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Microbes: The Practical and Environmental Safe Solution to Production Problems, Enhanced Production, and Enhanced Oil Recovery

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ABSTRACT

This paper presents the theory and field application of microbial treating oil well systems and reservoirs to control paraffin wax deposition, increase producing rates and enhance oil recoveries. The technology applies to paraffin base crude oils produced from solution gas drive reservoirs. The application of this microbial enhancement technology can increase oil recoveries in all stages of reservoir depletion.

INTRODUCTION

One of the major concerns facing the oil industry today is recovery of the large percentage of oil remaining unrecovered in the mature and near depleted producing oil fields. New technology is necessary to extend producing life and increase reservoir recovery by economically treating existing producing wells and reversing the accelerated rate of well plugging.

Migration microbial enhanced oil recovery (MMEOR) is a new technology that can enhance production and recoveries by treatment programs of existing producing wells. The microbial process thins or reduces oil viscosity in situ increasing production and recoveries. The process is applicable to single-well and multi-well projects and does not require capital expenditures or expensive well conversions. This new technology has the potential of substantially increasing oil recoveries in a majority of U.S. oil fields and is friendly to our environment.

An additional benefit from MMEOR is paraffin wax control in producing well systems. Biochemical changes in crude oil resulting from microbial treating can reduce or eliminate paraffin wax crystallization and deposition in well bores and producing formations. Microbial paraffin wax control can eliminate the use of solvents and disperants which can be toxic to our environment and can eliminate the need to use the often hazardous procedure of removing wax by hot oil/water treatments.

MMEOR BACTERIA

The microbial cultures used for paraffin control and MMEOR projects presented in this paper are naturally occurring, non-pathogenic and non-genetically engineered microorganisms. The products are mixtures of live facultative anaerobes containing several different principal strains which produce desirable changes in crude oil properties.[1] Due to the safe nature of these microorganisms, the EPA has chosen not to regulate their release into the environment.

Attempts were made to use freeze dried bacteria products with marginal success. Problems associated with dry products were found to be variability in rate of activation, bacteria carriers not soluble or dispersable in formation water, product adulteration and lack of quality control.

Bacteria used are generally of the dimensions of 1 to 4 micro-meters in length and 0.1 to 0.3 micro-meter in width. The strains are motile (they can move and migrate by their own propulsion system) and are capable of swimming toward surfaces which may act as a point of attachment or food source.[1] The bacteria are capable of migrating into the pore space of oil reservoirs through the free water phase and irreducible connate water wetting the surface area of water-wet formation rock.

The metabolic process of the select bacteria strains produce organic acids and alcohols and cause bio-degradation of saturated hydrocarbons (alkanes). The products consist of three groups or mixtures of different strains. Each group selectively bio-degrade alkanes according to their molecular carbon order. Table 1 shows the range of effectiveness for each product used in MMEOR projects. The alkane molecule range bio-degradable by the three products is shown to be C_{16} through $C_{31}+$.

TREATMENT DESIGN

Laboratory technology and methodology have been developed to determine bacteria blend and treatment volume for the many different crude oils and reservoir environments. This development was necessary to effectively test, blend and apply the groups of living cultures and to recognize and understand the effects of their metabolism process on oil producing systems. The methods and procedures are proprietary with National Parakleen Company but the basic concepts can be discussed.

Crude oil samples are inoculated (treated) in the laboratory with each bacteria product and the viscosity of each sample is measured. The viscosity of each sample is compared to the viscosity of the untreated oil sample. The percent viscosity change of each inoculated sample represents the percent alkanes in the oil sample that are affected by each bacteria product. The quantity of each product in the treatment blend is determined by this percent change in viscosity. Table 2 shows the effects of laboratory inoculation of Glorieta oil and the product treatment blend. The treatment blend for the Glorieta oil sample is 66%, 22% and 12% for products A, B and C respectively.

Product treatment blends vary with the stages of a microbial treating program. Initial treatments are blended to treat the liquid phase and wax solids deposited on the wellbore equipment and formation skin area. As the wax is removed and molecular composition increases in lighter hydrocarbons and decreases in heavier hydrocarbons, the blend is adjusted to treat the increased lower carbon order composition. Recognizing and reacting to the changes in the molecular structure of microbial treated oil is necessary in order to develop a bacteria colony that will migrate into the producing reservoir. Table 3 shows the different blend progressions of Glorieta oil as colonization develops in the wellbore and formation.

Treatment volume is determined by the empirical formula. Eq. (1)

$$\text{Treatment Volume, gal.} = 0.17 \times \sqrt{\text{Time between treatments, day}} \times \sqrt{\text{Production rate, BOPD + BWPD}} \quad \ldots(1)$$

Optimum treatment frequency was determined from empirical field performance data by monitoring oil viscosity change and production response of 10,000+ treatments over a period of 3 years in 33 fields in the Permian Basin, Powder River Basin and Unita Basin. Fourteen days between treatments is the optimum frequency for the majority of crude oils and reservoirs. Seven days between treatments is the optimum frequency for crude oils and reservoirs with $\geq 25\%$ $C_{18}+$ alkane composition and/or bottom temperature ≥ 180°F.

The treating method is to batch treat down the casing annulus and flush the bacteria blend with KCl water. The volume of flush is determined by the depth of the treated well and producing fluid level. The well should be shut in 24 hours after each treatment to allow the microorganisms to disperse and inoculate the system prior to fluid withdrawal.

MICROBIAL TREATING EFFECTS ON CRUDE OIL

In situ microbial bio-degradation in well bores and producing formations using products A, B & C changes the physical properties of crude oil. Figure 2 shows the changes in °API gravity, viscosity, pour point and solvent composition of Wasatch oil analyzied prior to and 30 days after starting microbial treating. The data shows gravity increase of 2.5°API, viscosity reduction of 10 cp. at 100°F, pour point reduction of 17°F and 12% increase in solvent composition.

PARAFFIN WAX CONTROL

The bio-degradation processes which enhance the physical properties of paraffinic oil affect the liquid/solid phase equalibrium of the oil. The ideal-solution theory provides the basis for reducing or eliminating wax crystallization in oil well systems through microbe treating. The theory states that the crystallization temperature at a given pressure is a function of the percent paraffin wax in solution and percent solvents dissolving the wax. When the temperature and pressure in a well system are lower than the crystallization temperature and pressure of the crude oil at a location in the well system, wax will begin to come out of solution and can be deposited.[2 3 4]

The increase in solvent composition and decrease in wax composition shown in Figure 1 illustrates the effects microbe treatments can have on reducing the critical waxing temperature and pressure of paraffinic oil. Microbial enhancement of crude oil can significantly reduce wax crystallization temperatures and pressures of oil in reservoirs, wellbores and surface equipment.

A test to determine the effectiveness of microbial treating for paraffin control was conducted on 72 producing oil wells in the Permian Basin. The purpose of the test was to monitor hot oil/water and chemical treatments nine months prior to microbial treating and the nine month period after starting microbial treatments.

Sixty-two of the wells were hot oil/water treated on a regular basis prior to microbial treating. The average hot oil/water frequency was 5.1 weeks between treatments for a total of 501 treatments for the nine months prior to microbes. No hot oil/water treatments were necessary for the nine months of microbial treating.

Ten wells were chemically treated for paraffin control prior to microbes. Six wells were batch treated in the casing annulus on a weekly basis and four wells were continuously treated in the casing annulus during the nine months prior to microbial treating. No chemical treating was necessary during the nine months of microbial treating.

THEORY OF MIGRATION MEOR

Migration microbial enhanced oil recovery (MMEOR) is the process of introducing select bacteria to a producing formation through the wellbore of a producing oil well. The microbes colonize outwardly from the wellbore into the producing formation. The microbial activity reduces reservoir oil viscosity resulting in increased production and enhanced oil recovery. The theory applies to single-well and multi-well projects. The theory is applicable in newly developed reservoirs as well as near depleted ones. The theory presented in this paper applies to reservoirs producing paraffin base crude oil.

A basic principle of MMEOR is that oil in solution gas reservoirs is subjected to gas/liquid/solid phase equilibrium behavior. Pressure depletion from fluid production causes lower molecular weight liquid solvents to vaporize and be stripped from reservoir oil as casinghead gas. This loss of intermediate hydrocarbons (propane, butane, pentane, hexane and heptane+) reduces the solvent composition of the oil resulting in increased viscosity. The effects of pressure depletion has on oil viscosity is shown in Figure 2. Figure 2 shows the viscosities of four oils at reservoir temperature, above and below bubble point pressure.[1] This increase in viscosity can have significant effects on oil production rates and reservoir recoveries.

MICROBIAL ENHANCED PRODUCTION

The effect of viscosity to producing rate is demonstrated by the basic flow equation derived from Darcy's Law and shown in Eq (2).

$$q = \frac{7.08\, k\, h\, (p_e - p_w)}{\mu_o B_o \ln r_e / r_w} \quad \ldots\ldots\ldots\ldots\ldots (2)$$

The equation defines the relationship that flow rate is inversely proportional to viscosity. Figure 3 is a hypothetical case that holds everything on the right side of Eq. (2) constant while varing the viscosity. This shows the effect increasing viscosity has on producing rates. Although this is a simple relationship, it is often ignored as a parameter influencing production decline.

To determine the effect MMEOR can have on oil producing rates, a hypothetical model was developed to simulate declining production versus time for a well producing from a solution gas reservoir. The model was developed from the material balance model discussed later in this paper. The model assumes: $\phi = 16.5\%$, $k = 10$ md., $Sw = 22\%$, $Bo_i = 1.32$, $r_e = 660$ feet, $r_w = 0.75$ feet, $p_e - p_w = 0.33\, p_e$, $h = 20$ feet, $\mu_o = 2.0$ cp., $\mu_m = 1.0$ cp. The equations used in developing the producing model are Eq. (3), Eq. (4), Eq. (5) and Eq. (6).

$$N = \frac{7758\, \phi\, (1 - S_w)}{B_{o_i}} \quad \ldots\ldots\ldots\ldots\ldots (3)$$

$$q = \frac{7.08\, k\, h\, (0.33 p_e)}{\mu_o B_o \ln r_e / r_w} \quad \ldots\ldots\ldots\ldots\ldots (4)$$

$$\mu_o = \frac{\mu_o \ln r_e / r_m + \mu_m \ln r_m / r_w}{\ln r_e / r_w} \quad \ldots\ldots\ldots\ldots\ldots (5)$$

$$T = \frac{30.4\, (N)(\Delta Np)}{q} \quad \ldots\ldots\ldots\ldots\ldots (6)$$

Eq. (3) is used to solve for original oil in place. Eq. (4) solves for oil producing rate for effective viscosity, μe. Eq. (5) calculates μe as the radius of microbial migration, r_m, extends into the reservoir outward from the well bore. Eq. (6) is the time in months to produce an incremental volume of the original oil in place at producing rate q.

Producing performance for the simulated model are shown in Figures 4, 5 and 6. The three figures compare theorethical production decline for conventional produced wells and MMEOR produced wells at radius of microbial migration, r_m, of 1, 10, 100, 300 and 600 feet and MMEOR starting at reservoir pressures of 3000 psi., 1500 psi. and 700 psi. It is shown from these decline curves that reduction in viscosity using MMEOR technology can increase production rates and change decline performance. The model demonstrates MMEOR can be effective in various stages of depletion.

MMEOR FIELD PERFORMANCE

Field performance for six MMEOR projects is shown in Figures 7, 8, 9, 10, 11 and 12. The project in Figure 7 is a 10 well composite out of 150 wells in the Unita Basin project. The 10 wells were chosen because no recompletions or stimulation work has been performed on the wells since MMEOR was initiated in 1988. Figure 7 shows substantial enhancement in production and recoveries for the wells after starting MMEOR.

Figures 8, 9, 10, 11 and 12 are pilot projects in the Permian Basin area. The projects were selected for inclusion in this paper because of their diversity in types of crude oil and producing formations. Figure 9 illustrates the different producing characteristics resulting from MMEOR, acid stimulation and new completions. All five projects show enhancement after MMEOR programs were initiated.

MMEOR MATERIAL BALANCE MODEL

Oil viscosity is an important factor in oil recovery. The average correlation between oil viscosity and residual oil saturation, under reservoir conditions, is shown in Table 4. It is shown from this reservoir analysis of 103 fields that the smaller the viscosity, greater the oil recovery. The effects of viscosity change to oil recovery is an integral part of the material balance equation applied to solution drive reservoirs. The oil viscosity relationship in the material balance equation is shown in Eq. (7.)[1]

$$\frac{dS_o}{dp} = \frac{\frac{S_o}{B_o B_g}\frac{dR_s}{dp} + \frac{S_o}{B_o}\frac{k_g}{k_o}\frac{\mu_o}{\mu_g}\frac{dB_o}{dp} + (1 - S_o - S_w)\frac{1}{B_g}\frac{dB_g}{dp}}{1 + \frac{k_g}{k_o} \times \frac{\mu_o}{\mu_g}} \qquad (7)$$

When gas saturation in solution gas drive reservoirs reach the critical value, free gas begins to flow. Below the critical gas saturation pressure, both gas and oil flow to the wellbore, their relative rates being controlled by their viscosities which change with pressure and by their relative permeabilities which change with their saturations. As the oil viscosity increases from vaporization of solvents, the oil mobility, k_o/u_o, becomes small. The result is reduced oil recoveries.

Figures 13, 14 and 15 show the conventional material balance performance of a solution gas drive reservoir calculated by the Tracy Modification of the Tanner Method.[1] The equation is

$$N = N_p \Phi_n + G_p \Phi_g \qquad (8)$$

where $$\Phi_n = \frac{B_o - R_s B_g}{B_o - B_{oi} + (R_{si} - R_s)B_g} \qquad (9)$$

and $$\Phi_g = \frac{B_g}{B_o - B_{oi} + (R_{si} - R_s)B_g} \qquad (10)$$

The rock and fluid data used in Eqs. (8), (9) and (10) are shown in Table 5. Included in Figures 13, 14 and 15 are performance curves simulating the effects of MMEOR reduced oil viscosities.

To simulate the effects of MMEOR in the model, oil viscosity $\mu_m = 0.5\,\mu_o$, r_m = 1, 10, 100, 300 and 600 feet and MMEOR begins at reservoir pressures of 3000 psi., 1500 psi. and 700 psi. Table 6 shows the theorethical recoveries for the MMEOR models shown in Figures 13, 14 and 15. MMEOR percent recoveries are greater than conventional recoveries at the three different stages of initiating MMEOR and also at the different radii of microbial migration.

CONCLUSIONS:

1. Select mixtures of live facultative anaerobic bacteria can bio-degrade saturated hydrocarbons (alkanes). The physical changes in crude oil from bio-degradation are reduction in viscosity and pour point and increase in °API gravity and solvent composition.

2. Technology is available to design bacteria treatment blends that can treat paraffin wax in the carbon molecular range C_{16} through C_{61}+. This same technology is used to design blends to treat the many different paraffinic crude oils and to adjust blend design as oil composition changes in well systems and reservoirs from bio-degradation.

3. Microbial treating can control paraffin wax deposition in well systems. This can eliminate the necessity to use toxic chemicals, solvents and hot oil/water treatments.

4. Migration microbial enhanced oil recovery (MMEOR) is a new technology that can increase oil producing rates and increase oil recoveries in solution gas reservoirs.

5. MMEOR project performance can be predicted using material balance and production models. MMEOR field performance confirms the validity of the theorethical assumptions used to develop the models.

6. MMEOR technology offers significant opportunities to produce more oil from solution gas drive reservoirs.

7. Natural occurring microorganisms used in MMEOR projects are friendly to our environment and not regulated by the EPA.

NOMENCLATURE

Bg	=	gas formation volume factor, bbl./SCF
Bo	=	oil formation volume factor, bbl./SCF
Boi	=	initial oil formation volume factor, bbl./SCF
Gp	=	cummulative produced gas, SCF.
h	=	reservoir thickness, ft.
k	=	rock permeability, md.
k_g	=	relative permeability to gas, md.
k_o	=	relative permeability to oil, md.
μc	=	effective viscosity, cp.
μ_g	=	gas viscosity, cp.
μm	=	microbe treated oil viscosity, cp.
μ_o	=	reservoir oil viscosity, not microbe treated, cp.
N	=	initial oil in place
Np	=	cummulative produced oil, STB.
ΔNp	=	incremental percent oil recovery, STB.
p	=	reservoir pressure, psi.
p_e	=	res. pressure at external drainage radius, psi.
p_w	=	well bore pressure, psi.
r_e	=	external drainage radius, ft.
r_m	=	microbial migration radius, ft.
r_w	=	well bore radius, ft.
Rs	=	solution GOR, SCF/STB.
Rsi	=	initial Rs, SCF/STB.
T	=	producing time, months
S_o	=	oil saturation as a fraction of pore volume
S_w	=	interstitial water as a fraction of pore volume
ϕ	=	porosity, fraction of bulk volume
Φn	=	pressure variant oil properties
Φ_g	=	pressure variant gas properties

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APPENDIX

Derivation of effective viscosity, μe

Consider the radial flow equation:

$$q = \frac{7.08\, k\, h\, (p_e - p_w)}{\mu\, B_o \ln r_e / r_w}$$

and a radial flow system of constant thickness with a viscosity of μe between the drainage radius r_e and some lesser radius r_m, and an altered viscosity μm between the radius r_m and the well bore radius r_w. The pressure drops are additive, and

$$p_e - p_w = (p_e - p_m) + (p_m - p_w)$$

then $$\frac{q \mu_e B_o \ln r_e / r_w}{7.08\, k\, h} = \frac{q \mu_o B_o \ln r_e / r_m}{7.08\, k\, h} + \frac{q \mu_m B_o \ln r_m / r_w}{7.08\, k\, h}$$

solving for μe:

$$\mu_e = \frac{\mu_o \ln r_e / r_m + \mu_m \ln r_m / r_w}{\ln r_e / r_w}$$

SI METRIC CONVERSION FACTORS

°API	141.5/(131.5 + °API)		= g/m^3
bbl	× 1.589 873	E−01	= m^3
cp	× 1.0*	E−03	= Pa.s
feet	× 3.048*	E−01	= m
°F	(°F − 32) 1/8		= °C
md	× 9.869 233	E−04	= um^2
psi	× 6.894 757	E+00	= kPa

* Conversion factor is exact

TABLE 1

Alkane Treating Range of Bacteria Products

Product	Carbon Order Treating Range
A	C_{16} − C_{40}
B	C_{40} − C_{55}
C	C_{55} − C_{63+}

TABLE 2

Bacteria Treatment Blend: Glorieta Oil Sample

Inoculum	Treated Viscosity, μ_m, cp	$\frac{\mu_o - \mu_m}{\mu_o}$	Product Blend Composition, %
Product A	1.1	0.66	66
Product B	2.5	0.22	22
Product C	2.8	0.12	12

μ_o = 3.2 cp

TABLE 3

Bacteria Blend Changes as a Result of Changes in Molecular Structure Caused by Microbial Treating: Glorieta Oil Sample

Inoculum	Product Blend Composition, % 1st Treatment	After 30 Days	After 90 Days
Product A	66	73	78
Product B	22	20	16
Product C	12	7	6

TABLE 4

Correlation Between Reservoir Oil Viscosity and Residual Oil Saturation[a]

Reservoir Oil Viscosity, cp	Residual Oil Saturation (% of Pore Space)
0.2	30.0
0.5	32.0
1.0	34.5
2.0	37.0
5.0	40.5
10.0	43.5
20.0	64.3

TABLE 5

Typical Rock and Fluid Data for Material Balance Model[5]

Pressure psia	Oil Volume Factor, B_o bbl/STB	Solution GOR, R_s SCF/STB	Gas Deviation Factor, z at 190°F	Gas Volume Factor, B_g bbl/SCF	Φ_n	Φ_g	Viscosity Ratio μ_o/μ_g
3000	1.315	650	0.745	0.000726	∞	∞	53.91
2500	1.325	650	0.680	0.000796	80.76	0.07960	56.60
2300	1.311	618	0.663	0.000843	34.35	0.03665	61.46
2100	1.296	586	0.652	0.000907	19.60	0.02325	67.35
1900	1.281	553	0.651	0.001001	11.53	0.01586	74.33
1700	1.266	520	0.660	0.001136	6.842	0.01151	81.96
1500	1.250	486	0.685	0.001335	3.906	0.008674	91.56
1300	1.233	450	0.717	0.001616	2.097	0.006700	102.61
1100	1.215	412	0.751	0.001998	1.043	0.005321	115.20
900	1.195	369	0.791	0.002626	0.3658	0.004250	129.96
700	1.172	320	0.832	0.003481	0.05765	0.003460	148.89
500	1.143	264	0.878	0.005141	−0.1181	0.002837	170.83
300	1.108	194	0.925	0.009027	−0.1645	0.002309	196.78
100	1.057	94	0.974	0.02852	−0.1041	0.001828	219.89
50	1.041	55	0.988	0.05786	−0.06286	0.001694	237.39

TABLE 6

Material Balance MMEOR Recoveries

Reservoir Pressure, MMEOR Started, psi	Recovery Percent r_m=0ft	r_m=1ft	r_m=10ft	r_m=100ft	r_m=300ft	r_m=600ft
3000	18.7	19.7	22.2	25.8	28.0	29.7
1500	18.7	19.6	21.8	25.0	27.0	28.6
700	18.7	19.2	20.6	22.7	24.0	25.1

r_m=0ft. is the case for conventionally produced reservoir without MMEOR

	Before Microbial Treatment	After Microbial Treatment
API Gravity	39.4	41.9
Viscosity at 100°F	25 cp	15 cp
Viscosity at 210°F	15 cp	9 cp
Pour Point	98°F	81°F
Inital Boiling Point	196°F	118°F
End Point	602°F	636°F
% Recovery (Gaso. Kero. Diesel)	40%	52%
% Residue (Wax)	60%	48%

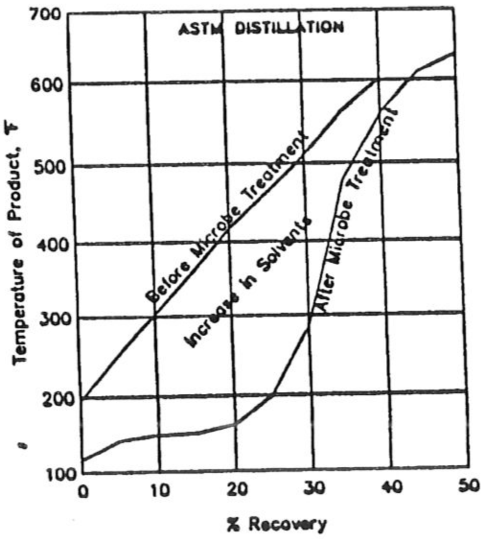

FIGURE 1
Analysis of Wasatch Well-Head Oil Sample Before Microbial Treating Program and 30 Days After Starting Program

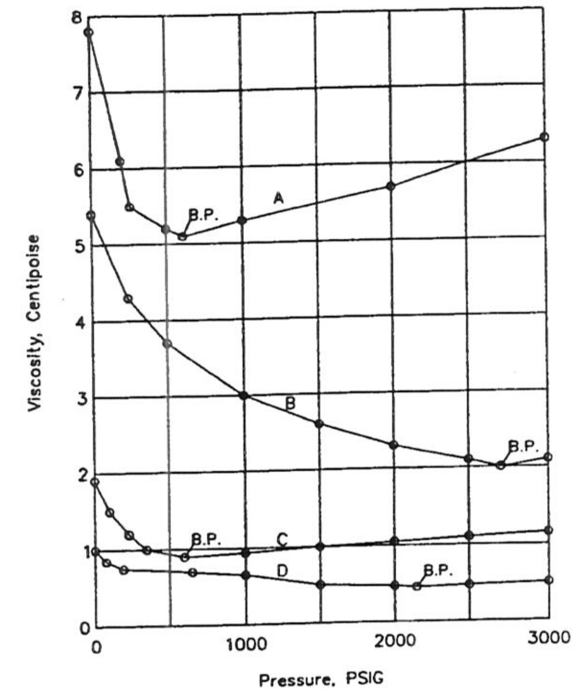

FIGURE 2
Viscosity of Four Crude Oil Samples Under Reservoir Conditions.[5]

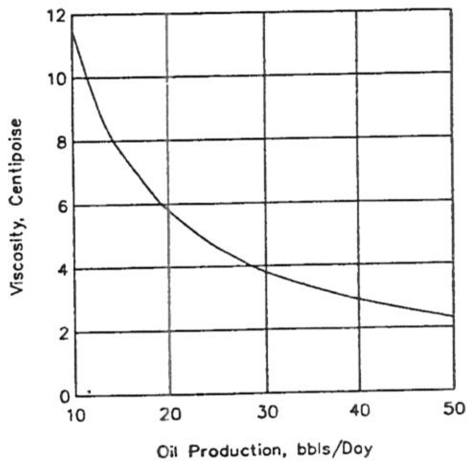

FIGURE 3
Relationship Between Increasing Reservoir Oil Viscosity and Oil Producing Rate

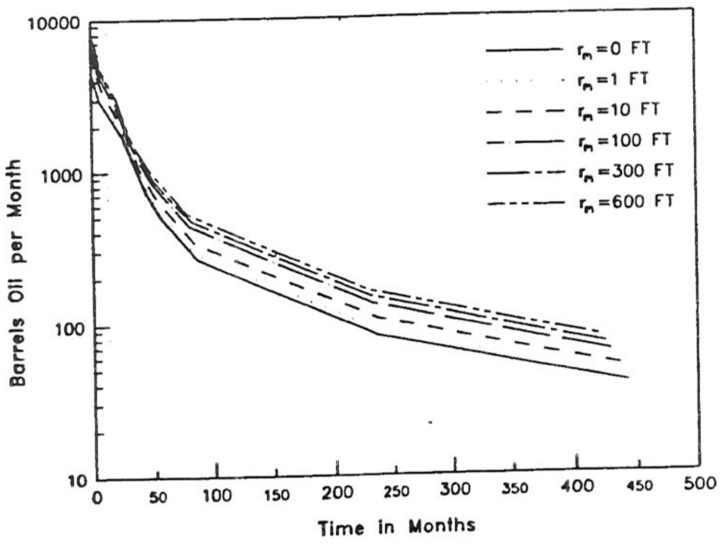

Figure 4
Calculated Producing Performance when MMEOR Starts at Reservoir Pressure = 3000 psi

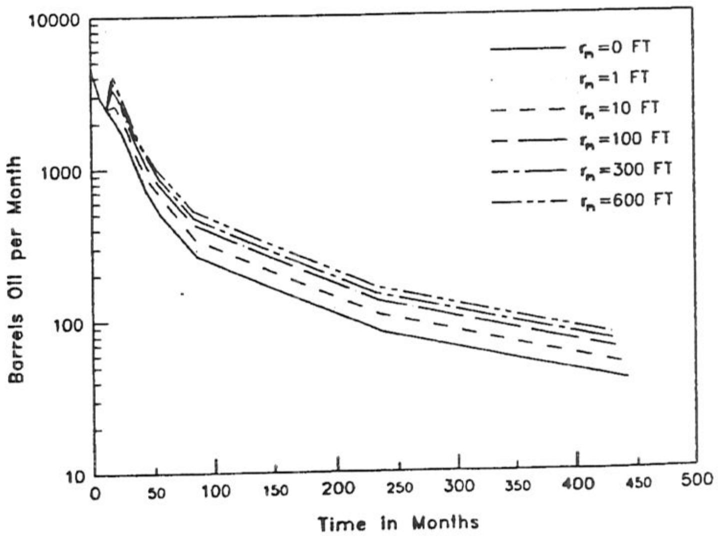

Figure 5
Calculated Producing Performance when MMEOR Starts at Reservoir Pressure = 1500 psi

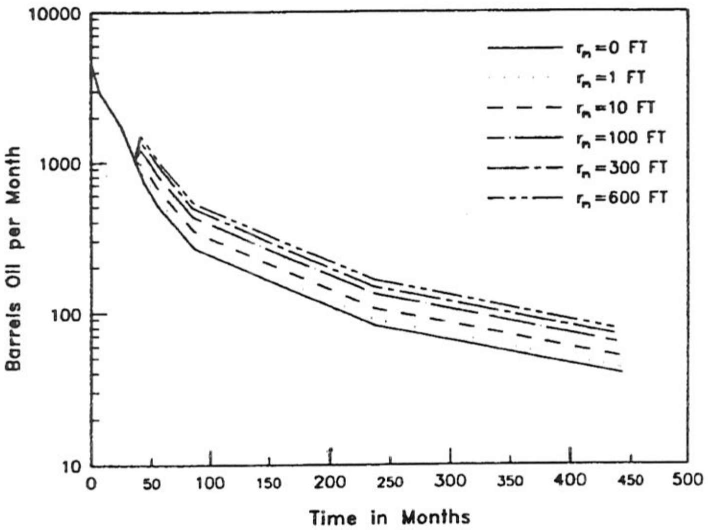

Figure 6
Calculated Producing Performance when MMEOR Starts at Reservoir Pressure = 700 psi

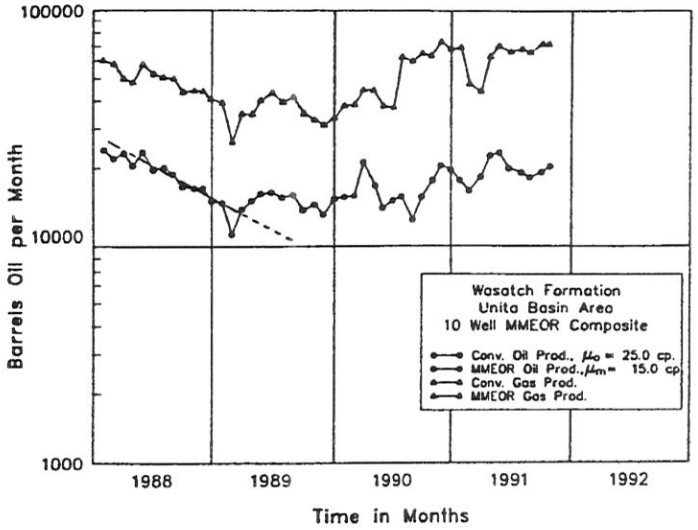

Figure 7
Production Curve Comparing Conventional Wells with MMEOR Operated Wells

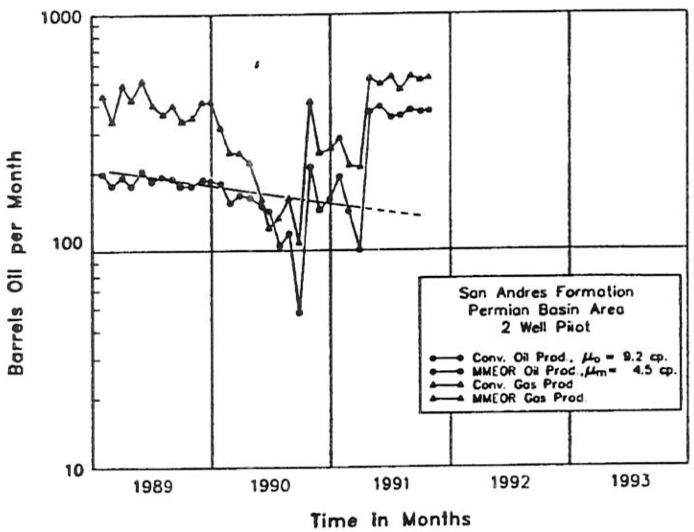

Figure 8
Production Curve Comparing Conventional Wells with MMEOR Operated Wells

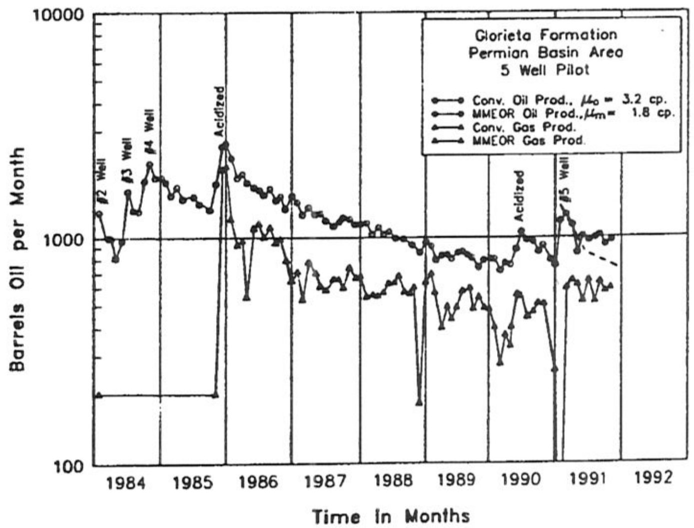

Figure 9
Production Curve Comparing Conventional Wells with MMEOR Operated Wells

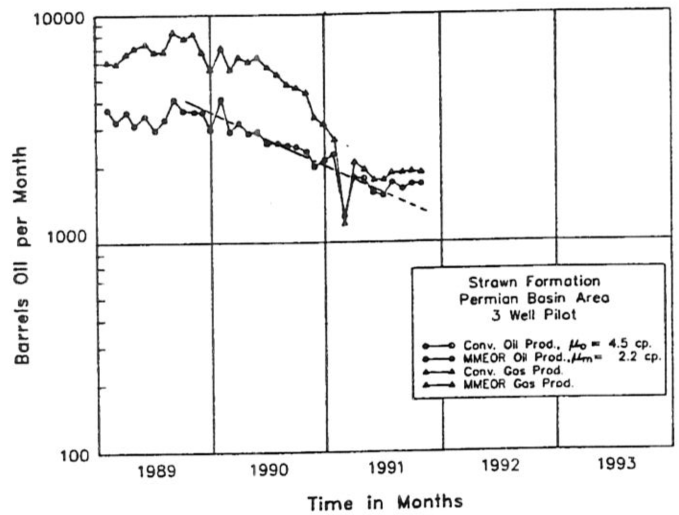

Figure 10
Production Curve Comparing Conventional Wells with MMEOR Operated Wells

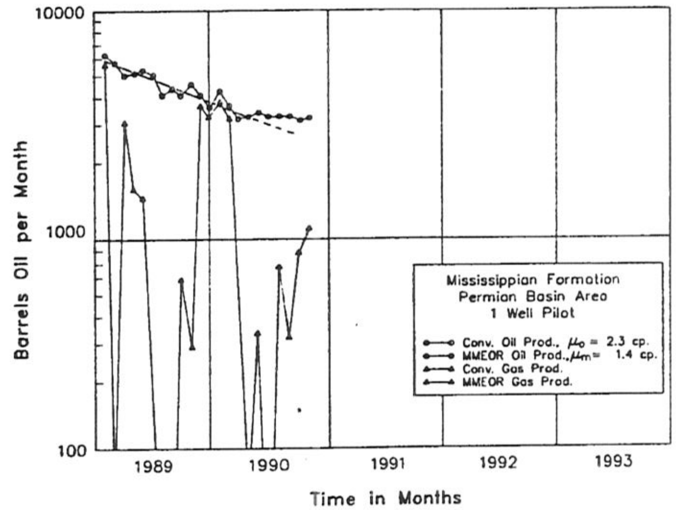

Figure 11
Production Curve Comparing Conventional Wells with MMEOR Operated Wells

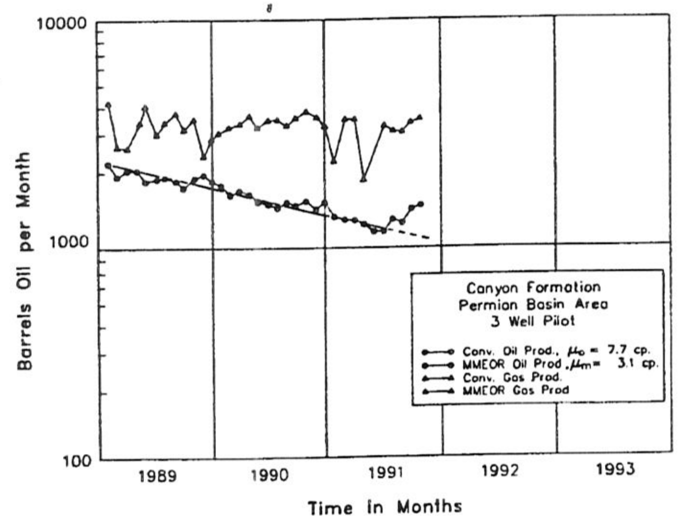

Figure 12
Production Curve Comparing Conventional Wells with MMEOR Operated Wells

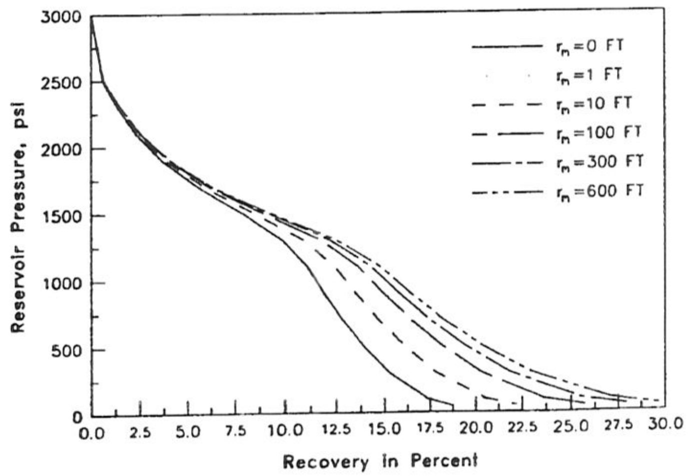

Figure 13
Percent Oil Recovery Using Material Balance Model when MMEOR Starts at Reservoir Pressure = 3000 psi

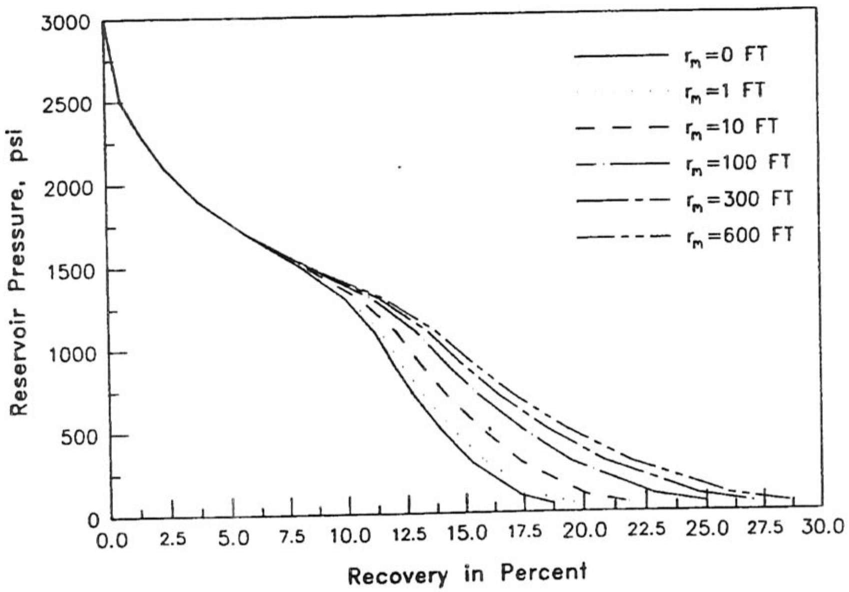

Figure 14
Percent Oil Recovery Using Material Balance Model
when MMEOR Starts at Reservoir Pressure = 1500 psi

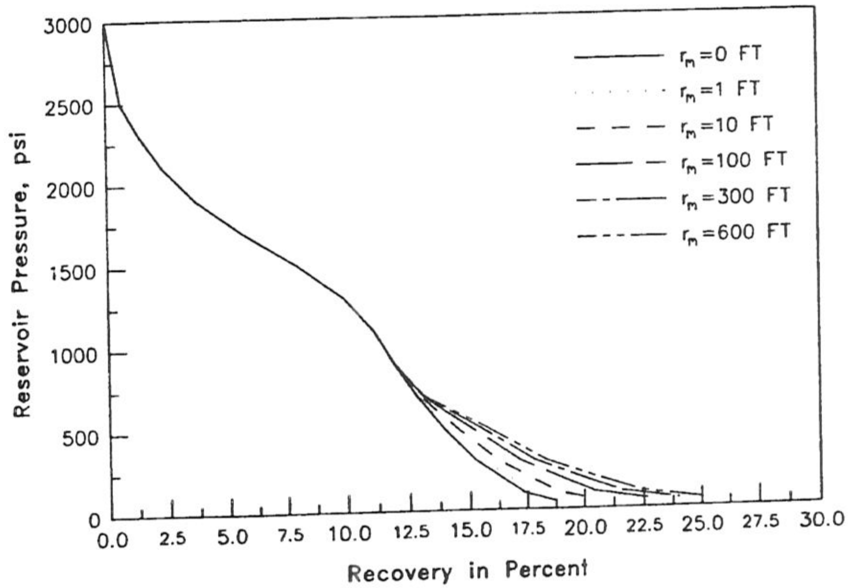

Figure 15
Percent Oil Recovery Using Material Balance Model
when MMEOR Starts at Reservoir Pressure = 700 psi