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A PARAMETRIC STUDY OF THE CO_2 HUF-n-PUF PROCESS

by John T. Patton, CBI, Inc.; Keith H. Coats, Intercomp, Inc.; Ken Spence, U.S. Department of Energy

ABSTRACT

Cyclic CO_2 stimulation of a production well, especially in viscous oil reservoirs, is developing as a method of rapidly producing tertiary oil and obtaining valuable data. History matching provides confirmation of CO_2 - crude interactions, measured in the laboratory, that can increase the accuracy of CO_2 flood predications.

Profitability of the process is enhanced by proper control of key operating parameters. The most important are:

(a) CO_2 injected per cycle
(b) number of cycles
(c) back pressure during production

Reservoir parameters dictate the selection of commercial applications. The dominant factors are:

(a) viscosity of the oil
(b) oil swelling and viscosity reduction due to CO_2 dissolving in the crude
(c) trapped gas saturations
(d) fluid saturation
(e) permeability
(f) wettability

In the absence of published field data, this study utilized a numerical simulator to predict incremental oil recovery as a function of the above operating and reservoir parameters. Multiple regression analysis was then used to relate the efficacy (STB incremental oil/MCF CO_2 injected) of the CO_2 cyclic stimulation process to six parameters.

Under ideal conditions one extra barrel of stock tank oil is produced for each MCF of CO_2 injected. Efficacy decreases with both number of cycles and volume injected.

INTRODUCTION

Starting with the early discovery of reservoirs containing viscous oil, engineers have been striving to develop commercial techniques for stimulating the production of this resource. In many instances viscous oil cannot be efficiently displaced by water and other flooding agents. Significant effort has therefore been directed at cyclic, single well processes. The steam stimulation process developed independently by Exxon and Shell during the early 1960's[1,2], was an early breakthrough in stimulation technology. Since that time, a variety of novel chemical additives have been evaluated for enhancing the flow of viscous oil. Until recently, hydraulic fracturing was the only commercially viable alternate to steam stimulation.

References and illustrations at end of paper.

The productivity problem stems from the retarding effect on oil flow imparted by the high viscosity of the fluid. Viscosity can be effectively reduced by heating, as in the steam process, or by diluting with proper solvents. The ideal solvent would possess the following desirable characteristics:

(a) dissolve in the oil thus reducing its viscosity.
(b) not break out as an immiscible, highly mobile phase produced preferentially to the oil.
(c) if it does break out as in (b), then it should remain trapped as an immobile phase providing energy by expansion to promote stimulated oil flow.

Over the past twenty years many solvents which more or less meet the above criteria have been evaluated for cyclic stimulation processes [3,4,5]. Early solvents tested lacked the cost effectiveness to be commercial. The main problem with the organic solvents is their inability to reach deep into the reservoir and, hence, most of the process is devoted to injecting and producing solvent with little net gain in oil production.

During 1977 a new dimension was added to the solvent concept, that being the use of supercritical carbon dioxide to achieve solvent reduced viscosity deep into the reservoir[6]. Since that time, three companies have field tested the process on widely varying viscous oils with good results. Because of today's more reasonable heavy oil pricing and incentives incorporated in the wind-fall profit tax, several commercial applications are now being designed and should be operating within the year.

The accelerating interest in the CO_2 Huf-n-Puf process has generated a need for a good definition of the process so that engineers can evaluate the technical merits and optimize applications for candidate reservoirs. This study was undertaken to provide an understanding of the effect of normal reservoir parameters on process efficiency. Since no field data have been published, computer simulation, such as the one described, must be used to predict recovery. For a potential CO_2 flood, history matching a single well stimulation test provides data to complement laboratory studies and reduce the degree of risk associated with the project.

CONCEPTUAL PROCESS

Mechanically, the use of CO_2 to stimulate all production is similar to the conventional steam process but CO_2's effect on the reservoir surrounding the treated well is uniquely different. The process is most applicable to viscous oil reservoirs having high oil saturations. A small mobile water saturation in the vicinity of the treated well is helpful.

Reservoir rock, which stores heat energy for steam stimulation, has no comparable capacity to store CO_2. The absence of storage capacity allows the carbon dioxide to migrate several hundred feet into the reservoir, primarily by displacing the mobile water saturation surrounding the well. The low mobility of the oil relative to water and CO_2 allows the oil to be bypassed. During the injection and soak periods the oil absorbs gaseous CO_2 and expands. At the end of an injection cycle the region around the well bore contains mostly low viscosity, mobilized oil and free CO_2. The absence of a large mobile water saturation allows stimulated oil production at attractively low water-oil ratios.

A unique feature of the CO_2 Huf-n-Puf process is that the adverse mobility that exists between CO_2 and oil is helpful and actually provides the mechanism by which CO_2 is propagated deep into the reservoir.

STIMULATION MODEL

The mathematical model used for simulating the CO_2 Huf-n-Puf process is described in the appendix. The model numerically simulates two or three dimensional transient multi-phase flow in oil or gas condensate reservoirs by implicitly solving the conventional Darcy flow and mass conservation equations. We have found the implicit formulation and direct solution necessary to simulate the rapid, large transients in pressure, saturation and R_s and high throughput ratios which occur in the CO_2 cyclic process.

Due to the high solubility of CO_2 in crude oil, a sharp CO_2 profile exists at the radius to which CO_2 has penetrated the formation. In cases involving large size treatments this can be several hundred feet from the well bore and, hence, a large number of grid blocks are required to accurately define the location of the sharp CO_2-oil interface. The truncation error introduced by using too few radial grids is illustrated in Table 1. All cases give about the same first cycle production. However, the nine block case erroneously produces much more second cycle oil because the CO_2 penetrated deep into the reservoir where the nine block definition is inadequate.

For the CO_2 stimulation application described here, the oil is assumed dead (devoid of dissolved hydrocarbon gas) and CO_2 assumes the role of gas with the b_o, R_s, μ_o, μ_g and b_g curves obtained from CO_2-oil lab swelling tests. We emphasize the assumption here of immiscibility between oil and CO_2.

The model was run in radial-z mode using formation and oil PVT properties from three fairly clean California sands. For the formation thicknesses of less than 107 ft. (32.6 m) and less we found that calculated oil recovery was not changed significantly by subdividing the thickness into 2 or more layers. The calculations are therefore 1D radial, using 20 radial grid blocks.

PROCESS VARIABLES

The variables which affect the performance of CO_2 stimulation can be divided into two classes, operational and reservoir. The operational variables should be managed in such a way as to maximize profitability. This may not always coincide with the optimization of variables in regard to process efficiency. The significant operational variables are treatment pressure, treatment volume, back pressure on the well during the production phase and number of cycles. Treatment pressure is the maximum reservoir pressure permitted during injection.

High treatment pressure forces more CO_2 into solution and promotes beneficial lowering of oil viscosity. It is recommended that the well be treated at the highest rate (pressure) consistent with availability of CO_2, injection equipment and depth. Injection pressures as high as 0.7 psi per foot of depth (15.8 kPa/m) have been utilized in several field tests with good results.

The effect of treatment volume for oils of different viscosities is shown in Figure 1. The early maximum shown for both oils is not well understood. One would normally expect steadily increasing production with treatment volume, approaching some limiting value asymptotically. For actual field situations the maximum profit point will be obtained for treatments less than 400 MCF/ft (37.2 m^3/m) and, hence, the unexplainable dip could be largely of academic interest. Additional work is planned, however, to try and explain the phenonoma.

A second key variable, over which control can be exercised, is the back pressure held on the formation during the production cycle. The effect of back pressure is shown in Figure 2. Solubility of CO_2 in crude oil increases rapidly with pressure causing significant viscosity reduction. This could suggest that back pressure might have a beneficial effect on oil production. This is not the case. For all oils studied, productivity increases with a declining bottom hole pressure as commonly observed in primary and secondary operations. During the injection cycle some oil is displaced away from the well bore requiring resaturation by return oil flow before stimulated oil production can be obtained. At high back pressures (low withdrawal rates) production consists mainly of gas and a little water, leaving the oil deep in the formation until the simulation cycle is essentially complete.

RESERVOIR PARAMETERS

Nature plays a major role concerning the potential of CO_2 stimulation. Reservoir parameters over which engineers have no control, dominate the process. The major variables are oil viscosity, reservoir depth, and current oil saturation. Another parameter, gas trapped during injection or production, also exerts a significant influence on the process. However, values do not vary widely between reservoirs.

There are three effects attributable to the presence of trapped gas, which bear on the efficacy of the process. During injection CO_2 gas must build up to a critical saturation, S_{gc}, before propagating deeper into the reservoir. A non-zero value for S_{gc} reduces both the rate of frontal advance and absolute penetration of CO_2 away from the well bore. During the production phase, both critical and residual gas saturations (S_{gc} and S_{gr}) play roles. Free gas saturation appears and increases toward critical S_{gc} as undersaturated oil pressure declines below bubble point. In addition, as oil and gas flow toward the well, the displacement process alone can reduce the gas saturation to only residual saturation S_{gr}. This residual immobile gas phase occupies oil flow passages thus reducing the production rate. This negative effect is usually more than offset by a second mechanism involving compressibility of the CO_2 gas. The residual gas trapped in the reservoir supplies extra energy by expansions and produces measurable additional oil.

For the energy mechanism, associated with trapped gas, to be effective the gas must propagate a large distance from the well. Large volume CO_2 treatments tend to achieve this deeper penetration and emphasize the beneficial effects of the trapped gas mechanism also shown in Figure 1.

The limited laboratory data available show a definite hysteresis between S_{gc} and S_{gr}. The two trapped gas saturations are usually not equal with S_{gc} normally being smaller. However, within the normal range of trapped gas saturations, their influence on the efficiency of the process is minimal. Equal values of 0.1 have been used for this study.

The effects of oil viscosity and reservoir pressure (depth) are shown in Figure 3. The process depends on solution of CO_2 in the oil to reduce the viscosity and promote stimulated production and CO_2 solubility increases with pressure. Deeper reservoirs capable of accepting higher pressure CO_2, produce the most efficient response. Very shallow reservoirs, which often contain the most viscous oil, are rarely commercial candidates for CO_2 stimulation.

Oil viscosities less than 2000 cp are usually required for commercial application. However, CO_2 can be injected into shallow reservoirs containing very viscous oil as a means of imparting some sort of fluid mobility where none exists in the virgin state. Such stimulation might be employed preceeding a thermal process in order to make the reservoir more accessible to steam or air.

The response are included between the two pressure limits represents the data obtained in this study. Variation of other process variables causes data scatter necessitating the use of a response area rather than the single curve correlating the two variables.

Somewhat unexpectedly, high oil saturation tends to reduce the efficacy of the process as shown in Figure 4. This is largely due to the decision to evaluate the process only on incremental production. Both primary and stimulated recovery are greatest for reservoirs having high oil saturations. However, the incremental production is less adversely affected by high water saturation and, hence, the process is well suited to high water-cut reservoirs.

The mixed effect of permeability on process efficacy, shown in Figure 5, requires some explanation. For oils too viscous to flow at commercial rates, high reservoir permeability serves to enhance stimulation from carbon dioxide injection. Around 1000 cp a reasonable balance is achieved between permeability and stimulated flow so that little or no effect is observed. For the least viscous oil studied, 177 cp, high permeability serves to drain the reservoir more efficiently in the primary base case. Less oil remains to be stimulated and efficacy shows a declining trend with increasing permeability. Again, as was the case with oil saturation, the high permeability reservoirs consistently produce more total oil for both primary and stimulated production phases. It is only the choice of defining efficacy in terms of incremental oil that gives rise to contrasting trends.

Reservoir wettability, reflected in relative permeability effects, also affects stimulation obtainable in the field. As one would expect, a shift toward oil wettness, characterized by higher water and lower oil permeabilities, tends to reduce the effectiveness of the treatment. For the purpose of this study a moderately water-wet system is assumed wherein oil and water have equal relative permeabilities of 0.13 at a water saturation of 57 percent. Oil permeabilities were calculated by the procedure developed by Stone[7].

The effect of subsequent cycles was investigated by making five sequential cyclic simulations for every set of parameters studied. With few exceptions, the first cycle, regardless of treatment size, is the most productive in terms of oil produced relative to CO_2 injected. Efficacy shows a downward trend in subsequent cycles with the average number of profitable cycles varying between three and five. The fifth cycle is almost always marginal and results at the end of the third cycle appear to best represent the effect of reservoir parameters. Cycle number has been included as one of the variables in the regression equation to provide a means of estimating total potential and maximum cycles for any given candidate reservoir.

The numerous variables affecting the process make it unwieldly to describe all effects by interrelated plots and cross plots. An alternate approach, multiple regression analysis, was employed in an attempt to correlate some 200 data points obtained in this study. The results of regression analysis is given by the following equation.

$$E = .6 - .04\,N_c - 9 \times 10^{-6}\,\mu_o + 2 \times 10^{-4}\,P_t + 5.2 \times 10^{-5}\,k - .4\,S_{oi} - 7.92 \times 10^{-3}\,V_c + 3 \times 10^{-3}\,V_c^2$$

Non-linearity between E and N_c was considered as was possible curvature due to a quadratic relationship between E and each independent variable. Only V_c showed significant curvature but its effect was pronounced. In final form the equation represents the data quite well enough for engineering estimates. Calculation of the coefficient of regression, R^2, indicated 74 percent of the variation in the data has been described.

The variable ranges included in the correlation are:

Variable	Range
N_c	1 - 5
μ_o	177 - 28,000
P_t	350 - 1800
k	176 - 800
S_o	.59 - .75
V_c	.05 - .75
E	.01 - .97

Although statistical fit is good, use of this equation is recommended only as a guide in selecting candidate reservoirs. It should not be used in place of competent reservoir simulation to predict performance or history match field data. Effects of significant reservoir stratification and/or miscible CO_2/oil displacement mechanisms are not reflected in the correlation.

CONCLUSIONS

The efficacy with which the CO_2 Huf-n-Puf process enhances the production of viscous crude oil appears to be comparable to values reported for a variety of field tests involving CO_2 flooding of low viscosity oils. It is predicted that 2-8 MCF of CO_2 will be required to recover an additional barrel of crude oil (.5-2 m^3/m^3). This range covers the results for a number of field tests including Chevron's commercial venture at Sacroc. CO_2's effectiveness decreases in subsequent cycles. Unless field data indicate otherwise, it would appear that the CO_2 stimulation process might be best applied in three cycle treatments for each well. If the third cycle response is better than anticipated, the facilities will be available to perform additional cycles if economics warrant.

Under optimum conditions to CO_2 Huf-n-Puf process can be considered economically attractive in it's own right. Even in reservoirs, where the conventional CO_2 flood is more appropriate, the Huf-n-Puf process can still be advantageous. By computer history matching one or two Huf-n-Puf tests one gains unique verification of the interaction between CO_2 and crude in a specific reservoir environment. Huf-n-Puf experiments will not void the need for good laboratory data but instead serve to complement them. A greatly increased confidence level for data interpretation and reservoir flood predictions can be obtained at reasonable expense.

NOMENCLATURE

b	formation volume factor std. vol/res. vol.
c	compressibility, 1/psi (1/k Pa)
E	efficacy of CO_2 cyclic stimulation process, STB incremental oil/MCF CO_2 injected
k	reservoir permeability, md
k_r	relative permeability fraction
N_c	number of cycles
P_t	treatment pressure, maximum CO_2 bottom-hole injection pressure, psia (k Pa)
p	pressure
P_{cwo}	water-oil capillary pressure
P_{cgo}	gas-oil capillary pressure
q	production rate, std. vol./day
R_s	dissolved gas, std. vol. gas/std. vol. oil
r_s	vaporized oil, std. vol. oil/std. vol. gas
S	saturation, fraction
S_{oi}	initial reservoir initial oil saturation, fraction
t	time
Δt	time step
V	grid block volume
V_c	volume CO_2 injected per cycle per foot of sand, MMSCF/ft. (std. m^3/m)
Z	subsea depth, measured positively downward

Subscripts, superscripts

g	gas
gc	critical gas
gr	residual gas
i, j, k	grid block indices
ℓ	iterate number
n	time step number
o	oil
w	water

Greek

γ	specific weight, psi/ft. (k Pa/m)
μ_o	oil viscosity, cp
μ	viscosity, cp
ϕ	porosity, fraction

Operators

$$\bar{\delta} X \equiv X_{n+1} - X_n, \text{ time difference}$$

$$\delta X \equiv X^{\ell+1} - X^{\ell}, \text{ iterate difference}$$

$$\Delta(\tau \Delta P) = \Delta_x(\tau_x \Delta_x P) + \Delta_y(\tau_y \Delta_Y P) + \Delta_z(\tau_z \Delta P)$$

$$\Delta_x(\tau_x \Delta_x P) = \tau_{xi+\frac{1}{2},j,k}(P_{i+1,j,k} - P_{i,j,k}) - \tau_{xi-\frac{1}{2},j,k}(P_{i,j,k} - P_{i-1,j,k})$$

APPENDIX

Description of the Implicit Flow Model

The Implicit Flow Model simulates one-, two- or three-dimensional, isothermal flow of three phases in Cartesian or cylindrical coordinates. The model treats two hydrocarbon components, is fully implicit* for reliability (stability), and accounts for the presence of vaporized oil in the gas phase (r_s) in addition to dissolved gas (R_s); it therefore simulates gas condensate reservoirs which do not require fully compositional (multicomponent) PVT treatment.

The model primary equations express conservation of mass of water, oil and gas for each grid block:

$$\Delta\left[\tau(b_w k_{rw}/\mu_w)(\Delta p_w - \gamma_w \Delta Z)\right] - q_w = \frac{V}{\Delta t}\bar{\delta}(\phi b_w S_w) \quad (1)$$

$$\Delta\left[\tau(b_o k_{ro}/\mu_o)(\Delta p_o - \gamma_o \Delta Z) + \tau(b_g r_s k_{rg}/\mu_g)(\Delta p_g - \gamma_g \Delta Z)\right] - q_o - q_g r_s = \frac{V}{\Delta t}\bar{\delta}(\phi b_o S_o + \phi b_g r_s S_g) \quad (2)$$

$$\Delta\left[\tau(b_o R_s k_{ro}/\mu_o)(\Delta p_o - \gamma_o \Delta Z) + \tau(b_g k_{rg}/\mu_g)(\Delta p_g - \gamma_g \Delta Z)\right] - q_o R_s - q_g = \frac{V}{\Delta t}\bar{\delta}(\phi b_o R_s S_o + \phi b_g S_g) \quad (3)$$

* The only exception is a semi-implicit treatment of the allocation of a well's total rate among its several completed layers.

The linearization of these equations is described in detail in references 8 and 9. Interblock flow terms are expressed implicitly at each iteration within the time step, using latest iterate values of all variables, coefficients and derivatives. The resulting linearization gives three difference equations (for each grid block) in the six dependent variables δS_w, δS_o, δS_g, δR_s, δr_s, and δp, where

$$\delta X \equiv X^{\ell+1} - X^{\ell} \cong X_{n+1} - X^{\ell} \quad (4)$$

and superscript ℓ denotes iteration. All variables or coefficients in the three primary equations are either one or more of the six unknowns or dependent upon one or more of them*.

If all three phases exist at the beginning of iteration ℓ+1 then the following three constraints allow elimination of δR_s, δr_s and one saturation:

$$R_s = R_s(p) \quad (5)$$

$$r_s = r_s(p) \quad (6)$$

$$S_w + S_o + S_g = 1.0 \quad (7)$$

If the grid block is two-phase water-oil, then δS_g and δr_s disappear from the list of six unknowns and constraint Equation (7) allows elimination of δS_w or δS_o. If the block is two-phase gas-water then δS_o and δR_s disappear and Equation (7) allows elimination of δS_w or δS_g. Thus in any case, the linearized primary Equations (1)-(3) become three simultaneous equations in <u>three</u> unknowns, which are solved by direct solution[10] or by an iterative method.

For saturated oil and gas, b_o and b_g are single-valued (tabular) functions of pressure. For undersaturated oil,

$$b_o = b_o(R_s)(1 + c_o(p - p_{sat}(R_s))) \quad (8)$$

where oil compressibility c_o is a function of R_s.

For undersaturated gas, b_g is a function of r_s and p and is obtained from a modified Redlich-Kwong equation-of-state. Saturated oil viscosity μ_o is a single-valued function of pressure and undersaturated μ_o is dependent upon R_s and p. Saturated gas viscosity μ_g is dependent upon pressure and undersaturated μ_g is dependent upon r_s and p. Remaining PVT terms are the normal

$$b_w = b_{wi}(1 + c_w(p - p_i)) \quad (9)$$

$$\phi = \phi_i(1 + c_r(p - p_i)) \quad (10)$$

* p is oil pressure p_o. p_w is $p_o - P_{cwo}(S_w)$ and p_g is $p_o + P_{cgo}(S_g)$. Alternatively, p may be selected as gas pressure with p_o and p_w expressed in terms of p_g and capillary pressures. We find this latter alternative advantageous since it eliminates capillary pressure nonlinearities from the most mobile phase (gas).

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TABLE 1

EFFECT OF RADIAL DEFINITION ON CALCULATED OIL PRODUCTION

	Incremental Oil Production*, STB				
Radial Blocks	9	13	14	20	24
CYCLE 1	23729	23077	22890	25350	25452
CYCLE 2	50988	34615	34213	36272	35833

*California Reservoir, H=107' μ_o = 177 cp CO_2 = 52 MMSCF/cycle

Fig. 1 - EFFECT OF CO_2 TREATMENT VOLUME ON INCREMENTAL OIL RECOVERY

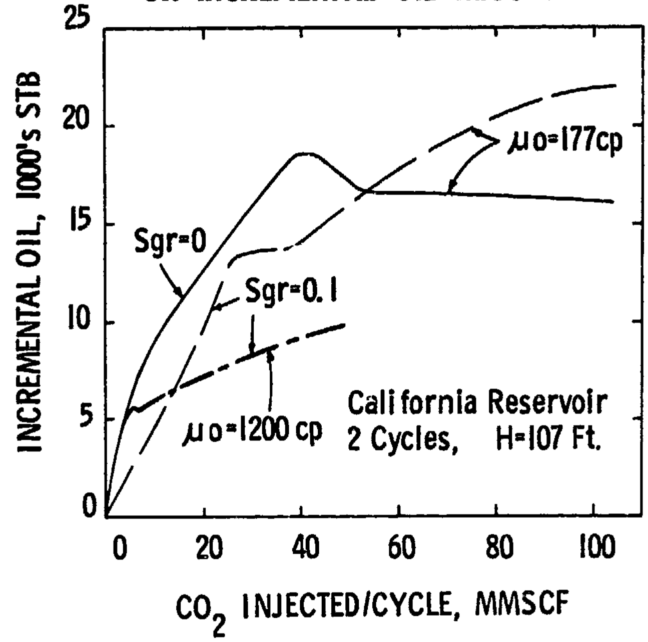

Fig. 2 - CO_2 HUF-n-PUF PROCESS BOTTOM HOLE PRESSURE EFFECT

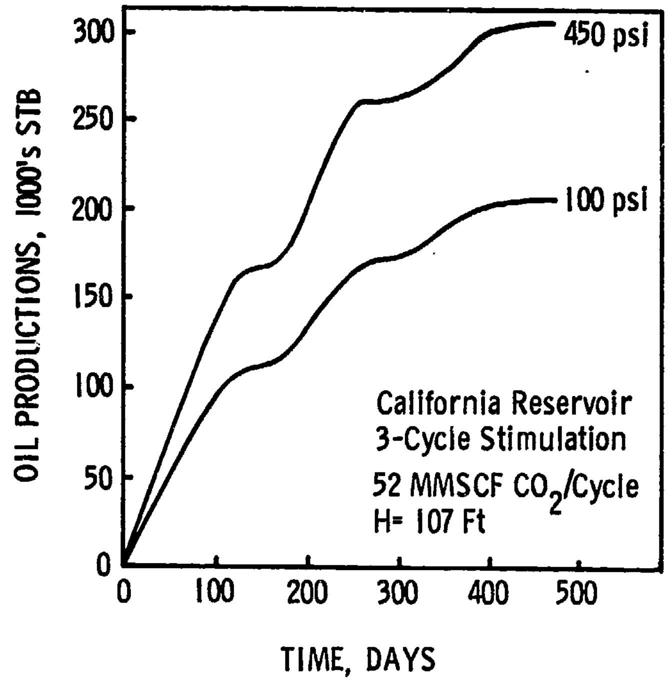

Fig. 3 - SHALLOW HI-VIS OILS ARE DIFFICULT TO STIMULATE

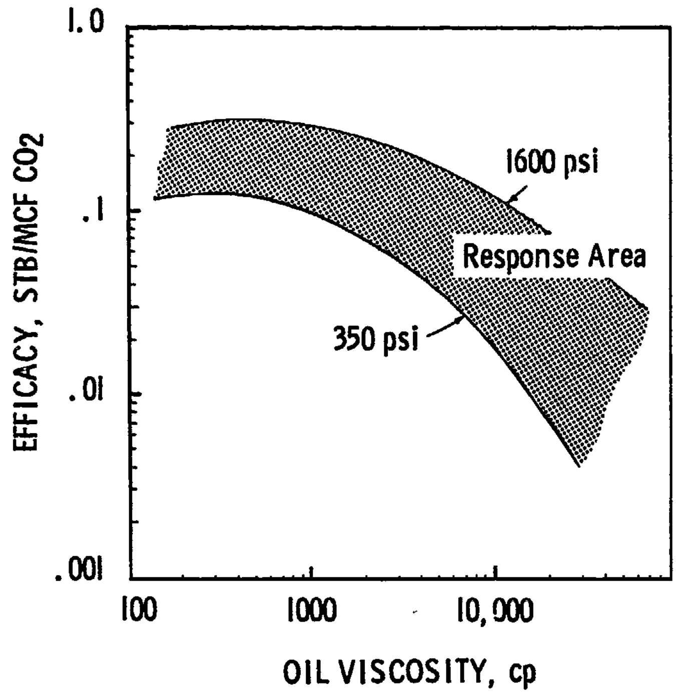

Fig. 4 - CO_2 STIMULATION DOES NOT REQUIRE HIGH OIL SATURATION

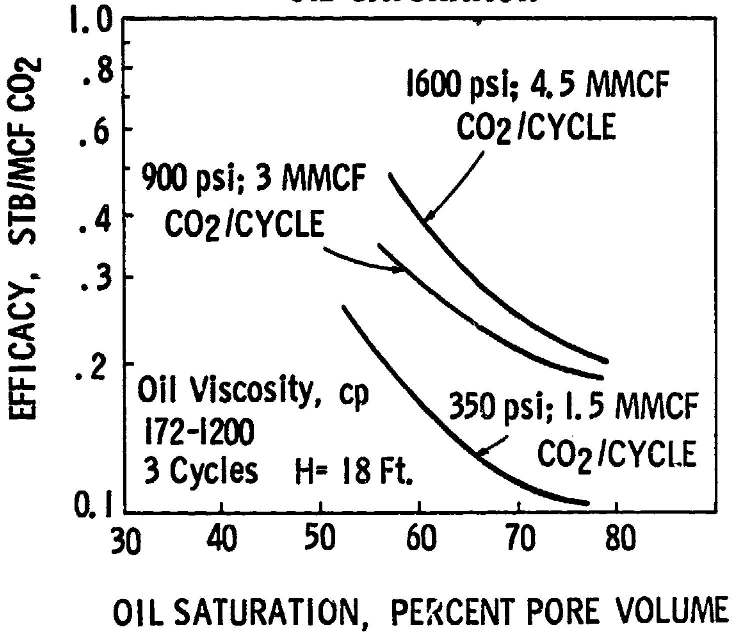

Fig. 5 - PERMEABILITY HAS A MIXED EFFECT ON PROCESS EFFICACY