



Enhanced Oil Recovery

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GLOSSARY

Capillary pressure Difference in the pressure between two fluids measured at the interface between the two fluids.

Interfacial tension Measure of the ease with which a new interface between two fluids can be made.

Miscible When two or more phases become single phased.

Mobility Measure of the ease with which a fluid moves through porous media.

Permeability Measure of the capacity of a porous medium to conduct a fluid.

Polymer Large-molecular-weight chemical used to thicken a solution.

Primary production Production of oil using only the natural energy of the formation.

Reservoir Volume of underground porous media usually containing rock, oil, gas, and water.

Residual oil Amount of oil remaining in a reservoir after primary and secondary production.

Secondary production Production of oil when gas, water, or both are injected into the formation and the injected fluid immiscibly displaces the oil.

Surfactant Molecule that is made up of both hydrophilic and hydrophobic entities and can reduce the interfacial tension between two fluids.

Sweep efficiency Measure of how evenly a fluid has moved through the available flow volume in a porous medium.

Viscosity Property of a fluid that is a measure of its resistance to flow.

ENHANCED OIL RECOVERY refers to the process of producing liquid hydrocarbons by methods other than the conventional use of reservoir energy and reservoir repressurizing schemes with gas or water. On the average, conventional production methods will produce from a reservoir about 30% of the initial oil in place. The remaining oil, nearly 70% of the initial resource, is a large and attractive target for enhanced oil recovery methods.

I. INTRODUCTION

A. Classification of Hydrocarbon Production

The initial production of hydrocarbons from an underground reservoir is accomplished by the use of natural reservoir energy. This type of production is termed primary production. Sources of natural reservoir energy that lead to primary production include the swelling of reservoir fluids, the release of solution gas as the reservoir pressure declines, nearby communicating aquifers, and gravity drainage. When the natural reservoir energy has been depleted, it becomes necessary to augment the natural energy with an external source. This is usually accomplished by the injection of fluids, either a natural gas or water. The use of this injection scheme is called a secondary recovery operation. When water injection is the secondary recovery process, the process is referred to as waterflooding. The main purpose of either a natural gas or a water injection process is to repressurize the reservoir and then to maintain the reservoir at a high pressure. Hence, the term *pressure maintenance* is sometimes used to describe a secondary recovery process.

When gas is used as the pressure maintenance agent, it is usually injected into a zone of free gas (i.e., a gas cap) to maximize recovery by gravity drainage. The injected gas is usually natural gas produced from the reservoir in question. This, of course, defers the sale of that gas until the secondary operation is completed and the gas can be recovered by depletion. Other gases, such as N₂, can be injected to maintain reservoir pressure. This allows the natural gas to be sold as it is produced.

Waterflooding recovers oil by the water's moving through the reservoir as a bank of fluid and "pushing" oil ahead of it. The recovery efficiency of a waterflood is largely a function of the sweep efficiency of the flood and the ratio of the oil and water viscosities.

Sweep efficiency is a measure of how well the water has come in contact with the available pore space in the oil-bearing zone. Gross heterogeneities in the rock matrix lead to low sweep efficiencies. Fractures, high-permeability streaks, and faults are examples of gross heterogeneities. Homogeneous rock formations provide the optimum setting for high sweep efficiencies.

When an injected water is much less viscous than the oil it is meant to displace, the water could begin to finger, or channel, through the reservoir. This is referred to as viscous fingering and leads to significant bypassing of residual oil and lower flooding efficiencies. This bypassing of residual oil is an important issue in applying enhanced oil recovery techniques as well as in waterflooding.

Tertiary recovery processes were developed for application in situations in which secondary processes had become ineffective. However, the same tertiary processes

were also considered for reservoir applications for which secondary recovery techniques were not used because of low recovery potential. In the latter case, the name *tertiary* is a misnomer. For most reservoirs, it is advantageous to begin a secondary or a tertiary process concurrent with primary production. For these applications, the term *enhanced oil recovery (EOR)* was introduced and has become popular in referring to, in general, any recovery process that enhances the recovery of oil beyond what primary and secondary production would normally be expected to yield.

Enhanced oil recovery processes can be classified into four categories:

1. Miscible flooding processes
2. Chemical flooding processes
3. Thermal flooding processes
4. Microbial flooding processes

The category of miscible displacement includes single-contact and multiple-contact miscible processes. Chemical processes are polymer, micellar-polymer, and alkaline flooding. Thermal processes include hot water, steam cycling, steam drive, and *in situ* combustion. In general, thermal processes are applicable in reservoirs containing heavy crude oils, whereas chemical and miscible displacement processes are used in reservoirs containing light crude oils. Microbial processes use microorganisms to assist in oil recovery.

B. Hydrocarbon Reserves and Potential of Enhanced Recovery

In the United States, the remaining producible reserve is estimated to be 21 billion barrels. Of this 21 billion, currently implemented EOR projects are expected to recover 3 billion barrels. A 1998 report in the *Oil and Gas Journal* listed a production of 759,653 barrels of oil per day (b/d) from EOR projects in the United States. This amount represented about 12% of the total U.S. oil production.

A somewhat dated but highly informative study conducted by the U.S. National Petroleum Council (NPC) and published in 1984 determined that, with current EOR technology, an estimated 14.5 billion barrels of oil could be produced in the United States over a 30-yr period. This amount includes the 3 billion barrels that are expected to be produced from current EOR projects. The 14.5-billion-barrel figure was derived from a series of assumptions and subsequent model predictions. Included in the assumptions was an oil base price of \$30 per barrel in constant 1983 U.S. dollars. The ultimate oil recovery was projected to be very sensitive to oil price, as shown in [Table I](#).

TABLE I Ultimate Oil Recovery from Enhanced Oil Recovery Methods as a Function of Oil Price^a

Oil price per bbl (1983 U.S. dollars)	Ultimate recovery (billions of bbl)
20	7.4
30	14.5
40	17.5
50	19.0

^a bbl, barrel(s).

The NPC study also attempted to predict what the ultimate recoveries could reach if technological advancements were made in EOR processes. A potential 13–15 billion barrels of oil could be added to the figures in Table I if research activities led to improvements in EOR technology.

Interest in EOR activity is increasing outside the United States. In the same *Oil and Gas Journal* report that was referenced earlier, the worldwide production from EOR projects was listed as 2.3 million b/d. The largest project in the world at the time of the 1998 *Oil and Gas Journal* report was a steam drive in the Duri field in Indonesia. The Duri steam drive was producing about 310,000 b/d in the first quarter of 1998. Total estimated recovery from the Duri field is expected to be nearly 2 billion barrels of oil. Canada continues to report significant EOR production of 400,000 b/d, while China and Russia have increased their production to 280,000 and 200,000 b/d, respectively.

II. FUNDAMENTALS OF FLUID PRODUCTION

A. Overall Recovery Efficiency

The overall recovery efficiency E of any fluid displacement process is given by the product of the macroscopic, or volumetric, displacement efficiency E_v and the microscopic displacement efficiency E_d :

$$E = E_v E_d.$$

The macroscopic displacement efficiency is a measure of how well the displacing fluid has come in contact with the oil-bearing parts of the reservoir. The microscopic displacement efficiency is a measure of how well the displacing fluid mobilizes the residual oil once the fluid has come in contact with the oil.

The macroscopic displacement efficiency is made up of two other terms, the areal, E_s , and vertical, E_i , sweep efficiencies:

$$E_v = E_s E_i.$$

B. Microscopic Displacement Efficiency

The microscopic displacement efficiency is affected by the following factors: interfacial and surface tension forces, wettability, capillary pressure, and relative permeability.

When a drop of one immiscible fluid is immersed in another fluid and comes to rest on a solid surface, the surface area of the drop will take a minimum value due to the forces acting at the fluid–fluid and rock–fluid interfaces. The forces per unit length acting at the fluid–fluid and rock–fluid interfaces are referred to as interfacial tensions. The interfacial tension between two fluids represents the amount of work required to create a new unit of surface area at the interface. The interfacial tension can also be thought of as a measure of the immiscibility of two fluids. Typical values of oil–brine interfacial tensions are on the order of 20–30 dyn/cm. When certain chemical agents are added to an oil–brine system, it is possible to reduce the interfacial tension by several orders of magnitude.

The tendency for a solid to prefer one fluid over another is called wettability. Wettability is a function of the chemical composition of both the fluids and the rock. Surfaces can be either oil-wet or water-wet, depending on the chemical composition of the fluids. The degree to which a rock is either oil-wet or water-wet is strongly affected by the adsorption or desorption of constituents in the oil phase. Large, polar compounds in the oil phase can adsorb onto the solid surface; this leaves an oil film that may alter the wettability of the surface.

The concept of wettability leads to another significant factor in the recovery of residual oil. This factor is capillary pressure. To illustrate capillary pressure, let us consider a capillary tube that contains both oil and brine, the oil having a lower density than that of the brine. The pressure in the oil phase immediately above the oil–brine interface in the capillary tube will be slightly greater than the pressure in the water phase just below the interface. This difference in pressure is called the capillary pressure P_c of the system. The greater pressure will always occur in the nonwetting phase. An expression relating the contact angle θ , the radius r of the capillary, the oil–brine interfacial tension γ_{wo} , and the capillary pressure P_c is given in Eq. (1):

$$P_c = (2\gamma_{wo} \cos \theta)/r. \quad (1)$$

This equation suggests that the capillary pressure in a porous medium is a function of the chemical composition of the rock and fluids, the pore size distribution, and the saturation of the fluids in the pores. Capillary pressures have also been found to be a function of the saturation history, although this dependence is not reflected in Eq. (1). Because of this, different values will be obtained during the drainage process (i.e., displacing the wetting phase

with the nonwetting phase) than those obtained during the imbibition process (i.e., displacing the nonwetting phase with the wetting phase). This hysteresis phenomenon is exhibited in all rock–fluid systems and is an important consideration in the mathematical modeling of EOR processes.

It has been shown that the pressure required to force a nonwetting phase through a small capillary can be very large. For instance, the pressure drop required to force an oil drop through a tapering constriction that has a forward radius of 0.00062 cm, a rearward radius of 0.0015 cm, a contact angle of 0° , and an interfacial tension of 25 dyn/cm is 0.68 psi. If the oil drop were 0.01 cm long, a pressure gradient of 2073 psi/ft would be required to move the drop through the constriction. This is an enormous pressure gradient, which cannot be achieved in practice. Typical pressure gradients obtained in reservoir systems are of the order of 1–2 psi/ft.

Another factor affecting the microscopic displacement efficiency is the fact that two or more fluids are usually flowing in an EOR process. When two or more fluid phases are present, the saturation of one phase affects the permeability of the other(s), and relative permeabilities have to be considered. Figure 1 is an example of a set of relative permeability curves plotted against the wetting phase saturation (water in this case).

The relative permeability to oil, K_{ro} , is plotted on the left vertical axis, whereas the relative permeability to water, K_{rw} , is plotted on the right. The curve for K_{ro} goes to zero at S_{or} , the residual oil saturation. Once the oil saturation has been reduced to this point in a pore space by a water-flood, no more oil will flow, since K_{ro} is zero. Similarly, at saturations below the irreducible water saturations, S_{wr}

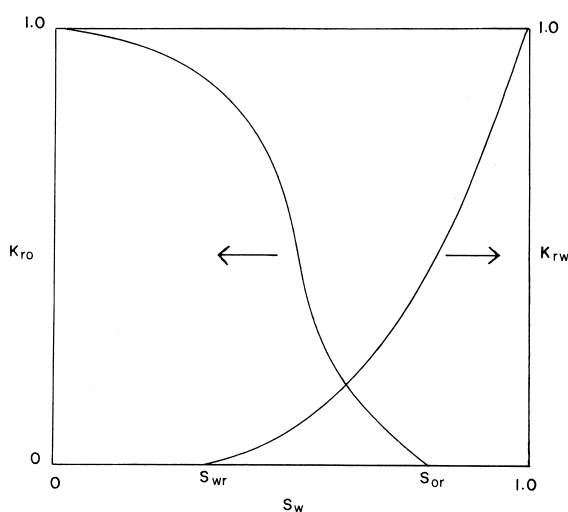


FIGURE 1 Typical water–oil relative permeability curves for a porous medium.

in the figure, water will not flow, since K_{rw} is zero. The curves are strong functions of wettability and do exhibit a hysteresis effect (especially for the nonwetting phase permeability).

C. Macroscopic Displacement Efficiency

Factors that affect the macroscopic displacement efficiency are the following: heterogeneities and anisotropy, the mobility of the displacing fluids compared with the mobility of the displaced fluids, the physical arrangement of injection and production wells, and the type of rock matrix in which the oil exists.

Heterogeneities and anisotropy of an oil-bearing formation have a significant effect on the macroscopic displacement efficiency. The movement of fluids through the reservoir will not be uniform if there are large variations in such properties as porosity, permeability, and clay content. Limestone formations generally have wide fluctuations in porosity and permeability. Also, many formations have a system of microfractures or large macrofractures. Any time a fracture occurs in a reservoir, fluids will be inclined to travel through the fracture because of the high permeability of the fracture. This may lead to substantial bypassing of residual oil. The bypassing of residual oil by injected fluids is a major reason for the failure of many pilot EOR projects. Much research is being conducted on how to improve the sweep efficiency of injected fluids.

Mobility is a relative measure of how easily a fluid moves through porous media. The apparent mobility is defined as the ratio of effective permeability to fluid viscosity. Since the effective permeability is a function of fluid saturations, several apparent mobilities can be defined. The mobility ratio M is a measure of the relative apparent mobilities in a displacement process and is given by Eq. (2):

$$M = \frac{\text{mobility of displacing phase}}{\text{mobility of displaced phase}} \quad (2)$$

When a fluid is being injected into a porous medium containing both the injected fluid and a second fluid, the apparent mobility of the displacing phase is usually measured at the average displacing phase saturation as the displacing phase just begins to break through at the production site. The apparent mobility of the nondisplacing phase is measured at the displacing phase saturation that occurs just before the beginning of the injection of the displacing phase. Sweep efficiencies are a strong function of the mobility ratio. The phenomenon called viscous fingering can take place if the mobility of the displacing phase is much greater than the mobility of the displaced phase.

The arrangement of injection and production wells depends primarily on the geology of the formation and the

size (areal extent) of the reservoir. When an operator is considering an EOR project for a given reservoir, he or she will have the option of using the existing well arrangement or drilling new wells in different locations. If the operator opts to use the existing well arrangement, there may be a need to consider converting production wells to injection wells or vice versa. This will require analysis of tubing and other factors to determine whether the existing equipment can withstand the properties of the chemicals or thermal energy to be injected. An operator should also recognize that when a production well is converted to an injection well, the production capacity of the reservoir has been reduced. Often this decision can lead to major cost items in the overall project and should involve a great deal of consideration. Knowledge of any directional permeability effects and other heterogeneities can aid in the consideration of well arrangements. The presence of faults, fractures, and high-permeability streaks could dictate the shutting in of a well near one of these heterogeneities. Directional permeability trends could lead to a poor sweep efficiency in a developed pattern and might suggest that the pattern be altered in one direction or that a different pattern be used.

Sandstone formations are characterized by a more uniform pore geometry than that of limestones. Limestones have large holes (vugs) and can have significant fractures, which are often connected. Limestone formations are associated with connate water that can have high levels of divalent ions such as Ca^{2+} and Mg^{2+} . Vugular porosity and high divalent ion content in their connate waters hinder the application of EOR processes in limestone reservoirs. Conversely, a sandstone formation can be composed of such small sand grain sizes and be so tightly packed that fluids will not readily flow through the formation.

D. Capillary Number Correlation

In a water-wet system, during the early stages of a waterflood, the brine exists as a film around the sand grains and the oil fills the remaining pore space. At an intermediate time during the flood, the oil saturation has been decreased and exists partly as a continuous phase in some pore channels but as discontinuous droplets in other channels. At the end of the flood, when the oil has been reduced to residual oil saturation S_{or} , the oil exists primarily as a discontinuous phase of droplets or globules that have been isolated and trapped by the displacing brine.

The waterflooding of oil in an oil-wet system yields a different fluid distribution at S_{or} . Early in the waterflood, the brine forms continuous flow paths through the center portions of some of the pore channels. The brine enters more and more of the pore channels as the waterflood progresses. At residual oil saturation, the brine has entered

a sufficient number of pore channels to shut off the oil flow. The residual oil exists as a film around the sand grains. In the smaller flow channels this film may occupy the entire void space.

The mobilization of the residual oil saturation in a water-wet system requires that the discontinuous globules be connected to form a flow channel. In an oil-wet porous medium, the film of oil around the sand grains needs to be displaced to large pore channels and be connected in a continuous phase before it can be mobilized. The mobilization of oil is governed by the viscous forces (pressure gradients) and the interfacial tension forces that exist in the sand grain–oil–water system.

There have been several investigations of the effects of viscous forces and interfacial tension forces on the trapping and mobilization of residual oil. From these studies correlations between a dimensionless parameter called the capillary number N_{vc} and the fraction of oil recovered have been developed. The capillary number is the ratio of viscous forces to interfacial tension forces and is defined by Eq. (3):

$$N_{vc} = V\mu_w/\gamma_{ow} = K_0 \Delta P/\phi\gamma_{ow}L, \quad (3)$$

where V is the Darcy velocity, μ_w the viscosity of displacing fluid, γ_{ow} the interfacial tension between displaced and displacing fluid, K_0 the effective permeability to displaced phase, ϕ the porosity, and $\Delta P/L$ the pressure drop associated with Darcy velocity.

Figure 2 is a schematic representation of the capillary number correlation. The correlation suggests that a capillary number greater than 10^{-5} is necessary for the mobilization of unconnected oil droplets. The capillary number

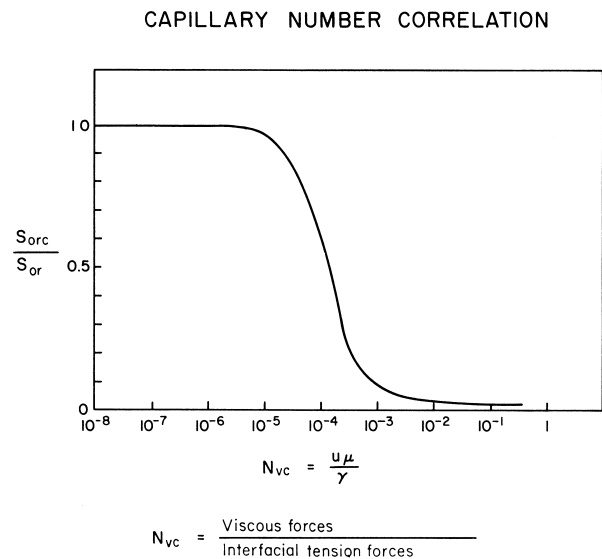


FIGURE 2 Capillary number correlation.

increases as the viscous forces increase or as the interfacial tension forces decrease.

III. MISCIBLE FLOODING

A. Introduction

In the previous section, it was noted that the microscopic displacement efficiency is largely a function of interfacial forces acting between the oil, rock, and displacing fluid. If the interfacial tension between the trapped oil and the displacing fluid could be lowered to 10^{-2} to 10^{-3} dyn/cm, the oil droplets could be deformed and could squeeze through the pore constrictions. A miscible process is one in which the interfacial tension is zero; that is, the displacing fluid and the residual oil mix to form one phase. If the interfacial tension is zero, then the capillary number N_{vc} becomes infinite and the microscopic displacement efficiency is maximized.

Figure 3 is a schematic of a miscible process. Fluid A is injected into the formation and mixes with the crude oil, which forms an oil bank. A mixing zone develops between fluid A and the oil bank and will grow due to dispersion. Fluid A is followed by fluid B, which is miscible with fluid A but not generally miscible with the oil and which is much cheaper than fluid A. A mixing zone will also be created at the fluid A–fluid B interface. It is important that the amount of fluid A that is injected be large enough that the two mixing zones do not come in contact. If the front of the fluid A–fluid B mixing zone reaches the rear of the fluid A–oil mixing zone, viscous fingering of fluid B through the oil could occur. Nevertheless, the volume of fluid A must be kept small to avoid large injected-chemical costs.

Consider a miscible process with *n*-decane as the residual oil, propane as fluid A, and methane as fluid B. The

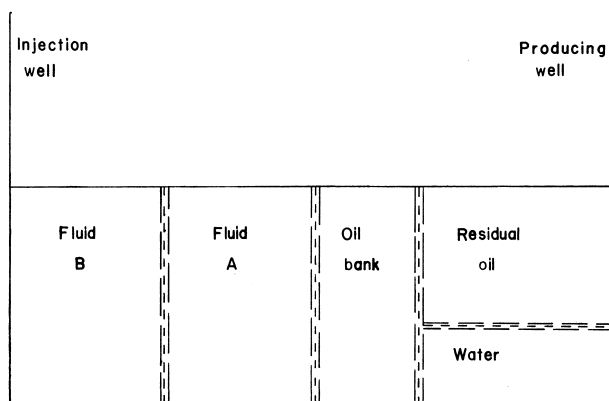


FIGURE 3 Schematic of an enhanced oil recovery process requiring the injection of two fluids.

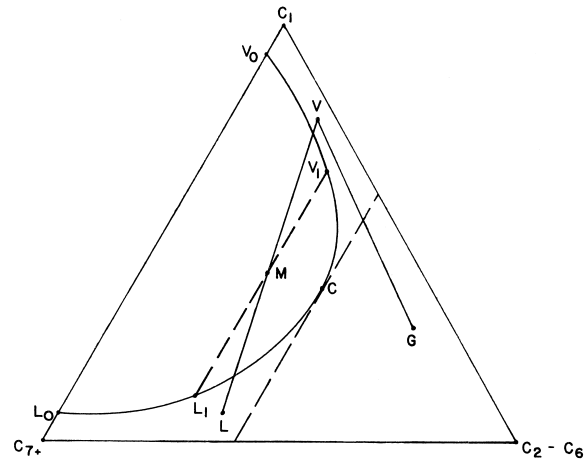


FIGURE 4 Ternary diagram illustrating typical hydrocarbon phase behavior at constant temperature and pressure.

system pressure and temperature are 2000 pounds per square inch absolute (psia) and 100°F, respectively. At these conditions both the *n*-decane and the propane exist as liquids and are therefore miscible in all proportions. The system temperature and pressure indicate that any mixture of methane and propane would be in the gas state; therefore, the methane and propane would be miscible in all proportions. However, the methane and *n*-decane would not be miscible for similar reasons. If the pressure were reduced to 1000 psia and the temperature held constant, the propane and *n*-decane would again be miscible. However, mixtures of methane and propane could be located in a two-phase region and would not lend themselves to a miscible displacement. Note that in this example the propane appears to act as a liquid when it is in the presence of *n*-decane and as a gas when it is in contact with methane. It is this unique capacity of propane and other intermediate gases that leads to the miscible process.

There are, in general, two types of miscible processes. One is referred to as the single-contact miscible process and involves such injection fluids as liquefied petroleum gases (LPGs) and alcohols. The injected fluids are miscible with residual oil immediately on contact. The second type is the multiple-contact, or dynamic, miscible process. The injected fluids in this case are usually methane, inert fluids, or an enriched methane gas supplemented with a C_2 – C_6 fraction. The injected fluid and oil are usually not miscible on first contact but rely on a process of chemical exchange between phases to achieve miscibility.

B. Single-Contact Miscible Processes

The phase behavior of hydrocarbon systems can be described with the use of ternary diagrams such as Fig. 4. Researchers have shown that crude oil phase behavior can

be represented reasonably well by three fractions of the crude. One fraction is methane (C_1). A second fraction is a mixture of ethane through hexane (C_2 – C_6). The third fraction is the remaining hydrocarbon species lumped together and called C_{7+} . Figure 4 illustrates the ternary phase diagram for a typical hydrocarbon system with these three pseudocomponents at the corners of the triangle. There are one-phase and two-phase regions in the diagram. The one-phase region may be vapor or liquid (to the left of the dashed line through the critical point C) or gas (to the right of the dashed line through the critical point). A gas could be mixed with either a liquid or a vapor in appropriate percentages and yield a miscible system. However, when liquid is mixed with a vapor, often the result is a composition in the two-phase region. A mixing process is represented on a ternary diagram as a straight line. For example, if compositions V and G are mixed in appropriate proportions, the resulting mixture would fall on the line VG . If compositions V and L are mixed, the resulting overall composition M would fall on the line VL but the mixture would yield two phases. If two phases are formed, their compositions, V_1 and L_1 , would be given by a tie line extended through the point M to the phase envelope. The part of the phase boundary on the phase envelope from the critical point C to point V_0 is the dew point curve. The phase boundary from C to L_0 is the bubble point curve. The entire bubble point–dew point curve is referred to as the binodal curve.

The oil–LPG–dry gas system will be used to illustrate the behavior of the first-contact miscible process on a ternary diagram. Figure 5 is a ternary diagram with the points O , P , and V representing the oil, LPG, and dry gas, respectively. The oil and LPG are miscible in all proportions. A mixing zone at the oil–LPG interface will grow

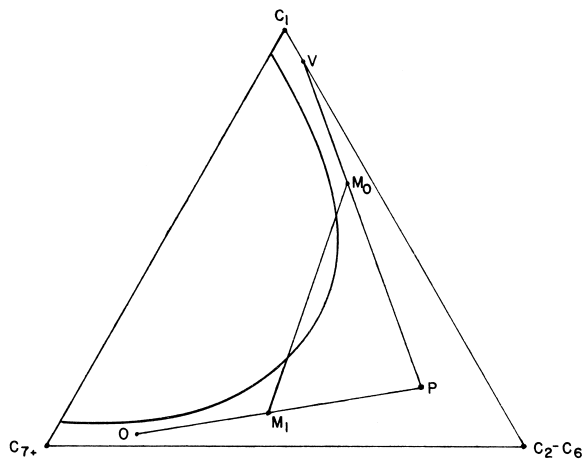


FIGURE 5 Ternary diagram illustrating the single-contact miscible process.

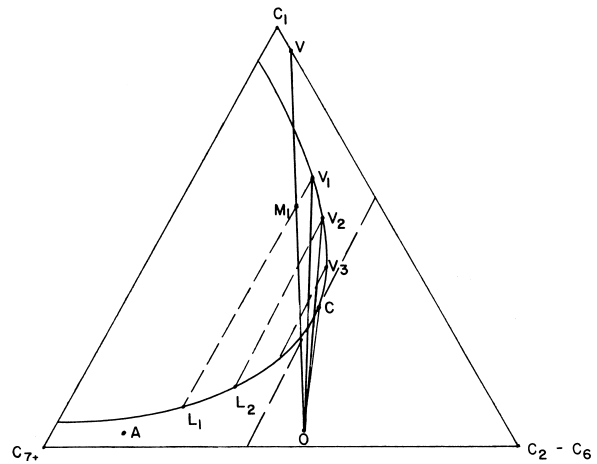


FIGURE 6 Ternary diagram illustrating the multicontact dry gas miscible process.

as the front advances through the reservoir. At the rear of the LPG slug, the dry gas and LPG are miscible and a mixing zone will also be created at this interface. If the dry gas–LPG mixing zone overtakes the LPG–oil mixing zone, miscibility will be maintained unless the contact of the two zones yields mixtures inside the two-phase region (see line M_0M_1 , Fig. 5).

Reservoir pressures sufficient to achieve miscibility are required. This limits the application of LPG processes to reservoirs having pressures at least of the order of 1500 psia. Reservoirs with pressures less than this might be amenable to alcohol flooding, another first-contact miscible process, since alcohols tend to be soluble with both oil and water (the drive fluid in this case). The two main problems with alcohols are that they are expensive and they become diluted with connate water during a flooding process, which reduces the miscibility with the oil. Alcohols that have been considered are in the C_1 – C_4 range.

C. Multiple-Contact Miscible Processes

Multiple-contact, or dynamic, miscible processes do not require the oil and displacing fluid to be miscible immediately on contact but rely on chemical exchange between the two phases for miscibility to be achieved. Figure 6 illustrates the high-pressure (lean-gas) vaporizing process. The temperature and pressure are constant throughout the diagram at reservoir conditions. A vapor denoted by V in Fig. 6, consisting mainly of methane and a small percentage of intermediates, will serve as the injection fluid. The oil composition is given by the point O . The following sequence of steps occurs in the development of miscibility:

1. The injection fluid V comes in contact with crude oil O . They mix, and the resulting overall composition is

given by M_1 . Since M_1 is located in the two-phase region, a liquid phase L_1 and a vapor phase V_1 will form with the compositions given by the intersections of a tie line through M_1 with the bubble point and dew point curves, respectively.

2. The liquid L_1 has been created from the original oil O by vaporization of some of the light components. Since the oil O was at its residual saturation and was immobile due to K_{ro} 's being zero, when a portion of the oil is extracted, the volume, and hence the saturation, will decrease and the oil will remain immobile. The vapor phase, since K_{rg} is greater than zero, will move away from the oil and be displaced downstream.

3. The vapor V_1 will come in contact with fresh crude oil O , and again the mixing process will occur. The overall composition will yield two phases, V_2 and L_2 . The liquid again remains immobile and the vapor moves downstream, where it comes in contact with more fresh crude.

4. The process is repeated with the vapor phase composition moving along the dew point curve, $V_1-V_2-V_3$, and so on, until the critical point, c , is reached. At this point, the process becomes miscible. In the real case, because of reservoir and fluid property heterogeneities and dispersion, there may be a breaking down and a reestablishment of miscibility.

Behind the miscible front, the vapor phase composition continually changes along the dew point curve. This leads to partial condensing of the vapor phase with the resulting condensate being immobile, but the amount of liquid formed will be quite small. The liquid phase, behind the miscible front, continually changes in composition along the bubble point. When all the extractable components have been removed from the liquid, a small amount of liquid will be left, which will also remain immobile. There will be these two quantities of liquid that will remain immobile and will not be recovered by the miscible process. In practice, operators have reported that the vapor front travels anywhere from 20 to 40 ft from the well bore before miscibility is achieved.

The high-pressure vaporizing process requires a crude oil with significant percentages of intermediate compounds. It is these intermediates that are vaporized and added to the injection fluid to form a vapor that will eventually be miscible with the crude oil. This requirement of intermediates means that the oil composition must lie to the right of a tie line extended through the critical point on the binodal curve (see Fig. 6). A composition lying to the left, such as denoted by point A , will not contain sufficient intermediates for miscibility to develop. This is due to the fact that the richest vapor in intermediates that can be formed will be on a tie line extended through point A . Clearly, this vapor will not be miscible with crude oil A .

As pressure is reduced, the two-phase region increases. It is desirable, of course, to keep the two-phase region minimal in size. As a rule, pressures of the order of 3000 psia or greater and an oil with an American Petroleum Institute (API) gravity greater than 35 are required for miscibility in the high-pressure vaporizing process.

The enriched-gas-condensing process is a second type of dynamic miscible process (Fig. 7). As in the high-pressure vaporizing process, where chemical exchange of intermediates is required for miscibility, miscibility is developed during a process of exchange of intermediates with the injection fluid and the residual oil. In this case, however, the intermediates are condensed from the injection fluid to yield a "new" oil, which becomes miscible with the "old" oil and the injected fluid. The following steps occur in the process (the sequence of steps is similar to those described for the high-pressure vaporizing process but contain some significant differences):

1. An injection fluid G rich in intermediates mixes with residual oil O .
2. The mixture, given by the overall composition M_1 separates into a vapor phase V_1 and a liquid phase L_1 .
3. The vapor moves ahead of the liquid that remains immobile. The remaining liquid L_1 then comes in contact with fresh injection fluid G . Another equilibrium occurs, and phases having compositions V_2 and L_2 are formed.
4. The process is repeated until a liquid is formed from one of the equilibration steps that is miscible with G . Miscibility is then said to have been achieved.

Ahead of the miscible front, the oil continually changes in composition along the bubble point curve. In contrast with the high-pressure vaporizing process, there is the potential for no residual oil to be left behind in the reservoir as

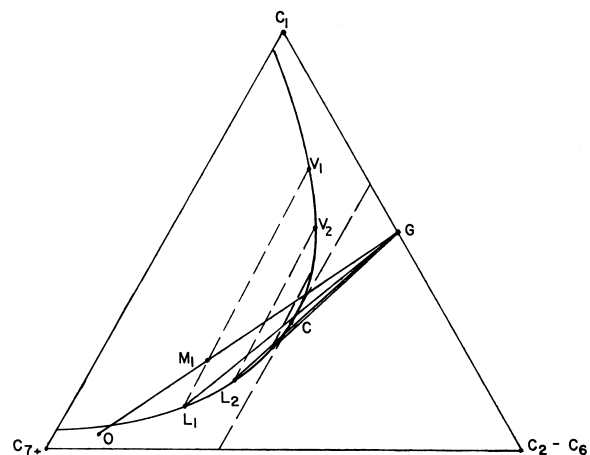


FIGURE 7 Ternary diagram illustrating the multicontact enriched-gas-condensing miscible process.

long as there is a sufficient amount of G injected to supply the condensing intermediates. The enriched gas process may be applied to reservoirs containing crude oils with only small quantities of intermediates. Reservoir pressures are usually in the range 2000–3000 psia.

The intermediates are expensive, so usually a dry gas is injected after a sufficient slug of enriched gas has been injected.

D. Inert Gas Injection Processes

The use of inert gases, in particular carbon dioxide, CO_2 , and nitrogen, N_2 , as injected fluids in miscible processes has become extremely popular. The ternary diagram representation of the process with CO_2 or N_2 is exactly the same as that for the high-pressure vaporizing process except that either CO_2 or N_2 becomes a component and methane is lumped with the intermediates. Typically the one-phase region is largest for CO_2 , with N_2 and dry gas having about the same one-phase size. The larger the one-phase region, the more readily miscibility will be achieved. Miscibility pressures are lower for CO_2 , usually in the neighborhood of 1200–1500 psia, whereas N_2 and dry gas yield much higher miscibility pressures (i.e., 3000 psia or more).

The capacity of CO_2 to vaporize hydrocarbons is much greater than that of natural gas. It has been shown that CO_2 vaporizes hydrocarbons primarily in the gasoline and gas–oil range. This capacity of CO_2 to extract hydrocarbons is the primary reason for the use of CO_2 as an oil recovery agent. It is also the reason CO_2 requires lower miscibility pressures than those required by natural gas. The presence of other diluent gases such as N_2 , methane, or flue gas with the CO_2 will raise the miscibility pressure. The multiple-contact mechanism works nearly the same with a diluent gas added to the CO_2 as it does for pure CO_2 . Frequently an application of the CO_2 process in the field will tolerate higher miscibility pressures than what pure CO_2 would require. If this is the case, the operator can dilute the CO_2 with other available gas, which will raise the miscibility pressure but also reduce the CO_2 requirements.

The pressure at which miscibility is achieved is best determined by conducting a series of displacement experiments in a long, slim tube. A plot of oil recovery versus flooding pressure is made, and the minimum miscibility pressure is determined from the plot. There have been several attempts to correlate miscibility pressures for CO_2 –oil systems. An early study showed that there is a correlation among the API gravity of the crude, the temperature of the reservoir, and the minimum miscibility pressure. A second study revealed that the molecular weight of the C_{5+} fraction was a better variable to use than the API gravity. In further investigations, it has been found that the minimum miscibility pressure is the

pressure that will achieve a minimum density in the CO_2 phase.

E. Problems in Applying the Miscible Process

Because of differences in density and viscosity between the injected fluid and the reservoir fluid(s), the miscible process often suffers from poor mobility. Viscous fingering and gravity override frequently occur. The simultaneous injection of a miscible agent and a brine was suggested in order to take advantage of the high microscopic displacement efficiency of the miscible process and the high macroscopic displacement efficiency of a waterflood. The improvement was not as good as hoped for since the miscible agent and brine tended to separate due to density differences, with the miscible agent flowing along the top of the porous medium and the brine along the bottom.

Several variations of the simultaneous injection scheme have been suggested and researched. They typically involve the injection of a miscible agent followed by brine or the alternating of miscible agent–brine injection. The latter variation has been named the WAG (water alternate gas) process and has become the most popular. A balance between amounts of injected water and gas must be achieved. Too much gas will lead to viscous fingering and gravity override of the gas, whereas too much water could lead to the trapping of reservoir oil by the water. The addition of foam-generating substances to the brine phase has been suggested as a way to aid in reducing the mobility of the gas phase. Research is continuing in this area.

Operational problems involving miscible processes include transportation of the miscible flooding agent, corrosion of equipment and tubing, and separation and recycling of the miscible flooding agent.

IV. CHEMICAL FLOODING

A. Introduction

Chemical flooding relies on the addition of one or more chemical compounds to an injected fluid either to reduce the interfacial tension between the reservoir oil and the injected fluid or to improve the sweep efficiency of the injected fluid.

There are three general methods in chemical flooding technology. The first is polymer flooding, in which a large macromolecule is used to increase the displacing fluid viscosity. This leads to improved sweep efficiency in the reservoir. The second and third methods, micellar–polymer and alkaline flooding, make use of chemicals that reduce the interfacial tension between an oil and a displacing fluid.

B. Polymer Processes

The addition of large-molecular-weight molecules called polymers to an injected water can often increase the effectiveness of a conventional waterflood. Polymers are usually added to the water in concentrations ranging from 250 to 2000 parts per million (ppm). A polymer solution is more viscous than a brine without polymer. In a flooding application, the increased viscosity will alter the mobility ratio between the injected fluid and the reservoir oil. The improved mobility ratio will lead to better vertical and areal sweep efficiencies and thus higher oil recoveries. Polymers have also been used to alter gross permeability variations in some reservoirs. In this application, polymers form a gel-like material by cross-linking with other chemical species. The polymer gel sets up in large permeability streaks and diverts the flow of any injected fluid to a different location.

Two general types of polymers have been used. These are synthetically produced polyacrylamides and biologically produced polysaccharides. Polyacrylamides are long molecules with a small effective diameter. Thus, they are susceptible to mechanical shear. High rates of flow through valves will sometimes break the polymer into smaller entities and reduce the viscosity of the solution. A reduction in viscosity can also occur as the polymer solution tries to squeeze through the pore openings on the sand face of the injection well. A carefully designed injection scheme is necessary. Polyacrylamides are also sensitive to salt. Large salt concentrations (i.e., greater than 1–2 wt %) tend to make the polymer molecules curl up and lose their viscosity-building effect.

Polysaccharides are less susceptible to both mechanical shear and salt. Since they are produced biologically, care must be taken to prevent biological degradation in the reservoir. As a rule, polysaccharides are more expensive than polyacrylamides.

Polymer flooding has not been successful in high-temperature reservoirs. Neither polymer type has exhibited sufficiently long-term stability above 160°F in moderate-salinity or heavy-salinity brines.

Polymer flooding has the best application in moderately heterogeneous reservoirs and reservoirs containing oils with viscosities less than 100 centipoise (cP). In the United States, there has been a significant increase in the number of active polymer projects since 1978. The projects involve reservoirs having widely differing properties, that is, permeabilities ranging from 20 to 2000 millidarcies (mD), *in situ* oil viscosities of up to 100 cP, and reservoir temperatures of up to 200°F.

Since the use of polymers does not affect the microscopic displacement efficiency, the improvement in oil recovery will be due to an improved sweep efficiency over

what is obtained during a conventional waterflood. Typical oil recoveries from polymer flooding applications are in the range of 1–5% of the initial oil in place. It has been found that operators are more likely to have a successful polymer flood if they start the process early in the producing life of the reservoir.

C. Micellar–Polymer Processes

The micellar–polymer process uses a surfactant to lower the interfacial tension between the injected fluid and the reservoir oil. A surfactant is a surface-active agent that contains a hydrophobic (“dislikes” water) part to the molecule and a hydrophilic (“likes” water) part. The surfactant migrates to the interface between the oil and water phases and helps make the two phases more miscible. Interfacial tensions can be reduced from ~ 30 dyn/cm, found in typical waterflooding applications, to 10^{-4} dyn/cm with the addition of as little as 0.1–5.0 wt % surfactant to water–oil systems. Soaps and detergents used in the cleaning industry are surfactants. The same principles involved in washing soiled linen or greasy hands are used in “washing” residual oil off rock formations. As the interfacial tension between an oil phase and a water phase is reduced, the capacity of the aqueous phase to displace the trapped oil phase from the pores of the rock matrix increases. The reduction of interfacial tension results in a shifting of the relative permeability curves such that the oil will flow more readily at lower oil saturations.

When surfactants are mixed above a critical saturation in a water–oil system, the result is a stable mixture called a micellar solution. The micellar solution is made up of structures called microemulsions, which are homogeneous, transparent, and stable to phase separation. They can exist in several shapes, which depend on the concentrations of surfactant, oil, water, and other constituents. Spherical microemulsions have typical size ranges from 10^{-6} to 10^{-4} mm. A microemulsion consists of external and internal phases sandwiched around one or more layers of surfactant molecules. The external phase can be either aqueous or hydrocarbon in nature, as can the internal phase.

Solutions of microemulsions are known by several other names in the petroleum literature. These include surfactant solutions and soluble oils.

Figure 3 can be used to represent the micellar–polymer process. A certain volume of the micellar or surfactant solution fluid A is injected into the reservoir. The surfactant solution is then followed by a polymer solution, fluid B, to provide a mobility buffer between the surfactant solution and a drive water, which is used to push the entire system through the reservoir. The polymer solution is designed to prevent viscous fingering of the drive

water through the surfactant solution as it starts to build up an oil bank ahead of it. As the surfactant solution moves through the reservoir, surfactant molecules are retained on the rock surface due to the process of adsorption. Often a preflush is injected ahead of the surfactant to precondition the reservoir and reduce the loss of surfactants to adsorption. This preflush contains sacrificial agents such as sodium tripolyphosphate.

There are, in general, two types of micellar-polymer processes. The first uses a low-concentration surfactant solution (<2.5 wt %) but a large injected volume (up to 50% pore volume). The second involves a high-concentration surfactant solution (5–12 wt %) and a small injected volume (5–15% pore volume). Either type of process has the potential of achieving low interfacial tensions with a wide variety of brine-crude oil systems. Both have been used in pilot field trials with moderate technical success.

Whether the low-concentration or the high-concentration system is selected, the system is made up of several components. The multicomponent facet leads to an optimization problem, since many different combinations could be chosen. Because of this, a detailed laboratory screening procedure is usually undertaken. The screening procedure typically involves three types of tests: (1) phase behavior studies, (2) interfacial tension studies, and (3) oil displacement studies.

Phase behavior studies are typically conducted in small (up to 100 mL) vials in order to determine what type, if any, of microemulsion is formed with a given micellar-crude oil system. The salinity of the micellar solution is usually varied around the salt concentration of the field brine where the process will be applied. Besides the microemulsion type, other factors examined could be oil uptake into the microemulsion, ease with which the oil and aqueous phases mix, viscosity of the microemulsion, and phase stability of the microemulsion.

Interfacial tension studies are conducted with various concentrations of micellar solution components to determine optimal concentration ranges. Measurements are usually made with the spinning drop, pendent drop, or sessile drop techniques.

The oil displacement studies are the final step in the screening procedure. They are usually conducted in two or more types of porous media. Often initial screening experiments are conducted in unconsolidated sand packs and then in Berea sandstone. The last step in the sequence is to conduct the oil displacement experiments in actual cored samples of reservoir rock. Frequently, actual core samples are placed end to end in order to obtain a core of reasonable length since the individual core samples are typically only 5–7 in. long.

If the oil recoveries from the oil displacement tests warrant further study of the process, the next step is

usually a small field pilot study involving anywhere from 1 to 10 acres.

The micellar-polymer process has been applied in several pilot projects and one large field-scale project. The results have not been very encouraging. The process has demonstrated that it can be a technical success, but the economics of the process has been either marginal or poor in nearly every application.

D. Alkaline Processes

When an alkaline solution is mixed with certain crude oils, surfactant molecules are formed. When the formation of surfactant molecules occurs *in situ*, the interfacial tension between the brine and oil phases could be reduced. The reduction of interfacial tension causes the microscopic displacement efficiency to increase, which thereby increases oil recovery.

Alkaline substances that have been used include sodium hydroxide, sodium orthosilicate, sodium metasilicate, sodium carbonate, ammonia, and ammonium hydroxide. Sodium hydroxide has been the most popular. Sodium orthosilicate has some advantages in brines with a high divalent ion content.

There are optimum concentrations of alkaline and salt and optimum pH where the interfacial tension values experience a minimum. Finding these requires a screening procedure similar to the one discussed above for the micellar-polymer process. When the interfacial tension is lowered to a point where the capillary number is greater than 10^{-5} , oil can be mobilized and displaced.

Several mechanisms have been identified that aid oil recovery in the alkaline process. These include the following: lowering of interfacial tension, emulsification of oil, and wettability changes in the rock formation. All three mechanisms can affect the microscopic displacement efficiency, and emulsification can also affect the macroscopic displacement efficiency. If a wettability change is desired, a high (2.0–5.0 wt %) concentration of alkaline should be used. Otherwise, concentrations of the order of 0.5–2.0 wt % of alkaline are used.

The emulsification mechanism has been suggested to work by either of two methods. The first is by forming an emulsion, which becomes mobile and later trapped in downstream pores. The emulsion “blocks” the pores, which thereby diverts flow and increases sweep efficiency. The second mechanism is by again forming an emulsion, which becomes mobile and carries oil droplets that it has entrained to downstream production sites.

The wettability changes that sometimes occur with the use of alkaline affect relative permeability characteristics, which in turn affect mobility and sweep efficiencies.

Mobility control is an important consideration in the alkaline process as it is in all EOR processes. Often, it is

necessary to include polymer in the alkaline solution in order to reduce the tendency of viscous fingering to take place.

Not all crude oils are amenable to alkaline flooding. The surfactant molecules are formed with the heavier, acidic components of the crude oil. Tests have been designed to determine the susceptibility of a given crude oil to alkaline flooding. One of these tests involves titrating the oil with potassium hydroxide (KOH). An acid number is found by determining the number of milligrams of KOH required to neutralize 1 g of oil. The higher the acid number, the more reactive the oil will be and the more readily it will form surfactants. An acid number larger than ~ 0.2 mg KOH suggests a potential for alkaline flooding.

In general, alkaline projects have been inexpensive to conduct. However, recoveries have not been large in the past field pilots.

E. Problems in Applying Chemical Processes

The main technical problems associated with chemical processes include the following: (1) screening chemicals to optimize the microscopic displacement efficiency, (2) making contact with the oil in the reservoir, and (3) maintaining good mobility in order to lessen the effects of viscous fingering. The requirements for screening of chemicals vary with the type of process. Obviously, as the number of components increases, the more complicated the screening procedure becomes. The chemicals must also be able to tolerate the environment they are placed in. High temperature and salinity may limit the chemicals that could be used.

The major problem experienced in the field to date in chemical flooding processes has been the inability to make contact with residual oil. Laboratory screening procedures have developed micellar-polymer systems that have displacement efficiencies approaching 100% when sand packs or uniform consolidated sandstones are used as the porous medium. When the same micellar-polymer system is applied in an actual reservoir rock sample, however, the efficiencies are usually lowered significantly. This is due to the heterogeneities in the reservoir samples. When the process is applied to the reservoir, the efficiencies become even worse. Research is being conducted on methods to reduce the effect of the rock heterogeneities and to improve the displacement efficiencies.

Mobility research is also being conducted to improve displacement sweep efficiencies. If good mobility is not maintained, the displacing fluid front will not be effective in making contact with residual oil.

Operational problems involve treating the water used to make up the chemical systems, mixing the chemicals to maintain proper chemical compositions, plugging the formation with particular chemicals such as polymers,

dealing with the consumption of chemicals due to adsorption and mechanical shear and other processing steps, and creating emulsions in the production facilities.

V. THERMAL FLOODING

A. Introduction

Primary and secondary production from reservoirs containing heavy, low-gravity crude oils is usually a small fraction of the initial oil in place. This is due to the fact that these types of oils are very thick and viscous and as a result do not migrate readily to producing wells. Figure 8 shows a typical relationship between the viscosity of a heavy, viscous crude oil and temperature. As can be seen, for certain crude oils, viscosities decrease by orders of magnitude with an increase in temperature of 100–200°F. This suggests that if the temperature of a crude oil in the reservoir can be raised by 100–200°F over the normal reservoir temperature, the oil viscosity will be reduced significantly and will flow much more easily to a producing well. The temperature of a reservoir can be raised by injecting a hot fluid or by generating thermal energy *in situ* by combusting the oil. Hot water or steam can be injected as the hot fluid. Three types of processes will be discussed in this section: steam cycling, steam drive, and *in situ* combustion. In addition to the lowering of the crude oil viscosity, there are other mechanisms by which these three processes recover oil. These mechanisms will also be discussed.

Most of the oil that has been produced by EOR methods to date has been as a result of thermal processes. There is

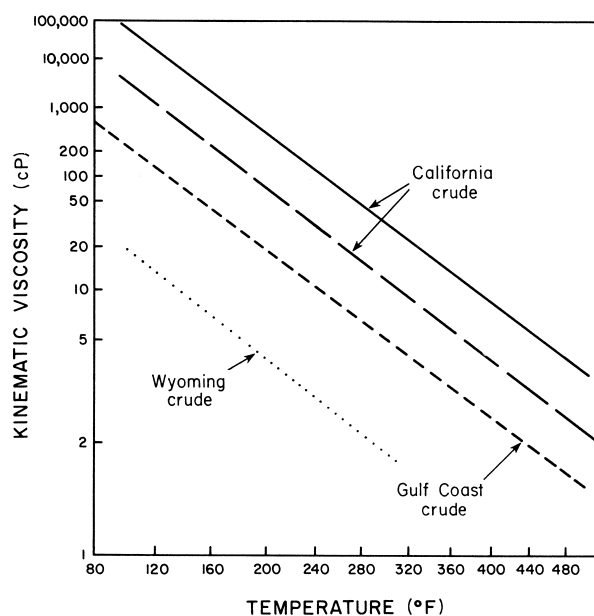


FIGURE 8 Typical viscosity-temperature relationships for several crude oils.

a practical reason for this, as well as several technical reasons. In order to produce more than 1–2% of the initial oil in place from a heavy-oil reservoir, operators had to employ thermal methods. As a result, thermal methods were investigated much earlier than either miscible or chemical methods, and the resulting technology was developed much more rapidly.

B. Steam Stimulation Processes

The steam stimulation process was discovered by accident in the Mene Grande Tar Sands, Venezuela, in 1959. During a steam injection trial, it was decided to relieve the pressure from the injection well by backflowing the well. When this was done, a very high oil production rate was observed. Since this discovery, many fields have been placed on steam stimulation.

The steam stimulation process, also known as the steam huff and puff, steam soak, or cyclic steam injection, begins with the injection of 5000–15,000 bbl of high-quality steam. This can take a period of days to weeks to accomplish. The well is then shut in, and the steam is allowed to soak the area around the injection well. This soak period is fairly short, usually from 1 to 5 days. The injection well is then placed on production. The length of the production period is dictated by the oil production rate but can last from several months to a year or more. The cycle is repeated as many times as is economically feasible. The oil production will decrease with each new cycle.

Mechanisms of oil recovery due to this process include (1) reduction of flow resistance near the well bore by reducing the crude oil viscosity and (2) enhancement of the solution gas drive mechanism by decreasing the gas solubility in an oil as temperature increases.

Often, in heavy-oil reservoirs, the steam stimulation process is applied to develop injectivity around an injection well. Once injectivity has been established, the steam stimulation process is converted to a continuous steam drive process.

The oil recoveries obtained from steam stimulation processes are much smaller than the oil recoveries that could be obtained from a steam drive. However, it should be apparent that the steam stimulation process is much less expensive to operate. The cyclic steam stimulation process is the most common thermal recovery technique. Recoveries of additional oil have ranged from 0.21 to 5.0 bbl of oil per barrel of steam injected.

C. Steam Drive Processes

The steam drive process is much like a conventional waterflood. Once a pattern arrangement is established, steam is injected into several injection wells while the oil is produced from other wells. This is different from the steam stimulation process, whereby the oil is produced from the

same well into which the steam is injected. As the steam is injected into the formation, the thermal energy is used to heat the reservoir oil. Unfortunately, the energy also heats the entire environment such as formation rock and water. Some energy is also lost to the underburden and overburden. Once the oil viscosity is reduced by the increased temperature, the oil can flow more readily to the producing wells. The steam moves through the reservoir and comes in contact with cold oil, rock, and water. As the steam comes in contact with the cold environment, it condenses and a hot water bank is formed. This hot water bank acts as a waterflood and pushes additional oil to the producing wells.

Several mechanisms have been identified that are responsible for the production of oil from a steam drive. These include thermal expansion of the crude oil, viscosity reduction of the crude oil, changes in surface forces as the reservoir temperature increases, and steam distillation of the lighter portions of the crude oil.

Steam applications have been limited to shallow reservoirs because as the steam is injected it loses heat energy in the well bore. If the well is very deep, all the steam will be converted to liquid water. Recently, interest has been shown in downhole steam generation; research to develop an economical system is continuing in this area.

Steam drives have been applied in many pilot and field-scale projects with very good success. Oil recoveries have ranged from 0.3 to 0.6 bbl of oil per barrel of steam injected.

D. *In Situ* Combustion

Early attempts at *in situ* combustion involved what is referred to as the forward dry combustion process. The crude oil was ignited downhole, and then a stream of air or oxygen-enriched air was injected in the well where the combustion was originated. The flame front was then propagated through the reservoir. Large portions of heat energy were lost to the overburden and underburden with this process. To reduce the heat losses, researchers devised a reverse combustion process. In reverse combustion, the oil is ignited as in forward combustion but the airstream is injected in a different well. The air is then “pushed” through the flame front as the flame front moves in the opposite direction. Researchers found the process to work in the laboratory, but when it was tried in the field on a pilot scale, it was never successful. What they found was that the flame would be shut off because there was no oxygen supply and that where the oxygen was being injected, the oil would self-ignite. The whole process would then revert to a forward combustion process.

When the reverse combustion process failed, a new technique called the forward wet combustion process was introduced. This process begins as a forward dry

combustion does, but once the flame front is established, the oxygen stream is replaced by water. As the water comes in contact with the hot zone left by the combustion front, it flashes to steam, using energy that otherwise would have been wasted. The steam moves through the reservoir and aids the displacement of oil. The wet combustion process has become the primary method of conducting combustion projects.

Not all crude oils are amenable to the combustion process. For the combustion process to function properly, the crude oil has to have enough heavy components to serve as the fuel source for the combustion. Usually this requires an oil of low API gravity. As the heavy components in the oil are combusted, lighter components as well as flue gases are formed. These gases are produced with the oil and raise the effective API gravity of the produced oil.

The number of *in situ* combustion projects has decreased since 1980. Environmental and other operational problems have proved to be more than what some operators want to deal with.

E. Problems in Applying Thermal Processes

The main technical problems associated with thermal techniques are poor sweep efficiencies, loss of heat energy to unproductive zones underground, and poor injectivity of steam or air. Poor sweep efficiencies are due to the density differences between the injected fluids and the reservoir crude oils. The lighter steam or air tends to rise to the top of the formation and bypass large portions of crude oil. Data have been reported from field projects in which coring operations have revealed significant differences in residual oil saturations in the top and bottom parts of the swept formation. Research is being conducted on methods of reducing the tendency for the injected fluids to override the reservoir oil. Techniques involving foams are being employed.

Large heat losses continue to be associated with thermal processes. The wet combustion process has lowered these losses for the higher-temperature combustion techniques, but the losses are severe enough in many applications to prohibit the combustion process. The losses are not as large with the steam processes because they involve smaller temperatures. The development of a feasible downhole generator will significantly reduce the losses associated with steam injection processes.

The poor injectivity found in thermal processes is largely a result of the nature of the reservoir crudes. Operators have applied fracture technology in connection with the injection of fluids in thermal processes. This has helped in many reservoirs.

Operational problems include the following: the formation of emulsions, the corrosion of injection and production tubing and facilities, and the creation of adverse

effects on the environment. When emulsions are formed with heavy crude oil, they are very difficult to break. Operators need to be prepared for this. In the high-temperature environments created in the combustion processes and when water and stack gases mix in the production wells and facilities, corrosion becomes a serious problem. Special well liners are often required. Stack gases also pose environmental concerns in both steam and combustion applications. Stack gases are formed when steam is generated by either coal- or oil-fired generators and, of course, during the combustion process as the crude is burned.

VI. MICROBIAL FLOODING

A. Introduction

Microbial enhanced oil recovery (MEOR) flooding involves the injection of microorganisms that react with reservoir fluids to assist in the production of residual oil. The U.S. National Institute for Petroleum & Energy Research (NIPER) maintains a database of field projects that have used microbial technology. There has been significant research conducted on MEOR, but few pilot projects are currently being conducted. The *Oil and Gas Journal's* 1998 survey reported just 1 ongoing project in the United States related to this technology out of 199 projects. However, China reported several pilot projects that indicated mild success with MEOR.

There are two general types of MEOR processes—those in which microorganisms react with reservoir fluids to generate surfactants and those in which microorganisms react with reservoir fluids to generate polymers. Both processes are discussed below along with a few concluding comments regarding the problems in applying them. The success of MEOR processes will be highly affected by reservoir characteristics. MEOR systems can be designed for reservoirs that have either a high or a low degree of channeling. Therefore, MEOR applications require a thorough knowledge of the reservoir. Mineral content of the reservoir brine will also affect the growth of microorganisms.

B. Microbial Processes

Microorganisms can be reacted with reservoir fluids to generate either surfactants or polymers in the reservoir. Once either the surfactant or the polymer is produced, the processes of mobilizing and recovering residual oil become similar to those discussed with regard to chemical flooding.

Most pilot projects have involved near-well treatments of stripper wells in an application of the huff and puff process discussed with regard to thermal flooding. A solution of microorganisms is injected along with a nutrient, usually molasses. When the solution of microorganisms has been designed to react with the oil to form polymers,

the injected solution will enter high-permeability zones and react to form the polymers that will then act as a permeability-reducing agent. When oil is produced during the huff stage, oil from lower permeability zones will be produced. Conversely, the solution of microorganisms can be designed to react with the residual crude oil to form a surfactant. The surfactant lowers the interfacial tension of the brine-water system, which thereby mobilizes the residual oil. The oil is then produced in the huff part of the process.

The reaction of the microorganisms with the reservoir fluids may also produce gases, such as CO₂, N₂, H₂, and CH₄. The production of these gases will result in an increase in reservoir pressure, which will thereby enhance the reservoir energy.

C. Problems in Applying Microbial Processes

Since microorganisms can be reacted to form either polymers or surfactants, a knowledge of the reservoir characteristics is critical. If the reservoir is fairly Heterogeneous, then it would be desirable to generate polymers *in situ* that could be used to divert fluid flow from high- to low-permeability channels. If the reservoir has low injectivity, then using microorganisms that produced polymers could be very damaging to the flow of fluids near the well bore. Hence, a thorough knowledge of the reservoir characteristics, particularly those immediately around the well bore, is extremely important.

Reservoir brines can inhibit the growth of the microorganisms. Therefore, some simple compatibility tests can result in useful information as to the viability of the process. These can be simple test-tube experiments in which reservoir fluids and/or rock are placed in microorganism–nutrient solutions and growth and metabolite production of the microorganisms are monitored.

MEOR processes have been applied in reservoirs with brines up to less than 100,000 ppm, rock permeabilities greater than 75 mD, and depths less than 6800 ft. This depth corresponds to a temperature of about 75°C. Most MEOR projects have been performed with light crude oils having API gravities between 30 and 40. These should be considered “rule of thumb” criteria. The most important consideration in selecting a microorganism–reservoir system is to conduct compatibility tests to make sure that microorganism growth can be achieved.

VII. SCREENING CRITERIA FOR EOR PROCESSES

A. Introduction

A large number of variables are associated with a given oil reservoir, for instance, pressure and temperature, crude oil type and viscosity, and the nature of the rock matrix

and connate water. Because of these variables, not every type of EOR process can be applied to every reservoir. An initial screening procedure would quickly eliminate some EOR processes from consideration in particular reservoir applications. This screening procedure involves the analysis of both crude oil and reservoir properties. This section presents screening criteria for each of the general types of processes previously discussed in this article except microbial flooding. (A discussion of MEOR screening criteria was presented in Section VI). It should be recognized that these screening criteria are only guidelines. If a particular reservoir–crude oil application appears to be on a borderline between two different processes, it may be necessary to consider both processes. Once the number of processes has been reduced to one or two, a detailed economic analysis will have to be conducted.

Some general considerations can be discussed before the individual process screening criteria are presented. First, detailed geological study is usually desirable, since operators have found that unexpected reservoir heterogeneities have led to the failure of many EOR field projects. Reservoirs that are found to be highly faulted or fractured typically yield poor recoveries from EOR processes. Second, some general comments pertaining to economics can be made. When an operator is considering EOR in particular applications, candidate reservoirs should contain sufficient recoverable oil and be large enough for the project to be potentially profitable. Also, deep reservoirs could involve large drilling and completion expenses if new wells are to be drilled.

B. Screening Criteria

Table II contains the screening criteria that have been compiled from the literature for the miscible, chemical, and thermal techniques.

The miscible process requirements are characterized by a low-viscosity crude oil and a thin reservoir. A low-viscosity oil will usually contain enough of the intermediate-range components for the multicontact miscible process to be established. The requirement of a thin reservoir reduces the possibility that gravity override will occur and yields a more even sweep efficiency.

In general, the chemical processes require reservoir temperatures of less than 200°F, a sandstone reservoir, and enough permeability to allow sufficient injectivity. The chemical processes will work on oils that are more viscous than what the miscible processes require, but the oils cannot be so viscous that adverse mobility ratios are encountered. Limitations are set on temperature and rock type so that chemical consumption can be controlled to reasonable values. High temperatures will degrade most of the chemicals that are currently being used in the industry.

TABLE II Screening Criteria for Enhanced Oil Recovery Processes

Process	Oil gravity (°API)	Oil viscosity (cP)	Oil saturation (%)	Formation type	Net thickness (ft)	Average permeability (mD)	Depth (ft)	Temp (°F)
Miscible								
Hydrocarbon	>35	<10	>30	Sandstone or carbonate	15–25	— ^a	>4500	— ^a
Carbon dioxide	>25	<12	>30	Sandstone or carbonate	15–25	— ^a	>2000	— ^a
Nitrogen	>35	<10	>30	Sandstone or carbonate	15–25	— ^a	>4500	— ^a
Chemical								
Polymer	>25	5–125	— ^b	Sandstone preferred	— ^a	>20	<9000	<200
Surfactant–polymer	>15	20–30	>30	Sandstone preferred	>10	>20	<9000	<200
Alkaline	13–35	<200	— ^b	Sandstone preferred	— ^a	>20	<9000	<200
Thermal								
Steamflooding	>10	>20	>40–50	Sand or sandstone with high porosity	>10	>50	500–5000	— ^a
Combustion	10–40	<1000	>40–50	Sand or sandstone with high porosity	>10	>50	>500	— ^a

^a Not critical but should be compatible.

^b Ten percent mobile oil above waterflood residual oil.

In applying the thermal methods, it is critical to have a large oil saturation. This is especially pertinent to the steamflooding process, because much of the produced oil will be used on the surface as the source of fuel to fire the steam generators. In the combustion process, crude oil is used as fuel to compress the airstream on the surface. The reservoir should be of significant thickness in order to minimize heat loss to the surroundings.

VIII. SUMMARY

The recovery of nearly two-thirds of all the oil that has been discovered to date is an attractive target for EOR processes. The application of EOR technology to existing fields could significantly increase the world's proven reserves. Several technical improvements will have to be made, however, before EOR processes are widely implemented. The current economic climate will also have to improve because many of the processes are either marginally economical or not economical at all. Steamflooding and polymer processes are currently economically viable, with produced oil prices per barrel within a range of \$20 to \$28. In comparison, the CO₂ process is more costly, \$26–\$39. The micellar–polymer process is even more expensive, at \$35–\$46. (These prices are in 1985 U.S. dollars.) An aggressive research program is needed to assist in making EOR processes more technologically and economically sound.

Enhanced oil recovery technology should be considered early in the producing life of a reservoir. Many of the processes depend on the establishment of an oil bank in order for the process to be successful. When oil saturations are high, the oil bank is easier to form. It is crucial for engineers to understand the potential of EOR and the way EOR can be applied to a particular reservoir.

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