A Niche for Enhanced Oil Recovery in the 1990s

Aging fields and dwindling prospects for finding new, large reserves are turning attention to improving recovery from known oil fields. What is the status of enhanced oil recovery (EOR) and what role might it potentially play in the next few years?

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Traditional primary and secondary production methods typically recover one third of oil in place, leaving two thirds behind. The reasons for this are not difficult to understand. During the life of a well, there is always a point at which the cost of producing an additional barrel of oil is higher than the price the market will pay for that barrel. Production then halts. Under normal circumstances, the well is abandoned, with 70% of the oil left in the ground.

Except for brief periods in which EOR was economical, or perceived to be so, there were good economic reasons not to nurse every drop of oil from a well. Oil was easy to find and another giant field was just around the corner—the cost of a newly found barrel of oil was far less than the cost of an EOR incremental barrel. This situation has begun to change, especially in North America. Reserves in the aging oil fields of the US and Canada are declining faster than new oil is being added by discoveries. In the US, for example, 70% of the approximately 500 billion barrels of oil discovered were found during the earliest 20% of drilling. About 130 billion barrels have been produced to date and up to another 170 billion barrels are considered a long-term target for advanced EOR technology. The situation is similar in Canada. Given the declining reserves and the low probability of locating significant new fields, producers sought additional oil in old reservoirs, making North America a proving ground for EOR techniques. Today, it is estimated that North America produces more than half the world's EOR production (*below*).

Research and development on many fronts indicate that the risks of EOR are

Estimated Annual Wordwide EOR Produced Oil, B/D (x1000)

Country	Thermal	Miscible	Chemical	EOR Total	%
USA	454	191	11.9	656.9	42
Canada	8	127	17.2	152.2	10
Europe	14	3	—	17.0	1
Venezuela	108	11	—	119.0	7
Other S. American	2	NA	NA	17.0	1
USSR	20	90	50.0	160.0	10
Other (estimated)	171*	280**	1.5	452.5	29
Total	777	702	80.6	1574.6	100

*Mainly Duri field (Indonesia) **Mainly Hassi-Messaoud (Algeria) and Intisar (Libya)

□***Estimated annual worldwide production of oil by EOR.***
(USSR data from Simandoux P and Valentin E: "Improved Recovery, Strategic Option or Not?" presented at the Offshore North Seas Conference, Stavanger, Norway, August 28-31, 1990; other data from Oil & Gas Journal 88, no. 17 (April 23, 1990): 62-67.)

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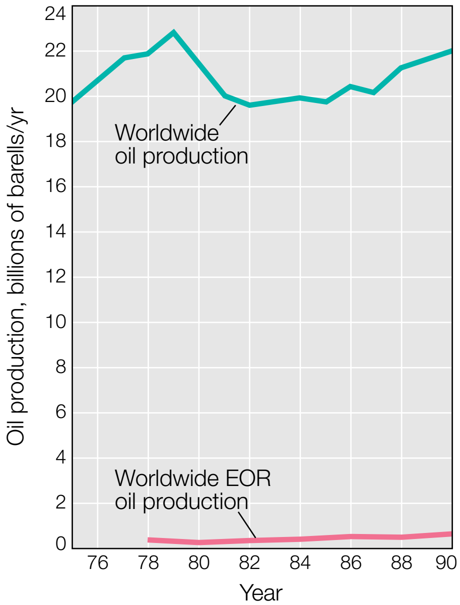


□***A slow, but steady increase in percent of world oil produced by EOR. Percent of oil produced by EOR has more than doubled since 1982, when EOR oil accounted for 0.9% of worldwide production. In 1990, EOR accounted for 450 million—about 2%—of the 22 billion barrels of oil produced.*** *(From Oil & Gas Journal data.)*

being reduced and the potential for EOR profitability increased (*above*). Computerized characterization of the reservoir, which quantifies the physical characteristics and dynamic behavior of a field, is becoming one of the most important tools for improved oil recovery (see "Reservoir Characterization Using Expert Knowledge, Data and Statistics," *page 25*). Success of oil recovery depends on applying the energy of injected fluids in the right place, in the right amount and at the right time—a strategy that a well-constructed reservoir simulator can help develop.

EOR is an imprecise term that historically has been used to describe the third step (tertiary recovery) in oil and gas production. The term "improved oil recovery" (IOR) has come into use to describe all recovery methods other than natural (primary) production, reserving the designation EOR for those processes beyond simple waterflood and gasflood—basically, recovery by injection of anything not originally in the reservoir (*next page, top*). The three major EOR methods are thermal (application of heat), miscible (mixing of oil with a solvent) and chemical (flooding with chemicals).

Primary recovery, in long accepted practice, is defined as production by natural reservoir pressure, or pumping, until depletion. Until the early 1940s, economics dictated when a well was to be plugged and abandoned, usually after recovery of 10 to 25% of original oil in place (OOIP).

Secondary recovery methods are generally used to repressure the reservoir and drive out some of the remaining oil. Because water is usually readily available and inexpensive, the oldest secondary recovery method is waterflooding, pumping water through injection wells into the reservoir. The water is forced from injection wells through the rock pores, sweeping the oil ahead of it toward production wells. This is practical for light to medium crudes. Over time, the percentage of water in produced fluids—the water cut—steadily increases. Some wells remain economical with a water cut as high as 99%. But at some point, the cost of removing and disposing of water exceeds the income from oil production, and secondary recovery is then halted.

Extensive waterflooding, which began in the 1940s, within a few decades became the established method for secondary oil recovery, usually recovering about another 15% of OOIP. On average, about one-third of OOIP is recovered, leaving two-thirds, or twice as much oil as is produced, in the ground after secondary recovery.[1]

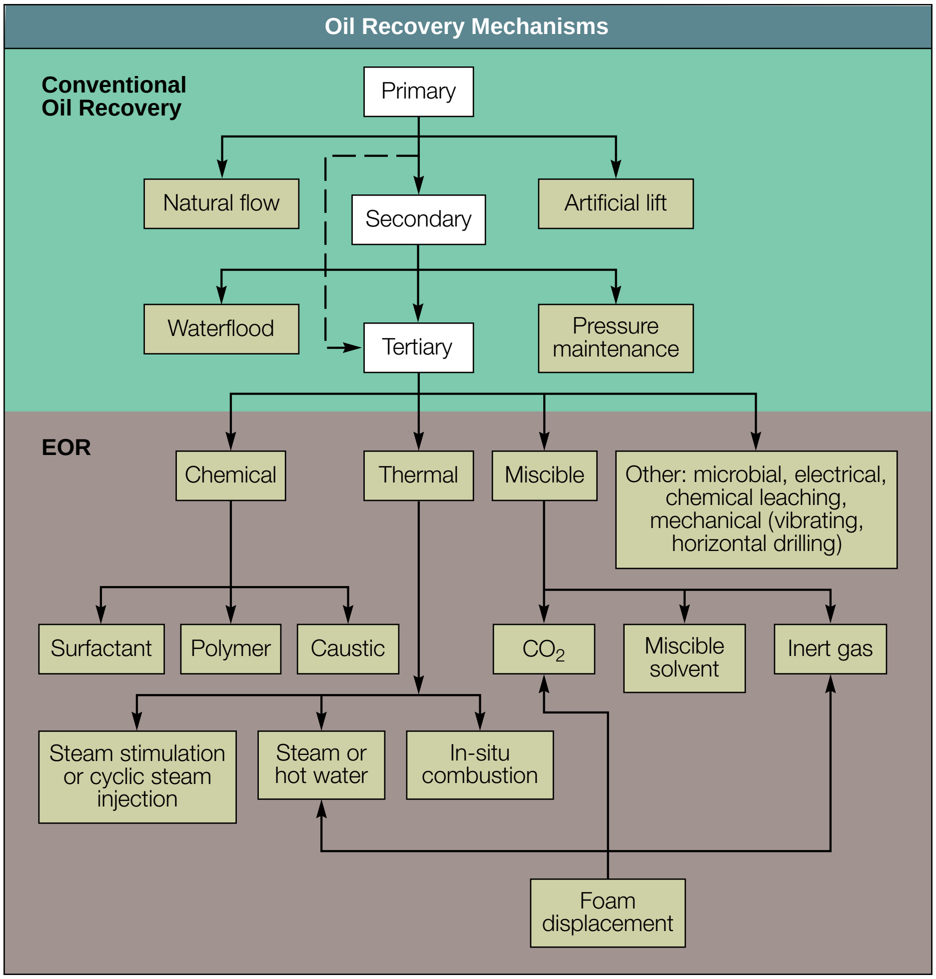
Another recognized secondary recovery technique is injection of a hydrocarbon-based gas into an existing gas cap or directly into the oil itself. Gas may be injected over a considerable period of time—up to a year—while producing wells are shut in, until reservoir pressure is restored and production resumed. Another method is injection of gas to sustain pressure during production. Gas injection requires a nearby source of inexpensive gas in sufficient volume.

While waterflooding is effective in nearly all reservoirs, no single EOR technique is a cure-all. Most reservoirs are complex, as are most EOR processes. Efficient reservoir management treats EOR as a high-cost, high-risk but critical component of a comprehensive plan that spans primary recovery through abandonment.[2]

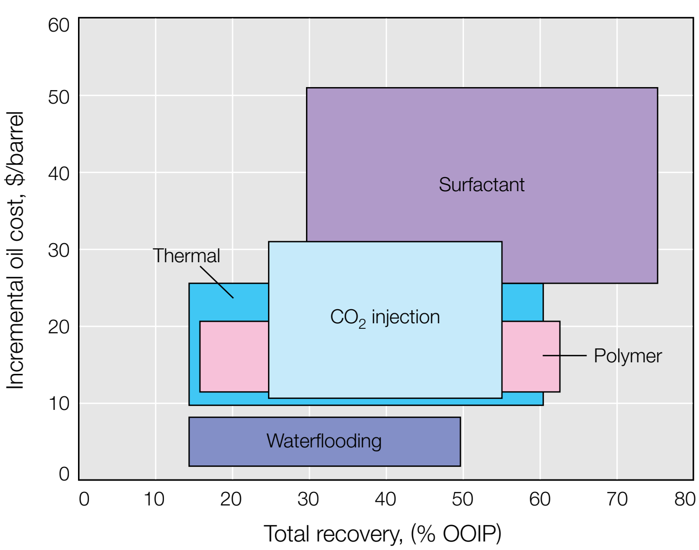
Once preliminary reservoir information has been assembled and used to select EOR options, engineering project design usually follows several steps.

- Laboratory studies test the proposed EOR processes in corefloods with samples of reservoir rock and fluids. These small, one-dimensional flow tests in relatively homogeneous media do not always successfully scale up to reservoir dimensions. But if the process fails in the laboratory, it will more than likely fail in the field.
- Fluid-flow simulations, based on a geologic reservoir model, can start with assessment of primary and secondary recovery, matching the production history to determine residual oil and waterflood recovery. Then EOR process-variable sensitivities can be calculated, followed by predictions of EOR recovery, incremental production rate and payout economics. Reservoir geologic models are always constrained by sparse data, simplified concepts of reservoir structure and dynamics, inadequate data for history matching and increasing computational uncertainty as calculations are extrapolated into the future. Consequently, predictions that cover years of EOR performance may be seriously in error. In addition, small-scale heterogeneities, which are difficult to define, are critical to the success of EOR.
- Usually, a pilot test of the proposed EOR process is carried out to investigate a novel technique or to confirm expected performance before an expensive, full-scale implementation. Ideally, the pilot test is performed in an area that is geologically similar to the field and large enough to be statistically representative of overall heterogeneity. Monitoring and data acquisition throughout pilot testing provide information needed to plan a full-scale commercial operation.
- For commercial operations, important considerations are secure sources of water and other injectants, storage and transportation facilities (like pipelines), surface processing, separation, recycling and upgrading facilities, and environmental and safety requirements.[3]

The same principles of EOR engineering may not apply to offshore oil fields. Because offshore wells tend to be highly deviated or extended reach, the distance between them is often greater than between onshore wells. This extends the time between EOR initiation and meaningful results and flattens the recovery response. These effects complicate process control and limit the number of EOR techniques that may be applicable. Greater spacing between wells also increases the likelihood of undetectable heterogeneities between wells, impairing simulations of well behavior. Because the number of wells that can be drilled from a platform is fixed, infill drilling, often an important strategy for both secondary recovery and EOR, may not be possible. High costs and extended time before EOR production begins mean that offshore EOR projects must be planned and started early



□***Oil recovery mechanisms.***
(Adapted from Venuto PB, reference 2 and Donaldson EC et al, reference 5.)



□***Cost-performance comparison of major EOR methods.*** *(Adapted from Simandoux P, Champlon D and Velentin E: "Managing the Cost of Enhanced Oil Recovery," Revue de L'Institut Français du Pétrole 45, no. 1 (January-February 1990): 131-139.)*

enough so that production increases incrementally before primary and secondary production begins to decline. Otherwise, marginal costs may be too high to sustain profitability. However, this option must be balanced against other risks: insufficient reservoir description at early stages of field production and lack of time to acquire pilot test results to evaluate the EOR process.[4]

Various mechanisms thwart recovery of much of OOIP after secondary recovery.[5] Reservoir geologic heterogeneities may cause a large volume of mobile oil to be bypassed and remain within a field. This is a result of poor sweep efficiency when injected displacement water moves preferentially through higher permeability zones toward the production well. Even in regions that have been swept by large quantities of water, residual, immobile oil is held in the pore spaces by capillary forces.

Many techniques have been tried in the laboratory and field in hopes of recovering this additional oil. All employ one or more of three basic mechanisms for improving on waterdrive alone:

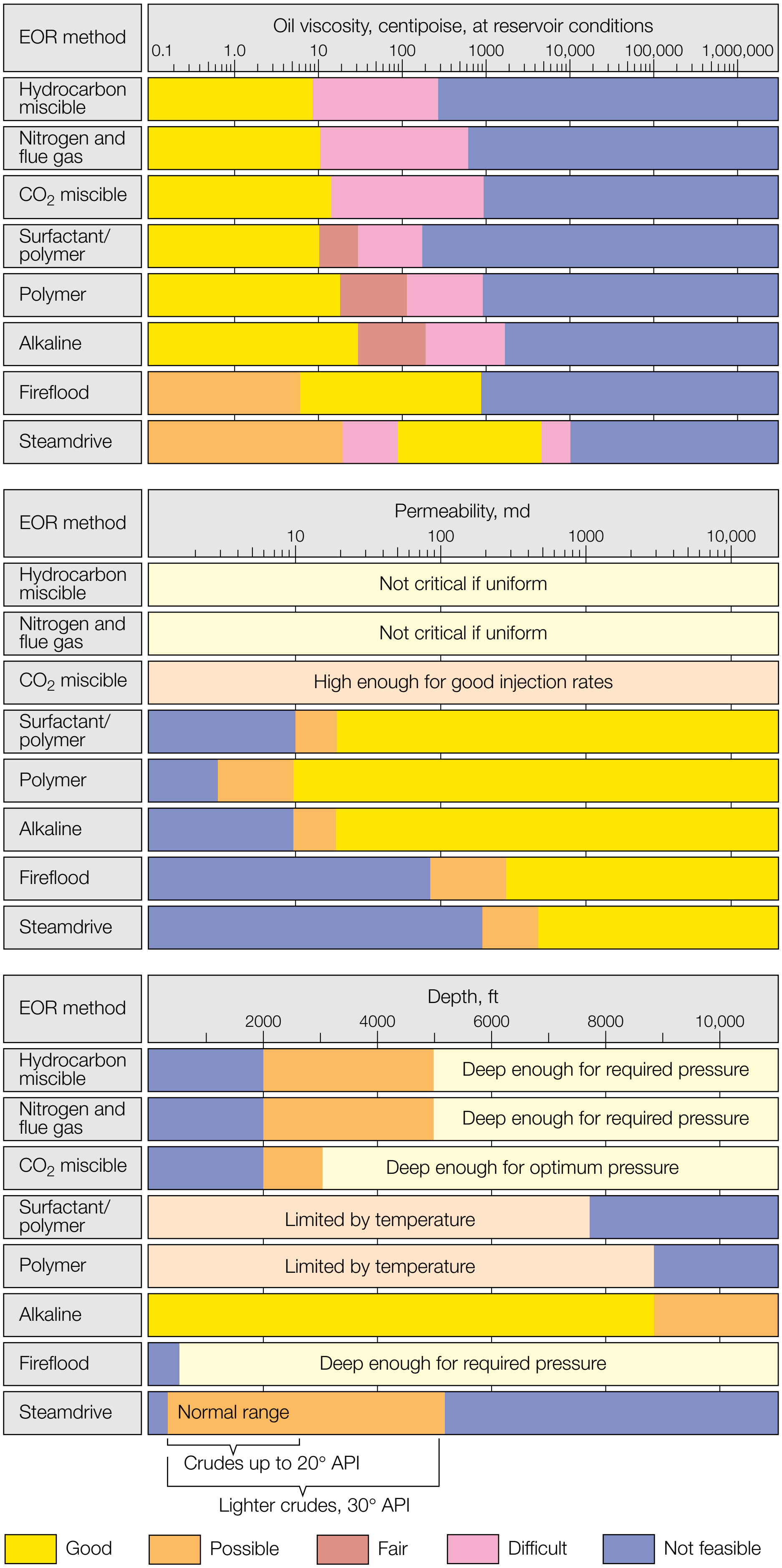
- Increase the mobility of the displacement medium by increasing the viscosity of the water, decreasing the viscosity of the oil, or both.
- Extract the oil with a solvent.
- Reduce the interfacial tension between the oil and water.

The three major EOR processes—thermal, miscible and chemical—are each subdivided into several categories. Among the three, thermal processes dominate, having the greatest certainty of success and potential application in about 70% of enhanced oil recovery worldwide. Thermal methods also give the highest recoveries at the lowest costs (*left*).

The term miscible means the mixing of two fluids—for instance, oil and a solvent such as carbon dioxide [CO_2]—into a single-phase fluid. It may also apply to a continuity between the oil and injected gas, due to a multiphase transition zone between the two. Use of miscible gasdrive has grown rapidly in recent years, and today the method accounts for about 18% of EOR applications worldwide. It has been successful at depths greater than 2000 ft [610 m] for CO_2 and greater than 3000 ft [915 m] for other gases.

EOR chemical processes, such as surfactant (detergent) flooding, have tantalized the industry with promises of significantly improved recovery. As yet, cost and technical problems have precluded them from mainstream application. Waiting in the

1. Smith RV: "Enhanced Oil Recovery Update," *Petroleum Engineer International* 60, 61, four-part series (November 1988 to March 1989).
2. Venuto PB: "Tailoring EOR Processes to Geologic Environments," *World Oil* 209 (November 1989): 61-68.
3. Venuto PB, reference 2.
Schmidt RL: "Thermal Enhanced Oil Recovery—Current Status and Future Needs," *Chemical Engineering Progress* (January 1990): 47-59.
4. Simandoux P and Valentin E: "Improved Recovery, a Strategic Option or Not?" Presented at the Offshore North Seas Conference, Stavanger, Norway, August 28-31, 1990.
5. Smith RV, reference 1.
Donaldson EC, Chilingarian GV and Yen TF (eds): *Enhanced Oil Recovery, II—Processes and Operations*, Developments in Petroleum Science. Amsterdam, The Netherlands: Elsevier Science Publishers, 1989.
Schmidt RL, reference 3.



Selection of EOR techniques by oil viscosity, permeability and depth. *(Adapted from Taber JJ and Martin FD, reference 6.)*

wings are processes like microbial EOR (MEOR) and some novel and exotic proposals; these await confirmation by lab and field experimentation and evaluation before taking their place as accepted practice.

Each EOR process is suited to a particular type of reservoir. Because unexpected or unknown reservoir characteristics cause most EOR failures, EOR begins with thorough geologic study. Technical rule-of-thumb screening criteria are available to aid preliminary evaluation of a reservoir's suitability for EOR (*left*). After these criteria are applied to a prospect, stringent economic analysis follows, generally through repeated reservoir simulations[6] (see "Trends in Reservoir Management," *page 8*).

Thermal

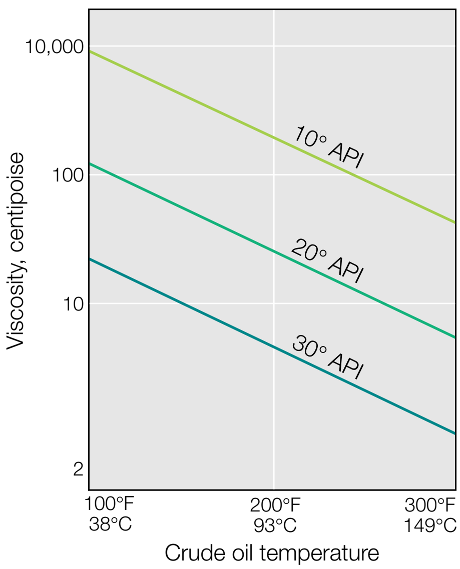
Thermal methods are the main means of recovering heavy oils, those with gravity less than 20° API, representing viscosities of 200 to 2000 centipoise (cp). Such heavy oils generally don't respond significantly to primary production or waterflooding so initial oil saturation is typically high at the start of a thermal recovery project. The principle of thermal recovery is simple: increasing the oil's temperature dramatically reduces its viscosity, improving the mobility ratio (*next page, left*). The two primary methods of heating reservoir oil are injection of fluid heated at the surface or production of heat directly within the reservoir by burning some of the oil in place.

Although the idea of heating reservoirs dates back more than 100 years, large-scale steamdrive projects began in heavy oil fields in the US in the early 1950s and were followed shortly by projects in The Netherlands and Venezuela. A relative of steamdrive is cyclic steam injection, also called steam soak or "huff and puff." It was discovered accidentally in 1960 during a Venezuelan recovery project. Cyclic steam recovery uses a single well for both injection and production. Steam is injected into a well for several days or weeks, then the well is shut in for several days to a month or more, the soak period. After this, the well is produced for up to six months, after which the process is repeated. The steam heats the rock and fluids surrounding the wellbore and also provides some drive pressure; by the time production resumes, the steam has condensed and oil and water are produced.

6. Taber JJ and Martin FD: "Technical Screening Guides for the Enhanced Recovery of Oil," paper SPE 12069, presented at the 58th SPE Annual Technical Conference and Exhibition, San Francisco, California, USA, October 5-8, 1983.
   Venuto PB, reference 2.
7. Taber JJ and Martin FD, reference 6.
   Smith RV, reference 1.
   Donaldson et al, reference 5.
   Venuto PB, reference 2.
   Schmidt RL, reference 3.

The advantage of "huff and puff" is the relatively short "huff" time so that the well is producing most of the time. The disadvantage is that only the reservoir near the wellbore is stimulated. This method therefore often has to be followed by continuous steam injection to drive oil toward a separate production well. Reservoir pressure, dictated by depth, imposes a limit on steamflooding: higher pressures require more fuel to generate higher temperatures on the surface to produce saturated steam needed for efficient steamflood. The higher temperature also leads to greater heat losses.

The recovery mechanism of steamflooding is complex. Besides viscosity reduction, the second most important recovery mechanism is steam distillation of lighter compo-

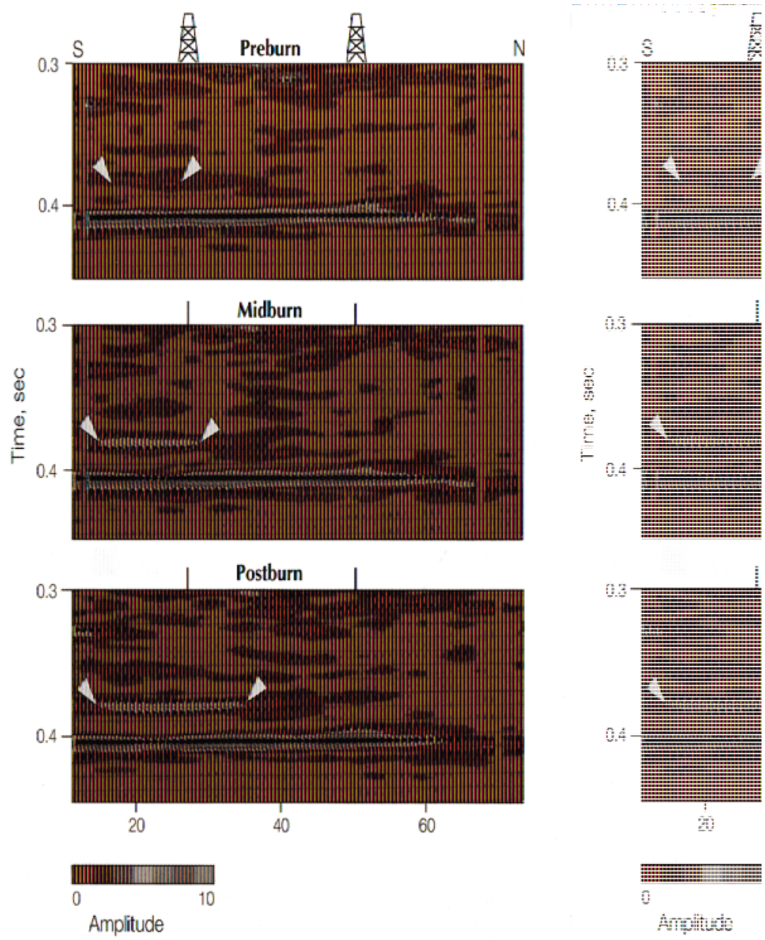


□***The empirical relationship of crude oil viscosity and temperature depends on oil composition.*** *(Adapted from Lake LW, reference 10.)*

nents of the oil which form a solvent bank ahead of the steam. Other factors are thermal expansion, solution gasdrive and miscible and emulsion drive. Steamflooding has been tested in light oil reservoirs where the viscosity mechanism plays a minor role and distillation to solvents predominates. Some field tests of light oil steamfloods have shown virtually 100% recovery of oil from zones reached by the steam.

All is not roses with steamflooding, as numerous technical problems may combine to make a recovery project uneconomical, inefficient or even dangerous. Heat losses in surface equipment, in the wellbore, in rocks around the reservoir, in connate water and in the gas cap may defeat the process. Surface equipment must be insulated, as well as downhole tubing below 1500 ft [460 m]. Thermal expansion may damage downhole equipment and cause cement failure. Steam is very reactive, causing pipe corrosion and scaling, mineralogical dissolution or reprecipitation, clay swelling and changes in permeabilities. Steam is more mobile than oil, overriding the oil and channeling through thief zones; no satisfactory methods have been found to improve sweep efficiency. Steam is usually generated by burning natural gas, but if lease crude is used—typically at about one barrel of crude for three or four barrels of oil recovered—the air pollution byproduct may be costly to control.

The other significant thermal recovery process, in-situ combustion or fireflooding, attempts to recover oil by igniting a portion of the in-place crude by injecting air or oxygen or by chemical or electrical means (*below*). Fireflooding appears attractive: it is thermally more efficient than steam, has no depth restriction and is well suited to relatively thin (less than 25 ft [8 m]) reservoir sands. But in practice it is not so simple. Capital costs are high, the process is extremely complicated and difficult to predict or control, and operational problems from the high temperatures include cement failures, sanding/erosion, corrosion at both injection and production wells because of oxygen and moisture, and high gas production rate. Despite some successes and more than 30 years of laboratory and field trials, in-situ combustion applications have not increased.[7]



□***Changes in a 3D seismic section for "preburn," "midburn" and "postburn." The bright spot—an increase in envelope amplitude, marked by arrowheads—appeared at midburn time and expanded by postburn time. Below the bright spot is a dim spot, caused by a decrease in envelope amplitude. The bright spot is caused by increased gas saturation along the top of the reservoir boundary. The dim spot shows good correlation with the burn volume in distribution and direction, as determined by core analysis. From studies like these, seismic data can be used to map an estimated burn thickness.*** *(Courtesy of the Society of Exploration Geophysicists. From Greaves RJ and Fulp TJ: "Three-dimensional Seismic Monitoring of an Enhanced Oil Recovery Process," Geophysics 52, no. 9 (September 1987): 1175-1187.)*

Miscible

The fastest growing EOR process, miscible flooding, uses a solvent that mixes fully with residual oil to overcome capillary forces and increase oil mobility. Displacement efficiency nears 100% where the solvent contacts the oil and miscibility occurs. The numerous successful solvents include liquified petroleum gas (LPG), nitrogen, CO_2, flue gas (mainly nitrogen and CO_2) and alcohol.

A sufficient supply of a particular solvent and the value of injected hydrocarbons, like natural gas, have considerable impact on the choice and economics of miscible flood projects. In Canada, for example, the abundance of natural gas makes that the choice, while the US has huge reserves of CO_2 in the western states that have been tapped for EOR in the Permian Basin fields of west Texas.

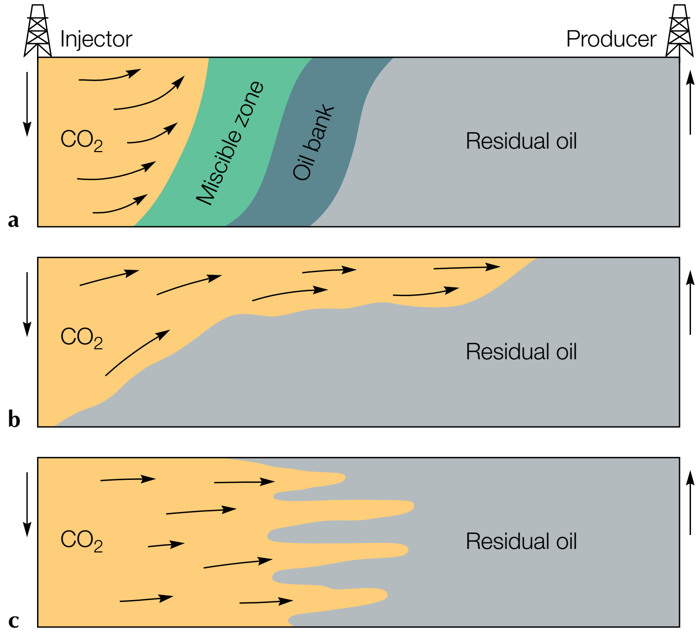
Miscible displacement EOR can be subdivided into three significant processes: miscible slug, enriched gas and high-pressure lean gas, including CO_2. For each of these processes, there is a range of pressures, or depths, temperatures and oil gravities necessary to achieve and maintain miscibility. Solvents have much lower viscosity than oil, so reservoir stratification—vertical and horizontal permeability contrast—strongly affects sweep efficiency. Early breakthrough, bypassing substantial amounts of oil, and viscous fingering problems have plagued many field projects involving the four miscible displacement processes:

- In the miscible slug process, a slug of liquid hydrocarbons, about half the reservoir pore volume (PV), is injected and mixes with the oil on contact. This is followed by water or chase gas to push the slug through the reservoir.
- For the enriched, or condensing, gas process, 10 to 20% PV of natural gas, enriched with intermediate molecular weight hydrocarbons, is injected, followed by lean gas and, in some cases, water. At the proper reservoir pressure, the C_2–C_6 components transfer from the enriched gas to the oil, forming a miscible solvent bank.
- Similarly, in vaporizing gasdrive, lean gas is injected at high pressure, 3000 to 6000 pounds per square inch gauge, and C_2–C_6 components from the oil are vaporized and mutually exchanged between the oil and gas during multiple contacts, eventually forming a miscible slug.

Carbon dioxide is a special case of high-pressure miscible recovery. This gas is highly soluble in crude oil, swelling the oil and reducing its viscosity, while simultaneously extracting lighter hydrocarbons by vaporization. The displacing gas front, enriched by vaporized hydrocarbons through multiple contacts, forms a miscible slug as long as minimum miscibility pressure (MMP) is maintained. Since CO_2 can extract heavier components, it is miscible with crude oils having fewer C_2–C_6 components. Carbon dioxide has a lower MMP than natural gas, nitrogen or flue gas, and therefore can be applied in shallower (lower pressure) wells.

A major problem with miscible gasflood EOR is the adverse mobility ratio caused by the low viscosity of the typical injectant gas compared to oil, perhaps by one or two orders of magnitude. The result is an unstable front between the gas and oil which allows viscous fingers to form and propagate through the displaced fluid, leaving much of the hydrocarbon uncontacted (*above*). Today, the primary means of attacking this problem is the water-alternating-gas (WAG) technique. In this process, waterflood and gasflood are alternated, with the design parameters being timing and the ratio of water to gas. WAG claims the virtues of decreasing the mobility of the gas, maintaining pressure and saving operating costs by substituting inexpensive water for relatively expensive gas. Ideally, the gas provides miscibility and the water improves sweep efficiency. However, one study of WAG in 15 CO_2 flood projects showed lower recoveries than for cases using a single injection of CO_2 followed by a waterflood. Gravity segregation between water and gas is thought to compromise the effectiveness of the WAG process.[8]

Performance of many EOR techniques suffers from differences in mobility between the EOR product and the oil it is supposed to recover. One possible solution to this is foam, which is dispersed gas bubbles in a liquid. Foam can reduce reservoir gas phase permeability to less than 1% of its original value. Typical surfactant-based foams can last indefinitely. Such foams have been used for mobility control miscible gas injection and steamfloods with mixed results. Problems include abnormally high injector-to-producer pressure differentials required for propagation, rapid changes in foam stability and quality as it migrates away from the injection well and foam breakdown in small pores.



Phase behavior and flow dynamics in miscible flooding (a) for ideal performance, (b) during the influence of fluid density and (c) in the setting of viscosity contrasts, which produce fingering of the EOR gas into oil. *(Adapted from Venuto PB, reference 2.)*

8. Taber JJ and Martin FD, reference 6.
   Smith RV, reference 1.
   Donaldson et al, reference 5.
   Stosur G, Singer M, Luhning R and Yurk W: “Enhanced Oil Recovery in North America: Status and Prospects,” *Energy Sources* 12, no. 4 (1990): 429-437.
9. Taber JJ and Martin FD, reference 6.
   Smith RV, reference 1.
10. Taber JJ and Martin FD, reference 6.
    Lake LW: *Enhanced Oil Recovery.* Englewood Cliffs, New Jersey, USA: Prentice-Hall, Inc., 1989.
11. Bondor PL: “Dilute Surfactant Flooding for North Sea Applications—Technical and Economics Considerations,” *Proceedings of the 6th European Symposium on Improved Oil Recovery*, Stavanger, Norway, May 21-23, 1991, volume 2: 749-758.
12. Taber JJ and Martin FD, reference 6.
    Smith RV, reference 1.
    Venuto PB, reference 2.
    Lake LW, reference 10.
13. Donaldson et al, reference 5.
    Simkin EM and Surguchev ML: “Advanced Vibroseismic Technique for Water Flooded Reservoir Stimulation, Mechanism and Field Tests Results,” *Proceedings of the 6th European Symposium on Improved Oil Recovery*, Stavanger, Norway, May 21-23, 1991, volume 1: 233-241.

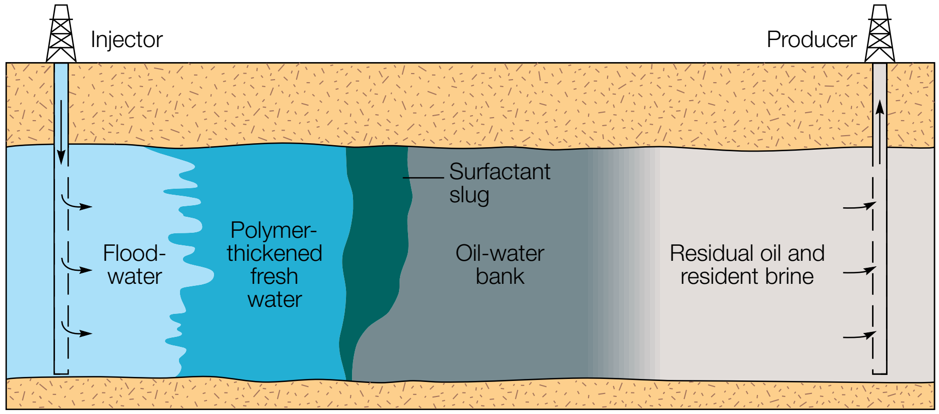
Chemical

Chemicals used in EOR include polymers, surfactants and alkalis. All are mixed with water and, occasionally, other chemicals before injection. Broadly speaking, targets for chemical recovery are crudes in the range between the heavy oils recovered by thermal processes and light oils recovered by miscible gas injection.

Polymer flooding is simply an accompaniment to waterflooding. It is the most commonly used chemical enhancement process since it is easy to apply and requires relatively small investment. Although polymer flooding increases recovery by a modest amount, on the order of 5%, it can yield solid profits under the right circumstances. Adding high molecular weight polymers increases the viscosity of water and, with some polymers, reduces the aqueous phase permeability without changing the relative permeability to oil. This can greatly improve waterflood volumetric sweep efficiency. Polymer concentrations are 100 to 1000 parts per million (ppm) and treatment may require injection of 15 to 25% PV over several years followed by a typical waterflood.[9] Cross linking, or gelling, polymers in situ with metallic ions can augment performance in sweep profile control—helping to plug high conductivity zones or minor fractures that degrade sweep efficiency. The main drawbacks to the use of polymers are their high cost and the low injection rate caused by high viscosity (which impacts economic rate of return), degradation at higher temperatures, intolerance to high salinity, polymer deterioration from shear stress imparted by pumping, flow through tubulars and perforations, and long-term instability in the reservoir environment.

Surfactant flooding, also known as detergent, micellar-polymer or microemulsion flooding, uses low concentrations of surfactants in water to reduce the interfacial tension between oil and water. Although the idea has been around since the 1920s, serious research and field trials did not start until 20 years ago, and uniformly profitable field performance is still elusive. Of all EOR processes, surfactant floods may be riskiest, involving the most difficult design decisions, requiring large capital investments, and being strongly affected by reservoir heterogeneities. For these reasons, and as a result of marginal field performance, interest in surfactant flooding has declined.

A surfactant flood must be designed for a specific crude oil in a specific reservoir taking into account such factors as salinity, temperature, pressure and clay content.[10] Generally, multiple slugs are used. Surfactant performance is optimal over a narrow salinity range and is subject to adsorption and retention through ionic exchange with reservoir rocks. To avoid these problems, the first slug may be a preflush water solution. However, it is often ineffective. The second slug, perhaps 10 to 30% PV, contains the surface active agent (5 to 10% by volume), hydrocarbons, electrolyte and cosolvent, usually alcohol. This is followed by a slug of polymer-thickened water for mobility control and, finally, typical waterflood (*above*).



Surfactant-polymer flooding, showing the surfactant slug on its way toward the producer, pushed by polymer-thickened fresh water and floodwater from the injector well. *(Adapted from Donaldson EC et al, reference 5.)*

Koninklijke-Shell Exploratie en Produktie Laboratorium in Rijswijk, The Netherlands, developed a surfactant capable of being injected in low concentrations (less than 1% by volume) in seawater in an offshore environment during late secondary recovery waterfloods.[11] Shell's analysis of the economics of implementing this technique in a moderately sized North Sea field—100 million stock-tank barrels of OOIP—is revealing. Shell found that high front-end capital costs would include building a chemical plant to manufacture the product and additional dedicated floating facilities to handle injection and production. The surfactant cost alone was $18 per barrel of incremental oil recovered, undiscounted at an estimated 9 kilograms (kg) [20 lb] of product injected for each barrel of oil. Projections showed that front-end investment of $750 million would be incurred in front-end capital costs and chemicals injected prior to the production of significant amounts of incremental oil. The analyzed technical cost came to $90 per barrel assuming a 15% discount rate (cost of capital).

The caustic or alkali flooding process relies on a chemical reaction between the caustic and organic acids in the crude oil to produce in-situ surfactants that lower interfacial tension between water and oil. Other mechanisms that may enhance recovery are changing rock from oil-wet to water-wet, which lowers interfacial tension, and emulsification, which lowers viscosity. Alkalies such as sodium or potassium hydroxide are used. Caustics can react strongly with minerals in the connate water and with the reservoir rocks to the detriment of the process. This complex process is poorly understood; it has had some technical successes but no great financial successes.[12]

Besides the mainstream techniques discussed, many interesting ideas have been proposed and tried. Today, most of these are not economical or have some technical flaw:

- Microbial EOR injects bacteria and nutrients into the reservoir where the bacteria multiply and biochemically manufacture polymers and surfactants; this technique is still unproved, although some successes have been reported.
- Thermal enhancements include downhole steam generation, mixing gas and solvents with steam, downhole radio frequency (induction) heating, nuclear steam generation and jet leaching by high-pressure hot water with additives.
- Other ideas: injection of direct current for electro-osmotic effect, chemical alteration of micellar configuration of in-situ petroleum, earthquake simulation using high-powered surface vibrators (successful in the USSR[13]).

EOR technology does not seem to be on the threshold of any dramatic technological breakthroughs. Instead progress will probably come through gradual evolution, stimulated by growing motivation to recover more oil from known fields. The major contribution to EOR is likely to be from the constantly improving art of reservoir characterization for predicting EOR response and from horizontal drilling. —SM