ENHANCED OIL RECOVERY: POTENTIAL, PROCESSES, AND ECONOMICS

Tim D. Taylor
Sipes, Williamson & Associates, Inc.

ABSTRACT

This paper presents the potential for enhanced oil recovery, the processes by which this potential might be realized and the pertinent economic considerations, with special emphasis on the Permian Basin.

Of the more than 440 billion barrels of oil that have been discovered in the continental U.S., approximately 300 billion barrels will be left in the ground after primary and secondary recovery methods are terminated. Although not all of the remaining oil can be recovered by enhanced oil recovery methods, as much as 39 billion additional barrels can be extracted using currently available technology.

This paper will discuss the potential for enhanced oil recovery in the Permian Basin and the most technically and economically feasible methods for its recovery.

INTRODUCTION

Prior to the early 1970's, domestic oil reserves exceeded demand and, in fact, the industry operated under proration rules. New fields were being discovered to replace old fields that were depleting. Engineering manpower was being directed toward these new discoveries rather than toward coaxing more production from old fields. This situation changed dramatically when, in 1973, the first Arab oil embargo made us painfully aware that domestic production capacity had dropped below demand. No longer were new discoveries keeping up with the decline of old fields. Imported oil had become a necessity.

It then became clear that the oil remaining in developed fields could no longer be ignored. It was at this this time that engineering talent began to be directed toward more efficiently recovering this valuable resource. It has long been recognized that the naturally occurring producing mechanisms in a petroleum reservoir fall far short of recovering all the original-oil-in-place. These "primary" mechanisms are relatively inefficient and are expected to recover only about 24 percent of the U.S. domestic reserves. "Secondary" techniques, primarily waterflooding, have added about 8 percent to the total reserves that would have been produced using only primary recovery methods. The remaining "residual" oil is the target oil for enhanced recovery methods and the subject of this paper.

EOR POTENTIAL

As stated earlier, statistically only about 24 percent of known reserves will be recovered by primary producing mechanisms. This will be increased to a cumulative 32 percent by the combination of primary and secondary recovery leaving 68 percent of the original-oil-in-place as residual oil. Applying these percentages to the approximately 940 billion barrels of oil discovered in the lower 48 states yields an astounding 300 billion barrels that will be left in the ground after primary and secondary techniques are terminated. This is oil whose location is known and therefore does not have to be explored for, oil in reservoirs in which we have a history of production behavior, and the oil that is the target for enhanced recovery methods.

Obviously, not all of the residual oil can be recovered by EOR techniques. Many reservoirs are unsuitable for any type of improved recovery. Still, as much as

200 billion barrels of residual oil will remain in reservoirs suitable for some type of EOR. Of this amount, it is estimated that 15-39 billion barrels of oil are recoverable by existing technology. Table 1 shows the geographical distribution of EOR reserves. As can be seen, the greatest potential resides in South and West Texas and New Mexico with 6-18 billion barrels of recoverable EOR reserves. The majority of this is in the Permian Basin.

To put the 6-18 billion barrels of estimated recoverable EOR reserves in the West Texas area in perspective, one should consider that 100 years of drilling in Texas has resulted in 156 billion barrels of oil discovered. Of this amount, approximately 46 billion barrels have been produced and 8 billion remain as proven reserves. It is also interesting to note with all the drilling activity during the 1970's in Texas, less than 5 percent of our current production comes from fields discovered in that decade. As an example of our declining reserve base, Texas Railroad Commission District 8A had a peak oil production in 1975 of 369.77 million barrels. In 1981, that District's production was 253.24 million barrels, a 32 percent decrease from the peak year. Statewide, oil production has declined about 1 million barrels per day since 1972.

It is apparent that new discoveries will not arrest our declining production. The current oil "glut" has caused investments in EOR to suffer. But delays in investment now may mean that some candidate reservoirs are permanently abandoned. For enhanced recovery to become a factor in the domestic energy situation, our industry must believe in the long-term value of oil. The challenge we face is to turn at least some of this large resource into producible reserves.

PROCESSES

Considerable research has been conducted over a number of years in an effort to learn how to recover more of the residual oil. Three major groups of enhanced recovery processes have been developed to recover oil by means other than conventional primary and/or secondary methods. These major processes are Thermal, Chemical and Miscible.

Thermal

The thermal techniques (steam stimulation, steam flooding and in-situ combustion) account for about 70 percent of the world's present EOR production. These methods use heat to lower the viscosity of heavy oils. Thermal processes have been used extensively since the early 1950's, with most of the early work being concentrated on in-situ combustion. During the 1960's, the emphasis swung more toward the steam injection methods. Today steam flooding is the most commonly used thermal enhanced recovery method. However, since these processes are applicable primarily in shallow, heavy oil reservoirs, there is little application for them in West Texas.

Chemical

The chemical EOR methods, consisting primarily of polymer, surfactant and alkaline injections, are probably the least understood and have the greatest technical and economic risks. The chemical processes currently account for only about one percent of the incremental production from EOR methods in the United States. Research is continuing on these processes and there have been some applications in the Permian Basin but, generally, they are not suited to the heterogeneous carbonate reservoirs in this area.

Miscible

The third category of EOR processes is miscible gas flooding. Miscibility refers to the ability of fluids to mix with each other. Fluids that are not miscible tend to segregate according the their specific gravities. Fluids that are miscible dissolve into each other to form a single fluid under certain conditions of temperature and pressure. Since miscible fluids lessen the physical forces which make oil resistant to flow, the injection of such fluids makes the deplacement of oil highly efficient.

The miscible gas processes generally consist of hydrocarbon miscible, CO_2 miscible and nitrogen miscible. The nitrogen process is the least expensive but requires deep reservoirs with high pressures to achieve miscibility. Few Permian Basin reservoirs exhibit these characteristics. The hydrocarbon gas miscible projects are the most expensive because of the high cost of hydrocarbon fluids and the high reservoir pressure requirements.

It is generally accepted that the CO_2 miscible process is best suited for Permian Basin reservoirs. This is true because miscibility can be achieved in most of these reservoirs and the injectant, CO_2, is relatively inexpensive compared to hydrocarbon gases. At present, two major pipelines are under construction which will supply CO_2 to the Permian Basin. The first of these, scheduled for completion this year, is a 405 mile line from the Sheep Mountain area in southeastern Colorado to Seminole, Texas. The pipeline is a joint venture of ARCO Oil & Gas Co., Exxon Co., USA and Amerada Hess Corp. and is expected to have a capacity of approximately 500 MMCF per day.

Shell Oil, Mobil Oil and Continental Resources Co. plan the completion of a 480 mile pipeline from the McElmo Dome field in Colorado to the Permian Basin in 1984. The line will have a capacity of 1 Bcf per day although initial deliveries will be somewhat less. Amoco Pipeline Co. will firm up their plans within the next few months for building a CO_2 pipeline from the Bravo Dome area in northeastern New Mexico to West Texas. Although the recent softening of oil prices has delayed the planned start-up of some EOR projects in the Basin, the pipeline activity is an indicator of industry interest in the miscible CO_2 process.

ECONOMICS

In order to demonstrate the performance and economics of a West Texas CO_2 project, a set of economic cases was run on a hypothetical reservoir which has characteristics similar to many Permian Basin reservoirs. It was assumed that this reservoir is operated by an independent and that it is a mature waterflood nearing peak performance. The technical and economic assumptions made about this reservoir are shown in Table 2. The first economic case run was for continued waterflood operations. As can be seen in Table 3, the waterflood will yield an undiscounted future net income of $226 million.

A base CO_2 case with technical and economic assumptions as shown in Table 4 was run and compared to the waterflood case. Table 5 shows the cash flow summary for the CO_2 base case incremental to the waterflood case. This table shows an undiscounted future net income of $296 million for a 37.13 percent rate of return (ROR) on an incremental investment of $13.4 million. Capital costs on this table are spread over a number of years because all the CO_2 plant costs and compression facilities are not needed in the first year of the project. This investment schedule is somewhat different from other EOR processes which have a much higher percentage of first and second year investments and it provides an opportunity to terminate a poorly performing project before all capital investments are made. Also, the purchased CO_2 costs in this example case are spread over a ten year period and decrease with time. This is because, in the later injection years, the recycled CO_2 volume is large enough to offset much of the injection requirements.

Since initial CO_2 and oil prices will undoubtedly vary with the economy, selected economic cases were run to investigate the effect of these variables. Table 6 summarizes the effects of a $2.00/MCF starting price, initial oil prices of $28, $30 and $32/bbl, and a low recovery case on ROR and future net revenue. The oil price sensitivity cases were run incrementally to waterfloods having the same starting oil price.

The low recovery case has all variables the same as the base CO_2 case but recovers one-third the incremental oil. It was assumed that the reduction in expected ultimate recovery would occur late in the project life rather than uniformly over the project life. This is reasonable since the most likely reason for lower than predicted recovery would be due to the presence of previoulsy unidentified high permeability streaks in the reservoir that would preferentially accept injected CO_2. If this occurs, the incremental recovery in these high permeability streaks will be extremely efficient. In fact, early oil production in this type of reservoir could be much higher than expected. Since this production loss occurs late in the project life, there is little effect on present worth and ROR. If this situation occurs, injectivity and production tests can be run to identify the reason for the deviation from predictions and remedial action can be taken to change the pattern of injection, the injection rates, the injection interval, etc., in order to maximize recovery over the life of the project.

In conclusion, it is imperative to recognize that the greatest risk in an EOR project is poor engineering. If the reservoir is adequately characterized and carefully studied for conditions adverse to EOR and the process properly selected and designed, it will be possible to anticipate and therefore minimize the technical and economic risks. Advances in the understanding of the processes and the industry's growing experience should result in steadily increasing EOR activity in the Permian Basin.

BIBLIOGRAPHY

1. Norman J. Clark, Elements of Petroleum Reservoirs, (Society of Petroleum Engineers, 1960).

2. R. Dafter, Scraping the Barrel - The Worldwide Potential for Enhanced Oil Recovery, (The Financial Times Information Ltd., 1980).

3. "Enhanced Oil Recovery - An Analysis of the Potential for Enhanced Oil Recovery from Known Fields in the United States - 1976 to 2000," National Petroleum Council, December 1976.

4. Thomas C. Frick, Petroleum Production Handbook, Vol. II, (McGraw-Hill, 1962).

5. D. R. Phelps, T. D. Taylor and S. W. Daniel, "An Engineering Look at the Government Programs and Incentives Offered for Tertiary Projects," Society of Petroleum Engineers, Paper No. 9713, Presented at the 1981 Permian Basin Oil and Gas Recovery Symposium, Midland, Texas, March 12-13, 1981.

6. F. I. Stalkup, "Carbon Dioxide Miscible Flooding: Past, Present, and Outlook for the Future," Journal of Petroleum Technology, August 1978, pp 1102-1112.

7. H. K. van Poolen and Associates, Inc., Fundamentals of Enhanced Oil Recovery, (Penn Well Publishing Company, 1980).

8. W. R. Whitehead et al, Department of Petroleum Engineering, Louisiana State University, "Investigation of Enhanced Oil Recovery Through Use of Carbon Dioxide," U.S. Department of Energy, DOE/MC/03103-2, June 1980.

TABLE 1 — GEOGRAPHICAL DISTRIBUTION OF POTENTIAL EOR RESERVES

REGION	TARGET OIL	ESTIMATED EOR RECOVERY
Gulf Coast	25	1-5
S. & W. Texas & New Mexico	97	6-18
California	40	4-8
Oklahoma	20	2-4
Rockies	10	1-2
Other	14	1-2
		15-39

TABLE 2 — WATERFLOOD CASE

TECHNICAL ASSUMPTIONS

1. Reservoir type - hetergeneous carbonate
2. No. of wells - 30
3. Permeability - low (<4 md.)
4. OOIP - 50,000,000 bbls
5. Reservoir Pressure - 2,500 psi
6. Reservoir depth - 5,000 ft

ECONOMIC ASSUMPTIONS

1. All capital investments have been made
2. Initial oil price of $34/bbl. held constant for 2 years then escalated at 8%/yr. to a maximum of $75/bbl
3. Windfall profit tax rate of 50%

TABLE 3 CASH FLOW SUMMARY
WATERFLOOD CASE

YEAR	OPERATING COSTS (M$)	AD VALOREM TAXES (M$)	FUTURE NET INCOME (M$)	DISCOUNTED 18.000 PCT	CUM DISC 18.000 PCT
1983	524	219	6,137	5,650	5,650
1984	567	217	6,209	4,844	10,494
1985	612	223	6,441	4,258	14,752
1986	661	259	7,724	4,328	19,080
1987	714	275	8,174	3,881	22,961
1988	771	291	8,661	3,485	26,446
1989	833	309	9,171	3,127	29,573
1990	899	327	9,670	2,795	32,368
1991	972	342	10,069	2,466	34,834
1992	1,049	360	11,121	2,308	37,142
1993	1,133	377	12,769	2,246	39,388
1994	1,224	397	14,589	2,175	41,563
1995	1,267	410	15,408	1,946	43,509
1996	1,267	403	15,102	1,617	45,126
1997	1,267	397	14,888	1,351	46,477
1998	1,267	390	14,612	1,123	47,600
1999	1,267	384	14,335	934	48,534
2000	1,267	377	14,060	776	49,310
2001	1,267	370	13,784	645	49,955
2002	1,267	365	13,568	538	50,493
TOTAL	20,095	6,692	226,492	50,493	50,493

DISC NET REVENUE AT	8.000 PERCENT	101,961
	10.000 PERCENT	86,536
	15.000 PERCENT	60,567
	25.000 PERCENT	35,623

TABLE 4 — BASE CO_2 CASE

TECHNICAL ASSUMPTIONS

1. CO_2 slug size of 40% HCPV
2. Continuous CO_2 injection
3. CO_2 injection rate of 4 HCPV/yr.
4. CO_2 requirement of 8.0 Mcf/incremental bbl
5. 57% of injected CO_2 will be recycled
6. Two Mcf of CO_2 at surface conditions occupies one bbl of volume in reservoir
7. Produced hydrocarbon gas will be recycled with CO_2

ECONOMIC ASSUMPTIONS

1. Initial CO_2 cost of $1.35/Mcf, inflated at 8%/yr.
2. Recycle cost of $0.50/Mcf
3. Windfall profit tax rate of 30% for all oil above the statutory decline curve

TABLE 5 — INCREMENTAL CASH FLOW SUMMARY

CO_2 BASE CASE

(ALL VALUES EXPRESSED IN M$)

YEAR ENDS DEC 31	NET REV (AFT WPT SEV AD-VAL OPS)	PURCHASED CO_2 COSTS	CAPITAL COSTS	FUTURE NET INCOME	CUMULATIVE NET INCOME	CUM DISC NET INCOME 18.000 PCT
1983	-266	0	1,742	-2,008	-2,008	-1,849
1984	2,216	0	5,544	-3,328	-5,336	-4,445
1985	5,095	6,200	5,263	-6,368	-11,704	-8,655
1986	7,629	6,082	3,275	-1,728	-13,432	-9,623
1987	9,242	5,787	0	3,455	-9,977	-7,982
1988	9,759	5,163	4,705	-109	-10,086	-8,026
1989	11,317	40,37	0	7,280	-2,806	-5,543
1990	12,069	3,141	0	8,928	6,122	-2,963
1991	14,613	2,760	5,904	5,949	12,071	-1,506
1992	20,607	2,471	0	18,136	30,207	2,258
1993	21,766	1,626	0	20,140	50,347	5,800
1994	25,785	1,206	0	24,579	74,926	9,464
1995	33,287	0	0	33,287	108,213	13,669
1996	30,772	0	0	30,772	138,985	16,963
1997	30,986	0	0	30,986	169,971	19,774
1998	29,062	0	0	29,062	199,033	22,008
1999	27,506	0	0	27,506	226,539	23,800
2000	25,948	0	0	25,948	252,487	25,233
2001	21,458	0	0	21,458	273,945	26,237
2002	21,674	0	0	21,674	295,619	27,097
TOTAL	360,525	38,473	26,433	295,619	295,619	27,097

INCOME RATE OF RETURN 37.13 PCT

DISC NET REVENUE AT		
	8.000 PERCENT	98,323
	10.000 PERCENT	75,701
	15.000 PERCENT	39,834
	25.000 PERCENT	10,429

TABLE 6 — SUMMARY OF ECONOMIC SENSITIVITY CASES

	ROR (%)	Undiscounted Future Net Revenue (thousands of dollars)	Incremental Investment (thousands of dollars)
Base CO_2 Case	37.13	295,619	13,432
$2.00/Mcf CO_2	29.50	277,550	20,905
$32/bbl initial oil price	34.65	283,545	14,345
$30/bbl initial oil price	32.17	269,548	15,267
$28/bbl initial oil price	29.54	252,564	16,583
Low recovery	34.16	173,212	13,418