EOR Screening Criteria Revisited—Part 2: Applications and Impact of Oil Prices

J.J. Taber, SPE, **F.D. Martin,** SPE, and **R.S. Seright,** SPE,
New Mexico Petroleum Recovery Research Center

Summary

Screening criteria are useful for cursory examination of many candidate reservoirs before expensive reservoir descriptions and economic evaluations are done. We have used our CO_2 screening criteria to estimate the total quantity of CO_2 that might be needed for the oil reservoirs of the world. If only depth and oil gravity are considered, it appears that about 80% of the world's reservoirs could qualify for some type of CO_2 injection.

Because the decisions on future EOR projects are based more on economics than on screening criteria, future oil prices are important. Therefore, we examined the impact of oil prices on EOR activities by comparing the actual EOR oil production to that predicted by earlier Natl. Petroleum Council (NPC) reports. Although the lower prices since 1986 have reduced the number of EOR projects, the actual incremental production has been very close to that predicted for U.S. \$20/bbl in the 1984 NPC report. Incremental oil production from CO_2 flooding continues to increase, and now actually exceeds the predictions made for **U.S.** \$20 oil in the NPC report, even though oil prices have been at approximately that level for some time.

Utilization of Screening Guides

With the reservoir management practices of today, engineers consider the various IOR/EOR options much earlier in the productive life of a field. For many fields, the decision is not whether, but when, to inject something. Obviously, economics always play the major role in "go/no-go" decisions for expensive injection projects, but a cursory examination with the technical criteria **(Tables 1 through 7)** is helpful to rule out the less-likely candidates. The criteria are also useful for surveys of a large number of fields to determine whether specific gases or liquids could be used for oil recovery if an injectant was available at a low cost. This application of the CO_2 screening criteria is described in the next section.

Estimation of the Worldwide Quantity of CO_2 That Could Be Used for Oil Recovery. The miscible and immiscible screening criteria for CO_2 flooding in Table **3** of this paper and in Table 3 of Ref. 1 were used to make a rough estimate of the total quantity of CO_2 that would be needed to recover oil from qualified oil reservoirs throughout the world. The estimate was made for the IEA Greenhouse Gas R&D Program as part of their ongoing search for ways to store or dispose of very large amounts of CO_2 in case that becomes necessary to avert global warming. The potential for either miscible or immiscible CO_2 flooding for almost 1,000 oil fields was estimated by use of depth and oil-gravity data published in a recent survey.[2] The percent of the fields in each country that met the criteria in Table **3** for either miscible or immiscible CO_2 flooding was determined and combined with that country's oil reserves to estimate the incremental oil recovery and CO_2 requirements. Assuming that one-half of the potential new miscible projects would be carried out as more-efficient enhanced secondary operations, an average recovery factor of 22% original oil in place (OOIP) was used, and 10% recovery was assumed for the immiscible projects. A CO_2 utilization factor of **6** Mcf/incremental bbl was assumed for all estimates. This estimated oil recovery for each country was then totaled by region, and all the regions were totaled in **Table 8** to provide the world totals.[3] The basis for the assumed incremental oil recovery percentage and CO_2 utilization factors and other details are given in Ref. **3.**

Economics was not a part of this initial hypothetical estimate. Although pure CO_2 can be obtained from power-plant flue gases (which contain only 9 to 12% CO_2), the costs of separation and compression are much higher than the cost of CO_2 in the Permian Basin of the U.S.[3-5] For this study, we assumed that pure, supercritical CO_2 was available (presumably by pipeline from power plants) for each of the fields and/or regions of the world. Table 8 shows that about 67 billion tons of CO_2 would be required to produce 206 billion bbl of additional oil. The country-by-country results and other details (including separate sections on the costs of CO_2 flooding) are given in Ref. **3.** Although not much better than an educated guess with many qualifying numbers, our estimate agrees well with other estimates of the quantity of CO_2 that could be stored (or disposed **of)** in oil reservoirs.[3]

Although this is a very large amount of CO_2, when the CO_2 demand is spread over the several decades that would be required for the hypothetical CO_2 flooding projects, it would reduce worldwide power-plant CO_2 emissions into the atmosphere by only a few percent per year. Therefore, more open-ended CO_2 disposal methods (such as the more-costly deep-ocean disposal) will probably be needed if the complex general circulation models of the atmosphere ever prove conclusively that global warming from excess CO_2 is under way.[6,7] However, from the viewpoint of overall net cost, one of the most efficient CO_2 disposal/storage systems would be the combined injection of CO_2 into oil reservoirs and into any aquifers in the same or nearby fields.[3,8] By including aquifers, this potential for underground CO_2 storage would be increased significantly, and the quantity sequestered could have a significant impact on reducing the atmospheric CO_2 emissions from the world's power plants.

Impact of Oil Prices on EOR

Major new EOR projects will be started only if they appear profitable. This depends on the perception of future oil price. Therefore, the relationship between future oil prices and EOR was a major thrust of the two NPC reports.[9,10] These extensive studies used as much laboratory and field information as possible to predict the EOR production in the future for different ranges of oil prices. Now, it is possible to compare the NPC predictions with actual oil production to date. These comparisons were made recently to see how oil prices might affect oil recovery from future CO_2 projects? We have extended these graphical comparisons and reproduced them here as **Figs. 1 through 3.** In general, the figures confirm that EOR production increases when prices increase and EOR production declines when prices fall, but not to the extent predicted. There is a time lag before the effect is noted. Figs. 1 and 2 show that total EOR production did increase in the early 1980's when oil prices were high. This was in response to an increase in the number of projects during this period when prices of up to U.S. \$50/bbl or more were predicted. Although the rate of increase slowed in 1986 when oil prices dropped precipitously, EOR production did not decline until 1994, after several years of low oil prices (i.e., less than U.S. \$20/bbl).[11]

The 1984 predictions were made while oil prices were high ($\approx$U.S. \$30/bbl), but they were not nearly as optimistic as those made in 1976 when oil prices were lower. However, the 1984 predictions benefited from experience gained from the field projects conducted in the interim. The only price common to both NPC reports is U.S. \$20/bbl. The 1976 U.S. \$20/bbl prediction would be off the scale by 1990 if plotted on the 1984 graph of Fig. 2. However, the U.S. \$20/bbl prediction of 1984 is close to the U.S. \$10/bbl value of 1976. Note that the actual oil production does track predictions

Original SPE manuscript received for review 16 May 1996. Revised manuscript received 20 May 1997. Paper peer approved 6 June 1997. Paper (SPE 39234) first presented as part of SPE 35365 at the 1996 SPE/DOE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, 21-24 April.

TABLE 1—NITROGEN AND FLUE-GAS FLOODING

Description

Nitrogen and flue gas are oil recovery methods that use these inexpensive nonhydrocarbon gases to displace oil in systems that may be either miscible or immiscible depending on the pressure and oil composition (see Table 3 of Ref. 1 for immiscible criteria). Because of their low cost, large volumes of these gases may be injected. Nitrogen and flue gas are also considered for use as chase gases in hydrocarbon-miscible and CO_2 floods.

Mechanisms

Nitrogen and flue gas flooding recover oil by (1) vaporizing the lighter components of the crude oil and generating miscibility if the pressure is high enough; (2) providing a gas drive where a significant portion of the reservoir volume is filled with low-cost gases, and (3) enhancing gravity drainage in dipping reservoirs (miscible or immiscible).

Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>35	38 to 54 (miscible)
Viscosity, cp	<0.4	0.07 to 0.3
Composition	High percentage of light hydrocarbons	
Reservoir		
Oil saturation, % PV	>40	59 to 80
Type of formation	Sandstone or carbonate with few fractures and high permeability streaks	
Net thickness	Relatively thin unless formation is dipping	
Average permeability	Not critical	
Depth, ft	>6,000	10,000 to 18,500
Temperature, °F	Not critical for screening purposes, even though the deep reservoirs required to accommodate the high pressure will have high temperatures.	

Limitations

Developed miscibility can only be achieved with light oils and at very high pressures; therefore, deep reservoirs are needed. A steeply dipping reservoir is desired to permit gravity stabilization of the displacement, which has an unfavorable mobility ratio. For miscible or immiscible enhanced gravity drainage, a dipping reservoir may be crucial to the success of the project.

Problems

Viscous fingering results in poor vertical and horizontal sweep efficiency. The nonhydrocarbon gases must be separated from the saleable produced gas. Injection of flue gas has caused corrosion problems in the past. At present, nitrogen is being injected into large successful projects that formerly used flue gas.

TABLE 2—HYDROCARBON-MISCIBLE FLOODING

Description

Hydrocarbon-miscible flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood. Three different methods have been used. The first-contact miscible method uses about 5% PV slug of liquefied petroleum gas (LPG), such as propane, followed by natural gas or gas and water. A second method, called enriched (condensing) gas drive, consists of injecting a 10 to 20% PV slug of natural gas that is enriched with ethane through hexane (Cp through C_6), followed by lean gas (dry, mostly methane) and possibly water. The enriching components are transferred from the gas to the oil. The third and most common method, called high-pressure (vaporizing) gas drive, consists of injecting lean gas at high pressure to vaporize C_2 through C_6 components from the crude oil being displaced. A combination of condensing/vaporizing mechanisms also occurs at many reservoir conditions, even though we usually think that one process is dominant. Immiscible criteria are given in Table 3 of Ref 1.

Mechanisms

Hydrocarbon miscible flooding recovers crude oil by (1) generating miscibility (in the condensing and vaporizing gas drive); (2) increasing the oil volume (swelling); (3) decreasing the oil viscosity; and (4) immiscible gas displacement, especially enhanced gravity drainage with the right reservoir conditions.

Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>23	24 to 54 (miscible)
Viscosity, cp	< 3	0.04 to 2.3
Composition	High percentage of light hydrocarbons	
Reservoir		
Oil saturation, % PV	>30	30 to 98
Type of formation	Sandstone or carbonate with a minimum of fractures and high-permeability streaks	
Net thickness	Relatively thin unless formation is dipping	
Average permeability	Not critical if uniform	
Depth, ft	>4,000	4,040 to 15,900
Temperature, °F	Temperature can have a significant effect on the minimum miscibility pressure (MMP); it normally raises the pressure required. However, this is accounted for in the deeper reservoirs that are needed to contain the high pressures for the lean gas drives.	

Limitations

The minimum depth is set by the pressure needed to maintain the generated miscibility. The required pressure ranges from about 1,200 psi for the LPG process to 4,000 to 5,000 psi for the high-pressure gas drive, depending on the oil. A steeply dipping formation is very desirable to permit some gravity stabilization of the displacement, which normally has an unfavorable mobility ratio.

Problems

Viscous fingering results in poor vertical and horizontal sweep efficiency. Large quantities of valuable hydrocarbons are required. Solvent may be trapped and not recovered in the LPG method.

TABLE 3—CO_2 FLOODING

Description

CO_2 flooding is carried out by injecting large quantities of CO_2 (30% or more of the hydrocarbon PV) into the reservoir. Although CO_2 is not first-contact miscible with the crude oil, the CO_2 extracts the light-to-intermediate components from the oil and, if the pressure is high enough, develops miscibility to displace the crude oil from the reservoir (MMP). Immiscible displacements are less effective, but they recover oil better than waterflooding (see below and Table 3 of Ref. 1 for immiscible criteria).

Mechanisms

CO_2 recovers crude oil by (1) swelling the crude oil (CO_2 is very soluble in high-gravity oils); (2) lowering the viscosity of the oil (much more effectively than N_2 or CH_4); (3) lowering the interfacial tension between the oil and the CO_2/oil phase in the near-miscible regions; and (4) generation of miscibility when pressure is high enough (see below).

Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>22	27 to 44
Viscosity, cp	<10	0.3 to 6
Composition	High percentage of intermediate hydrocarbons (especially C_5 to C_{12})	
Reservoir		
Oil saturation, % PV	>20	15 to 70
Type of formation	Sandstone or carbonate and relatively thin unless dipping.	
Average permeability	Not critical if sufficient injection rates can be maintained.	
Depth and temperature	For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP, which increases with temperature (see Fig. 7 of Ref. 1) and for heavier oils. Recommended depths for CO_2 floods of typical Permian Basin oils follow.	
	Oil Gravity, °API	Depth must be greater than (ft)
For CO_2-miscible flooding	>40	2,500
	32 to 39.9	2,800
	28 to 31.9	3,300
	22 to 27.9	4,000
	<22	Fails miscible, screen for immiscible*
For immiscible CO_2 flooding (lower oil recovery)	13 to 21.9	1,800
	<13	All oil reservoirs fail at any depth

At <1,800 ft, all reservoirs fail screening criteria for either miscible or immiscible flooding with supercritical CO_2.

Limitations

A good source of low-cost CO_2 is required.

Problems

Corrosion can cause problems, especially if there is early breakthrough of CO_2 in producing wells.

*All reservoirs with oils with gravities greater than 22°API can qualify for some immiscible displacement at pressures less than the MMP. In general, the reduced oil recovery will be proportional to the difference between the MMP and flooding pressure achieved. [These arbitrary criteria have been selected to provide a safety margin of approximately 500 feet above typical reservoir fracture depth for the required miscibility (MMP) pressures, and about 300 psi above the CO_2 critical pressure for the immiscible floods at the shallow depths. Reservoir temperature is included and assumed from depth. See Fig. 7 of Ref. 1 and text for the depth/temperature/MMP relationship.]

TABLE 4—MICELLAR/POLYMER, ASP, AND ALKALINE FLOODING

Description

Classic micellar/polymer flooding consists of injecting a slug that contains water, surfactant, polymer, electrolyte (salt), sometimes a cosolvent (alcohol), and possibly a hydrocarbon (oil). The size of the slug is often 5 to 15% PV for a high-surfactant-concentration system and 15 to 50% PV for low concentrations. The surfactant slug is followed by polymer-thickened water. The polymer concentration often ranges from 500 to 2,000 mg/L, and the volume of polymer solution injected may be 50% PV or more.

ASP flooding is similar except that much of the surfactant is replaced by low-cost alkali so the slugs can be much larger but overall cost is lower and polymer is usually incorporated in the larger, dilute slug. For alkaline flooding much of the injection water was treated with low concentrations of the alkaline agent and the surfactants were generated in situ by interaction with oil and rock. At this time (May 1997) we are not aware of any active alkali-only floods.

Mechanisms

All surfactant and alkaline flooding methods recover oil by (1) lowering the interfacial tension between oil and water; (2) solubilization of oil in some micellar systems; (3) emulsification of oil and water, especially in the alkaline methods; (4) wettability alteration (in the alkaline methods); and (5) mobility enhancement.

Technical Screening Guides

	Recommended
Crude Oil	
Gravity, °API	>20
Viscosity, cp	<35
Composition	Light intermediates are desirable for micellar/polymer. Organic acids needed to achieve lower interfacial tensions with alkaline methods.
Reservoir	
Oil saturation, % PV	>35
Type of formation	Sandstones preferred
Net thickness	Not critical
Average permeability, md	>10
Depth, ft	<about 9,000 ft (see Temperature)
Temperature, °F	<200

Limitations

An areal sweep of more than 50% on waterflood is desired. Relatively homogeneous formation is preferred. High amounts of anhydrite, gypsum, or clays are undesirable. Available systems provide optimum behavior over a narrow set of conditions. With commercially available surfactants, formation-water chlorides should be <20,000 ppm and divalent ions (Ca^{++} and Mg^{++}) <500 ppm.

Problems

Complex and expensive systems. Possibility of chromatographic separation of chemicals in reservoir. High adsorption of surfactant. Interactions between surfactant and polymer. Degradation of chemicals at high temperature.

TABLE 5—POLYMER FLOODING					
Description					
The objective of polymer flooding is to provide better displacement and volumetric sweep efficiencies during a waterflood. In polymer flooding, certain high-molecular-weight polymers (typically polyacrylamide or xanthan) are dissolved in the injection water to decrease water mobility. Polymer concentrations from 250 to 2,000 mg/L are used; properly sized treatments may require 25 to 60% reservoir PV.					
Mechanisms					
Polymers improve recovery by (1) increasing the viscosity of water; (2) decreasing the mobility of water; and (3) contacting a larger volume of the reservoir.					
Technical Screening Guides*					
	Wide-Range Recommendation			Range of Current Field Projects	
Crude Oil					
Gravity, °API	>15			14 to 43	
Viscosity, cp	<150 (preferably <100 and >10)			1 to 80	
Composition	Not critical				
Reservoir					
Oil saturation, % PV	>50			50 to 92	
Type of formation	Sandstones preferred but can be used in carbonates				
Net thickness	Not critical				
Average permeability, md	>10 md**			10 to 15,000	
Depth, ft	<9,000 (see Temperature)			1,300 to 9,600	
Temperature, °F	<200 to minimize degradation			80 to 185	
Properties of Polymer-Flood Field Projects					
Property	1980's median (171 projects)	Marmul	Oerrel	Courtenay	Daqing
Oil/water viscosity ratio at reservoir temperature	9.4	114	39	50	15
Reservoir temperature, °F	120	115	136	86	113
Permeability, md	75	15,000	2,000	2,000	870
% OOIP present at startup	76	≈92	81.5	78	71
WOR at startup	3	1	4	8	10
HPAM concentration, ppm	460	1,000	1,500	900	1,000
lbm polymer/acre-ft	25	373	162	520	271
Projected IOR, % OOIP	4.9	25***	-13	30	11
Projected bbl oil/lbm polymer	1.1	1.2	≈1.4	0.96	0.57
Projected bbl oil/acre-ft	27	461	≈230	499	155
Limitations/Problems					
See text for limitations and recommendations for overcoming problems.					

*These screening guides are vely broad. When identifying polymer-flood candidates, we recommend the reservoir characteristics and polymer-flood features be close to those of the four successful projects at the bottom of table.
**In reservoirs where the rock permeability is less than 50 md, the polymer may sweep only fractures effectively unless the polymer molecular weight is sufficiently low.
***IOR over primaly production for this case only. For the others, IOR is incremental over waterflooding.

of U.S. $10/bbl for 1976 and U.S. $20/bbl for 1984 in Figs. 1 and 2. Because oil prices were at or below U.S. $20/bbl for much of the period since 1986, the NPC predictions have merit. The impact of the lower oil prices since 1986 was finally felt in 1994 when EOR production (except for CO_2 flooding) dropped for the first time owing to fewer projects. The number of EOR projects has been declining steadily since 1986, the year that oil prices fell. However, **Table 9** shows that the profits from EOR projects did not decline during the recent years of low oil prices. For most EOR methods, Table 9 shows that there was an increase in the percentage of projects that were profitable, presumably because the less-efficient projects were discontinued. Also note on Figs. 1 and 2 that the EOR production rate started to increase again in 1996.[12]

The optimism that came from the much higher oil prices in the late 1970's and early 1980's was probably very fortunate for the CO_2 flooding industry in the **U.S.** During this period, the large natural CO_2 sources were developed and pipelines were built. The inexpensive, supercritical CO_2 has been flowing into the Permian Basin ever since. The pipelines are being extended, and more projects are being started as C02 flooding efficiencies continue to increase.[13,14] Fig. 3 shows that (after the long "incubation" period) CO_2 flooding has now exceeded the NPC prediction for oil prices of U.S. $20/bbl. This is in spite of the fact that oil prices were near or less than U.S. $20/bbl for much of the time since 1986.

Future Technical and Economic Improvements Expected

Even with the low oil prices, there are many technological advances that should continue to improve the outlook for EOR and IOR. These include (1) three-dimensional seismic—to determine where the target oil is located, in old as well as new fields; (2) use of horizontal injection as well as production wells[15]; (3) cheaper horizontal injection wells with multilaterals, short radius, and those used in lieu of more costly infill drilling; (4) more efficient reservoir simulation methods; and (5) foam for mobility control, especially in CO_2 flooding. These and other technological advances are expected to improve the process efficiency and cost effectiveness of EOR methods in the future.

Conclusions

1. The CO_2 screening criteria were used to estimate the capacity of the world's oil reservoirs for the storage/disposal of CO_2. If only depth and oil gravity are considered, it appears that about 80% of the world's reservoirs could qualify for some type of CO_2 injection to produce incremental oil.
2. The impact of oil prices on EOR production in the U.S. was considered by comparing the recent EOR production to that predicted by the NPC reports for various oil prices. Although lower oil prices since 1986 have reduced the number of EOR projects, the actual incremental production has been very close to that predicted for U.S. $20/bbl in the 1984 NPC report. Incremental oil production from CO_2 flooding has increased continuously and now exceeds the predictions for **U.S.** $20 oil in the NPC report.

Acknowledgments

We thank Tommy Moms for assistance in screening many reservoirs for C02 flooding potential, Mailin Seldal and Steve Anderson

TABLE 6—IN-SITU COMBUSTION

Description

In-situ combustion or fireflooding involves starting a fire in the reservoir and injecting air to sustain the burning of some of the crude oil. The most common technique is forward combustion in which the reservoir is ignited in an injection well, and air is injected to propagate the combustion front away from the well. One of the variations of this technique is a combination of forward combustion and waterflooding (COFCAW). A second technique is reverse combustion in which a fire is started in a well that will eventually become a producing well, and air injection is then switched to adjacent wells; however, no successful field trials have been completed for reverse combustion.

Mechanisms

In-situ combustion recovers crude oil by (1) the application of heat which is transferred downstream by conduction and convection, thus lowering the viscosity of the oil; (2) the products of steam distillation and thermal cracking that are carried forward to mix with and upgrade the crude; (3) burning coke that is produced from the heavy ends of the oil; and (4) the pressure supplied to the reservoir by injected air

Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	10 to 27	10 to 40
Viscosity, cp	<5,000	6 to 5,000
Composition	Some asphaltic components to aid coke deposition	
Reservoir		
Oil saturation, % PV	>50	62 to 94
Type of formation	Sand or sandstone with high porosity	
Net thickness, ft	>10	
Average permeability, md	>50	85 to 4,000
Depth, ft	<11,500	400 to 11,300
Temperature, °F	>100	100 to 22

Limitations

If sufficient coke is not deposited from the oil being burned, the combustion process will not be sustained; this prevents the application for high-gravity paraffinic oils. If excessive coke is deposited, the rate of advance of the combustion zone will be slow and the quantity of air required to sustain combustion will be high. Oil saturation and porosity must be high to minimize heat loss to rock. Process tends to sweep through upper part of reservoir so that sweep efficiency is poor in thick formations.

Problems

Adverse mobility ratio. Early breakthrough of the combustion front (and, 02-containing gas mixtures). Complex process that requires large capital investment and is difficult to control. Produced flue gases can present environmental problems. Operational problems, such as severe corrosion caused by low-pH hot water, serious oil/water emulsions, increased sand production, deposition of carbon or wax, and pipe failures in the producing wells as a result of the very high temperatures.

TABLE 7—STEAMFLOODING

Description

The steamdrive process or steamflooding involves continuous injection of about 80% quality steam to displace crude oil toward producing wells. Normal practice is to precede and accompany the steamdrive by a cyclic steam stimulation of the producing wells (called huff 'n' puff).

Mechanisms

Steam recovers crude oil by (1) heating the crude oil and reducing its viscosity; (2) supplying the pressure to drive oil to the producing well; and (3) steam distillation, especially in light crude oils

Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	8 to 25	8 to 27
Viscosity, cp	<100,000	10 to 137,000
Composition	Not critical but some light ends for steam distillation will help	
Reservoir		
Oil saturation, % PV	>40	35 to 90
Type of formation	Sand or sandstone with high porosity and permeability preferred	
Net thickness, ft	>20	
Average permeability, md	>200 md (see Transmissibility)	63 to 10,000
Transmissibility, md-ft/cp	>50	
Depth, ft	<5,000	150 to 4,500
Temperature, °F	Not critical	60 to 280

Limitations

Oil saturations must be quite high, and the pay zone should be more than 20 ft thick to minimize heat losses to adjacent formations. Lighter, less-viscous crude oils can be steamflooded but normally will not be if the reservoir responds to an ordinary waterflood. Steamflooding is primarily applicable to viscous oils in massive, high-permeability sandstones or unconsolidated sands. Because of excess heat losses in the wellbore, steamflooded reservoirs should be as shallow as possible as long as pressure for sufficient injection rates can be maintained. Steamflooding is not normally used in carbonate reservoirs. Because about one-third of the additional oil recovered is consumed to generate the required steam, the cost per incremental barrel of oil is high. A low percentage of water-sensitive clays is desired for good injectivity.

or help on the figures, and Liz Bustamante for valuable assistance in the preparation of this manuscript.

References

1. Taber J.J, Martin, F.D., and Seright, R.S.: "EOR Screening Criteria Revisited: Part 1—Introduction to Screening Criteria and Enhanced Recovery Field Projects," *SPERE* (August 1997).
2. "Worldwide production falls as market plays its wild cards," *Oil & Gas J. Worldwide Production Report: O&G J. Special* (27 December 1993) 37.
3. Taber, J.J.: "A Study of Technical Feasibility for the Utilization of CO_2 for Enhanced Oil Recovery," *The Utilization of Carbon Dioxide from Fossil Fuel Fired Power Stations*, P. Reimer (ed.), IEA Greenhouse Gas R&D Programme, Cheltenham, England (1994) Appendix B, 134–204.
4. Taber, J.J.: "Environmental Improvements and Better Economics in EOR Operations," *In Situ* (1990) 14, No. 4, 345.

TABLE 8—SUMMARY OF ESTIMATED WORLDWIDE CO_2 DEMAND/UTILIZATION AND POTENTIAL OIL RECOVERY					
	Potential Oil Production by CO_2 Injection*		Total CO_2 Required To Produce Incremental Oil*	Urgency, Timing or Regional Adjustment	Potential CO_2 Utilization
Oil-Producing Region	(billion bbl)	(billion tons)	(billion tons)	(%)	(billion tons)
Middle East	141.04	26.28	49.39	-12	43.47
Western Hemisphere	28.78	5.36	10.08	+10	11.09
Africa	13.18	2.46	4.62	-5	4.39
Eastern Europe and CIS	10.85	2.02	3.80	0	3.80
Asia-Pacific	8.59	1.60	3.01	-5	2.86
Western Europe	3.52	0.65	1.23	+15	1.42
World Totals	205.96	38.37	72.14	[-7]”	67.03

'From tables in Ref. 3.
“Net reduction in world total.

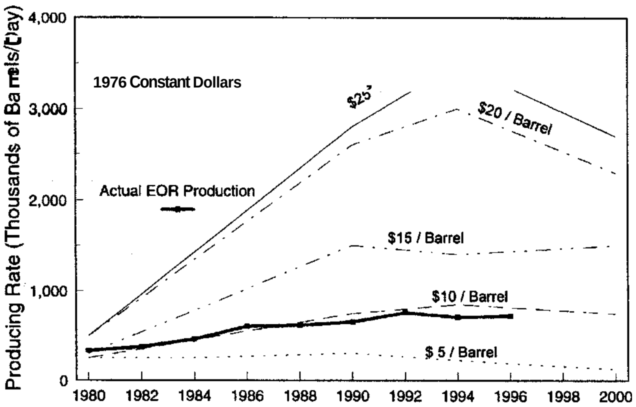


Fig. 1—Actual U.S. EOR production vs. 1976 NPC predictions (extended from Ref. 3, data from Refs. 9, 11, and 12).

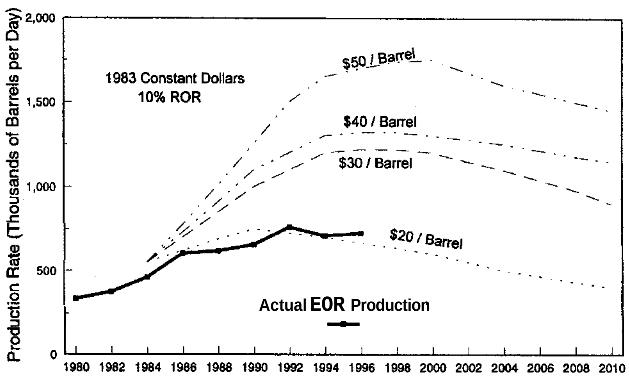


Fig. 2-Sensitivity of U.S. EOR production to the crude price predicted in 1984 NPC report (extended from Ref. 3, data from Refs. 10 through 12.)

5. Martin, F.D. and Taber, J.J.: “Carbon Dioxide Flooding,” *JPT* (April 1992) 396.
6. “It's Official: First Glimmer of Greenhouse Warming Seen,” *Science* (8 December 1995) 270, 1565.
7. “1995 the Warmest Year? Yes and No,” *Science* (12 January 1996) 271, 137.
8. Ribeiro, J. and Henry, B.: “Carbon Dioxide Disposal and Storage Technologies: Part I: Current Status; Part II: Prospective Study towards the Year 2020 and Beyond,” Inst. for Prospective Technological Studies, European Commission Joint Research Centre, Ispra, Italy (January 1995).
9. Haynes, H.J. *et al.*: *Enhanced Oil Recovery,* Natl. Petroleum Council, Industry Advisory Council to the U.S. Dept. of the Interior (1976).
10. Bailey, R.E. *et al.*: *Enhanced Oil Recovery,* Natl. Petroleum Council, Industry Advisory Committee to the U.S. Secretary of Energy, Washington, DC (1984).
11. Moritis, G.: “EOR Dips in U.S., but Remains a Significant Factor,” *Oil & Gas J.* (26 September 1994) 51.
12. Moritis, G.: “New Technology, Improved Economics Boost EOR Hopes,” *Oil & Gas J.* (15 April 1996) 39.
13. “CO_2 Activity Picks up in W. Texas, New Mexico,” *Oil & Gas J.* (17 July 1995) 26.
14. Hsu, C-F., Koinis, R.L., and Fox, C.E.: “Technology, Experience Speed CO_2 Flood Design,” *Oil & Gas J.* (23 October 1995) 51.
15. Taber, J.J. and Seright, R.S.: “Horizontal Injection and Production Wells for EOR or Waterflooding,” paper SPE 23952 presented at the 1992 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, 22–24 April.

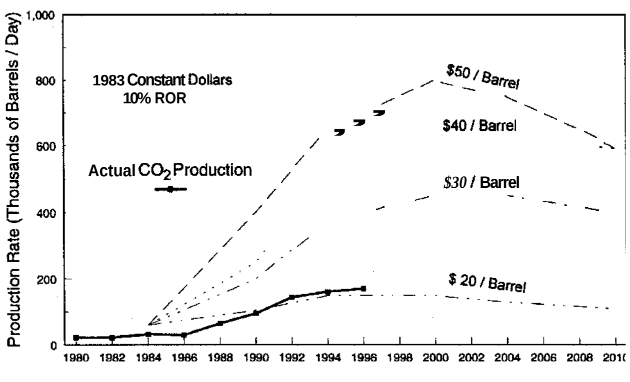


Fig. 3—Sensitivity of U.S. CO_2 production to crude oil price predicted by 1984 NPC report (extended from Ref. 3, data from Refs. 10 through 12).

TABLE 9—PROFITABILITY OF EOR PROJECTS IN THE U.S.				
	Percent Reported as Profitable			
Method	1982	1988	1990	1994
Steam	86	95	96	96
Combustion	65	78	88	80
Hot water	—	89	78	100
CO_2	21	66	81	81
Hydrocarbon	50	100	100	100
Nitrogen	100	100	100	100
Flue gas	100	100	100	—
Polymer	72	92	86	100
Micellar/Polymer	0	0	0	0
Alkaline or alkaline/surfactant	40	100	*	100

'One success.
Table updated from Refs. 4 and 11.

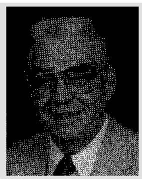
SI Metric Conversion Factors

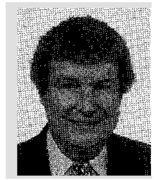
acre-ft	× 1.233 489	E−03	= ha
"API	141.5/(131.5 + °API)		= g/cm^3
bbl	× 1.589 873	E−01	= m^3
cp	× 1.0*	E−03	= Pa·s
ft	× 3.048*	E−01	= m
°F	(°F − 32)/1.8		= °C
lbm	× 4.535 924	E−01	= kg
md	× 9.869 233	E−04	= μm^2
psi	× 6.894 757	E+00	= kPa
ton	× 9.071 847	E−01	= Mg
tonne	× 1.0*	E+00	= Mg

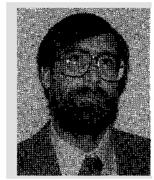
'Conversion factor is exact

SPERE

Joseph J. Taber was the first Director and is now Director Emeritus of the Petroleum Recovery Research Center (PRRC), a division of the New Mexico Inst. of Mining and Technology, where he continues his study of advanced recovery methods. He previously was a professor of petroleum engineering and chemistry at the U. of Pittsburgh and Senior Project Chemist with Gulf R&D Co., where he worked on new oil-recovery methods, especially horizontal wells for EOR and waterflooding. His recent work has dealt with CO_2 and EOR as they relate to environmental issues. He holds a BS degree from Muskingum (Ohio) College and a PhD degree from the U. of Pittsburgh. Taber was a 1989–90 Distinguished Lecturer on EOR and was named a Distinguished Member of SPE in 1994. **F. David Martin** is Manager and Chief Operating Officer of Strategic Technology Resources LLC, a technology-development company based in New Mexico. Martin has more than 35 years' petroleum industry experience. He worked at PRRC from 1976 to 1996, serving as Director during 1987–96. In that capacity, he supervised research on improved oil recovery, including C02 and chemical flooding. He holds a BS degree in chemical engineering from Texas Tech U. and an MS degree in petroleum engineering from New Mexico Tech. Martin has 16 patents and is the author of more than 50 technical papers related to petroleum production and of the chapter on "Reservoir Engineering" in the *Standard Handbook of Petroleum and Natural Gas Engineering.* Martin served as 1987–90 SPE Director for the Southwest Region and on several Society committees. **Randy Seright** is a Senior Engineer at the PRRC. He holds a PhD degree in chemical engineering from the U. of Wisconsin, Madison. Program Chairman for the 1998 SPE/DOE Improved Oil Recovery Symposium and a member of the Editorial Review Committee, Seright was a 1993–94 SPE Distinguished Lecturer and 1995 Program Chairman for the SPE International Symposium on Oilfield Chemistry.


Taber


Martin


Seright