FIELD TESTS FOR POLYMERFLOOD DESIGN PARAMETERS

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INTRODUCTION

Knowledge of oil-water relative permeability, polymer viscosity, and polymer retention is required to design a polymerflood. These properties are routinely determined in laboratory tests with reservoir rock and fluids.

Lacking reservoir core material for laboratory measurements, Chain Oil Co. used a series of single well tests to define the required properties. Transient tests of buildup and falloff pressures were used to find the relative permeability end points, while a single well pumpin-pumpout test was conducted to determine polymer retention. Apparent reservoir dispersivity was also calculated.

The field test results were used to design a J-Sand polymerflood. During polymer injection, pressure falloff tests were run to measure the in-situ viscosity at different polymer concentrations. Non-Newtonian type curves were used to analyze the transient data.

TRANSIENT TESTING

As an alternative to core work, pressure transient tests were used to determine fluid mobilities required for reservoir engineering calculations. Water injection into well #C-2X had resulted in response at offset producing well #C-1 prior to the pressure testing program.

A pumping well pressure buildup test was run on well #C-1. Bottomhole pressures were measured with acoustic fluid levels. The pressure buildup history is illustrated by a Miller-Dyes-Hutchinson (MDH) plot in Fig. 1. Other pertinent test information is tabulated in Table I.

Well #C-1 had been hydraulically fractured with 18,000 lb of sand, so a logarithmic plot of dT vs. dP illustrated in Fig. 2, was matched to the vertically fractured well type curve, Fig. C.18 in the SPE type curve packet. The match points suggested that k_o was 115 md; more importantly, the type curve indicated that the MDH straight line starts at 100 psi, but ends quickly due to boundary effects.

Analysis of the proper straight line on the MDH plot resulted in k_o equal to 93 md and a -6 skin. The oil mobility, λ_o, is

$$\lambda_o = k_{ro}*k/\mu_o = 23.3 \text{ md/cp} \qquad (1)$$

A pressure transducer was installed in the wellhead of injector #C-2X providing continuous surveillance of surface pressure. The well was shut in, and the resulting pressure falloff history is depicted as a MDH plot in Fig.

A logarithmic plot of dT vs. dP is illustrated in Fig. 4. The curve was matched to the non-propped fracture type curve, Fig. C.19 in the SPE type curve packet. The computed k_w was 34 md. The type curve indicates that the proper MDH straight line begins at 0.4 hr. Notice that the double dP rule is in effect as the half slope ends at 0.04 hr (144 sec) where dP is 720 psi(5000 kPa), and the proper straight line starts at ten times the end of the half slope line where dP is 1433 psi(10,000 kPa).

From the MDH proper straight line, k_w is 33 md with a -3.6 skin. Water mobility, λ_w, is

$$\lambda_w = k_w/\mu_w = 70.2 \text{ md/cp} \qquad (2)$$

Oil-water relative permeability curves required for reservoir engineering computations were derived from the fluid mobilities by assuming that absolute permeability, k, is equal at both wells. Then oil mobility is

$$\lambda_o = k_{ro}*k/\mu_o \qquad (3)$$

and water mobility is

$$\lambda_w = k_{rw}*k/\mu_w \qquad (4)$$

Since well #C-1 was producing only oil during the buildup test, k_{ro} was 1.0. From the oil mobility equation, k is 93.2 md which when substituted into the water mobility equation results in k_{rw} equal to 0.354 at the end point. Water saturation at irreducible oil saturation, S_{or}, was 0.65 and irreducible water saturation, S_{wr}, was 0.30.

Pirson's k_{ro} equation[1], $[(1-(S_w-S_{rw})/(1-S_{rw}-S_{ro})]$, and a concave line from the k_{rw} end point to the irreducible water saturation yields the relative permeability curves depicted in Fig. 5. The mobility ratio derived with k_{rw} at breakthrough average water saturation was 1.3, or about half the end point mobility ratio. The waterflood and polymerflood forecasts were based on the 1.3 mobility ratio.

PUMPIN-PUMPOUT TESTING

Polymer retention and in-situ viscosity are two key polymerflood design parameters. Lacking cores, the parameters were estimated with pumpin-pumpout test data from well #C-2X. The test consisted of thoroughly mixing the tracer-tagged, 5 cp polymer solution to ensure a uniform mixture. Fifty-three barrels of the solution were then injected into the J-Sand reservoir adjacent to the C-2X wellbore. After an overnight shutin, the fluid was swabbed from the well. The average viscosity of the 53 bbl was 1.3 cp (27% of the injected viscosity). At the 140°F bottomhole temperature the viscosity was 0.7 cp.

The tracer was 500 mg/L ammonium thiocyanate. Polymer consisted of 500 mg/L of an intermediate molecular weight, emulsion type, polyacrylamide. Fresh injection water was used to prepare the solution. Polymer viscosity was measured by a Brookfield viscometer with a UL adapter. An analytical method based on ferric chloride was used to measure the tracer concentration, and an acetic acid / hypochlorite method was used to determine the polymer concentration in the swab samples.

Swab sample tracer and polymer concentrations were normalized with their injection concentration. The normalized concentrations vs. the cumulative swab volume are presented in Figs. 6 and 7. In the absence of a comprehensive theory, the data were smoothed with a least square fit line which enabled further computations. Laboratory analytical problems are believed to contribute to data irregularities.

Integration of the tracer curve indicates that 37% of the injected tracer was produced. Since the tracer is non-adsorbing, the remainder appears to have been lost to drift (offset wells were producing during the test period). Polymer curve integration indicates that 19% of the injected polymer was produced. The difference between the two curves is 18% or 1.4 lb of active polyacrylamide. Swept area was estimated to be 0.0194 AF from the 53 bbl injected, 16% porosity, 30% residual oil saturation and a two foot zone. Retention was 72 lb/AF by this method.

The pumpin-pumpout data were also examined utilizing the concept of fluid mixing in porous media. It has been shown[2] that during single phase flow when a tracer is pumped through a core, the effluent concentration profile pictured in Fig. 8 can be described mathematically by

$$c/c_i = 1/2[(1-\mathrm{erf}((1-V/V_p)/2(V\gamma/V_p)^{1/2})] \tag{5}$$

where c_i is the inlet concentration, c is outlet concentration, V is the injected or produced volume, V_p is the pore volume, and γ is the dimensionless dispersion, often called the macroscopic Peclet number. Notice that at one PV injected (1.0 V/V_p) the argument of the error function, erf, is zero and the normalized concentration, c/c_i. is 0.5 as illustrated in Fig. 8. Thus, given a tracer concentration profile the single phase pore volume can be determined. It is expected that the same will be true in a pumpin-pumpout situation

Figs. 9 and 10 plot tracer and polymer concentrations produced vs. the cumulative amounts produced. Returning to Fig. 6, notice that the swab volume is 11.8 bbl at 0.5 c/c_i, but from Fig. 9 the cumulative tracer produced is 8.4 (c/c_i)(bbl). Since c/c_i was 1.0 during injection, the difference between injected and produced is 3.2 (c/c_i)(bbl) or 28% of the injected amount. The tracer is non-adsorbing so by this analysis it seems 28% was lost to drift.

In a similar manner as shown in Figs. 7 and 10, 39% of the injected polymer was lost. Assuming tracer and polymer drift are equal, polymer retention is 11% of that injected or 1.66 lb. From Fig. 7 at 0.5 c/c_i, volume is 7.5 bbl or 0.00275 AF with 16% porosity, 30% residual oil saturation, and a 2 ft zone. It follows that retention is 66 lb/AF.

Dispersivity, sometimes called the dispersion constant, can be expressed in units of length and is used to calculate the mixing zone of two miscible fluids. The constant is calculated by plotting the normalized concentration, c/c_i, vs. the dimensionless volume parameter, $[(V/(V_p-1)/(V/V_p)^{1/2}]$, used in Eq. 1. The tracer profile shown in Fig. 6 is replotted on cartesian probability paper as shown in Fig. 11. From Fig. 8 the pore volume at 0.5 concentration is 11.8 bbl which was used to calculate the dimensionless volume axis in Fig. 11.

Dispersivity, α, is found from

$$\alpha = L[(\gamma_{10} - \lambda_{90})/3.625]^{1/2} \quad (6)$$

where λ_{10} is taken at the 10 percentile and λ_{90} is read at the 90 percentile. Length, L, is the radius of the slug at 0.5 concentration. In this case L is based on 11.8 bbl and equals 10.1 ft. And

$$\alpha = 10.1[(2.15+2.15)/3.625)^{1/2} = 11 \text{ ft.} \quad (7)$$

This method of determining dispersivity is based on linear flow, but seems to give reasonable results when applied to this radial system.

Slug size can be calculated from Raimondi's[3] equation

$$c/c_i = \mathrm{erf}(3R^4/64\alpha r^3)^{1/2} \quad (9)$$

where R is the slug radius and r is the interwell distance. Selecting a 30% minimum slug concentration at the producer and solving for R with an eleven ft. α and r equal to 1320 ft

$$\mathrm{erf}\ 0.30 = [3R^4/(64)(11)(1320^3)]^{1/2}$$
$$R = 500 \text{ ft} \quad (10)$$

A slug with a 500 ft radius from the injection wellbore is about 15% PV.

POLYMER FALLOFF TESTING

Two injection well falloff tests were run during the course of polymer injection. The pressure histories are compared in the Fig. 3 MDH plot. The erratic nature of the 20 cp falloff was due to an electronic malfunction in the pressure recorder caused by temperature over 120°F during the heat of the day. As the ambient temperature fell, the late time data corrected nicely.

In SPE #13058 Raghavan[4] and his co-workers presented a uniform flux type curve for analyzing non-Newtonian pressure transient data. This curve was used to match successfully the late time portion of the 20 cp falloff data, the previous 7 cp data, and the water falloff test. The lines in Fig. 3 are the type curves which illustrate the goodness of the match. Notice that the test data are in SI units enabling the use of the type curves. All pertinent transient test data are listed on Tables I-IV.

Given water viscosity of 0.47 cp at bottomhole temperature, the type curve match points, along with Raghavan's dimensionless pressure definition

$$Pds/n^{2} = 2\Pi khdP/qB\mu^{*}n^{2} \quad (11)$$

where n is the Power Law index (0.8 in this instance) which yields

Surface viscosity cp	Mobility md/cp	In-situ Viscosity cp
1.0	66.4	0.470
7.0	27.9	1.086
20.0	17.3	1.751

The surface viscosity is correlated with the in-situ viscosity on logarithmic paper as shown in Fig. 12. From the 100% correlation, notice that the in-situ viscosity is 0.95 cp at 5cp injected, whereas the pumpin-pumpout test indicated that the average viscosity was 0.7 cp at 140°F. The 0.7 cp was measured at 7 sec^{-1} while the transient test 0.95 cp is taken at 1 sec^{-1} indicating very good agreement between the two types of viscosity determinations.

A 100% logarithmic correlation between the in-situ viscosities from transient tests and the injectivity index is shown in Fig. 13. Injectivity index is defined as the injection rate divided by the flowing bottomhole pressure. Included are data from similar tests done in a limestone reservoir.[5] The slopes are identical indicating that they may be useful for predicting injection rates given a desired in-situ viscosity.

In conclusion, pressure transient tests defined the oil and water mobilities used to forecast waterflood and polymerflood performance. Pumpin-pumpout testing was used to estimate viscosity and retention parameters required to design a polymerflood. Additional pressure testing during polymer injection confirmed the in-situ viscosity measured during the pumpin-pumpout test. Examination of the pumpin-pumpout data indicates that polymer retention was about 70 lb/AF.

References

1) Smith, C.R.: Mechanics of Secondary Oil Recovery, Reinhold Publishing Corp., New York City (1966).

2) Brigham, W.E.: "Mixing Equations in Short Laboratory Cores," Soc. Pet. Eng. J. (Feb. 1974) 91-99/.

3) Raimondi, P., Gardner, G.H.F., and Petrick, C.B.: "Effect of Pore Structure and Molecular Diffusion on the Mixing of Miscible Liquids Flowing in Porous Media," preprint 43 presented at the 1959 AIChE/SPE Joint Symposium on Fundamental Concepts of Miscible Displacement: Part II, Fifty-second Annual Meeting, San Francisco, Dec. 6-9.

4) Vongvuthipornchai, S. and Raghavan, R.: "Pressure Falloff Behavior in Vertically Fractured Wells: Non-Newtonian Power-Law Fluids," paper SPE 13058 presented at the 1984 Annual SPE Meeting, Houston, Sept. 16-19.

5) Weiss, W.W., and Baldwin, R.W.: "Planning and Implementing a Large-Scale Polymer Flood," J. Pet. Tech. (April 1985) 720-730.

Table 1
Well C-1: Producing Well Buildup

Time hr	BHP psig
0.00	0.0
0.25	23.6
0.50	29.0
0.75	36.3
1.00	42.7
1.25	48.1
1.50	53.5
1.75	53.5
2.00	58.9
2.50	66.3
3.00	77.1
4.00	93.2
5.00	104.0
6.00	114.8
7.00	125.6
8.00	136.4
24.00	279.5
25.00	279.5

Rate	=	60 BPD
RVF	=	1.1
Viscosity	=	4.0 cp
Thickness	=	3.25
Compressibility	=	12 x 10^{-5}/psi
Wellbore Radius	=	0.1875 ft
Porosity	=	16%
Spacing	=	40 ac

Table 2
Injection Well C-2X: Water Falloff

Time hr	BHP psig	Dp psig
0.000	4309	7
0.033	3625	684
0.066	3446	863
0.100	3344	965
0.133	3275	1034
0.155	3224	1085
0.200	3183	1126
0.233	3150	1159
0.266	3122	1187
0.300	3097	1212
0.400	3037	1272
0.500	2986	1323
0.600	2948	1361
0.700	2915	1394
0.800	2885	1424
0.900	2858	1451
1.000	2834	1475
1.100	2811	1498
1.200	2790	1519
1.300	2771	1538
1.400	2752	1557
1.500	2736	1573
1.600	2718	1591
1.700	2703	1606
1.800	2688	1621
1.900	2674	1635
2.000	2662	1647

Rate	=	460 BPD
FVF	=	1.01
Viscosity	=	0.47 cp
Thickness	=	2.0 ft
Compressibility	=	1 x 10^{-5}/psi
Wellbore Radius	=	0.1875
Porosity	=	16%
Spacing	=	40 ac
Cum Injection	=	46,400 Bbl

Table 3
Injection Well C-2X: 7 cp Polymer Falloff

Time hr	BHP psig	dP psig
0.000	4758	0
0.010	4597	161
0.25	4437	321
0.050	4270	488
0.101	4063	695
0.150	3950	808
0.201	3865	893
0.251	3805	953
0.299	3753	1005
0.402	3671	1087
0.501	3605	1153
0.605	3550	1208
0.700	3503	1255
0.799	3463	1295
0.900	3425	1333
1.010	3388	1370
1.504	3241	1517
1.776	3172	1586
2.385	2950	1808
3.341	2900	1858
3.718	2849	1909
4.133	2801	1957
4.596	2749	2009
5.088	2701	2057
5.619	2660	2098

Rate	=	317 BPD
FVF	=	1.01
Viscosity	=	7 cp (surface)
Thickness	=	2.0 ft
Compressibility	=	1×10^{-5}/psi
Wellbore Radius	=	0.1875
Porosity	=	16%
Spacing	=	40 ac
Cum H20 Inj	=	83,626 Bbl
Cum Polymer Inj	=	13,763 Bbl

Table 4
Injection Well C-2X: 20 cp Polymer Falloff

Time hr	BHP psig	dP psig
0	6345	0
0.015	6160	185
0.036	6060	285
0.066	5960	385
0.105	5860	485
0.152	5760	585
0.220	5645	700
0.250	5591	754
0.299	5525	820
0.352	5465	880
0.404	5420	925
0.450	5369	976
0.503	5330	1015
0.620	5255	1090
0.700	5209	1136
0.806	5165	1180
0.903	5121	1224
1.008	5100	1245
1.244	5045	1300
1.305	5033	1312
1.404	5010	1335
1.506	4991	1354
1.597	4975	1370
1.741	4955	1390
1.910	4936	1409
7.060	4962	1383
8.268	4891	1454
9.064	4857	1488
10.089	4791	1554
11.321	4740	1605
12.120	4699	1646
13.266	4661	1684
13.922	4637	1708
14.924	4603	1742
16.008	4569	1776
17.195	4529	1816
18.060	4495	1850
19.015	4465	1880
19.937	4443	1902
21.093	4417	1928
22.296	4383	1962
23.147	4365	1980
23.995	4345	2000
25.068	4317	2028
26.109	4295	2050
27.268	4273	2072
28.284	4245	2100
30.046	4215	2130
31.853	4175	2170
35.502	4110	2235
38.099	4077	2268

Rate	=	325 BPD
FVF	=	1.01
Viscosity	=	20 cp (surface)
Thickness	=	2.0 ft
Compressibility	=	1×10^{-5}/psi
Wellbore Radius	=	0.1875 ft
Porosity	=	16%
Spacing	=	40 ac
Cum H20 Inj	=	83,626 Bbl
Cum Polymer Inj	=	72,653 Bbl

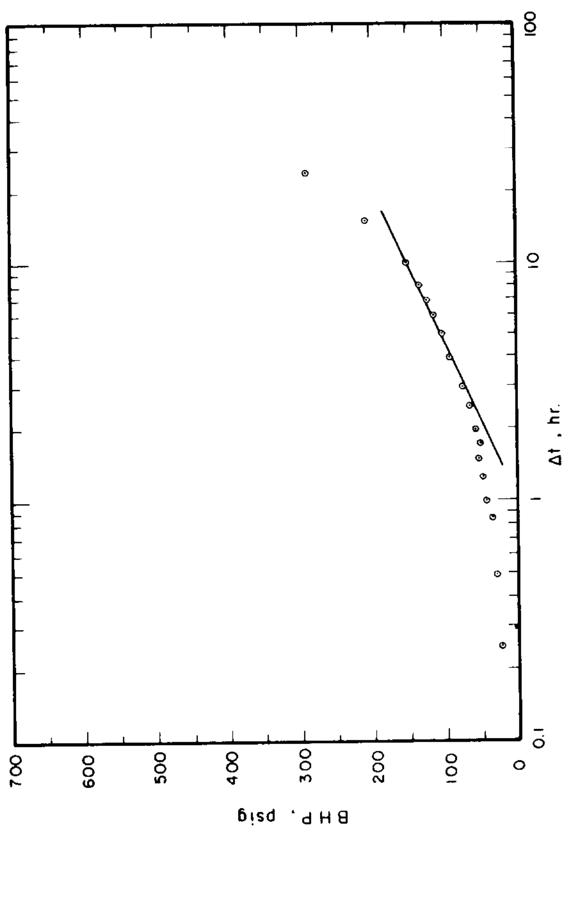

Figure 1 - Pressure buildup history of Well #C-1 (MDH plot)

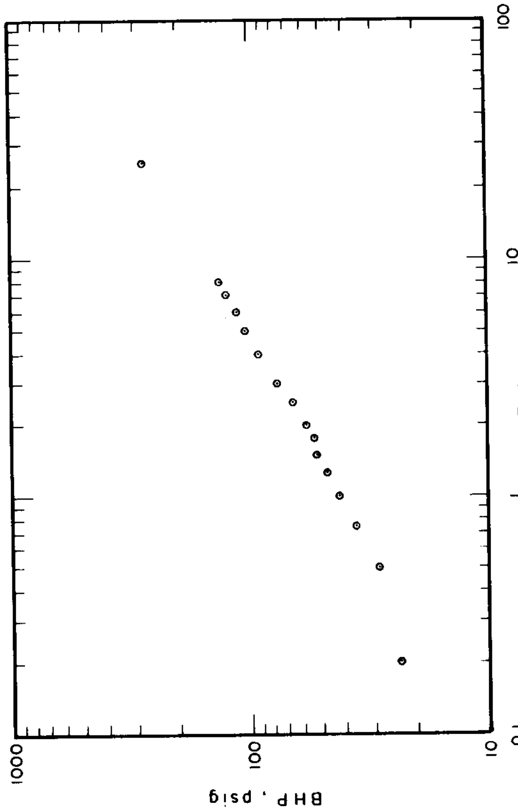

Figure 2 - Pressure buildup history of Well #C-1 (logarithmic plot)

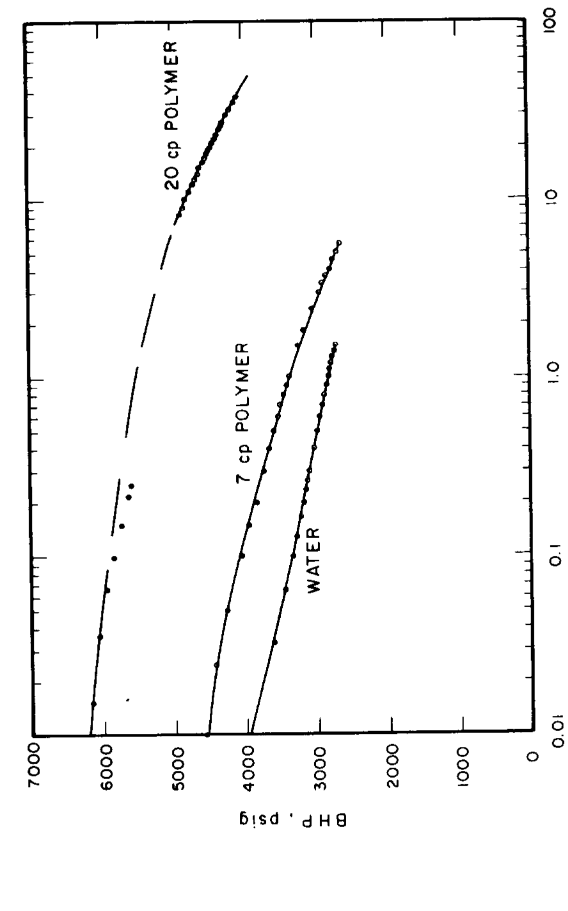

Figure 3 - Pressure falloff history of Well #C-2X (MDH plot)

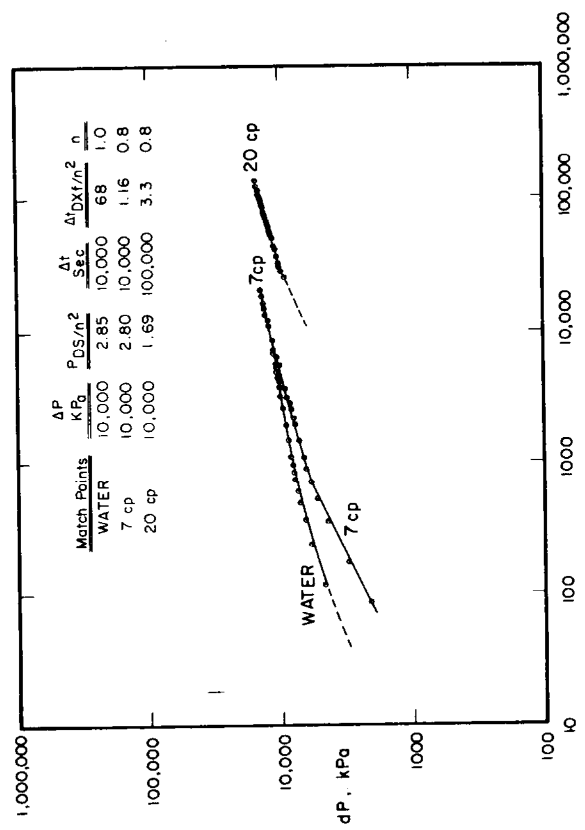

Figure 4 - Pressure falloff history (SI units) of Well #C-2X (logarithmic plot)

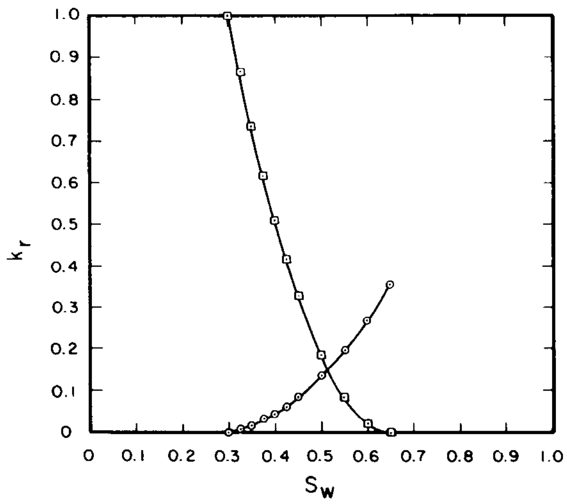

Figure 5 - Relative permeability from transient tests

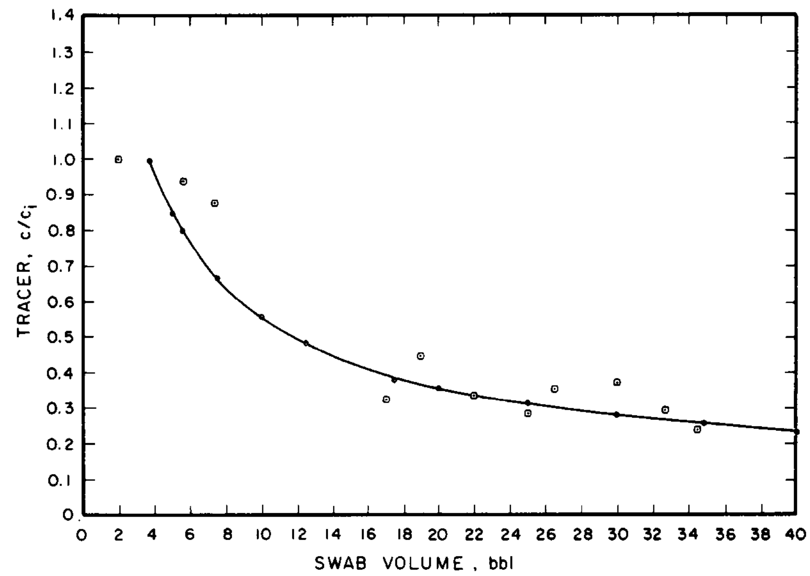

Figure 6 - Tracer concentration vs. cumulative volume swabbed from Well #C-2X

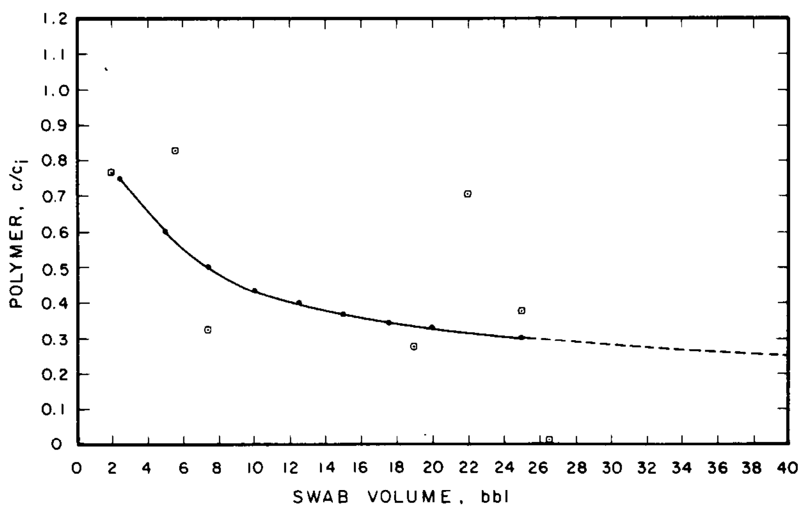

Figure 7 - Polymer concentration vs. cumulative volume swabbed from Well #C-2X

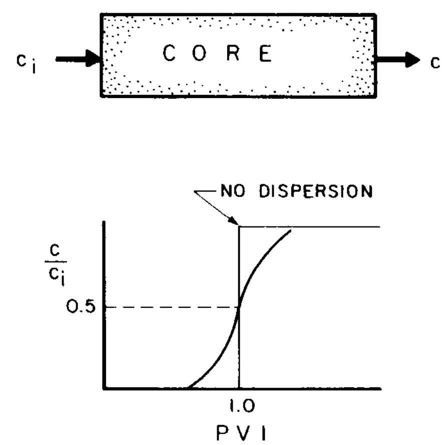

Figure 8 - Definition of tracer dispersion

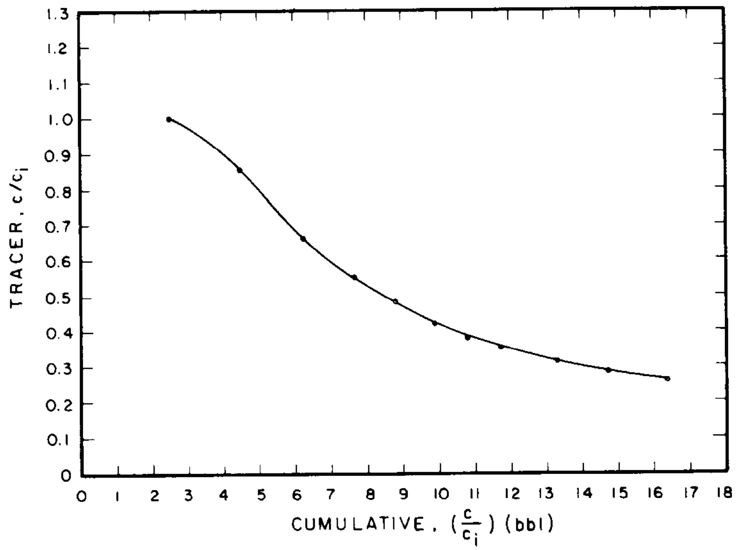

Figure 9 - Tracer concentration vs. cumulative tracer swabbed from Well #C-2X

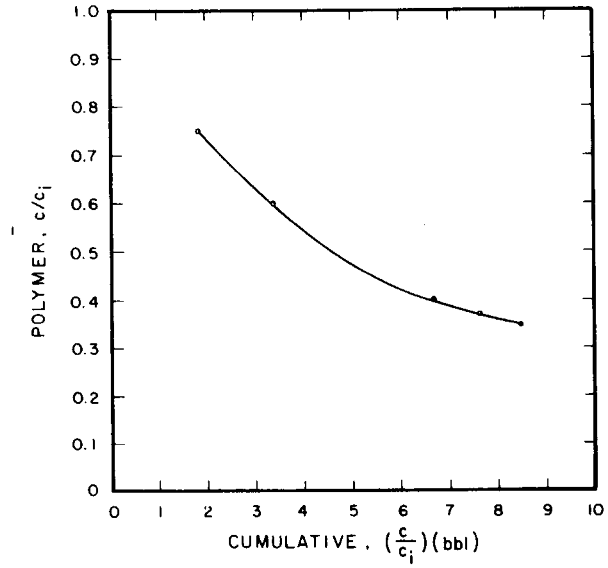

Figure 10 - Polymer concentration vs. cumulative polymer swabbed from Well #C-2X

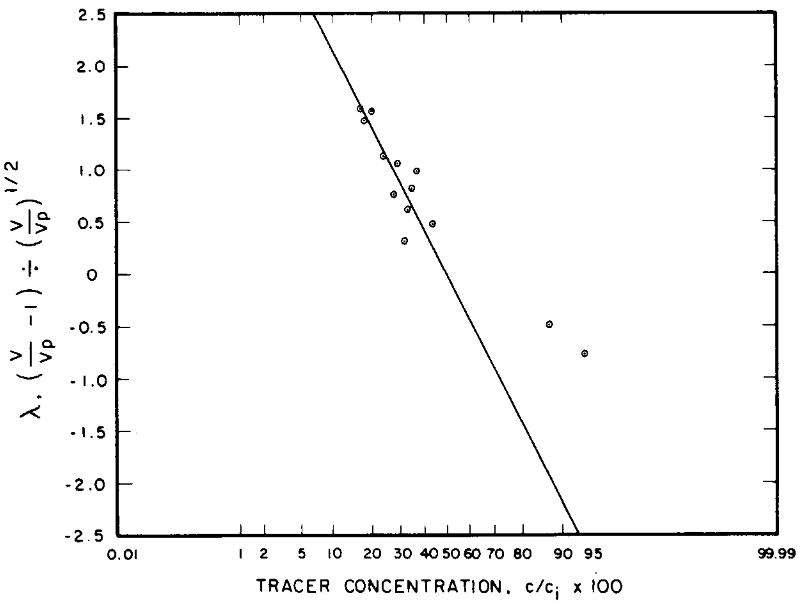

Figure 11 - Tracer probability plot

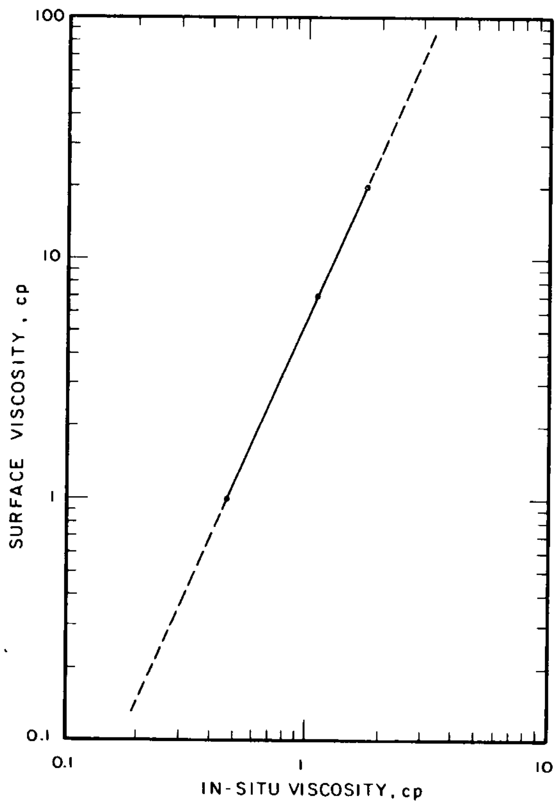

Figure 12 - Surface viscosity, in-situ viscosity correlation

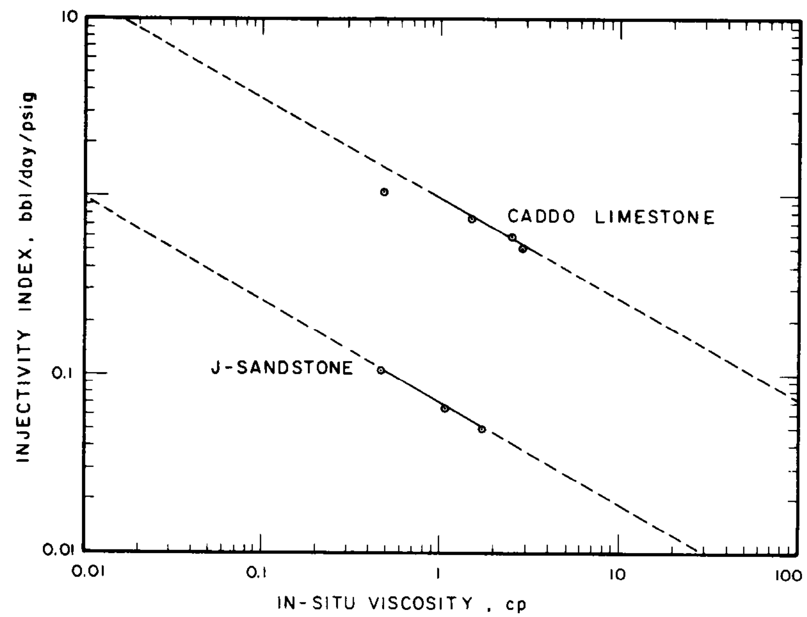

Figure 13 - Injectivity index, in-situ viscosity correlation