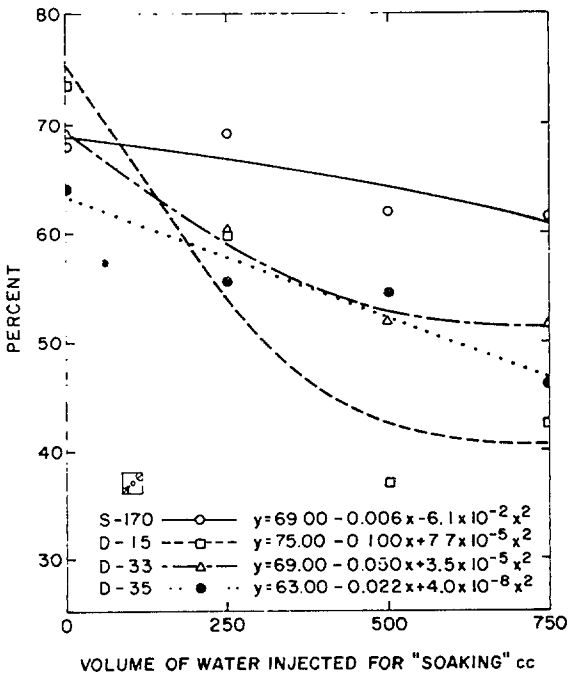


Fig. 12 - Steamflood recovery vs volume of water used for "soaking", for irreducible water type runs.