Enhanced Oil Recovery Potential in the United States

January 1978

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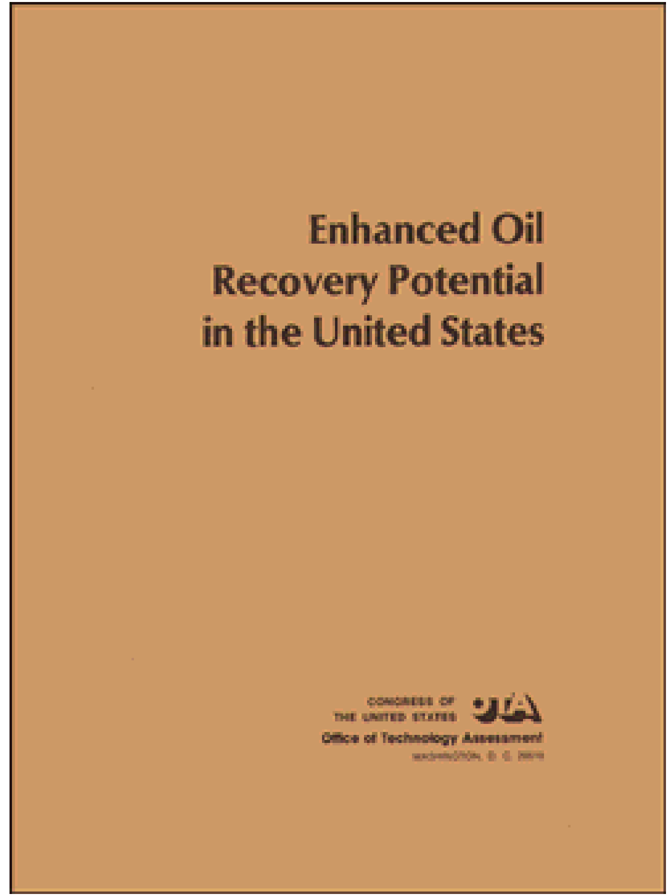

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OFFICE OF TECHNOLOGY ASSESSMENT
WASHINGTON, D.C. 20510

January 6, 1978

The Honorable Ted Stevens
Technology Assessment Board
Office of Technology Assessment
United States Senate
Washington, D. C. **20510**

Dear Senator Stevens :

On behalf of the Board of the Office of Technology Assessment, we are pleased to forward the results of the assessment you requested of the potential of enhanced recovery of oil and Devonian gas in the United States.

This report, Enhanced Recovery of Oil coincides with the recently released Status Report on the Potential for Gas Production From the Devonian Shales of the Appalachian Basin.

These assessments will provide additional perspective on future U.S. energy supplies and we hope that they will be helpful as the Congress continues its review of national energy policy.

Sincerely,

Edward M Kennedy

EDWARD M. KENNEDY
Chairman

Sincerely,

Larry Winn Jr.

LARRY WINN, JR.
Vice Chairman

Enclosure

Foreword

It is estimated that about 300 billion barrels of discovered oil remain in the United States. However, conventional techniques of extraction can deliver only 10 percent of that oil economically, or about 30 billion barrels. What about the remaining 270 billion barrels?

This report assesses the potential of enhanced recovery techniques for freeing more of this oil from the sandstone and limestone formations in which it is trapped. The methods for doing this include injecting steam, chemicals, or carbon dioxide to either break the oil loose and push it up or make it easier to flow. The question is at what price?

At current world oil prices, enhanced oil recovery methods could yield from 11 to 29 billion additional barrels of that trapped oil. And at oil prices comparable to those required to produce synthetic oil from coal, enhanced recovery methods could increase the yield to as much as 42 billion extra barrels of oil. At the utmost, about 51 billion barrels might be recoverable, assuming the most favorable economic factors and technologies that can now be foreseen.

This report discusses the uncertainties in these estimates and assesses policy options available to Congress for recovering more of America's oil resources.

This assessment is another in the series of energy policy projects that the Off ice of Technology Assessment is conducting for the Congress.

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1. Executive Summary

Introduction and Summary of Findings

Since 1970, the Nation's known oil reserves have declined by an average 3.8 percent a year as discoveries of new oil continued to lag behind domestic production. During that same period, domestic production has declined steadily from its 1970 peak of 9,6 million barrels a day (MMBD) to 8.0 MMBD in early 1977. These declines, coupled with the disruptive 1973-74 Organization of Petroleum Exporting Countries (OPEC) oil embargo and a four-fold increase in world oil prices, have not yet depressed demand for oil in the United States. Except for a temporary drop in consumption in 1975, the United States has continued to increase its demand each year and imports have climbed steadily to make up the difference between domestic supplies and domestic demand.

Unless steps are taken to reduce demand, increase domestic production, or achieve some combination of both, the United States will be obliged to continue to increase its imports, which averaged 8.8 million barrels a day during the first 8 months of 1977. The United States would remain vulnerable to future embargoes or arbitrary price increases. increased U.S. oil imports could contribute to imbalances between supply and demand on a world scale in the early 1980's that would mean even sharper increases in world prices.

There are only two ways to increase domestic production:

- accelerate exploration for new oil supplies, particularly along the Outer Continental Shelf; and
- develop more efficient methods for recovering oil" which remains in the ground in known reservoirs after the first and second phases of conventional oil production.

This report concentrates on the second approach and assesses the potential for increasing domestic production from such known reservoirs with five technologies and methods, known collectively as enhanced oil recovery (EOR) techniques.

The target for these EOR techniques is some 298 billion barrels of oil that will remain trapped in known sandstone and limestone reservoirs in the United States after producers have pumped all of the oil that can be taken with primary and secondary production methods. The EOR processes use heat or chemical fluids which are injected into reservoirs to sweep additional amounts of oil from the sandstone and limestone pore spaces and force it to the surface.

Recent studies of the potential production possible with EOR techniques have arrived at estimates that range all the way from 7 billion to 76 billion barrels of oil at prices ranging from $10 to $15 per barrel, Estimates of the rate of production as of 1985 range from 0.9 MMBD to 2.3 MMBD.

The major findings of the Office of Technology Assessment study are:

- At current world oil prices ($1 3.75 per barrel in 1976 dollars[1]), EOR techniques could add between 11 billion and 29 billion barrels of oil to existing domestic reserves. Annual production rates could range from 0.5 MMBD to 1.0 MMBD in 1985 and from 0.7 MMBD to 1.7 MMBD in 1990.
- At the price at which synthetic oil or other alternate sources might become available ($22 per barrel), the potential for EOR appears to be between 25 billion and 42 billion barrels, with daily production rates

[1]$13.75 is the January 1977 average price ($14, 32/per barrel) of foreign oil delivered to the east coast, deflated to July 1, 1976. Only the incremental oil resulting from EOR techniques would be eligible for the prices used in this assessment, current and future oil production resulting from primary and secondary methods was assumed to be at price levels existing in 1976.

of between 0.9 MMBD and 1.3 MMBD in 1985 and 1.8 MMBD to 2.8 MMBD in 1990.

- A vigorous program of research and development, with many field tests supported by laboratory investigations, must be undertaken to achieve significant EOR production. Even with such a program, eventual production would depend on the effectiveness of EOR processes and the validity of estimates of the amounts of oil remaining in the known reservoirs.
- Estimates of the daily rates of EOR oil production are much less certain than those for ultimate oil production, partly because the rate of development of EOR technology is uncertain and partly because EOR operations will have to compete for funds with other investment opportunities. Enhanced oil recovery processes are relatively new and the investment risk is high compared to more familiar oil exploration and production methods. If the oil industry hesitates to invest large amounts of capital in EOR processes in the next few years, the production of oil with enhanced methods would be delayed.
- Estimates of EOR potential presume the availability of very large quantities of injection materials, such as carbon dioxide **(CO_2) and surfactant. A 50-percent increase in the real cost of these two materials** could limit potential EOR production to 6 billion to 12 billion barrels at the world oil price, or 16 billion to 33 billion barrels at the alternate fuels price.
- The responsiveness of EOR potential to increases in the real price of oil drops off above $22 per barrel. An increase in price to $30 per barrel has the potential of increasing the production only about 17 percent, from 42 billion barrels to 49 billion barrels (assuming high process performance). Removing all economic constraints might add about 2 billion barrels more. Thus, it is doubtful that more than about 51 billion of the remaining 300 billion barrels of oil can be recovered under any economic conditions using current and foreseeable enhanced recovery technology.
- Investment tax incentives (a change from 10 to 12 percent in the investment tax credit and accelerated depreciation) appear to have relatively little effect on investor decisions to use EOR processes, but an Internal Revenue Service interpretation that the cost of injection chemicals must be depreciated rather than treated as an expense could seriously inhibit the use of the high-potential surfactant/polymer and CO_2 miscible processes.
- Neither a guarantee of $13.7s per barrel nor a 15-percent investment subsidy would substantially reduce the element of risk in EOR decisions for investors.
- If investors expect real oil prices to rise at an average annual rate of 5 percent, decontrolling the price of oil produced by EOR techniques would reduce risk and increase potential production more than all other tax and price policies examined, including a $3 per barrel subsidy.
- Any effort to permit a higher price for oil produced by EOR processes than that allowed for other oil produced from the same reservoir would require a fairly precise determination of the fraction of total oil production that resulted from EOR operations. Highly technical judgments would be involved, and there is some doubt that qualified personnel would be available at the Federal or State levels to undertake this task.
- In general, the environmental impacts of EOR techniques are not expected to be significantly different from those of primary and secondary production operations. There are two main exceptions. First, combustion of oil in thermal processes produces atmospheric pollutants. Until technology is implemented to control these emissions, air quality standards are expected to limit expansion of thermal processes already being used in California. Second, some EOR processes may require large volumes of fresh water, which could strain the capacity of local water supplies. Application of EOR technology which allows the use of saline water could reduce this problem.

- In order to undertake fieldwide oil recovery operations (waterflood or EOR), it is generally necessary to secure the consent of all parties with an interest in the field through a unitization agreement. Owners of relatively small interests can effectively prevent the initiation of an enhanced project by refusing to accept the risks and expenses associated with a joint EOR venture. The magnitude of this problem was not determined, but it could be reduced through compulsory unitization statutes if it proved to be a serious block to EOR operations.
- Proposed regulations being promulgated by the Environmental Protection Agency (EPA) pursuant to the Safe Drinking Water Act could adversely affect EOR development. These proposed regulations cover injection of materials into the ground. Many producers believe the proposed regulations will significantly restrict or hinder enhanced recovery of oil,

Method of Analysis

Data Base

This assessment of EOR potential is based on a reservoir-by-reservoir analysis of the anticipated performance of EOR processes. The data base for the analysis comprises 385 fields (835 reservoirs) in 19 States, and includes the 245 onshore reservoirs used in recent studies of EOR potential published by the Federal Energy Administration (FEA) and the National Petroleum Council (NPC). The 385 fields used in the OTA assessment include 24 offshore fields (372 reservoirs) and contain 52 percent of the known remaining oil in place (ROIP) in the United States. Results obtained from the data base were extrapolated on a State-by-State basis to obtain national totals. Alaskan reservoirs were not analyzed because there was not enough cost data on EOR operations in a hostile environment.

Technical Screen

Five EOR processes were examined for technical applicability to each reservoir in the data base:

in situ combustion,
steam injection,
CO_2 miscible flooding,
surfactant/polymer flooding, and
polymer-augmented waterflooding.

Physical properties of each reservoir were compared with a set of technical criteria based on an assessment of current technology and expected technological advances. In the first stage in the analysis, a reservoir could qualify for more than one process. Reservoirs representing about 76 billion barrels of oil remaining in place (when extrapolated for the Nation) were determined to be unsuited for any known EOR process because of physical properties of the reservoir.

Economic Screen

Reservoirs that qualified for one or more EOR process during the technical screening were then analyzed to determine the amount of oil that would be produced and the rate of return that would result at various oil prices for each applicable process. Where reservoirs qualified for more than one EOR process, the results of this analysis were compared for each acceptable process. Because the purpose of the assessment was to determine the maximum amount of oil that could profitably be produced under various economic conditions, the process selected for each reservoir was the one which yielded the greatest ultimate oil recovery. In cases where none of the five processes could show a 10-percent return from a given reservoir at the world oil price, the procedure was repeated at the alternate fuels price of $22 per barrel. Reservoirs that did not yield 10 percent for any process at the alternate fuels price were assigned to the process that appeared to have the best economic chance, or were dropped from consideration if no economic development seemed likely.

Rate of Initiation of EOR Projects

Because worldwide oil supplies may be limited starting in the 1980's, the daily rates of production that are possible with EOR operations between 1985 and 2000 may be more important to national energy policy than the ultimate potential production. However, the potential production rates are more difficult to estimate than ultimate oil production because the rates depend on the pace of technological development and the speed with which investors are willing to initiate EOR projects. Initiation of EOR projects depends on availability of capital, willingness of investors to accept high risks of new and relatively untested technologies, and the availability of more attractive investment opportunities. Because an analysis of the likely rate of investments in EOR was beyond the scope of this assessment, OTA postulated that EOR projects would become economically acceptable as investment risks decreased. Under this assumption, high potential rates of return (30 percent in 1977) would be needed in the early years of EOR development to compensate for the high risks of EOR projects; as field experience reduces investment risk, lower rates of return (1 O percent in 1989) would become attractive.

Cases Examined

Estimates of the technical and economic performance of each EOR process were based on an optimistic but realistic forecast of technological advances. Such technological advances are expected to result from an ambitious research and development program involving many field tests supported by basic research. Incorporating a postulated schedule of technology advancement, each EOR process was analyzed using high and low estimates of process performance. The resulting high- and low-process performance estimates represent OTA's judgment of the likely range of uncertainty in EOR potential. No attempt was made to determine the most probable value within this range.

Each case was evaluated at three oil prices (using constant 1976 dollars): FEA's upper tier price of $11.62 per barrel, the current world oil price of $13.75 per barrel, and an alternate fuels price of $22 per barrel, at which petroleum from coal might become available. The effects of higher costs for injection chemicals, of air quality standards, and of a s wer than anticipated rate of investment-risk reduction were determined for the high- and low-process 'performance cases. In addition, the effects of a **sec** of price, tax, and leasing options were determined by using a sample of reservoirs representing about 25 percent of the data base reservoirs that qualified for an EOR process,

Oil Recovery Potential

Estimates of the amount of oil that can be recovered using enhanced methods must be interpreted with caution. Enhanced methods, except for thermal processes, have not been extensively field tested. The Office of Technology Assessment assumed that results obtained from controlled laboratory experiments and carefully conducted field tests were representative of what would happen in each of the 835 reservoirs in the OTA data base. The uncertainties inherent in this assumption must be considered when evaluating OTA's estimates of EOR potential. By means of reviews of existing field and laboratory EOR data, specific reservoir characteristics, petroleum engineering principles, and reservoir mechanics, OTA has attempted to develop oil recovery estimates that are realistic. The major uncertainties in these estimates are identified and, where possible, are included in the analysis.

Ultimate Oil Recovery

Proved oil reserves are defined as oil that can be produced with current technology under specified economic conditions (usually current costs and prices). Consequently, estimates of potential additions to proved reserves resulting from the application of EOR techniques vary with the price of the oil. The results of OTA's analysis are summarized in table 1.

At the FEA upper tier price of $11,62 per barrel, the likely range for EOR production is 8 billion to 21 billion barrels, depending on process performance. The results represent an increase in proved and indicated reserves from primary and secondary production of between 23 and 60 percent.

At the FEA upper tier price of $11.62 per barrel likely range of EOR production is 11 billion to 29

Table 1
Estimates of Ultimate Recoverable Oil and Daily Production Rates From EOR: Advancing Technology Case With 10 Percent Minimum Acceptable Rate of Return

		Price per barrel	Ultimate recovery[c] (billions of barrels)	Production rates (millions of barrels/day)		
				1985	1990	2000
High-pr(xess performance'	Upper tier:	$11.62	21.2	0.4	1.1	2.9
	World Oil:	$13.75''	29.4	1.0	1.7	5.2
	Alternate fuels:	$22.00"	41.6	1.3	2,8	8.2
		530.00	49.2	d		
	More than	.s30.00	51.1			
Low-process performance	Upper tier:	$11.62	8.0	0,4	0.5	1.1
	World 011:	$13.75	11.1	0,5	0.7	1.7
	Alternate fuels:	$22.00	25.3	0.9	1.8	5.1

[a]$13.75 is the January 1977 average price ($14.32 per barrel) of toreign 011 (1(11 iveredtothe eastcoast, detlatedto July 1, 1 976

[b]$22.00 per barrel is the price at which the Synfuels Interagency Task Force estimated that petroleum liquids could become available from coal

[c]These figures include 2.7 billion barrels from enhanced recovery processes that are included in the API estimates of proved and indicated reserves

[d]Productionrates were notcalculatedfor 011 at pricesof $30 per barrel or higher

billion barrels, representing a 31- to 83-percent increase in proved and indicated reserves from primary and secondary production. increasing the price to the alternate fuels price of $22 per barrel yields a range of *25* billion to *42* billion barrels, an increase of *71* to **120** percent in proved and indicated reserves.

The high-process performance case was used to estimate the amount of oil that could be economically produced at a price of $30 per barrel. This increase in price might yield an additional 7 billion barrels, a 17-percent increase over the **42** billion barrels estimated to be available at $22 per barrel in the high-process performance case. The 49 billion barrels that might be recoverable at $30 per barrel represent about 96 percent of the 51 billion barrels technologically recoverable (assuming high-process performance) with no economic constraints. While it is possible that new technologies with greater recovery potential could be developed if oil prices rose as high as $30 per barrel, it is not likely that this would occur before the end of this century; this possibility would therefore not significantly affect the policy implications of this assessment.

Rate of Oil Production

Current (mid-1977) oil production from known reservoirs using conventional techniques in the United States is about 8 MMBD. Daily oil production is expected to decline to about 7.5 MMBD by 1980, including production from Alaska's Prudhoe Bay; by 1990 production could be as low as 4.2 MMBD. This assessment indicates that EOR has the potential of significantly reducing the decline in domestic production from known reservoirs, particularly after 1990, if investors initiate EOR projects on the schedule assumed in this analysis. it is anticipated that EOR could add between 0.4 MMBD and 1.3 MMBD to domestic production by 1985. The lower figure represents low price ($1 1.62 per barrel) and low-process performance, while the upper figure reflects a higher price ($22 per barrel) and high-process performance. At the current world oil price ($1 *3.75* per barrel) the range would be **0.5** MMBD to 1.0 MMBD.

The potential contribution to domestic production could increase rapidly after 1985. By 1990, the extremes of potential production are estimated to be 0.5 MMBD and 2.8 MMBD, with a range of 0.7 MMBD to 1.7 MMBD at the world oil price. By the year 2000, possible production could be as low as 1.1 MMBD or as high as 8.2 MMBD. This higher rate of potential production exceeds the current rate of domestic oil production using conventional techniques.

Major Uncertainties

Enhanced oil recovery methods represent a developing and relatively unproven technology.

For example, the two processes which represent over half of the total EOR potential-CO_2 miscible flooding and surfactant/polymer flooding— have received only limited field testing. Consequently there are many uncertainties that must be considered when interpreting the results of assessments of the potential of EOR. The following is a brief discussion of the major areas of uncertainty.

Resource Availability and Process Performance

There is an uncertainty of 15 to 25 percent (or more) jn the amount of oil remaining in reservoirs after primary and secondary recovery, In addition, there is uncertainty about the fraction of the remaining oil that can be recovered by an EOR process even after the process has been successfully pilot tested. Analysis of the low- and high-process performance cases shows that a relatively small reduction in process performance can lead to a much larger reduction in potential EOR production; a 12- to 30-percent reduction in the amount of oil recovered (depending on the process) produces a 64-percent reduction in ultimate production at $22 per barrel, and a 163-percent reduction at $13.75 per barrel. Similar reductions result for the 15- to 25-percent uncertainty in remaining oil. This disproportionate effect occurs because a relatively small decrease in expected production can reduce the rate of return from many reservoirs to below the 10 percent needed to make EOR operations an attractive investment.

Availability and Cost of Injection Materials

The OTA estimates of EOR potential presume the availability of large quantities of injection materials. Limitations in availability and/or increases in real prices above the level's assumed in this **analysis could significantly reduce both the** ultimate oil recoverable by EOR methods and the rate at which EOR oil might be produced. The most important materials in this regard are CO_2, surfactant, and fresh water.

The CO_2 miscible process, which is expected **to** provide between 41 and 51 percent "of the total potential EOR production; requires extremely large quantities of CO_2. Production of 13.8 billion barrels of oil (estimated for the high-process performance case at $13.75 per barrel) would require a total of about 53 trillion cubic feet (Tcf) of CO_2, a volume nearly three times the annual consumption of natural gas in the United States. The estimates of the production potential of the CO_2 miscible process are based on the assumption that most of the CO_2 would be provided from natural deposits. Natural CO_2 can be delivered to reservoirs by pipeline at lower cost (from about $.60 to $.90 per thousand cubic feet (Mcf)) than manufactured CO_2 delivered by truck (on the order of $2.75 per Mcf). The Energy Research and Development Administration (ERDA) is currently conducting a study of the availability of natural CO_2 for use in EOR. However, even if deposits of sufficient magnitude are found, it is possible that the CO_2 would be sold at prices considerably above the production costs assumed in this study. Higher costs could significantly reduce the amount of oil economically recoverable using the CO_2 miscible process. For example, a 50-percent increase in price of CO_2 could reduce the potential production from the CO_2 miscible process by 49 percent, from 13.8 billion to 7.1 billion barrels ($13.75 per barrel and high-process performance).

Chemical costs are also important variables in the surfactant process, the EOR process which OTA estimates might provide 13 to 34 percent of the ultimate EOR production. This process is extremely sensitive to the costs of the injection chemicals (surfactant and polymer) used. A 5O-percent increase in price of surfactants and polymers over the level assumed in this study would practically eliminate the potential of this process at the world oil price, reducing production in the high-process performance case from 10.0 billion to 0.2 billion barrels. However, this oil could eventually be produced at the alternate **fuels price, with an ultimate** recovery of an estimated 9 billion barrels.

The final critical injection material is water. While secondary oil production (waterflooding) already requires significant quantities of water, existing EOR methods require relatively fresh water. Availability of fresh or nearly fresh water could ultimately constrain EOR development, because EOR processes have a large potential in Texas, western Louisiana, and California-areas where water shortages already exist and are predicted to be more severe by the year 2000. Achievement of the full potential of EOR will require the development of means for using water of higher salinities in EOR processes.

Rate of Investment in EOR Projects

As noted, OTA's estimates of the potential daily production from EOR processes are based on the assumption that EOR projects will be initiated according to a postulated schedule related to expected rates of return. However, difficulties in forecasting actual investor behavior suggest that the estimates of daily production rates are less certain than the estimates of ultimate oil recovery. Enhanced oil recovery investments will have to compete for funds with other investment opportunities. Enhanced oil recovery processes are relatively new, and the investment risk is high compared to more familiar oil exploration and production methods. The oil industry may therefore be reluctant to invest large amounts of capital in EOR processes in the next few years, which would delay the production of oil by means of enhanced recovery methods.

Marketability of Heavy Crudes

Market constraints could limit the development of thermal methods in California where the market for the heavy crudes is limited primarily because heavy oil requires more processing than lighter oils, Crude oil from Prudhoe Bay may further reduce the market for California heavy crude for a short period. A real or perceived weak market for heavy oils produced by thermal methods in California will be a deterrent to thermal EOR development in that State. This delay may well be temporary, but it could result in lower rates of oil production from thermal EOR methods in the 1980's than those estimated in this report.

Combinations of Uncertainties

The effects of uncertainties have been evaluated independently. Reductions in ultimate recovery and/or changes in timing of production resulting from altered assumptions in each of these uncertain areas are presented above and in more detail in chapter III. Changes in ultimate recovery or timing of production have not been evaluated for combinations of uncertainties. it is possible that two or more uncertainties could simultaneously reduce EOR potential. In fact, it is remotely possible that resource availability could be lower than expected, low-process performance prevail, supply of injection materials be constrained or costly, and EOR investments remain relatively risky-all at the same time. Should this occur, EOR potential would be very low, and EOR production would never make a significant contribution to national production.

The Office of Technology Assessment does not believe this combination of circumstances is likely. The lower bounds presented in this study represent a more realistic estimate of the minimum production which could be expected from EOR techniques,

Impact of Price and Tax Policies

Price

The OTA analysis has assumed that the price being tested would apply only to the increment of production from a well that could be directly attributed to the EOR process, while oil being produced by primary and secondary methods from the same well would continue to receive the price for which it is qualified under current price control regulations. The same assumption was used in independent analyses of EOR potential conducted for FEA and ERDA.

Both the amounts and timing of potential EOR production are sensitive to the price that will be received for the oil. In both the low- and high-process performance cases, the two possible price increases considered ($1 1.62 per barrel to $13.75 **per barrel and $13.75** per barrel to $22 per barrel) produced more than proportional increases in potential recovery. Increases in price had an even greater effect on the rate at which EOR production might be brought on-line.

In 1976, Congress amended the Emergency Petroleum Allocation Act to provide additional price incentives for bona fide "tertiary enhanced recovery" (EOR) techniques. Since then, FEA has published proposed regulations and has held public hearings on price incentives for oil produced by enhanced techniques. In addition, the President recommended decontrolling the price of EOR oil in his National Energy Plan.

The effects of decontrol of oil produced by EOR methods were tested using a sample of about 25 percent of the OTA data base reservoirs that technically qualified for an EOR process. im- pacts of decontrol depend primarily on investor expectations about the future market price of oil, It was assumed that investors expected the real price of oil to rise at an average annual rate of 5 percent. With this assumption, more reservoirs could be profitably developed (34 percent more in the sample) with prices decontrolled than if prices were held at a $13.75 constant real price, At the same time, decontrol would significantly decrease the risk for investors in all EOR processes except in situ combustion. Decontrol of oil price was more effective at stimulating development than any of the other price and tax options considered. As long as investors expect the market price of oil to rise, decontrol will reduce the risk of EOR investments compared to a controlled-price policy.

The OTA analysis presumes that oil produced by EOR operations will be priced differently from oil produced by primary and secondary methods from the same well at the same time. The Federal Energy Administration proposed the same approach in applying price incentives for EOR production. This policy creates the problem of deciding what fraction of total oil production should be attributed to EOR when primary and secondary methods are being used at the same reservoir. The challenge is to define this increment in such a way as to encourage the application of EOR processes without significantly distorting decisions concerning primary and secondary production.

The FEA proposal involves case-by-case judgments concerning the production that would normally be expected using primary and secondary methods. But that proposal raises questions about whether the technical expertise for making such decisions would be available at the Federal and/or State levels. An alternative approach, supported by industry in comments on FEA's pricing proposals, would be to apply the same price incentives to all oil produced from a field to which an EOR process was applied. While this would avoid the problem of defining EOR incremental oil, it would leave the problem of defining the level of effort required for a project to qualify as a bona fide EOR process, and would require monitoring to ensure that the effort is maintained.

A more detailed analysis of the advantages and disadvantages of these and other incentive pricing options was beyond the scope of OTA's assessment of the potential contribution of EOR processes to national reserves. Because of the importance and complexity of the associated issues, Congress may wish to examine the problem of defining and monitoring EOR operations, and possibly hold oversight hearings on the proposed FEA pricing regulations for EOR production. If defining EOR incremental oil production and monitoring EOR operations are found to be critical issues, a mechanism could be developed whereby bona fide EOR projects could be certified and monitored. Certification and monitoring of EOR operations could be performed by the operator, a State regulatory group, a Federal agency, or a combination of State, Federal, and producer interests.

Special Tax Treatment for EOR Projects

The impacts of several tax incentives for EOR investments were analyzed at the world oil price. The options included an increase in the investment tax credit from 10 to 12 percent, accelerated depreciation, and an option in which injection costs were depreciated over the life of the project rather than treated as expenses during the year they were incurred. Neither the investment tax credit nor accelerated depreciation had much effect on the development of reservoirs using EOR methods, On the other hand, a requirement that injection costs be depreciated rather than treated as expenses led to a large decrease (29 percent) in total production. Depreciating rather than expensing costs of injection materials could greatly inhibit the development of the surfactant and CO_2 miscible processes, which have the potential of providing well over half of the total EOR production at prices at or above $13.75 per barrel.

Price Guarantees and Subsidies for EOR Production

Three forms of explicit and implicit subsidies were evaluated: a price guarantee at $13.75 per barrel; a 15-percent subsidy of EOR investment costs (excluding costs of injection materials); and a $3 per barrel price subsidy of EOR oil. The effectiveness of a price guarantee depends almost entirely on the probability that the world market price of oil will decline below the current level in real terms. Assuming that this probability is quite low, a $13.75 per barrel price guarantee would probably have little effect on the risk of EOR investments. The 15-percent investment subsidy also exhibited little impact on risk or on potential production, although its effects might be somewhat greater than the tax options that were considered.

A $3 per barrel price subsidy would be more effective than the tax and subsidy options analyzed, and could result in a 6-percent increase in ultimate EOR production and substantially reduce the risk to investors. Because the cost of the subsidy would be offset to some extent by increased Government tax revenues from increased production, the actual cost of the subsidy would be somewhat less than $3 per barrel.

Alternative OCS Leasing Systems

Because a large part of future oil discoveries are expected to be on the Outer Continental Shelf (OCS), the effects of several OCS leasing policies were tested on a 25-reservoir sample of the 294 offshore reservoirs in the OTA data base which were amenable to EOR processes. The United States currently uses, almost exclusively, a cash-bonus bidding system in which exploration and development rights on an OCS tract are granted to the group offering the highest front-end payment, or bonus bid. In addition to the cash bonus, a 16.7-percent royalty on gross production is collected by the Government. The preceding analysis of policy options assumed that this method would be in use for the offshore CO_2 cases.

Recent discussions of alternate leasing systems have included proposals for greater use of contingency payments (royalties or profit shares, which collect Government revenue based upon the value of actual production), which are intended to reduce front-end capital requirements and shift a greater share of risk to the Government. The impacts on EOR production potential of two such systems were analyzed by OTA: cash bonus plus a 40-percent royalty, and a cash bonus plus a 50-percent net profit share. The 40-percent royalty was shown to increase the investment risk and to make some fields uneconomic for EOR, **a** result that confirms earlier studies of the impact of high royalties on primary and secondary OCS production. While the profit-share system did not eliminate any fields from consideration, it did tend to increase the risk of EOR investments and could therefore tend to delay EOR implementation. This is contrary to previous results on primary and secondary production, and suggests that a profit-share rate of 50 percent would be too high for EOR development on marginal fields.

A possible option would be the use of a variable-rate royalty or profit-share approach, in which rates would automatically be reduced for marginal fields. Alternatively, the contingency payment could be waived when that became necessary to enable further production, a provision included in proposed amendments to the Outer Continental Shelf Lands Act (S.9 and H.R, 1614). While this option was not tested directly, the $3 per barrel price subsidy approximates the removal of the 16.7-percent royalty at an oil price of $13.75 per barrel. The $3 per barrel price subsidy increased the number of offshore reservoirs in which EOR methods might be economical, These results may somewhat exaggerate the possible effect of **eliminating the royalty because** the $3 **per barrel subsidy is about 30 percent greater than the current 16.7-percent royalty on $13.75 per barrel** oil, and because the policy sample of reservoirs contained a higher proportion of marginal fields which would be more affected than the entire data base.

Legal Issues

To identify potential legal obstacles to EOR, questionnaires were sent to oil producers and to State and Federal regulatory authorities, and a study was made of pertinent laws, treatises, special reports, and periodical literature. The most significant existing or potential legal constraints identified were Federal price controls on crude oil, weakness or absence of compulsory unitization statutes in several crucial States, and existing and proposed environmental protection regulations. These legal constraints have an impact on secondary (waterflood) methods as well as on EOR.

The issue of price controls and alternative pricing policies has been discussed in an earlier section. The second legal constraint involves unitization, the joining of interest holders in a reservoir for the purpose of sharing the costs and benefits of an efficient development plan for the reservoir as a whole. Unitization is usually desirable; it often would be essential to make application of secondary and enhanced recovery techniques to a reservoir possible. Most producing States provide for compulsory joinder of interest owners in a unit once a certain percentage of interest holders have agreed to unitization. In the absence of such legislation, or where the necessary percentage of voluntary participation cannot be achieved, secondary and enhanced recovery operations can result in substantial liability for the operator if non joiners suffer damage.

While most States have compulsory unitization statutes, Texas does not, and the statutes in California are so limited as to be rather ineffective. These States together represent about half of the total national EOR potential, and the difficulties of forming unit agreements may therefore be a significant obstacle to large-scale development of EOR production. A field-by-field analysis of ownership patterns is needed to determine whether difficulties with unitization might prove to be a major obstacle to the development of a significant fraction of EOR potential, Such an analysis was beyond the scope of this study.

[If unitization problems were found to be serious constraints on EOR production, several actions could be considered. The Federal Government could recommend that each State adopt a statute that makes unitization compulsory when 60 percent of the working interest and royalty owners consent to unitized operations. The Federal Government could also recommend that the States adopt statutes to exempt producers from liability for any damages caused by State-approved enhanced recovery operations not involving negligence on the part of the producer. This would remove a significant constraint to unit operations in the absence of full participation by all the interest owners. Finally, the Government could require that States have appropriate compulsory unitization statutes in order to qualify for Federal administrative support, or to avoid having a Federal agency become responsible for unitization and enhanced recovery regulation.

The primary environmental regulatory constraints on EOR relate to air quality standards in California and EPA's proposed regulations under the Safe Drinking Water Act to control underground injections. Current Federal and State environmental regulations under the Clean Air Act limit total emissions in California to the pollution levels which existed in 1976. Therefore, use of additional steam generators and air compressors for thermal recovery operations in California may be significantly constrained. Using existing generators and compressors, the maximum increase in the production rate from thermal methods in California (the area where thermal processes have the greatest potential) will probably be no more than 110,000 barrels per day, about half of the estimated 1990 potential rate of production at the world oil price. Expansion of thermal production will require application of emission control technology capable of meeting air quality standards.

The Safe Drinking Water Act, passed in 1974, directs EPA to issue regulations to control underground injection of fluids that may threaten the quality of water in aquifers that are or may be used for public water supply. The act specifically provides that requirements in these regulations must not interfere with or impede any underground injection for the secondary or tertiary recovery of oil or natural gas unless such requirements are essential to ensure that underground sources of drinking water will not be endangered by such injection. However, reaction to EPA's proposed regulations by such groups as the interstate Oil Compact Commission, the American petroleum Institute, individual oil producers, and others indicate that the regulations are perceived as likely to have an adverse impact on enhanced recovery operations. Because EOR processes are expected to pose no greater threat to drinking water than waterflooding, which has a good safety record, Congress may wish to hold oversight hearings to determine if the proposed regulations would unduly inhibit the application of EOR techniques.

Environmental Effects

In general, the environmental impacts of EOR operations are not expected to be significantly different in type or magnitude than those from primary and secondary oil production activities. The major differences are air emissions from thermal processes, and increases in consumption of fresh, or relatively fresh, water.

Thermal EOR processes produce atmospheric pollutants from the combustion of large quantities of oil, either in steam generators (the steam injection process) or in the reservoir itself (the in situ combustion process). These types of emission are likely to have localized impacts and are expected to be highly significant in areas that are already in violation of Federal ambient air quality standards. Air quality standards are expected to limit expansion of thermal processes in California unless effective emission control devices are used or compensating reductions in emissions are made elsewhere in the affected area.

As noted in the discussion of resource constraints, EOR processes in general required significant quantities of fresh, or relatively fresh, water, whereas secondary waterflooding can use saline water. This consumption of fresh water not only will compete directly with domestic, agricultural, and other industrial uses, but also could result in a drawdown of surface water, which could, in turn, severely affect aquatic flora and fauna in the area of the drawdown. However, this impact usually would be localized and of short duration. The consumption of fresh water by EOR processes has the greatest potential impact in California, Texas, and western. Louisiana, where water supplies are limited. Development of EOR technologies to allow use of saline water could reduce this potential problem.

IL An Assessment of the Potential of Enhanced Oil Recovery

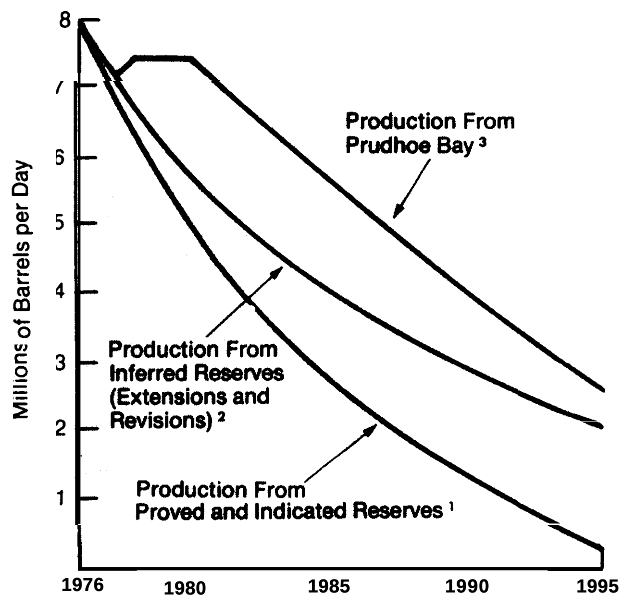
II. An Assessment of the Potential of Enhanced Oil Recovery

The United States must have reliable sources of energy to maintain stability. in its energy-intensive economic base—a fact dramatically emphasized in October 1973, when Arab oil producers imposed a 5-month embargo on oil shipments to the United States, and again in the record-cold winter of 1976-77, when natural gas supplies fell short of demand. Until the oil embargo, most Americans took it for granted that their energy needs would be met despite declining domestic production of oil and gas, which together provide 75 percent of the Nation's energy. The embargo and curtailments of natural gas supplies have made it clear that steady flows of energy cannot be taken for granted and have driven policy makers to a search for a national policy which will make the United States less reliant on foreign energy sources.

Because of congressional concerns over declining domestic supplies of oil and natural gas, and the possibility that new technologies can increase the Nation's oil and gas reserves, the Office of Technology Assessment (OTA) was asked to assess the potential of the technology associated with enhanced oil recovery (EOR). This report is in response to that request.

Proved reserves of crude oil (recoverable with current technology under current economics) in the United States increased from 20 billion barrels in 1946 to 30 billion barrels in 1959. Additions to reserves about equalled withdrawals from domestic reservoirs between 1959 and 1970. The discovery of oil in Alaska increased the proved U.S. oil reserve to 39 billion barrels in 1970. However, since 1970, the domestic proved oil reserve has declined at a 2- to 5-percent annual rate (table 2), annual production from old oilfields has fallen each year, and the United States has become increasingly dependent on imported oil (table 3). Unless these trends can be reversed, the gap between supplies of domestic oil and U.S. demand will widen within the next 10 to 15 years (figure 1). There are two approaches to increasing proved reserves of oil: (1) find additional oil through increased exploration; and (2) use more efficient methods to recover oil from known reservoirs. Enhanced oil recovery processes fall into the second category.

Figure 1. Projected Oil Production by Conventional Methods From Known U.S. Reservoirs, 1976-95



NOTE: The Decline Curves for Proved and Indicated Reserves, and Inferred Reserves Do Not Include Enhanced Oil Recoveries Recorded within these Categories.

SOURCES: [1] American Petroleum Institute, Reserves *of* Crude *Oil*, Natural Gas Liquids, and Natural Gas m the U.S. and Canada as of December 30, 1975: Lewin & Associates, Inc. for Federal Energy Administration, Dee/me Curve *Analysis*, 1976.

[2] U. S. Geological Survey, *Circular* 725, 1975.

[3] Federal Energy Administration, *National* Energy *Outlook*, 1976.

Traditional methods of oil production (natural flow and flushing the oil reservoir with water) recover on average only about one-third of the oil present in a producing formation. Methods

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Table 2
Proved Reserves of Crude Oil in the United States, 1959-76
(Billions of Barrels of 42 U.S. Gallcms)

Year	Proved reserves at beginning of year	Proved reserves at end of year	Net change from previous year
1959	30.5	31.7	+1.2
1960	31.7	31.6	-0.1
1961	31.6	31.8	+0.2
1962	31.8	31.4	-0.4
1963	31.4	31.0	-0.4
1964	31.0	31.0	+0.0
1965	31.0	31.4	+0.4
1966	31.4	31.5	+0.1
1967	31.5	31.4	-0.1
1968	31.4	30.7	-0.7
1969	30.7	29.6	–1,1
1970	29.6	39,0	+9,4
1971	39.0	38.1	-0.9
1972	38.1	36.3	–1.7
1973	36.3	35.3	–1.0
1974	35.3	34.3	–1.1
1975	34.3	32.7	–1.6
1976	32.7	30,9	–1.7

Note: 1970 figures reflect the addition of Prudhoe Bay Alaska reserves.

Source: Reserves *of Crude Oil Natural Gas Liquids,* and *Natural* Gas in *the United States* and Canada *as of December 31,* 7975, Joint publication by the American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, Vol. 30, May 1976,

Table3
U.S. Domestic Production and Imports of Oil, 1959-76
(Barrels of 42 U.S. Gallons)

Year	Production		Imports	
	Annual (billions of barrels)	Daily (millions of barrels)	Annual (billions of barrels)	Daily (millions of barrels)
1959	2.6	7.1	0.7	1.8
1960	2.6	7.5	0.7	1.8
1961	2.6	7.2	0$7	1.9
1962	2.7	7.3	0.8	2.1
1963	2.8	7.5	0.8	2.1
1964	2.8	7.6	0.8	2.3
1965	2.8	7.8	0.9	2.5
1966	3.0	8.3	0.9	2.6
1967	3.2	8,8	0.9	2.5
1968	3.3	9.1	1,0	2.8
1969	3.4	9.2	1.2	3.2
1970	3.5	9.6	1.2	3.4
1971	3.5	9,5	1.4	3.9
1972	3.5	9.5	1.7	4.7
1973	3.4	9.2	2.3	6.2
1974	3.2	8.8	2.2	6.1
1975	3.1	8.4	2.2	6.0
1976	3.0	8.1	2.7	7.3

Source: U.S. Bureau of Mines.

which increase the amount of oil that can be recovered from a reservoir increase the proved reserves of that reservoir. Recent studies using differing assumptions indicate that our oil reserves could be increased by as much as 76 billion barrels (table 4) by application of EOR methods. Large disparities not only of total future production but of daily production rates from EOR projects exist in these estimates.

This report assesses the magnitude of the increased oil reserves which may result from use of EOR in an effort to reduce the uncertainties posed by earlier studies, and determines reasonable limits of ultimate recovery and production rates under different sets of assumptions about technology, price, and investment climate. An assessment also has been made of the impact on EOR activity of various policies that could be implemented by Congress to increase total recovery and/or accelerate oil production.

Table 4
Estimates of Enhanced Oil Recovery Potential

Source		Potential EOR recover) (billions of barrels)	Production in 1985 (millions of barrels/day)
NPC Study[a]			
----- $ 5		2.2	0.3
----- $10		7.2	0.4
----- $15	(1 976 dollars)	13.2	0.9
----- $20		20.5	1.5
----- $25		24.0	1.7
GURC[b,c]			
---- $10	(1 974 dollars)	18-36	1.1
---$15		51-76	—
FEA/PIR[d]			
----- business as usual, $11		—	1.8
----- accelerated development, $11		—	2.3
EPA[e]			
----- $ 8-12	(1975 dollars)	7	—
----- $12-16		16	—
FEA/Energy Outlook[f]			
----- $12		—	0.9
FEA (3 States)[g]			
----- upper bound, $11.28 (1975 dollars)		30.5[h]	2
----- lower bound, $11,28		15.6[i]	1

[a]Total U. S.; base case performance and costs; minimum DCFROR requirement of 10 percent; moderate tax case.

[b]*Planning Criteria Relative to a National RDT & D Program to the Enhanced Recovery of Crude Oil and Natural Gas*, Gulf Universities Research Consortium Report Number 130, November 1973.

[c]*Preliminary Field Test Recommendations and Prospective Crude 01/ Fields or Reservoirs for High Priority Testing*, Gulf Universities Research Consortium Report Number 148, Feb. 28, 1976.

[d]*Project Idependence Report*, Federal Energy Administration, November 1974.

[e]*The Estimated Recovery Potent/a/ of Convention/ Source Domestic Crude 011*, Mathematical, Inc., for the US. Environmental Protection Agency, May 1975.

[f]*1976 National Energy Outlook*, Federal Energy Administration.

[g]*The Potential and Economics of Enhanced 01/ Recovery*, Lewin & Associates, Inc. for the Federal Energy Administration, April 1976.

[h]Reserves added by the year 2000 if projects return DCFROR of 8 percent or greater.

[i]Reserves added by the year 2000 if projects return DCFROR of 20 percent or greater.

III. Oil Recovery Potential

III. Oil Recovery Potential

The Resource Base

Original Oil In Place

The American Petroleum Institute reports that as of December 31, 1975, about 442 billion barrels of oil had been discovered in the United States, including the North Slope of Alaska.[1] Of that amount, 109 billion barrels had been produced and an additional 37.7 billion barrels remained to be produced at current economic conditions and with existing technology. This figure includes 32.7 billion barrels of proved reserves and 5.0 billion barrels of indicated reserves. The total, 37.7 billion barrels, also includes 1.0 billion barrels of proved EOR reserves and 1.7 billion barrels of indicated EOR reserves.[2] The remaining 295 billion barrels represents the resource base for enhanced oil recovery (EOR). (The resource base includes 11 billion barrels in the North Slope of Alaska but does not include tar sands and oil shale. Technologies to obtain petroleum from these sources are sufficiently different from EOR processes to deserve separate study.)

Petroleum Reservoirs

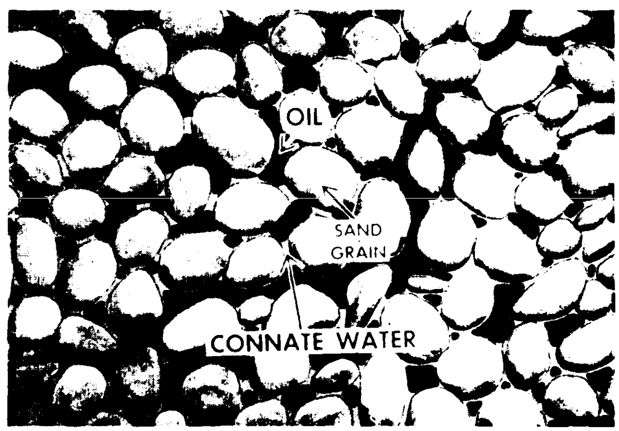
Oil is found in porous sedimentary rocks (sandstones and limestones) that were deposited under water and later overlain by formations that are impervious to these fluids. Localized accumulations of oil occur in traps (reservoirs) within these underground formations, or oil pools. An oil field is the surface region underlain by one or more of these separate oil reservoirs or pools.

Oil is found in such traps at depths of from less than 100 feet to more than 17,000 feet.[3] A reservoir may be small enough that a single well is sufficient to deplete it economically, or large enough to cover many square miles and require several thousand wells.

Oil is not found in underground lakes, but in open spaces between grains of rock; oil is held in these spaces much as water is held in a sponge, Almost invariably, water is mixed with oil in this open space between the grains; natural gas is found in the same kinds of formations. The distribution of fluids in one type of oil reservoir is displayed in figure 2.

Because oil is lighter than water, it tends to concentrate in the upper portions of a formation,

Figure 2. Close-up of Oil Between Grains of Rock



A thin film of water called connate water clings to the surface of the rock grains. This water occupies part of the space in the rock along with the oil.

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[1] *Reserves of Crude Oil, Natural* Gas *liquids, and* Natural Gas in *the* United States and Canada *as of* December *31, 1975*. Joint publication by the American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, Vol. 30, May 1976.

[2] *Enhanced Oil Recovery*, National Petroleum Council, December 1976

[3] "Production Depth Records Set in Three Areas, *World Oil*, p. 103, February 1975.

rising until it reaches an impervious barrier that forms a trap. Common traps include domes (figure 3), faults (figure 4), and salt domes (figure 5). An overlying cap rock can also seal off a formation in the manner shown in figure 6. Oil occasionally lies within sand bodies enclosed within a larger body of impervious shale (figure 7).

Regardless of rock type (sandstone, limestone) or trapping mechanism, there is little uniformity in the pattern in which different reservoirs contain and conduct fluids. This lack of uniformity influences both the amount of oil present in various regions of a reservoir and the degree to which injected fluids can sweep through a formation, collect oil, and force or carry it toward producing wells. It is this lack of a common pattern that introduces significant economic risk in every oil recovery project, including EOR.

Oil Recovery

Primary Recovery

The initial stage in producing oil from a reservoir is called primary production. During this stage oil is forced to the surface by such natural forces as: (a) expansion of oil, expansion of the contained gas, or both; (b) displacement by migration of naturally pressurized water from a communicating zone (i.e., a natural water drive); and (c) drainage downward from a high elevation in a reservoir to wells penetrating lower elevations.

The natural expulsive forces present in a given reservoir depend on rock and fluid properties, geologic structure and geometry of the reservoir, and to some degree on the rate of oil and gas production. Several of the forces may be present in a given reservoir. Recovery efficiencies in the primary stage vary from less than 10 percent to slightly more than 50 percent of the oil in place. Estimates of cumulative oil production, cumulative ultimate oil recovery, and cumulative original oil in place for 1959-75 are given in table 5.

Secondary Recovery

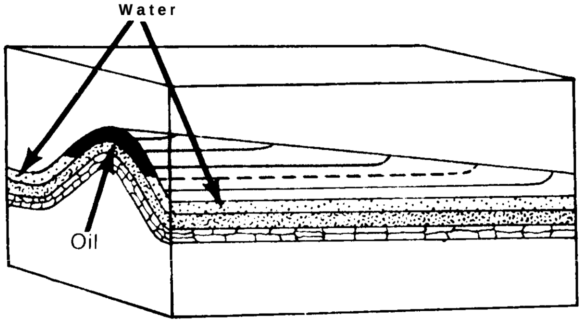
Most of a reservoir's oil remains in place after the natural energy pressurizing the reservoir has been dissipated. Several techniques for injecting fluids into an oil reservoir to augment the natural forces have been widely used for many years. Such fluid injection is generally known as secondary recovery. Fluids, most commonly natural gas and water, are injected through one series of wells to force oil toward another series of wells. The pattern of injection and production wells most appropriate to a reservoir are a matter of technical and economic judgment.

There is nothing inherent in fluid injection processes that requires their use only after the natural energy in a reservoir is exhausted. Indeed, it is frequently desirable to initiate such processes as soon as sufficient knowledge is available of the geology of the reservoir and the type of natural expulsive forces that are operative.

When water is the injection fluid, the process is commonly called waterflooding. If water is used to supplement a partially active natural water drive, the process is classified as a pressure maintenance project. When natural gas is injected, the operation is also called a pressure maintenance project. Injection of natural gas was widely used in the era of abundant low-cost gas, but the practice has decreased as the price of gas has increased.

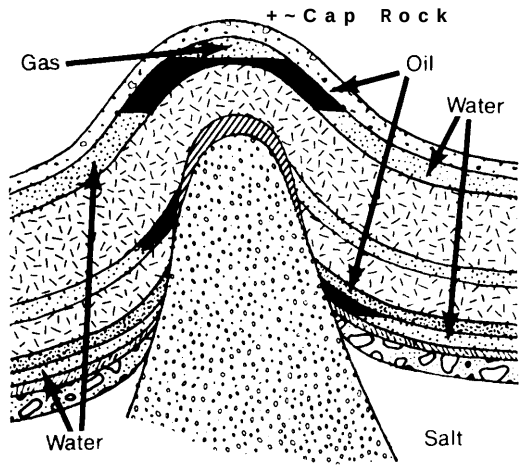
Types of Traps for Oil Accumulation*

Figure 3.



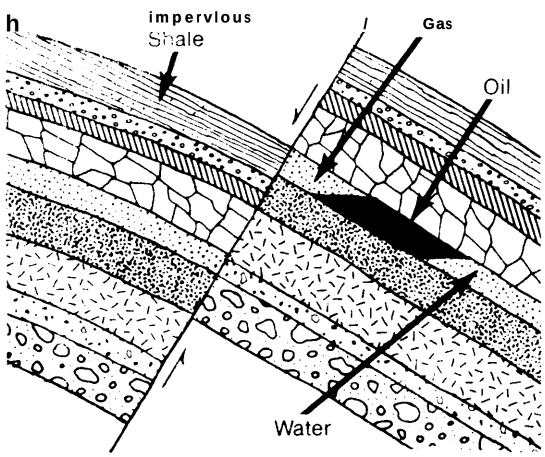
Oil accumulation in the top of a dome. Rock overlylng the dome is Impervious.

Figure 4.



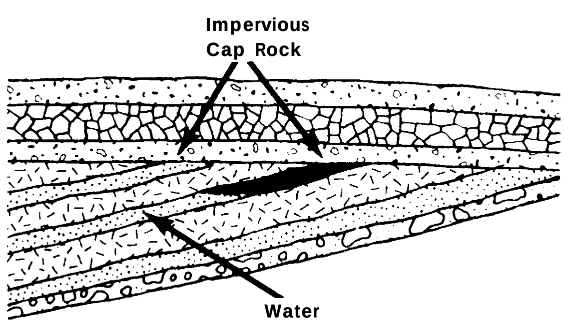
Oil accumulation in a dome at the top of a salt dome and also in a region on the side of the dome. Salt is Impervious to the oil.

Figure 5.



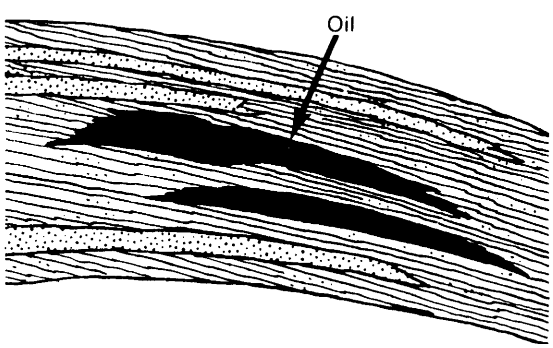
011 accumulation caused by a fault. The block to the right has moved upward so the oil formation is opposite the impervious shale, forming a trap.

Figure 6.



Oil trapped by overlying impervious cap-rock that interrupts lower lying formation of sandstone or limestone.

Figure 7.



Oil trapped within larger body of impervious shale.

*Illustratlons redrawn and prlnted with permission of the American Petroleum Instltute ı Amerıcan Petroleum Institute 1971

Table 5
Historicai Record of Production, Proved Reserves, Uitimate Recovery, and Original Oil in Place, Cumulatively by Year, Total United States.
(Billions of Barrels of 42 U.S. Gallons)

Year	Cumulative production	1975 estimate of cumulative ultimate recovery**	1975 estimate of cumulative original oil in place**
1959	62.3	122.3	384.7
1960	64.7	123.3	387.8
1961	67.2	123.7	389.8
1962	69.8	124.7	392.5
1963	72.4	125.3	394.7
1964	75.1	126.2	397.8
1965	77.8	127,6	402.4
1966	80.6	128.0	404.4
1967	83.7	128.7	407.0
1968	86.8	139.2	432.5
1969 ...., ...	90.0	139.8	434.8
1970	93.3	140.4	437.1
1971	96.6	140.9	438.7
1972	99.9	141.1	439.6
1973	103.1	141.4	440.9
1974	106.1	141.6	441.4
1975	109.0	141.7	441.9

● "For all fields discovered prior to the indicated year in Column 1.
"*Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 7975*, joint publication by the American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, Vol. 30, May 1976

Secondary recovery is proven technology; indeed, a recent study indicates that 50 percent of all domestic crude oil comes from secondary recovery operations.[4]

Waterflooding is inherently more efficient than gas displacement in pressure-maintenance projects and is the preferred process where feasible. Cumulative recoveries by primary and secondary production, where the secondary production is waterflooding, average between 38 and 43 percent of the original oil in place.

Some reservoirs, principally those containing heavy oil that flows only with great difficulty, not only provide poor primary recovery but often are not susceptible to waterflooding. Enhanced oil recovery would be especially useful in some of these reservoirs.

Enhanced Recovery

Processes that inject fluids other than natural gas and water to augment a reservoir's ability to produce oil have been designated "improved," "tertiary," and "enhanced" oil recovery processes. The term used in this assessment is enhanced oil recovery (EOR).

According to American Petroleum Institute estimates of original oil in place and ultimate recovery, approximately two-thirds of the oil discovered will remain in an average reservoir after primary and secondary production. This inefficiency of oil recovery processes has long been known and the knowledge has stimulated laboratory and field testing of new processes for

[4]*Enhanced Oil Recovery,* National Petroleum Council, December 1976.

more than 50 years. Early experiments with unconventional fluids to improve oil recovery involved the use of steam (1920's)[5] and air for combustion to create heat (1935).[6]

Current EOR processes may be divided into four categories: (a) thermal, (b) miscible, (c) chemical, and (d) other. Most EOR processes represent essentially untried, high-risk technology. One thermal process has achieved moderately widespread commercialization. The mechanisms of miscible processes are reasonably well understood, but it is still difficult to predict whether they will work and be profitable in any given reservoir. The chemical processes are the most technically complex, but they also could produce the highest recovery efficiencies.

The potential applicability of all EOR processes is limited not only by technological constraints, but by economic, material, and institutional constraints as well.

Thermal Processes

Viscosity, a measure of a liquid's ability to flow, varies widely among crude oils. Some crudes flow like road tar, others as readily as water. High viscosity makes oil difficult to recover with primary or secondary production methods.

The viscosity of most oils dramatically decreases as temperature increases, and the purpose of all thermal oil-recovery processes is therefore to heat the oil to make it flow or make it easier to drive with injected fluids. An injected fluid may be steam or hot water (steam injection), or air (combustion processes).

Steam *Injection.* **—Steam injection is the most advanced and most widely used EOR process. it has been successfully** used in some reservoirs in California since the mid-1960's. There are two versions of the process: cyclic steam injection and steam drive. In the first, high-pressure steam or steam and hot water is injected into a well for a period of days or weeks. The injection is stopped and the reservoir is allowed to "soak." After a few days or weeks, the well is allowed to backflow to the surface. Pressure in the producing well is allowed to decrease and some of the water that condensed from steam during injection or that was injected as hot water then vaporizes and drives heated oil toward the producing well. When oil production has declined appreciably, the process is repeated. Because of its cyclic nature, this process is occasionally referred to as the "huff and puff" method.

The second method, steam drive or steam flooding, involves continuous injection of steam or steam and hot water in much the same way that water is injected in waterflooding. A reservoir or a portion thereof is developed with interlocking patterns of injection and production wells. During this process, a series of zones develop as the fluids move from injection well to producing well. Nearest the injection well is a steam zone, ahead of this is a zone of steam condensate (water), and in front of the condensed water is a band or region of oil being moved by the water. The steam and hot water zone together remove the oil and force it ahead of the water.

Cyclic steam injection is usually attempted in a reservoir before a full-scale steam drive is initiated, partially as a means of determining the technical feasibility of the process for a particular reservoir and partly to improve the efficiency of the subsequent steam drive. A steam drive, where applicable, will recover more oil than cyclic **steam injection and** is one of the five EOR methods used in this study of the national potential for EOR processes. Illustrations of the operation of cyclic steam injection and steam drive are given in figures 8 and 9, respectively.

Cornbustiorl Processes. -Combustion projects are technologically complex, and difficult to predict and control. Interest in the process has declined within the last 6 years relative to other EOR processes. Active field tests declined from 30 in 1970 to 21 in 1976. Eight of the projects

[5] *Secondary and Tertiary Oil Recovery Processes,* Interstate Oil Compact Commission, Oklahoma City, Okla., p. 127, September 1974.

[6] Ibid., p. 94.

Figure 8. Cyclic Steam Stimulation Process*

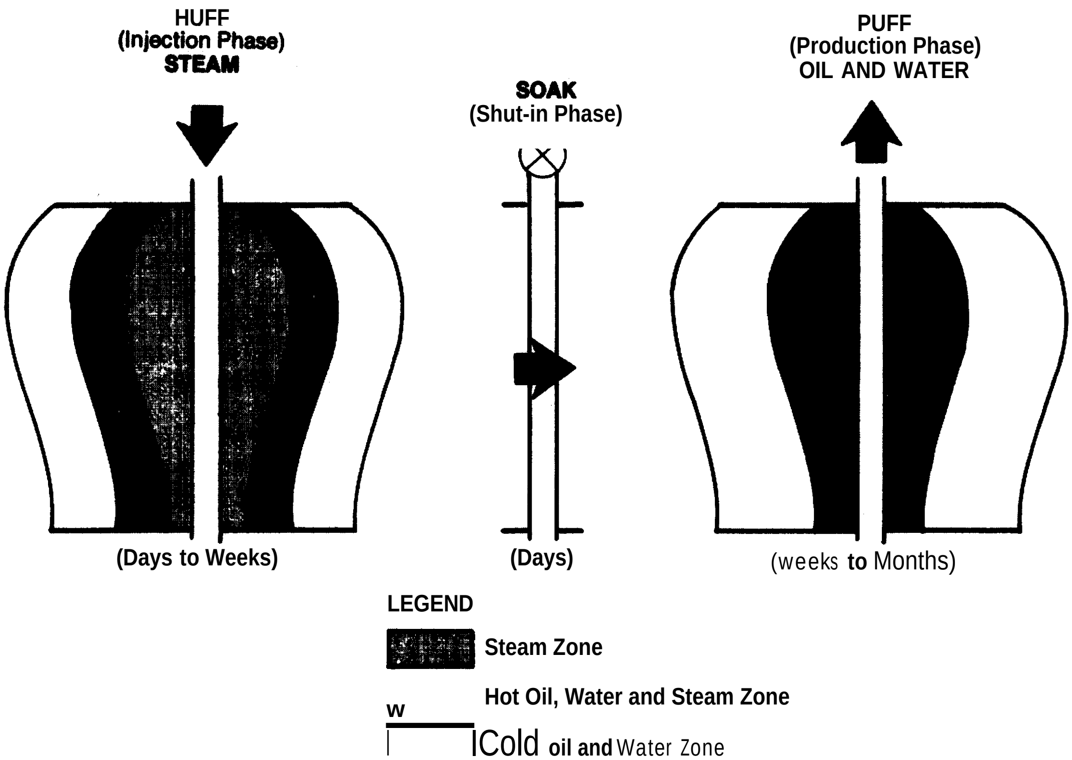
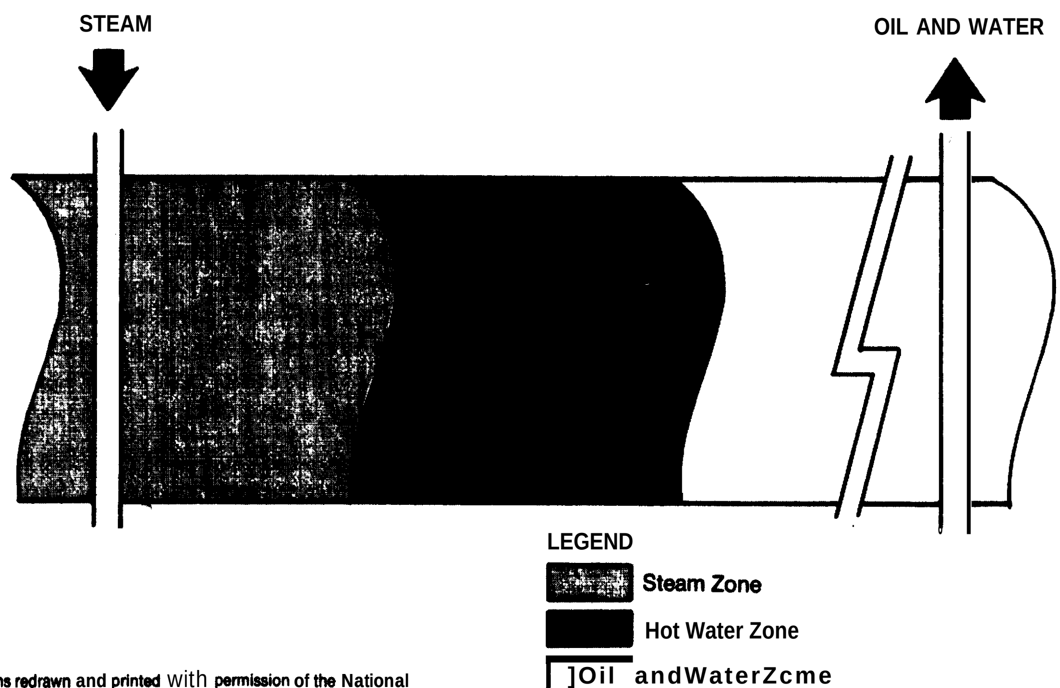


Figure 9. Steam Drive Process (Steam Flood)*



*Illustrations redrawn and printed with permission of the National Petroleum Council. © National Petroleum Council, 1976.

have been termed successful, **nine unsuccessful and four** have not yet been evaluated.[7]

Injection of hot air will cause ignition of oil within a reservoir. Although some oil is lost by burning, the hot combustion product gases move ahead of the combustion zone to distill oil and push it toward producing wells. Air is injected through one pattern of wells and oil is produced from another interlocking pattern of wells in a manner similar to waterflooding. This process is referred to as fire flooding, in situ (in place) combustion, or forward combustion. Although originally conceived to apply to very viscous crude oils not susceptible to waterflooding, the method is theoretically applicable to a relatively wide range of crude oils.

An important modification of forward combustion is the wet combustion process. Much of the heat generated in forward combustion is left behind the burning front. This heat was used to raise the temperature of the rock to the temperature of the combustion. Some of this heat may be recovered by injection of alternate slugs of water and air. The water is vaporized when it touches the hot formation. The vapor moves through the combustion zone heating the oil ahead of it and assists the production of oil. With proper regulation of the proportion of water and air, the combustion can proceed at a higher thermal efficiency than under forward combustion without water injection.

Combustion processes compete, at least technologically, with steam and some other EOR processes, and the choice depends upon oil and reservoir characteristics. The wet combustion process is illustrated in figure 10. It is the combustion process selected for technical and economic modeling in this study.

Miscible Processes

Miscible processes are those in which an injected fluid dissolves in the oil it contacts, forming a single oil-like liquid that can flow through the reservoir more easily then the original crude. A variety of such processes have been developed using different fluids that can mix with oil, including alcohols, carbon dioxide, petroleum hydrocarbons such as propane or propane-butane mixtures, and petroleum gases rich in ethane, propane, butane, and pentane.

The fluid must be carefully selected for each reservoir and type of crude to ensure that the oil and injected fluid will mix. The cost of the injected fluid is quite high in all known processes, and therefore either the process must include a supplementary operation to recover expensive injected fluid, or the injected material must be used sparingly. In this process, a "slug," which varies from 5 to 50 percent of the reservoir volume, is pushed through the reservoir by gas, water (brine), or chemically treated brine to contact and displace the mixture of fluid and oil.

Miscible processes involve only moderately complex technology compared with other EOR processes. Although many miscible fluids have been field tested, much remains to be determined about the proper formulation of various chemical systems to effect complete volubility and to maintain this volubility in the reservoir as the solvent slug is pushed through it.

One large (50,000 acre) commercial project in Texas uses carbon dioxide ($C0_2$) as the miscible agent, Eight other $C0_2$ projects covering 9,400 acres are. in early stages of development.[8]

Because of the high value of hydrocarbons and chemicals derived from hydrocarbons, it is generally felt that such materials would not make desirable injection fluids under current or future economic conditions. For this reason, attention has turned to $C0_2$ as a solvent. Conditions for complete mixing of $C0_2$ with crude oil depend on reservoir temperature and pressure and on the chemical nature and density of the oil.

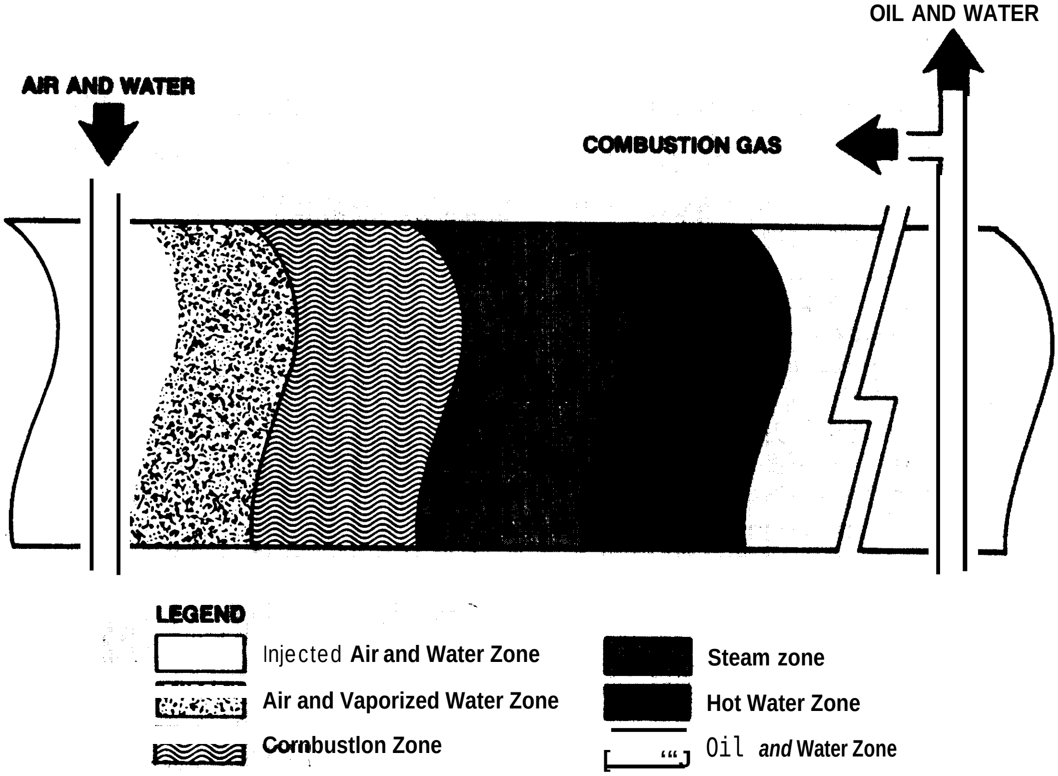
Although there are many possible CO_2 sources, the largest source should be naturally occurring deposits. Currently known sources of naturally occurring CO_2 are described in publications of the U.S. Bureau of Mines. A summary of CO_2 source locations is presented by the National petroleum Council,[9] although the actual

[7] *Management plan for Enhanced Oil Recovery,* ERDA 77-1 5/2, Vol. 2 (of 2), p. B-7, February 1977.

[8] *Management Plan for Enhanced Oil Recovery,* ERDA 77-1 5/2, Vol. 2 (of 2) p. B-4, February 1977.

[9] *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

Figure 10. In-Situ Combustion Process-Wet Combustion*



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amount of CO_2 at these locations is unknown. The potential demand for $C0_2$ is such that geological exploration is in progress.

A pictorial representation of a $C0_2$ miscible flood is shown in figure 11. In the past, CO_2 has sometimes, been injected into reservoirs in quantities and at pressures less than those necessary to achieve complete miscibility, resulting in less oil recovery than when complete mixing is achieved. In this assessment, quantities and pressures of CO_2 injected are designed to achieve complete miscibility.

Chemical Processes

Three EOR processes involve the use of chemicals—surfactant/polymer, polymer, and alkaline flooding.

Surfactant/Polyrner Flooding.—Surfactant/polymer flooding, also known as microemulsion flooding or micellar flooding, is the newest and most complex of the EOR processes, While it has a potential for superior oil recovery, few major field tests have been completed or evaluated. Several major tests are now under way to determine its technical and economic feasibility.

Surfactant/polymer flooding can be any one of several processes in which detergent-like materials are injected as a slug of fluid to modify the chemical interaction of oil with its surroundings. These processes emulsify or otherwise dissolve or partly dissolve the oil within the formation. Because of the cost of such agents, the volume of a slug can represent only a small percentage of the reservoir volume. To preserve the integrity of the slug as it moves through the reservoir, it is pushed by water to which a polymer has been added. The surfactant/polymer process is illustrated in figure 12.

The chemical composition of a slug and its size must be carefully selected for each reservoir/crude oil system. Not all parameters for this design process are well understood.

polymer Flooding. -Polymer flooding is a chemically augmented waterflood in which small concentrations of chemicals, such as polyacrylamides or polysaccharides, are added to injected water to increase the effectiveness of the water in displacing oil. The change in recov*ery* effectiveness is achieved by several different mechanisms, not all of which are completely understood. Improvement in the efficiency of waterflood recovery with the use of polymers is relatively modest, but it is large enough for the process to be in limited commercial use. If other EOR processes are technically possible they offer a possibility of both greater oil recovery and greater economic return than polymer flooding, although each reservoir must be evaluated individually to select the most effective process. As it is currently in use, polymer flooding is evaluated in this assessment.

Alkaline Flooding.—Water solutions of certain chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate are strongly alkaline. These solutions will react with constituents present in some crude oils or present at the rock/crude oil interface to form detergent-like materials which reduce the ability of the formation to retain the oil. The few tests which have been reported are technically encouraging, but the technology is not nearly so well developed as those described previously. Alkaline flooding was not quantitatively evaluated in the present study, largely because there is too little information about key oil characteristics in the OTA reservoir data base which are crucial to a determination of the feasibility of alkaline flooding. Reservoirs not considered for alkaline flooding became candidates for other processes.

Other EOR Processes

Over the years, many processes for improving oil recovery have been developed, a large number of patents have been issued, and a significant number of processes have been field tested. In evaluating a conceptual process, it should be recognized that a single field test or patent represents but a small step toward commercial use on a scale large enough to influence the Nation's supply of crude oil. Some known processes have very limited application, For example, if thin coalbeds lay under an oil reservoir this coal could be ignited, the oil **above** it would be heated, its viscosity would be reduced, and it would be easier to recover. This relationship between oil and coal is rare, however, and the process is not important to total national energy production. Another example involves use of electrical

Figure 11. Carbon Dioxide Miscible Flooding Process*

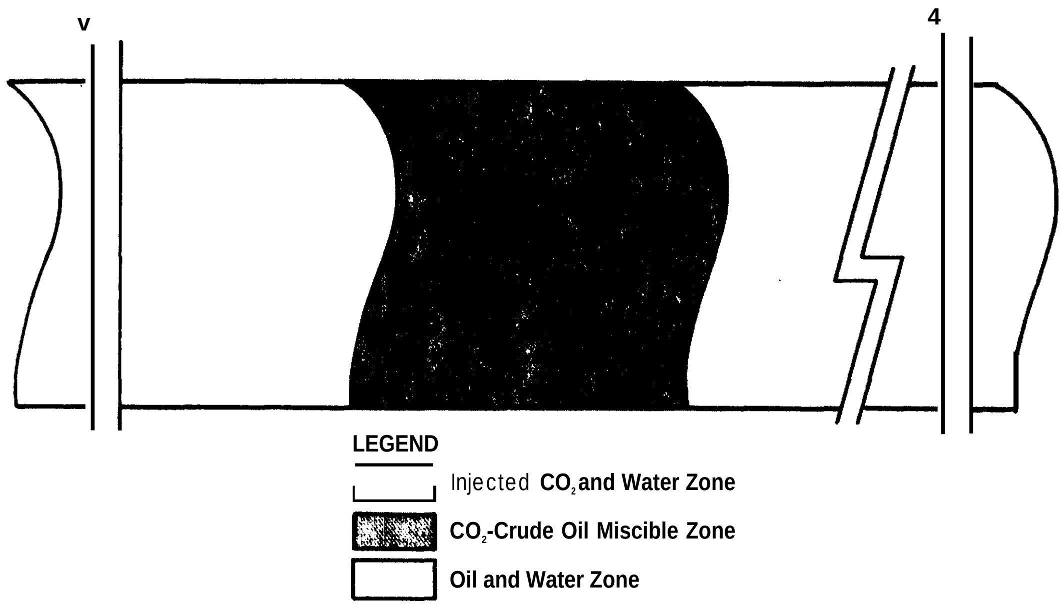
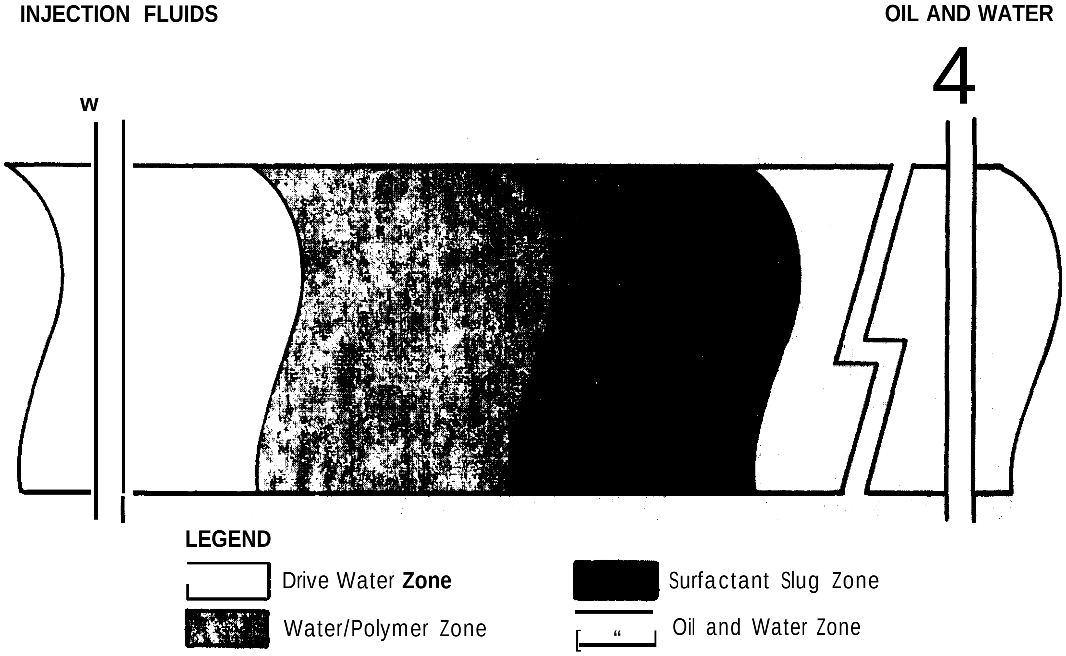


Figure 12. Surfactant Flooding Process



energy to fracture an oil-bearing formation and form a carbon track or band between wells. This band would then be used as a high-resistance electrical pathway through which electric current would be applied, causing the "resistor" to heat the formation, reduce oil viscosity, and increase oil recovery. The process was conceived over 25 years ago and has been tested sporadically, but does not appear to have significant potential. A third process in this category is the use of bacteria for recovery of oil. Several variations have been conceived. These include use of bacteria within a reservoir to generate surface-active (detergent-like) materials that would perform much the same function as a surfactant/polymer flood. Although some bacteria are able to withstand temperatures and pressure found in oil reservoirs, none have been found that will both successfully generate useful modifying chemicals in sufficient amounts and also tolerate the chemical and thermal environments in most reservoirs. It is uncertain whether nutrients to keep them alive could be provided. Further, any strain of bacteria developed would need to be carefully screened for potential environmental impacts. Finally, even should the concept prove feasible, it is unlikely that the bacteria could be developed, tested, and used in commercial operation in time to influence oil recovery by the year 2000.

Oil Resource for Enhanced Oil Recovery Processes

Data Base

The analytic approach used in this assessment of EOR potential relies on reservoir-by-reservoir simulations. The accuracy of this approach depends on the extent, representativeness, and precision of the reservoir data file. Earlier reports[10 11] have been based on data from 245 large onshore reservoirs in California, Louisiana, and Texas. For this assessment, additional data were collected for onshore reservoirs in those States, for reservoirs in other producing areas of the United States, and for reservoirs in offshore areas (primarily the Gulf of Mexico). The expanded data base for this assessment was acquired from Federal, State, and private sources. After all available data were examined and cataloged, they were edited for volumetric consistency. These data were reviewed by OTA as other sources of information became available. Additional data led to reductions in estimates of remaining oil in place (ROIP) in California reservoirs which contained oil with gravities above 25° API.

The resulting data base for the assessment ineludes 385 fields from 19 States (table 6). These 385 fields (835 reservoirs) contain 52 percent of the known ROIP in the United States. The reservoir data in the OTA data base are representative of the known oil reservoirs in the United States.

Uncertainty in the Oil Resource

Two EOR processes, surfactant/polymer and CO_2 miscible, are generally applied after a reservoir has been waterflooded. A large portion of the resource for these processes will be located in the reservoir volume which was contacted by water. The oil remaining in this region is termed the residual oil saturation.

There is uncertainty in the estimates of residual oil saturation and hence in the oil which is potentially recoverable with surfactant/polymer and CO_2 miscible processes. A review of the technical literature and discussions with knowledgeable personnel in the oil industry led to the following observations:

- **a** There are few reservoirs whose estimates of residual oil have been confirmed by independent measurement.
- **b** The uncertainty in the aggregate estimate is due to a lack of confidence in measurement

[10] *The Potential and Economics of Enhanced Oil Recovery*, Lewin and Associates, Inc., for the Federal Energy Administration, April 1976.

[11] *Enhanced Oil Recovery*, National Petroleum Council, December 1976.

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Table 6
Extent of the Reservoir Data Base Utilized in This Assessment of Enhanced Oil Recovery Potential

State	Remaining oil in place (MMB)	OTA database Fields	Reservoirs	Remaining oil in place (MMB)	Percent of State
Alabama ... ,	519	2	2	354	68
Alaska	14,827	6	9	14,601	98
Arkansas	2,768	3	3	1,328	48
California	62,926	41	67	45,125	72
Colorado	3,002	21	21	1,490	50
Florida	556	3	3	465	84
Illinois	5,726	8	9	2,421	42
Kansas	10,403	28	28	3,345	32
Louisiana					
Onshore	13,696	24	47	6,731	49
Offshore	7,349	24	372	2,983	41
Mississippi	2,988	11	12	1,187	40
Montana	3,796	15	15	1,443	38
New Mexico	11,241	15	18	4,960	44
North Dakota	1,849	6	7	548	30
Oklahoma	25,406	33	35	6,548	26
Pennsylvania	5,344	5	6	1,077	20
Texas	100,591	111	146	54,221	54
Utah	2,725	6	6	1,734	64
West Virginia	2,064	2	2	194	9
Wyoming	10,628	21	27	4,543	43
Total States covered (MMB)	288,404	385	835	115,298	54

Total U.S. (MMB) 300,338a
OTA database is 52 percent of remaining oil in place in the United States.

“This value includes 3.3 billion barrels of oil which are included In API Indlcated reserves as recoverable by secondary methods. it does not include 1.0 billion barrels of enhanced 011 in the API proven reserves.

techniques compounded by a limited application of those methods.

c. The estimates of residual oil saturation may be off by as much as 15 to 25 percent (or more).

d. Estimates of the oil recoverable by surfactant/polymer and CO_2 miscible processes will have a large range of uncertainty because of the uncertainties in the estimates of residual oil saturation.

Methodology for Calculating Oil Recovery

Estimates of the amount of oil that can be recovered by the different EOR processes were based upon an individual analysis of each reservoir in the data file. Results from the individual reservoir calculations were then compiled and extrapolated to a national total. In outline form, the procedure consisted of the following steps.

Technical Screen

A technical screen was established for each process. Reservoir rock and crude oil properties were screened against standards which had to be met before an EOR process could be considered applicable to that reservoir. The technical screens for all processes are shown in table 7. These screening parameters were established after an assessment of current technology and incorporation of expected technological advances. Each reservoir was compared to the technical screen for every process and either accepted or rejected for each process. A reservoir could be a candidate for more than one EOR process.

Calculation of Reservoir Production and Economics

Reservoirs which passed the technical screen were then analyzed to determine probable production performance and economics. Those reservoirs eligible for more than one EOR process were analyzed for all processes for which they were technically acceptable. For each process, both an oil recovery model and an economic model were established, Oil recovery models, described in appendix B, were used to predict the amount of oil which would be recovered and the rate at which the oil would be produced. These recovery models all incorporate features which made the calculations dependent upon the particular characteristics of the reservoirs.

The economic model described in appendix B was used to compute, at a specified oil price, a rate of return on investment which would result from application of a selected EOR process to a particular reservoir. The economic model allowed for different operating and drilling costs in different geographic regions, different well spacings, variable EOR process costs, etc. The model also incorporated a field development scheme. This scheme allowed a specified number of years for pilot tests and economic and engineering evaluations. It also provided for development of a field on a set time schedule rather than for simultaneous implementation of an EOR process over the entire field.[12]

Final EOR Process Selection for Reservoirs Passing More Than One Technical Screen

For reservoirs passing more than one technical screen, production resulting from application of a recovery technique and economic models for each acceptable EOR process were compared. The process selected was the one which yielded the greatest ultimate oil recovery, as long as the process earned at least a 10-percent rate of return on investment at the world oil price of $13.7s per barrel. If no process earned 10 percent at the world oil price, then the alternate fuels price of $22 **per barrel was used, again selecting the process which yielded the greatest amount of oil. Reservoirs not yielding 10 percent** for any process at the alternate fuels price of $22 per barrel were placed in the process which appeared to have the best economic potential. Reservoirs were deleted from consideration if the computations at the alternate fuels price resulted in a negative return on investment.

Ultimate Recovery for the Nation

Ultimate recovery for the Nation was estimated by extrapolating the individual reservoir

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[12]Our analysis assumed that enhanced recovery operations would be installed before producing wells are plugged and abandoned. If enhanced recovery operations are begun after producing wells are plugged and abandoned, oil recovery will be slightly more costly ($1 to $3 per barrel) and most likely delayed because of economics.

Table 7
Technical Screen
Enhanced Oil Recovery Processes

Property	Process				
	Carbon dioxide miscible	Steam drive	In situ combustion	Surfactant/polymer	Polymer
Oil gravity, °API	- - -	- - -	≤45	- - -	- -
Oi viscosity, cp. .	≤12	- - -	- - -	1976 1980 1995 ≤10 ≤20 ≤30	≤ °°
Depth, ft.	≤27°API, ≤7200 27° –30°, ≥5500 ≥30°, ≥2500 Depth correlated to miscibility pressure (Temp. correction also applied - see appendix B)	> 5°° < 5000	> 500	- - -	- -
Temperature, °F	- - -	- - -	- - -	1976 1980 1985 1990 1995 ≤120 ≤170 ≤200 ≤225 ≤250	1976 1980 1985 1990 1995 ≤120 ≤170 ≤200 ≤225 ≤250
Permeability, mD	- - -	- - -	- - -	≥20	≥20
Transmissibility, mD-ft / cp .	- - -	≥100	≥20	- - -	- - -
Salinity of brine*	- - -	- - -	- - -	- - -	- - -
TDS, ppm.	- - -	- - -	- - -	<200,000	- - -
Rock type.	- - -	- - -	sandstone	sandstone	- - -

For all processes—Gas Cap Reservoir—Considered applicable for EOR processes if a waterflood had carried out or was in progress.
If an EOR test or process is in progress, then the reservoir is considered to qualify for that process.
*Insufficient information to screen on this variable.

performances. Because a significant amount of the oil in each oil-producing State was represented in the data base, extrapolations were made on a district or State basis. Total recovery for each State or district, for a selected oil price and rate of return, was calculated in the following manner: The oil recovered from reservoirs in the data base for that State or district was multiplied by the ratio of total oil remaining in the State or district to oil remaining in the State or district data-base reservoirs. (The one exception to this rule was for West Virginia, where the sample included only 9 percent of the total oil in the State. For West Virginia, only the oil in the data base was included in the composite results. Deletion of West Virginia from the extrapolation process has no significant effect on ultimate recovery estimates because oil remaining in those reservoirs constitutes less than 1 percent of the oil remaining in U.S. reservoirs.) "Oil remaining, " as used here, refers to oil remaining after ultimate primary and secondary recovery. State and district productions were summed to obtain national production.

Rate of Production for the Nation

The starting date for the development of each reservoir was determined with the use of a rate-of-return criterion, Reservoirs earning the highest rates of return were assumed to be developed first. The schedule shown in table 8 was used to establish starting dates for reservoir evaluation, i.e., starting dates for pilot tests and economic and **engineering evaluations, which were then** followed by commercial development. Extrapolation of production rates from individual reservoirs to a State and then to the Nation was accomplished in the same manner as described for ultimate recovery.

This plan for reservoir development recognizes two factors which influence the application of improved oil recovery processes. First, it accounts in part for risk in that the highest rate-of-return projects will be initiated earliest when the technology is least certain. Lower rate-of-return projects would not be started until later dates, at which time the technological and economic risk should be reduced as a result of experience gained from field tests and commercial operations. Secondly, the timing plan in some measure simulates actual industry decisionmaking. As a general rule, the most promising projects are initiated first by industry.

Table 8
Schedule of Starting Dates
Based on Rate-of-Return Criterion

Date	Continuations of ongoing projects rate of return	New starts rate of return
1977	1 00/0	30 "/0
1978 ...., . . .	1 00/0	250/o
1979	10"/0	20 "/0
1980	"10"/0	19 "/0
1981	10%	18%
1982 , ...	10"/0	17'YO
1983	10%	160/0
1984	10%	15 "/0
1985	10%	14%
1986	10%	13"/0
1987 ...., . . .	1 0 %	12"/0
1988	10%	11 "/0
1989	10%	10"/0
1990-2000	10%	10"/0

Note: In the production models, after It has been decided to develop a reservoir, time is allowed to study the reservoir, conduct pilot tests and do engineering and economic analyses. These studies and evaluations are completed before initiating commercial production.

While OTA believes the timing plan is reasonable, it still is only an approximation of what will actually occur. Other factors such as level of technological risk, alternative investment opportunities, availability of resources required for the processes, etc., will significantly influence the implementation rate of EOR.

Exclusion of Alaska

The EOR potential of Alaska was not examined, for several reasons. A large portion of that State's oil resource was included in the data base (table 6). However, OTA felt that the economic data base required for the EOR economic models was not sufficiently well established. Alaska is a relatively young producing area and most of its oil fields are in a hostile environment. Costs are known to be high and difficult to estimate for future EOR projects. Also, because Alaska is a young producing area and because costs are high, EOR projects probably will not be considered to any significant degree for several years.

Estimated Oil Recovery

Definition of Cases

It is not possible to predict with certainty how much oil can be recovered in the future with EOR processes. Therefore, two principal cases were established, covering a range in the technological performance of the different processes. The more optimistic of these was labeled the "advancing technology—high-process performance case." The less optimistic was termed the "advancing technology—low-process performance case." These cases were designed in an effort to calculate realistic estimates of future recovery and at the same time reflect the uncertainty which exists in OTA's projection.

In addition to these two principal cases, estimates were made of the effects of variations in key parameters, such as injected chemical (CO_2, surfactant) costs, minimum specified acceptable rate of return, and resource availability, on recovery. These estimates, in essence, involved extensions and modifications of the two principal cases.

A description of the principal cases follows.

Case I: Advancing Technology—High-Process Performance

It was assumed for this case that the EOR processes which are now in their developmental stage (CO_2 miscible, surfactant/polymer, polymer-augmented waterflooding, and in situ combustion) would work as now generally envisioned by the petroleum industry. The production models for these processes, which are described in appendix B, were based largely on reported laboratory results with limited data from field tests. The steam process is the only technique that can currently be classified as a commercial process and as a result its production model is based on more field experience than the others.

Because of the nature of surfactant/polymer and polymer-augmented waterflood processes and their early stage of development, OTA assumed that certain technological advances would occur between now and the year 2000.

In the case of surfactant/polymer flooding, it was assumed that research and field testing would lead to a reduction in the volume of oil used in the surfactant slug and the volume of polymer needed to displace the surfactant slug through the reservoir. Reductions by a factor of two were assumed for both oil and polymer volumes from values representative of current technology. Current surfactant formulations are tolerant of total dissolved salt content of about 20,000 parts per million (ppm). It was also assumed that developments in the formulation of surfactant and polymer systems would extend salinity tolerance to 200,000 ppm. Finally, it was assumed that technological advances would occur in surfactant/polymer and polymer-augmented waterflooding processes which would raise the temperature constraint to 250° F. The timing of the advances is shown in table 7.

A major technological assumption for the CO_2 miscible process was that between 4 and 6 thousand cubic feet (Mcf) of CO_2 would be injected per barrel of EOR oil recovered. Although current pilot tests with CO_2 indicate that this injection-volume ratio may be on the order of 10 Mcf per barrel of oil, it was assumed that a technological advance to the above-stated injection efficiency would be achieved.

The advancing technology-high-process performance case was considered to be unconstrained by chemical resource availability. This assumption is also of paramount importance. For example, the amount of CO_2 required at the world oil price recovery is 53 trillion cubic feet (Tcf) (not including recycled CO_2). This is a very large quantity of CO_2, which simply may not be available at CO_2 prices used in the calculation. Chemical availability was also assumed for surfactant/polymer and polymer-augmented waterflooding processes.

Technological advances were assumed in the field application of steam and in situ combustion processes. Well-completion technology, which permitted selective depletion of each major zone within a reservoir, was assumed. All major zones were developed sequentially. Methods for controlling volumetric sweep efficiency of both processes were assumed to develop so that the processes could be applied to 80 percent of the reservoir acreage.

It was assumed in this case that the EOR processes could be made to operate without damage to the environment and that this could be done at no additional cost. For the thermal processes, in particular, this is an important assumption. For example, air pollution limitations now existing in California would allow little or no new steam recovery in that State without technological advances to reduce pollutant levels from steam generation.

In California, a limited number of refineries capable of processing heavy oil, an entitlements program, and a prospect of competing crude supplies from Prudhoe Bay combine to reduce the State demand for heavy oil production. The OTA study assumes that a market exists for all heavy oil produced in California.

Enhanced oil recovery production was assumed to occur in any reservoir if the rate of return after taxes was greater than 10 percent. This further implies advances in technology to reduce risk of failure, because investments at interest rates of 10 percent will only be made for relatively low-risk projects. Risk has been taken into account, as explained in a previous section, in that the production timing plan was based on rate of return with the "best" projects being initiated first, However, in the calculations a large amount of oil is recovered at rate-of-return values just slightly above 10 percent,

The advancing technology-high-process performance case implies a significant commitment to a research and development program which would be carried out in concert with the commercial implementation. The technological advances will not be made, nor will risk be reduced to the level assumed, without such an effort.

Case II: Advancing Technology-Low-Process Performance

Case II is a conservative estimate of future recoveries which assumes that no EOR process will work as successfully as it does in the advancing technology-high-process performance case. Changes were made in the production models which led to reductions in recoveries averaging between 12 and 30 percent for the different EOR processes. The details of the low-process performance case for each process are given in appendix B.

Case II essentially assumed that less oil would be recovered by the EOR processes using as large a dollar investment as was assumed in the high-performance case. Resource constraints were not imposed, and the assumption was made that the processes would operate without environmental damage.

Calculation Results

Low- and High-Process Performance Cases

The results of the high-process performance and low-process performance cases are shown in tables 9 through 14, Table 15 presents ultimate recovery by State while table 16 shows extrapolation proportions for each process under high- and low-process performance assumptions. Table 9 gives the cumulative figures for all processes. Individual process recoveries are shown in the other tables. Results are shown for three oil prices: upper tier ($11.62 per barrel), world oil ($13.75 per barrel), and alternate fuels ($22.00 per barrel).

These two cases represent the range of recoveries considered feasible for EOR technology. For these cases, recoveries were not restricted by resource availability and technology to meet environmental protection standards. Markets were assumed for heavy oil in California. The difference between the cases thus results from differences in assumptions about the technological performance of the processes.

For the high-process performance case at the upper tier price, it is estimated that approximately 21.2 billion barrels of oil could be recovered. The recovery increases to about 29.4 billion barrels at the world oil price and 41.6 billion barrels at the selected alternate fuels price, Corresponding uitimate recoveries for the low-process performance case are 8.0 billion, 11.1 billion, and 25.3 billion barrels, respectively.

Table 9
Estimated Recoveries for
Advancing Technology-Low- and High-Process Performance Cases
Aii Processes

	Low-process performance case			High-process performance case		
	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)
Ultimate recovery:						
(billion barrels)	8 0	11.1	2 5 3	21.2	29.4	41.6
Production rate in:						
(million barrels/day)						
1980. , ...	0.3	0.3	0.3	0.4	0.4	0.4
1985. ., ., ...	0.4	0.5	0.9	0.5	1.0	1.3
1990.	0.5	0.7	1.8	1.1	1.7	2.8
1995.	0,5	1.2	2.5	1.7	3.1	6.0
2000.	1,1	1.7	5.1	2.9	5.2	8.2
Cumulative production by:						
(million barrels)						
1980. ...., ...	400	400	400	500	500	500
1985.	1,200	1,300	1,700	1,700	2,000	2,400
1990, ., ...	2,000	2,300	4,200	3,300	4,700	6,200
1995.	2,800	3,800	7,500	5 , 6 0 0	8,700	12,800
2000. , ... , ...	4,200	6,900	‘1 6,000	10,400	17,300	29,200

Table 10
Estimated Recoveries for
Advancing Technology-Low- and High-Process Performance Cases
Steam Drive Process

	Low-process performance case			High-process performance case		
	Upper tier price $11.62/bbl)	World oil price [$13.75/bbl)	A1ternate fuels price ($22.00/bbl)	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)
Ultimate recovery:						
(billion barrels)	2.1	2.5	4.0	2.8	3..3	6.0
Production rate in:						
(million barrels/day)						
1980. . . . . ., ...	0.1	0 1	0.2	o.2	0.2	0.3
1985. .., ...	0 2	0.2	0.3	0.2	0.2	0.4
1990, ..., . .	0,2	0.2	0.5	0.2	0.3	0.7
1995.	0.2	0.3	0.4	0.2	0.3	0.7
2000, , ..., ...	0.2	0.3	0.4	0,3	0.4	0.6
Cumulative production by:						
(million barrels)						
1980. . . . ., ...	200	200	200	300	300	400
1985. ., ..., ...,	500	500	700	800	800	1,100
1990. ...., ., ...	800	800	1,400	1,100	1,100	2,000
1995. , ...	1,200	1,300	2,300	1,400	1,700	3,300
2000. ..., ...	1,600	1,800	3,100	1,900	2,400	4,600

Table 11
Estimated Recoveries for Advancing Technology-Low- and High-Process Performance Cases
In Situ Combustion

	Low-process performance case			High-process performance case		
	Upper tier price $11.62/bbl)	World oil price ($13.75/bbi)	Alternate fuels price ($22.00/bbl)	Upper tier price ($II.62/bbl)	world oil price ($13,75/bbl)	Alternate fuels price ($22,00/bbll
Ultimate recovery: (billion barrels)	1.2	1.4	1.6	1.7	1.9	1.9
Production rate in: (million barrels/day)						
1980	0.1	0.1	0.1	0.1	0.1	0.1
1985	0.1	0.2	0.2	0.2	0.2	0.2
1990	0.2	0.3	0.3	0.3	0.3	0.4
1995	0.1	0.1	0,2	0.2	0.2	0.2
2000	0.1	0.1	0.1	0.1	0.1	0.1
Cumulative production by: (million barrels)						
1980	*	*	•	•	•	*
1985	300	300	300	300	400	400
1990	600	700	800	800	900	1,000
1995	900	1,100	1,200	1,200	1,400	1,500
2000	1,000	1,200	1,400	1,400	1,600	1,700

*Less than 005 million barrels of daily production, or less than 50 million barrels of cumulative production.

Table 12
Estimated Recoveries for Advancing Technology-Low- and High-Process Performance Cases
Surfactant/Polymer

	Low-process performance case			High-process performance case		
	Upper tier price $11.62/bbl)	World oil price ($13.75/bbl)	A1ternate fuels price ($22.00/bbl)	Upper tier price $11.62/bbl)	World-oil price ($13.75‘bbl)	Alternate fuels price ($22.00/bbl)
Ultimate recovery: (billion barrels)	1 .0	2,3	7.1	7.2	10.0	12.2
Production rate in: (million barrels/day)						
1980	*	*	•	•	•	•
1985	*	*	0.1	·	0.2	0.2
1990	•	*	0.4	0.2	0.4	().7
1995	*	0.1	0.2	0.2	0.8	1,3
2000	0.2	0.2	1.3	0.9	1.9	2.5
Cumulative production by: (million barrels)						
1980	*	*	*	•	•	*
1985	100	100	200	100	300	300
1990	100	100	600	400	900	1,000
1995	100	200	900	700	1,800	2,000
2000	300	500	2,700	1,800	4,400	6,200

● less than 0.05 million barrels of daily production, or less than 50 million b.irrc~ls of cumulative production

Table 13
Estimated Recoveries for
Advancing Technology—Low- and High-Process Performance Cases
Carbon Dioxide Miscible

				High-process performance case								
	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)	Upper tier price ($11.62/bbl)			World oil price ($13.75/bbl)			Alternate fuels price ($22.00/bbl)		
				Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
Ultimate recovery (billion barrels) . . .	3.5	4.6	12.3	8.5	0.6	[illegible]	12.9	0.9	[illegible]	18.5	2.6	21.1
Production rate in: (million barrels/ day)**												
1980.	0.1	0.1	*	0.1	*	0.1	0.1	*	0.1	0.1	*	0.1
1985.	0.1	0.1	0.3	0.1	[illegible]	0.1	0.4	*	0.4	0.4	[illegible]	0.5
1990.	*	0.1	0.5	0.3		0.3	0.6	*	0.6	0.8		0.8
1995.	0.1	0.7	1.6	1.0	0.1	1.1	1.5	0.3	1.8	3.0	0.8	3.8
2000.	0.6	1.1	3.3	1.4	0.1	1.6	2.7	0.1	2.8	4.8	0.3	5.6
Cumulative production by: (million barrels)**												
1980.	100	100	100	100	*	100	100	*	[illegible]	100		
1985.	200	300	400	300	*	300	500	*	[illegible]	600		
1990.	300	500	1,200	700	100	800	1,400	200	1,[illegible]	1,700		1
1995.	400	1,000	2,800	1,700	300	1,900	3,000	500	3,[illegible]	4,400	1,	5
2000.	[illegible],100	3,100	8,500	4,400	500	4,900	7,600	900	8,[illegible]	13,700	2,	16

*Less than 0.05 million barrels of daily production, or less than 50 million barrels of cumulative production.
**Daily production figures rounded to 0.1 million barrels, cumulative production figures rounded to 100 million barrels; row totals may not add due to rounding.

Table 14
Estimated Recoveries for
Advancing Technology-Low- and High-Process Performance Cases
Polymer-Augmented Waterflooding

	Low-process performance case			High-process performance case		
	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)
Ultimate recovery: (billion barrels)	0.2	0.3	0.3	0.4	0.4	0,4
Production rate in: (million barrels/day)						
1980	*	•	•	*	*	•
1985	•	•	•	*	*	•
1990	0.1	0.1	0.1	0.1	0.1	0.1
1995	*	*	*	*	*	*
2000	•	*	•	*	•	•
Cumulative production by: (million barrels)						
1980		•	*	*	•	•
1985	100	100	100	100	100	100
1990	200	200	200	200	200	300
1995	200	300	300	300	400	400
2000	200	300	300	400	400	400

● Less than 0,05 million barrels of dally production, or less than SO million barrels of cumulative production.

Table 15
Ultimate Recovery by State
High-Process Performance

State	Ultimate recovery (billions of barrels)		
	Upper tier price ($11.62/bbl)	world oil price ($13.75/bbl)	Alternate fuels price ($2200/bbl)
California	6.8	7,8	11.4
Louisiana	1.1	1.2	2.0
Texas	4.7	7.9	11.6
New Mexico	1.2	1.7	1.7
Oklahoma	3.3	4.0	4.8
Kansas	1.6	2.3	2.7
Arkansas	0.3	0.4	0.4
Mississippi	0,2	0.3	0.4
Alabama	0,0	0.2	0.2
Florida	0.0	0.0	0.1
Colorado	0.0	0.4	0.4
Utah	0.0	0.0	0.2
Wyoming,	0.6	1.3	1.4
Montana	0.0	0.0	0.2
Illinois.	0.4	0.5	0.8
Pennsylvania	0.2	0,5	0.5
West Virginia	0.1	0.1	0.1
Offshore Gulf ot Mexico	0.6	0.9	2.6
Totals [a]	*21.2*	29.4	41.6

[a]Columns may not add due to roundlng

Table 16
Extrapolation of Ultimate Oil Recovery From Data Base Calculations to the Nation
World Oil Price ($13.75/bbl)

(Billions of Barrels)

Process	Low-process performance			High-process performance		
	Data base	Nation	Data base/ Nation percent	Data base	Nation	Data base/ Nation percent
Steam drive	1.40	2.5	56	1.83	3.3	55
In situ combustion	0.78	1.4	56	1.08	1.9	57
Carbon dioxide miscible	2.11	4.6	46	6.65	13.8	48
Surfactant/polymer	0.73	2.3	32	4.54	10.0	45
Polymer-augmented waterflood	0.15	0.3	50	0.19	0.4	48
Total	5.17	11.1	47	14.29	29.4	49

As indicated in table 9, all of this oil would not be recovered by the year 2000. For example, in the high-process performance case at the upper tier price, the production rate increases from slightly more than 0.5 MMBD in 1985 to nearly 3.0 MMBD in the year 2000. The daily production pattern shown results in a cumulative production by the year 2000 of 10.4 billion barrels, or sO percent of the projected ultimate recovery. At the other two oil prices, the production rate also increases through the year 2000. The cumulative productions by 2000 are 59 and 70 percent of ultimate recovery at the world oil and alternate fuels prices, respectively.

The five EOR processes examined yield markedly different amounts of oil as indicated in tables 10 through 14. This is illustrated by the high-process performance case. The CO_2 miscible process contributes about half of the ultimate recovery at the world oil and alternate fuels prices. The surfactant/polymer process is estimated to contribute about 30 percent of the total ultimate recovery and the thermal processes about 20 percent.

The only process found to be generally economical in the offshore reservoirs at the world oil price was CO_2 miscible. Other processes were found to be economical in only a very few reservoirs, Therefore, $C0_2$ miscible flooding was applied exclusively. The results are shown, along with the onshore recoveries, in table 13 for the high-process performance case. For low-process performance, offshore development was taken to be marginally economical and therefore unattractive.

Both the high- and low-process performance cases place great demands on resource requirements. For example, the amount of CO_2 that would be consumed in reaching the ultimate recovery at the world oil price is about 53 Tcf in the high-process performance case. This does not include about 18 Tcf of recycled $C0_2$. This is a very large amount of CO_2, and it is not known whether such a supply will be available at the costs assumed in the economic model.

Ultimate Oil Recovery by EOR Processes

Estimates of ultimate recovery were determined by extrapolating results from the 835 reservoirs in 19 States. Of the 835 reservoirs in the OTA data base, ***636*** were assigned to one of the five oil recovery processes. Nine reservoirs in Alaska were not evaluated for enhanced oil recovery processes due to insufficient cost data. Enhanced oil recovery processes were not technically feasible in the remaining ***190*** reservoirs.

The remaining oil in place (ROIP) in the 835 reservoirs is 155.3 billion barrels, which represents about 52 percent of the ROIP in the United States. About 14.6 billion barrels of this amount are in Alaskan reservoirs which were not considered for EOR processes. The ROIP in data base reservoirs which were evaluated for enhanced oil recovery processes was 140.7 billion barrels.

Net oil recovered from data base reservoirs by application of high-process performance models is 22.3 billion barrels at $30 per barrel. In estimating the net oil that can be recovered by enhanced oil processes, a reservoir was considered economic if it could be developed and yield a 10-percent rate of return at prices of $30 per barrel or less. This is about 95.5 percent of the oil considered technically recoverable using these models. Oil not recoverable under the high-process performance models is 133 billion barrels. Distribution of the potential recoverable and unrecoverable oil by process is shown in table 17.

Table 18 extends these results to the United States using the extrapolation procedure described in the section on *Ultimate Recovery for the Nation* on page 35.

The 49.2 billion barrels indicated as net oil recoverable by enhanced oil processes is an estimate of the upper limit of potential recovery at oil prices of $30 per barrel" or less. This is 95.6 percent of the oil considered to be recoverable. The estimate assumes successful application of EOR processes to all applicable reservoirs in the United States. If the EOR processes perform as assumed in the low-process performance case, the net potential EOR oil would be considerably less.

Unrecoverable oil in table 18 is estimated to be 248.8 billion barrels or 56.3 percent of the initial oil in place. About 76 billion barrels of oil will be left in reservoirs where no enhanced oil recovery process was considered applicable in the OTA study. Some portion of the 14.8 billion barrels which will remain in Alaskan reservoirs not evaluated in the OTA study may be recoverable at $30 per barrel. The approximately 170.4 billion barrels which remain in reservoirs after EOR processes are applied represent their inherent inefficiencies.

Table 17
Summary of Oil Recovery Evaluations
Data Base Resevoirs

Process	Reservoirs assigned[a] to process	Remaining oil in place (millions of barrels)	Net oil[b] recoverable (millions of barrels) at $30/barrel	Oil considered not recoverable (millions of barrels)
Steam drive	20	21,107	4,053	17,054
In situ combustion	20	7,585	1,126	6,459
CO_2 miscible				
Onshore	190	53,254	9,704	43,550
Offshore	294	2,695	1,298	1,397
Surfactant/Polymer	92	24,386	5,898	18,488
polymer augmented waterflood	20	3,949	189	3,760
No EOR	199	42,322	0	42,322
Total	835	155,298	22,268	133,030

[a]Process selected yielded maximum oil recovery at 10-percent rate of return or better at world oil price
[b]Oil used as fuel or injected as part of the displacement process was deducted from gross Production to find net production.
[c]Includes nine reservoirs in Alaska containing 14.6 billion barrels of remaining oil which were not evaluated due to insufficient cost data.

Discussion of Results

Table 18
Projected Distribution of Known Oil in the United States

	Billions of barrels	Percentage of original oil in place
Produced (December 31, 1975) . .	109.0	24.7
Proven reserve (including North Slope Alaska[a].	32.7	7.4
Indicated reserve[b].	5.0	1.1
Net oil recoverable by		
Enhanced oil processes in high-process performance case at $30/barrel. Not included in API proven or indicated reserves.	46.5	10.5
Unrecoverable oil		
Recoverable at price greater than $30/barrel	2.3	0.5
Oil left in reservoirs after enhanced oil recovery processes were applied and oil consumed as part of the recovery process	170.4	38.6
Oil in reservoirs where no enhanced oil recovery process was applicable at prices of $30/barrel[d].	76.1	17.2
	442.0	100.0

[a]API Proven Reserve (December 31, 1975) includes 1.0 billion barrels from enhanced oil recovery processes.
[b]API Indicated Reserve (December 31, 1975) includes 1.7 billion barrels from enhanced oil recovery processes.
[c]Net 011 recoverable in the high-process performance case is 49.2 billion barrels. The 2.7 billion barrels included in API Proven and Indicated Reserves as of December 31, 1975 were deducted from computed net EOR oil.
[d]Reservoirs in Alaska which will contain 14.8 billion barrels of oil after deduction of Proven and Indicated Reserves were not evaluated in this study due to insufficient cost data.

Projections of this study are based on application of EOR processes to reservoirs in the lower 48 States.

Projected Results for the United States

Ultimate Recovery

Results of the advancing technology cases, summarized in table 19, are estimates of the lower and upper bounds of the volumes of oil which are potentially recoverable at upper tier, world oil and alternate fuels prices. These volumes, ranging from 8 billion to 42 billion barrels, are significant when compared to the American Petroleum Institute (API) proven oil reserves (December 31, 1975) of 32.7 billion barrels which remained to be produced from existing fields.[13]

Table 19
Uncertainty in Projections of Ultimate Recovery for Advancing Technology Cases

Oil price $/barrel	Ultimate recovery (billions of barrels) Low-process performance	High-process performance
Upper tier ($11.62/bbl)	8.0	21.2
World oil ($13.75/bbl)	11.1	29.4
Alternate fuels ($22.00/bbl) .	25.3	41.6

The wide range in estimates is caused primarily by uncertainties in projecting oil recovery from application of the surfactant/polymer and CO_2 miscible flooding processes. Both processes are in early stages of development.

Production Rate

Daily production rates for the advancing technology cases at world oil prices are superimposed on the projected U.S. decline curve in figure 13. peak production rates are projected to be the same order of magnitude as the projected production rate from API proven, indicated, and inferred reserves in existing fields. Production rates in the mid-1980's are projected to vary between 8 and 17 percent of the projected produc-

[13]An additional 5 billion barrels are recognized by the API as Indicated Additional Reserves. About 3.3 billion barrels are projected from secondary recovery. The remainder (1.7 billion barrels) are attributed to enhanced oil recovery processes. A total of 31.7 billion barrels of the proven oil reserve will be produced by primary and secondary methods. One billion barrels will be produced by EOR techniques at current economics.

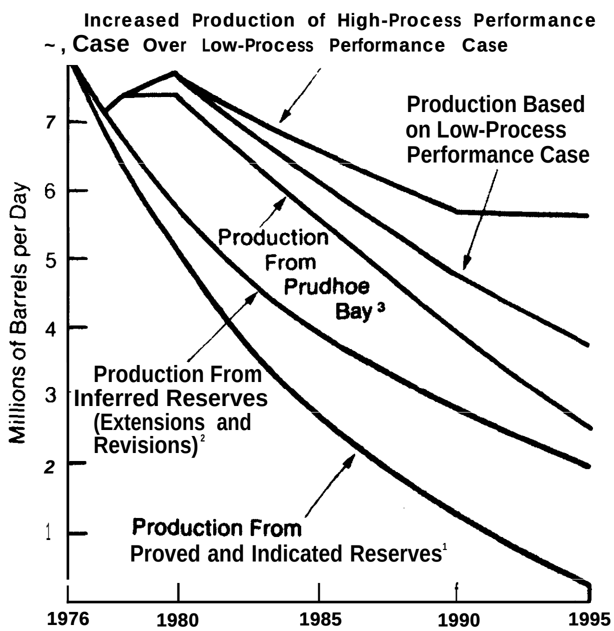
tion from existing fields by conventional methods.

Oil produced by improved oil recovery processes could become an important part of the Nation's oil supply for the period beginning in 1985 and extending beyond the year 2000. However, application of EOR technology would not offset the decline from existing fields until after 1990.

Uncertainties in Projections

The range of projections for ultimate recovery in table 19 and production rates in figure 13 represents OTA's judgment of the range of uncertainty which exists in the projections, Although uncertainties are present in projections of both ultimate recovery and production rate, the estimates of ultimate recovery are considered to be more certain than those for daily production rates.

Figure 13. Projected Production From Known U.S. Reservoirs, 1976-95, by Conventional Methods and by Enhanced Oil Recovery at World Oil Price



SOURCES [1] American Petroleum Institute, Reserves of *Crude Oil, Natural Gas Liquids, and Natural Gas in the U. S. and Canada as of December 30, 1975* Lewin & Associates, Inc for Federal Energy Administration, *Decline Curve Analysis, 1976*

[2] U S Geological Survey, *Circular 725,* 1975

[3] Federal Energy Administration, *National Energy Outlook,* 1976

Uncertainty in Ultimate Recovery

Projections of ultimate recovery at a specified oil price are uncertain because:

1) Estimates of ROIP volume and distribution within a reservoir may be as much as 25 percent (or more) in error. Further discussion of this problem is included in the section on the *Effect of Uncertainty in the Residual Oil Saturation and Volumetric Sweep on Projected Results* on page 50.

2) The ability to predict the oil recovery and the quantities of injected materials needed to obtain this recovery is different for each process and has wide ranges of uncertainty.

3) Materials used in the surfactant/polymer process are either derived from crude oil or compete with products derived from crude oil. Therefore, the costs of these components were increased for the purposes of this assessment as the price of crude oil increased. The cost of carbon dioxide was not varied with oil price. Because none of these materials is produced commercially in the volumes projected for this study, the cost estimates have some uncertainty. Sensitivity calculations described in appendix B show that both processes are extremely sensitive to costs of injected materials. A 50-percent increase in the estimated cost of chemicals would reduce the oil recovery from the surfactant/polymer process at $13.75 **per barrel** (high-process performance) from 10 billion barrels to 0.2 billion barrels. About 9 billion barrels of this oil would be recoverable at the alternate fuels price.

   The demand for natural CO_2 may be high enough for owners of these deposits to negotiate prices considerably above the production costs assumed in this study. For example, a 50-percent increase in the price of CO_2 would reduce the potential production from the CO_2 process from 13.8

billion barrels at $13.75 per barrel (high-process performance) to 7.0 billion barrels.

4) It is not known whether large volumes of injection fluids, particularly CO_2, will be available.[14] A comprehensive report of CO_2 availability in the United States has not been published, although ERDA is currently conducting such a study.

5) The level of uncertainty is influenced by the stage of technological development of each process. Steam displacement technology has been proven in portions of several California reservoirs. In situ combustion and polymer flooding have been tested extensively with mixed results. Surfactant/polymer flooding and CO_2 miscible displacement are still being investigated in laboratory and field tests.

Projected ultimate recoveries for steam displacement and in situ combustion are based on selective development of each major zone in a reservoir and application of the processes to 80 percent of each reservoir area. Selective completion has been used successfully in portions of a few reservoirs in California. There is no reservoir in the OTA data base where steam displacement or in situ combustion has been applied to 80 percent of the total reservoir acreage.

The CO_2 miscible process model is based on laboratory data and a number of field tests. Recent indications from the field tests are that the ratio of CO_2 injected to oil recovered may range above 10 Mcf of CO_2 per barrel of oil.[15] The assumption used in the present study for the high-process performance case was that this ratio would generally be reduced to 4 to 6 Mcf of CO_2 per barrel of oil, with 25 percent of the injection material being recycled CO_2. The average value for the high-process performance case was 5. I Mcf. For the low-process performance case, the average ratio was 5.4 Mcf per barrel of oil.

The effect of using a lower CO_2 injection ratio is to reduce chemical costs and thereby improve the economics. As an example, if the cost of injected CO_2 were increased by **a factor of 1.5 for the high-process performance case, the ultimate recovery by CO_2 miscible at world oil prices would be reduced from 13.8 billion barrels to 7.0 billion barrels. Additional discussion is presented** in appendix B.

Significant technological advances were assumed in application of the surfactant/polymer process. Specific assumptions are compared in table 20. The effect of the assumed technological advances on ultimate recovery for the surfactant/polymer process (shown in table 21) results in an increase in ultimate recovery from 2.9 billion barrels under current technology to 10.0 billion barrels at high-process performance at world oil prices.

Table 20
Comparison of Technological Assumptions for the Surfactant/Polymer Process

	Current Technology	Advancing technology
Reservoir temperature	≤200°F	<250°F
Oil viscosity, cp.	≤20	<30
Salinity, ppm.	≤20,000"	≤200,000*
Oil content in surfactant slug, vol. percent. ... , ...	20	10
Size of surfactant slug, fraction of volume swept by preceding waterflood	10	10
Size of polymer bank, fraction of (region) volume swept by preceding waterflood. .	1.0	0.50

*Constraint which could not be applied due to absence of salinity data,

Table 21
Comparison of Ultimate Recovery Under Two Technological Scenarios, Both Assuming High-Process Performance Surfactant/Polymer Process

Oil price $/barrel	Ultimate recovery (billions of barrels) Current technology	Advancing technology
Upper tier ($11.62/bbl)	0.2	7.2
World oil ($13.75/bbl)	2.9	10.0
Alternate fuels ($22.00/bbl) .	8.8	12.2

[14] EOR Workshop on Carbon Dioxide, Sponsored by ERDA Houston, Tex., April 1977.

[15] Ibid.

Uncertainty in Projected Production Rates

Production rate projections are influenced by the following factors:

1) A vigorous successful research and development and commercial exploitation program was assumed in the advancing technology cases. Time was allotted in the economic model for technical and economic pilot testing, which is necessary for fieldwide development. Each stage of testing was considered successful within a specified time frame. Development of the field was planned on a time schedule corresponding to normal oilfield development.

   partial success in initial field tests, low discovery rates for natural CO_2, and a slower rate of technological advance in the surfactant/polymer process are examples of factors which could delay or reduce the production rates projected in this study.

2) Production rates presented in tables 9 through 14 come from reservoirs which have a minimum discounted cash flow rate of return of 10 percent. Full-scale application of a process in a reservoir was done in a manner which approximates the pattern of industry investment decisions. In general, high-risk projects are undertaken early in a stage of technical development when the rate of return is high. Projects with 10-percent rate of return are undertaken when the risk of technical and economic failure is relatively low.

   The timing plan used to construct production rates for the Nation is dependent upon the projected rate of return for each reservoir. The economic model assumes that the reduction of technical and economic risk will occur at a rate (table 8) which initiates development of low rate-of-return (1 O percent) reservoirs in 1989. A result of this approximation is that a large volume of oil is produced after the year 2000 at the world oil price. Earlier or later reduction of risk could alter the annual production rates appreciably.

   The price of oil affects production rates in two ways. Higher oil prices encourage initiation of projects at earlier dates. Consequently, production from a reservoir which comes onstream in 1989 can be obtained at an earlier date and at a higher price if the technology is developed. A second effect of oil price is to add reservoirs at a higher price which cannot be developed economically at lower prices.

3) The rate-of-return criterion is a measure of risk in an advancing technology where the risks of technological and economic failures are high. In these instances, a high rate of return is required in order for the successful projects to carry those high-risk projects which fail.

Failures of a recovery process are not explicitly accounted for in this study. Thus, the projections of ultimate recovery and production rates assume a successful application of the process to every reservoir which meets the technical screen and the minimum after-tax rate of return. Thus, the projections have a built-in, but unknown, measure of optimism.

This optimism is offset to some extent by the fact that (1) the cost of failure in technical or economic pilot testing is comparatively small, and (2) no attempt was made to optimize process performance. Failure of a process in a reservoir at this stage would reduce the ultimate recovery and the predicted production rate. Overall economics for the process would not be significantly affected, provided other projects were economically successful.

If risk is reduced at a rate slower than that projected in table 8, only those projects and processes which have high rates of return will be pursued. For example, the majority of the surfactant/polymer flooding candidates have rates of return after taxes of between 10 and 15 **percent** at the world oil price for the high-process performance case, The technology is not proven and a 20-percent rate of return could be required by investors to offset the possibility of process failure in a given reservoir. If a 20-percent rate of return is required, few surfactant/polymer projects would be initiated.

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By contrast, steam displacement is a relatively proven process. Continued development and use of steam would be expected at rates of return of between 10 and 20 percent. The impact of high technical and economic risk on the ultimate recovery and production rates for all processes is illustrated by the comparison in table 22 for world oil prices. Reductions of 61 percent in ultimate production and 60 percent in average production rate for the time period from 1980 to 2000 are projected under high-risk conditions.

4) The production rate for the Nation is affected by environmental regulations and market conditions in California. Current environmental regulations limit the total emissions from steam generators and air compressors to pollution levels which existed in 1976. Under existing laws, the maximum incremental production rate from thermal methods in California will be 110,000 barrels per day. The impact of this constraint on the production rate is shown in table 23 for the advancing technology cases at world oil prices, Production rates for the Nation are reduced up to 29 percent for the period from 1980 to 1995 when constraints are applied. Ultimate recovery is not affected as the remaining oil will be produced after the year 2000.

A second factor limiting the development of thermal methods in California is the availability of refinery capacity to handle heavy oil. Heavy oil requires more processing to produce marketable products than do lighter oils such as Saudi Arabian light or Prudhoe Bay feedstocks. Ample supplies of these feedstocks on the west coast could suppress the development of heavy oil production even if environmental constraints were removed.

Effect of Uncertainty in Residual Oil Saturation and Volumetric Sweep on Projected Results

Residual Oil Saturation

The residual oil saturation in a reservoir following primary and secondary production sets an upper limit to the total amount of oil that could be produced using any EOR technique, no matter how good its performance may be. Thus, uncertainty about the residual oil saturation will lead to comparable uncertainty in the projected production from an EOR project, independent of uncertainty about process performance.

Table 22
High-Process Performance at World Oil Price ($13.75/bbl)

	Standard (1 O-percent rate of return)	High risk (20-percent rate of return)
Ultimate recovery (billion barrels)	29.4	9.5
Production rate in: (million barrels/day)		
1980	0.4	0.4
1985	1.0	0.5
1990	1.6	0.7
1995	3.1	1.0
2000	5.2	1.4
Cumulative production (million barrels)		
1980	500	500
1985	2,000	1,600
1990 ... ., ...	4,700	2,700
1995	8,700	4,100
2000, ...	17,300	6,800

Table 23
Impact of Technological Advances in Emission Control in California Thermal Recovery Projects on Projected Rates for the United States at World Oil Price ($13.75/bbl)

	Low-process per-		High-process per-	
	strained	strained	strained	strained
Ultimate recovery: (billion barrels)	11.1	11.1	29.4	29,4
Production rate: (million barrels/day)				
1980 ....., ...	0.3	0.3	0.4	0.3
1985, ...,	0.5	0.4	1.0	0.8
1990	0.7	0.5	1.7	1.4
1995	1.2	1.0	3.1	2.8
2000	1.7	1.5	5.2	4.9

The variations in parameters used to compare the high- and low-process performance cases for the surfactant/polymer and CO_2 miscible processes can also be used to simulate the effects of uncertainties in residual oil saturation. Specifically, the low-process performance case approximates a high-process performance case when the uncertainty in the residual oil saturation varies from 15 to 25 percent. As discussed in the section on *Uncertainty in the Oil Resource* on page 33, these figures represent the range of uncertainty which presently exists in the estimates of the process parameters.

Volumetric Sweep

The fraction of the reservoir which can be swept by the surfactant/polymer and CO_2 miscible processes was assumed to be the region which was previously contacted during waterflooding.[16] The volume of this region was assumed to be known with less certainty than residual oil saturation.

Two methods have been used to estimate the fraction of the volume of a reservoir that has been swept by earlier waterflooding. One method assigns values to reservoirs based on experience in the geographical region, The second method, used in the OTA study, is based on a material balance involving the oil initially present and the oil produced by primary and secondary methods.

The effect of these methods of determining sweep efficiencies was compared for the high-process performance case for a set of reservoirs consisting of 59 surfactant/polymer candidates and 211 onshore CO_2 miscible candidates. Use of estimated volumetric sweep efficiencies yielded 1.1 billion additional barrels of oil at the world oil price for the surfactant/polymer process. No significant difference was noted for onshore CO_2 results.

[16] Other possible interpretations are discussed in appendix B.

Maximum Oil Recovery by EOR Processes

Results of all cases show increased ultimate oil recovery with increased oil price. Further computations for the high-process performance case revealed that 95.6 percent of the oil considered technically recoverable would be produced at oil prices of $30 per barrel or less. Based on these estimates of technological advances, the volumes of oil which may be recoverable by enhanced oil process will not exceed 49.2 billion barrels for the United States (excluding Alaska). Thus, of the remaining 283 billion barrels of oil in the United States, excluding Alaska, 234 billion barrels are not recoverable under the technological advances assumed in the high-process performance case, Lower-process performance would reduce the ultimate recovery appreciably. Process improvements such as optimization of well spacing (i. e., infill drilling) and slug size were not considered in the OTA projections of ultimate recovery for the Nation, The effects of these improvements are expected to influence the projections less than the uncertainty in process performance. This assessment does not consider the potential of new processes or process modifications which might be developed at prices of $30 per barrel. These possibilities are not likely to have an impact on the Nation's crude oil supply during the period between 1976 and 2000.

Comparison With Other Studies

Estimates of the potential oil recovery and/or production rates resulting from the application of EOR processes have been published in seven documents.[17,18,19,20,21,22,23] Four of these[24,25,26,27] are based on surveys and other subjective methods and, as such, are considered preliminary estimates of the EOR potential for the Nation and not comparable to the OTA study in methodology, depth of investigation, or policy analysis.

Three of the studies[28,29,30] used a methodology similar to that used in the OTA study to estimate EOR potential. These studies are (1) the projections of enhanced oil recovery for California, Texas, and Louisiana, prepared by Lewin and Associates, Inc., for the Federal Energy Administration (FEA) (April 1976);[31] (2) the research and development program prepared by Lewin and Associates, Inc., for the Energy Research and Development Administration (ERDA) (November 1976);[32] and (3) an analysis of the potential for EOR from known fields in the United States prepared by the National Petroleum Council (NPC) for the Department of the Interior (December 1976).[33]

The methodologies of these studies are analogous in that the potential oil resource was determined using a reservoir-by-reservoir analysis. Each reservoir in the respective data base was considered for a possible EOR project. One or more EOR process was assigned to the reservoir. Oil recovery and economic simulations were made in a manner closely approximating commercial development in the oil industry. Ultimate production and production rates from economically acceptable reservoirs were used to extrapolate to the State and national totals.

Data bases varied somewhat between studies. The Lewin FEA and NPC studies used a common data base consisting of 245 reservoirs from California, Texas, and Louisiana. This data base was expanded to *352* reservoirs in 17 oil-producing States by Lewin and Associates, Inc., for their ERDA study. The OTA study incorporated, revised, and expanded the Lewin ERDA data base to 835 reservoirs containing 52 percent of the ROIP in the United States, as described in the section *Original Oil in* Place on page 23.

Cost data for development and operation of typical oilfields were obtained from the U.S.

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17 *The Estimated Recovery Potential of Conventional Source Domestic Crude Oil,* Mathematical, Inc., for the Environmental Protection Agency, May 1975.

18 *Project Independence Report,* Federal Energy Administration, November 1974.

19 *Planning Criteria Relative to a National RDT&D Program to the Enhanced Recovery of Crude Oil and Natural Gas,* Gulf Universities Research Consortium Report Number 130, November 1973.

20 *Preliminary Field Test Recommendations and Prospective Crude Oil Fields or Reservoirs for High Priority Testing,* Gulf Universities Research Consortium Report Number 148, Feb. 28, 1976.

21 *The Potential and Economics of Enhanced Oil Recovery,* Lewin and Associates, Inc., for the Federal Energy Administration, April 1976.

22 *Research and Development in Enhanced Oil Recovery,* Lewin and Associates, Inc., Washington, D. C., November 1976.

23 *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

24 *The Estimated Recovery Potential of Convention/ Source Domestic Crude Oil,* Mathematical, Inc., for the Environmental Protection Agency, May 1975.

25 *Project, /dependence Report,* Federal Energy Administration, November 1974.

26 *Planning Criteria Relative to a National RDT&D Program to the Enhanced Recovery of Crude Oil and Natural Gas,* Gulf Universities Research Consortium Report Number 130, November 1973.

27 *Preliminary Field Test Recommendations and Prospective Crude Oil Fields or Reservoirs for High Priority Testing,* Gulf Universities Research Consortium Report Number 148, Feb. 28, 1976.

28 *The Potential and Economics of Enhanced Oil Recovery,* Lewin and Associates, Inc., for the Federal Energy Administration, April 1976.

29 *Research and Development in Enhanced Oil Recovery,* Lewin and Associates, Inc., Washington, D. C., November 1976.

30 *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

31 *The Potential and Economics of Enhanced Oil Recovery,* Lewin and Associates, Inc., for the Federal Energy Administration, April 1976.

32 *Research and Development in Enhanced Oil Recovery,* Lewin and Associates, Inc., Washington, D. C., November 1976.

33 *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

Bureau of Mines[34] for all studies. Adjustments were incorporated to account for price changes between the reference dates for each study.

Results of these studies are compared with OTA projected results in table 24 for 1976 upper tier and world oil prices. There is agreement In the order of magnitude of the ultimate recovery among all the studies. The NPC projections include a base case which represents best estimates of process performance and associated process costs, and a range of uncertainty in the base case estimates due to poorer or better than expected process performance. Estimates from the OTA low-process performance case are within the NPC range of uncertainty for all oil prices. The OTA high-process performance case estimates more oil recovery than the upper estimates of the NPC study. At the world oil price, the OTA estimate is about 24 percent higher. The Lewin ERDA cases for upper tier price and $13 per barrel are close to the range of OTA values. The OTA projections are lower than the Lewin FEA results for California, Texas, and Louisiana, even if oil

[34] *Research and Development in Enhanced Oil Recovery,* Lewin and Associates, Inc., Washington, D. C., November 1976.

Table 24
Projections of Ultimate Recovery and Production Rate From the Application of Enhanced Oil Recovery Processes

Study	Reference date	Minimum rate of return for projection	Oil price ($/bbl)	Potential ultimate recovery (billion barrels)	Potential production rate in 1985 (million barrels/day)
OTA					
Low-process performance	1976	10 %	11.62	8.0	0.4
			13.75	11.1	0.5
High-process performance			11.62	21.2	0.5
			13.75	29.4	1.0
NPC'					
Poor performance	1976	10 %	10.00	3.1	
Expected performance (base case)				7.2	0.4
Better performance				13.4	
Poor performance			15,00	6.3	0.4
Expected performance (base case)				13.2	0.9
Better performance				26.9	1.6
ERDA[b]					
Industry base case**	1976	00/0	11.63	11.9	0.6
			13.00	13.1	0.6
Industry base case w/ERDA R&D**			11.63	26.2	1.7
			13.00	30.1	2.1
FEA					
California, Texas, and Louisiana	1975				
Lower Bound,		20%	11.28	15.6***	1.0
Upper Bound		80/0	11.28	30.5.	2.0

**Current tax case, 10-percent investment credit and expensing of injection materials and intangibles, with current environmental constraints.

"***Reserves added by the year 2000.

'*Enhanced Oil Recovery,* National Petroleum Council, Decemberl 976.

[b]*Research and Development in Enhanced Oil* **Recovery,** Lewin and Associates, Inc., for the Energy Research and Development Ad"nist"tio"I November 1976.

' *The Potential and Economics of Enhanced Oil Recovery,* Lewinand Associates, Inc., for the Federal Energy Administration, April 1976.

price, rate of return, and costs were placed on the same basis.

Estimates of producing rates in 1985 vary widely between studies. In general, the OTA projections are within the range of the NPC base-case study results and the Lewin industry base-case simulation. The OTA results are lower than the Lewin ERDA research and development case and the Lewin FEA projection for California, Texas, and Louisiana. The apparent agreement in producing rates between the OTA high-performance case and the Lewin ERDA case does not constitute confirmation of projections from independent studies for reasons outlined in a later section.

OTA-NPC Results

The OTA study team was provided access to all reports, oil recovery models, cost data, and results from the NPC study. Comparisons of projected ultimate recovery and production rates were made on a reservoir-by-reservoir basis. The same reservoirs which were included in the NPC base case for CO_2, surfactant/polymer, steam, and in situ combustion processes were studied in detail using NPC models and OTA models. All differences between OTA and NPC results can be traced to differences in recovery models, supplies of injected materials, costs of injected materials, and, in some cases, the timing plan used in the simulation to initiate projects.

The NPC study included a geological screen in which individual reservoirs were judged as good, fair, poor, or no EOR, based on qualitative information on the geology of each reservoir gathered from industry sources. The OTA study assumed all reservoirs had the same quality since geological information was available on only a small portion of the reservoirs in the data base. No reservoir was rejected for geological reasons, with the exception of those with a large gas cap which might prevent waterflooding.

The distribution of oil in a reservoir was treated differently in the OTA models. The OTA models assume 95 percent of the remaining oil is located in 80 percent of the reservoir acreage. All oil produced by. EOR processes is developed from the reduced portion of the acreage. This assumption was implemented by increasing the net thickness in the region developed. The use of economic models to determine the EOR process when two or more processes were possible led to different assignments of many reservoirs in the OTA study.

Major differences between the NPC and OTA results are:

a. Recovery from application of CO_2 displacement in the OTA high-process performance case exceeds NPC estimates by a factor of about two at all oil prices for which calculations were made. Comparable recovery models were used and the agreement in ultimate recovery for reservoirs common to both studies is reasonably close, In Texas, the OTA recovery at world oil price by CO_2 flooding is about 5.6 billion barrels. The corresponding NPC recovery is a little over 4.0 billion barrels.

   The NPC geological screen eliminated certain reservoirs in Texas from their study which OTA's study calculated would produce about 0.5 billion barrels of oil with the CO_2 process. When extrapolation was made to the entire State, this amounted to about 0.9 billion barrels. Considering the Texas results, as well as the entire Nation, the NPC geological screen accounts for part of the difference but is not considered the major factor,

   Expansion of the data base to other oil-producing States and offshore Louisiana resulted in more reservoirs as potential candidates for CO_2. A result was that considerably more oil was produced from States other than Texas, California, and Louisiana in the OTA study than was projected in the NPC report. In addition, in the OTA study at the world oil price, an ultimate recovery of 0.9 billion barrels was projected to be produced from offshore reservoirs that were not in the NPC data base (table 13).

   Oil recovery for the NPC CO_2 models varied according to geologic classifications of good, fair, and poor. The OTA recovery models were designed to represent an "average" reservoir. The use of this "average" reservoir in the OTA study may account for a significant portion of the difference in results for the three States of California, Texas, and Louisiana.

Significantly different pricing plans for the CO_2 resource were used by OTA and NPC, Prices used were similar in geographical areas such as western Texas, which have a high probability of obtaining supplies of natural CO_2 by pipeline. However, for other areas such as Oklahoma and Kansas there is less certainty of carbon dioxide pipelines and the pricing plans were quite different. In general, the NPC study used a significantly higher cost for CO_2 in these areas. This is considered to be a major reason for the difference in results for the Nation. The OTA CO_2 pricing model is given in appendix B.

b. Oil recovery from OTA surfactant/polymer projections for the low-process performance case at $13.75 Per barrel (2.3 billion barrels) is bounded by the NPC base case (2.1 billion barrels) and the NPC 5-year project life case (5.6 billion barrels) at $15 per barrel. (The NPC base case used a 10-year life while OTA models assumed a 7-year life.) The OTA high-process performance case at world oil price (10.0 billion barrels) projects about 1.0 billion barrels less oil recovery than the NPC better-than-expected performance projections (1 1.2 billion barrels) at $15 per barrel.

Two factors are the primary contributors to the slight differences in results of the two studies. First, more than twice as many OTA reservoirs were assigned to the surfactant/polymer process as in the NPC study. Forty-five percent of these reservoirs were not in the Lewin FEA data base used by NPC.

A second difference in the results was due to NPC's assignment of higher chemical costs to reservoirs which were ranked poor in the geologic screen. The OTA study assumed all reservoirs were of the same quality. Comparable projections of ultimate recovery at a specified oil price were obtained on individual reservoirs which had the same geological ranking and swept volume in both studies. Sensitivity analyses show agreement of the low-process performance projections and projections made by increasing chemical costs so that all reservoirs were "poor."

Some differences were attributed to the approaches used to estimate the volume of each reservoir swept by the surfactant flood. A discussion of this is included in the section on *Volumetric Sweep* on page 51. No offshore reservoirs were found to be economically feasible for application of the surfactant/polymer process in the OTA study. The NPC results included an estimate of 261 million barrels from offshore Louisiana reservoirs at $15 per barrel,

c. The OTA estimates of oil recoverable by thermal methods are within the range of uncertainty projected in the NPC study. The OTA low-process performance estimates are within 0.4 billion barrels (12 percent) of NPC base-case projections at prices between $10 per barrel and $15 per barrel. Projections for the OTA high-process performance case at these prices are about 1.0 billion barrels less than performance from the NPC high-recovery estimates. Comparisons by process are included in appendix B.

Oil recovery models for thermal processes in the NPC study were developed for areas with uniform reservoir properties. Projected recoveries from reservoir-wide application of these models were adjusted to account for variation of reservoir properties and process performance. This was done by reducing the ultimate recovery for uniform reservoir and process performance by factors of 0.7, 0.6, and 0.5, corresponding to the NPC geological screen of good, fair, or poor. Large reservoirs were subdivided into two or three areas judged to have different quality. Multiple-zone reservoirs were developed simultaneously. Crude oil consumed as fuel was deducted from gross production prior to computation of royalty and severance taxes.

The OTA thermal recovery models were developed to represent the average reservoir performance. Reservoirs were not assigned geological rankings based on reservoir quality. Multiple-zone reservoirs were developed zone by zone. Royalty and severance taxes were paid on lease crude consumed as fuel. This is a significant cost, as about one-third of the production in steam displacement projects is consumed as fuel.

d. polymer flooding models in both studies produce comparable results when polymer injection is initiated at the beginning of a waterflood. Some differences exist for waterfloods which have been underway for some period of time. The NPC recovery model projects a decline in oil recovery with age of waterflood, while the OTA study does not. Polymer flooding does not contribute much oil in either study.

e. The NPC study projected recovery from alkaline flooding. The OTA study acknowledges the potential of alkaline flooding for selected reservoirs but did not include the process for detailed study. Reservoirs which were alkaline-flood candidates in the NPC study became candidates for other processes in the OTA study.

OTA-FEA, ERDA Results

The OTA study used the economic programs and timing plans for reservoir development which were used to produce the results for the Lewin and Associates, Inc., studies for FEA and ERDA. Oil prices and a minimum acceptable rate of return (1 O percent) were selected for the OTA study. Costs of injected materials were obtained from both Lewin and NPC studies. Oil recovery models for the OTA study were developed independently of previous Lewin studies. The FEA study reported projections for three States; California, Texas, and Louisiana. The ERDA results include data from 17 oil-producing States while the OTA results use data from 18 oil-producing States. Projections for the Nation in the OTA and ERDA studies were obtained by summing State totals.

The OTA advancing technology cases assume a vigorous research and development program, although the stimulus for the program was not identified. Lewin and Associates, Inc., ERDA program assumes all improvements in recovery over an industry base case comes from an extensive ERDA R&D program which removes environmental and market constraints for thermal operations in California, results in improved recovery efficiencies for processes, and extends the processes to reservoirs not considered candidates in the industry base case. Targeted R&D projects were identified for specific reservoirs.

The documentation of anticipated improvement in the various processes is described in the report.[35] Incremental process costs and process performance associated with proposed process improvements were not identified. Consequently, there is no basis for a direct comparison with the Lewin ERDA projections resulting from an extensive R&D program. The agreement between OTA projections and the Lewin ERDA projections should not be considered confirmation of either study by independent methodology.

Although the ultimate recoveries and rates from the Lewin studies are close to the OTA results, there are significant differences in the assumptions which were used to develop the results. Distributions of oil recovery by process are also different. Principal differences between the OTA and Lewin studies involve the projected recovery for each process.

The **Oil** recovery models used by Lewin and Associates, Inc., for the FEA and ERDA studies were reviewed on a reservoir-by-reservoir basis. Comparisons between OTA recovery models and Lewin models produced the following observations:

a. Recoveries from the $C0_2$ flooding process are comparable in specific reservoirs. The

[35] *Research and Development in Enhanced* **Oil** *Recovery,* **Lewin and Associates, Inc., Washington, D. C., November 1976.**

OTA high-process performance case, at the world oil price, projects about a 40 percent greater ultimate recovery from CO_2 than the total for the Lewin ERDA research and development case plus the industry base case. A primary reason is the presence of additional reservoirs in the extended data base of the OTA study. The OTA low-process performance result is about half the Lewin ERDA value at world oil price. Costs of manufactured CO_2 in some areas are higher than in the Lewin study and this contributes in a minor way to the differences.

b. There are large differences between projections of ultimate recovery from the steam displacement process. The ERDA industry base case estimates ultimate recovery to be 66 billion barrels at $13 per barrel. Incremental oil expected from proposed ERDA R&D programs 8.2 billion barrels at the same price. Thus, an ultimate recovery of 14.8 billion barrels is projected from steam displacement as a result of ongoing industry activity and proposed ERDA R&D programs.

The OTA study projects an ultimate recovery of 3.3 billion barrels from steam displacement processes at $13,7'5 per barrel. This projection is lower than the ERDA industry base case by a factor of 2, and is lower than the ERDA industry base case with ERDA R&D by a factor of 4.5. The OTA and ERDA projections of ultimate recovery from steam displacement vary over a large range because of differences in specific technological advances which were incorporated in the displacement models. Major differences are discussed in the following paragraphs.

About one-third of the oil produced in a steam displacement process is consumed to generate steam. The amount of steam produced by burning a barrel of lease crude is not known with certainty. The OTA computations assumed 12 barrels of steam were produced per barrel of oil consumed, while the ERDA models assume 16 barrels of steam per barrel of oil. Applying the ERDA factor to OTA computations would increase the ultimate recovery about 10 to 15 percent. Differences of this order of magnitude are not considered significant.

Replacement of crude oil by a cheaper source of energy such as coal is a proposed ERDA steam program. Incremental production of 1.0 billion barrels was expected from this program. A successful program could increase the net crude oil produced by a factor of one-third in fields where it could be implemented. However, widespread substitution of coal for lease crude would have to be done in a manner which would satisfy environmental constraints.[36] The OTA study does not evaluate this possibility.

One ERDA program for steam projects an ultimate recovery of 1.8 billion barrels from light-oil reservoirs (less than 25°API) in Texas, Louisiana, and the midcontinent by a steam distillation process. This process was not considered in the OTA study. implementation of steam distillation on an economic scale requires development of a fuel for steam generation which is less expensive than lease crude oil. These reservoirs were assigned to other processes in the OTA study.

The principal difference between ERDA and OTA projections is in the recovery models for the steam displacement process. The ERDA steam model was developed using data from current field operations which are generally conducted in the best zones of a reservoir. Every part of the reservoir is considered to perform like the regions now under development. Steam drive was limited to depths of 2,500 feet in the ERDA industry base case. Increase in the depth to 5,000 feet added 1.6 billion barrels in the ERDA R&D case. The ERDA R&D program includes anticipated improvements in recovery efficiency for reservoirs which are less than 2,500 feet deep. The eventual

[36] ERDA Workshops on Thermal Recovery of Crude Oil, University of Southern California, Mar. 29-30, 1977.
[37] Ibid.

R&D goal for these reservoirs was to improve the overall recovery efficiency of steam drive by 50 percent. Incremental ultimate recovery for this program was expected to be 2.3 billion barrels.

The OTA steam displacement models are based on development of the entire reservoir using average oil saturations and recovery efficiencies. All reservoirs 5,000 feet in depth or less were developed. The OTA models underestimate recoveries from the better sections of a reservoir and overstate recoveries from poorer zones. Overall recovery from the OTA models is believed to be representative of the average reservoir performance.

Closer agreement between the ERDA industry base case and the OTA projections at the world oil price can be obtained by reducing the ratio of injection wells to production wells, thereby reducing the capital investment. The ERDA industry base case assumes fieldwide development on the basis of 0.8 injection well per production well. The OTA advancing technology cases used 1.0 injection well per production well. Reduction of the number of injection wells to 0.3 per production **well in the** OTA computations makes steam displacement economic in several large California reservoirs at the world oil price. Ultimate recovery at this price increases from 3,3 billion barrels (one injection well/production well) to 5.3 billion barrels (0.3 injection well/production well). Producing rates increase correspondingly. This comparison indicates potential improvements could result from optimizing well spacing. Additional results are included in appendix B.

In summary, steam displacement projections in the ERDA industry base case and ERDA R&D case assume more technological advances than judged to be attainable in the OTA study.

c. OTA surfactant/polymer projections for both low- and high-process performance cases fall between the projections from Lewin's ERDA industry base case and Lewin's FEA results for California, Texas, and Louisiana, for different reasons. Projected surfactant recoveries in the Lewin FEA study ranged between 3.8 billion barrels and 8.8 billion barrels at $11 per barrel. These projections are larger than OTA projections under the same economic conditions because the recovery models are based on different representations of the displacement process.

The industry base case for ERDA limits application of the surfactant/polymer process to shallow homogeneous reservoirs in the midcontinent. Ultimate recovery was estimated to be 0.6 billion barrels at $13 per barrel. This corresponds to the OTA projected recovery of 2.3 billion barrels at the world oil price for the low-process performance case and 10 billion barrels for the high-process performance case. The ERDA R&D program for the surfactant/polymer process projects an ultimate recovery of 1.4 billion barrels at the world oil price.

California reservoirs, which are major surfactant/polymer contributors in the OTA study, were excluded from the ERDA industry base case by assuming that technology would not be developed in the absence of the ERDA R&D program. The OTA methodology resulted in assignment of more reservoirs to the surfactant/polymer process than in the ERDA cases. A major difference exists in volumes and costs of chemicals used in the ERDA calculations. These volumes approximate those which have been tested extensively **in shallow reservoirs** in Illinois. The OTA advancing technology cases project technological advances which would reduce the volumes of chemicals required. This has a profound effect on the development of the surfactant/polymer process, as the projected recovery for the high-process performance case at the world oil price is reduced from 10 billion barrels to 2.9 billion barrels when OTA current technology surfactant and polymer slugs are used in the economic model.

- Ultimate recovery from polymer flooding varies from 0.2 billion to 0.4 billion barrels at the upper tier price in the OTA projections compared to 0.1 billion barrels in the ERDA industry base case. The OTA polymer model projects less recovery than the Lewin mod-cl 'for specific reservoirs. There were more reservoirs assigned to the polymer process in the OTA methodology.

Technological Constraints to EOR

Technological constraints are only one of several barriers to widespread commercialization of EOR[38] that include economic risks, capital availability, and institutional constraints. These constraints are coupled, and all must be removed or reduced to achieve major oil production from EOR processes.

The following section identifies and discusses the technological constraints that must be addressed in order to achieve the rate of progress that is postulated in the advancing technology case.

The technological constraints on EOR have been grouped in the following categories:

1. Resource availability.
2. Process performance,
3. Reservoir characteristics.
4. Materials availability.
5. Human resources.
6. Environmental impact.
7. Rate of technological evolution.

Resource Availability

The magnitude of the oil resource **for** EOR is not certain. The uncertainty is estimated to be 15 to 25 percent. Although this range may not seem large for the national resource, variation among reservoirs probably is larger. Furthermore, a small reduction in remaining oil in a reservoir may make it uneconomical to apply a high-cost EOR process at all, thereby leading to a disproportionate reduction in economically recoverable oil, The difference may be as high as the difference between the advancing technology-high- and low-process performance cases, which amounts to 18 billion barrels at the world oil price, equivalent to about half the current U.S. proved reserves.

Resource uncertainty represents a major technical and economic risk for any EOR project in any reservoir. Reduction of this risk would need high priority in any national program to stimulate EOR production.

Sampling a reservoir through core drilling, logging, and other well testing is an expensive, inexact, developing technology. The problem is that of finding methods which will probe outward a sufficient distance from a well bore to determine oil content in a large fraction of the region drained by the well. A further complication exists **in that oil saturation variations** occur both horizontally and vertically within a reservoir. Determinations at one well may not be applica**ble at other well sites.**

A program to stimulate EOR production should contain a major effort to promote measurement of residual oil saturations in key reservoirs until confidence is gained in methods to extrapolate **such data to other locations in the same** reservoir and other reservoirs. Equal emphasis should be placed on the gathering of such data and on the improvement of measurement methods.

Process Performance

Process Mechanisms

Enhanced oil recovery processes are in various stages of technological development. Even though steam drive is in limited commercial development, the outer limits of its applicability are not well understood. Steam drive can probably be extended to light **oil reservoirs but it has**

[38] *Management* ***plan*** **for** ***Enhanced*** *Oil* ***Recovery, ERDA,*** **Petroleum and Natural Gas Plan, ERDA 77-15/1, p. II-1, February 1977.**

not been tested extensively. Larger gaps in knowledge exist for other processes and process modifications which are in earlier stages of development. Field tests have consistently been undertaken with incomplete knowledge of the process mechanism. Most laboratory tests of processes are done on systems of simple geometry (generally linear or one-dimensional flow), leaving the problems that **occur because of the** more complex flow geometry to field testing.

As indicated in the section on *Process Field Tests* on page 61, extensive field testing of EOR processes will be required. As more field projects are undertaken, the tendency of industry is to shift research personnel from basic and theoretical studies to development activities. If this effort is widespread it may limit the ability of companies to undertake fundamental **EOR research. If this trend continues, additional public support for basic research applicable to EOR** may become advisable.

A major industry /Government coordinated effort is needed to thoroughly define the process mechanisms for each of the recognized basic EOR processes and process modifications, This effort would need to be initiated immediately and to proceed at a high level of activity for at least 5 years if the postulated rate of EOR applications is to be achieved.

Volumetric Sweep Efficiency

Recovery efficiency of all processes depends upon the fraction of the reservoir volume which can be swept by the process, i.e., sweep efficiency. Thus a strong economic incentive exists for improvement of volumetric sweep. Research in this area has **been carried** out for a number of years by many sectors of the oil production, oil service, and chemical industries. The importance to EOR success of improving sweep efficiency has been confirmed in a recent assessment of research needs.[40]

Despite the long-term effort on this problem, success has been limited. Solutions are not available for each process. Improvements are needed for each individual process and each process variation as well as for major classes of reservoirs. Progress will be difficult and will require major field testing supported by extensive prior laboratory work. This research effort, both basic and applied, must be significantly stimulated in the next 3 to 6 years in order to approach the estimated EOR production potential for the period between 1976 and the year 2000.

Brine-Compatible Injection Fluids

Enhanced oil recovery processes will **be used** largely in those parts of the country that face increasing shortages of fresh water. For surfactant/polymer and polymer flooding, relatively fresh water is still needed both for the polymer and surfactant solutions and for reservoir preflushing. Even where fresh water is available for preflushing, it is often not efficient in displacing brine. Consequently, injected fluids in such reservoirs must be brine compatible. Continued laboratory and field research is needed to develop surfactants and other oil-recovery agents which are brine compatible.

In the present study, brine compatibility of injected fluids was assumed in the advancing technology cases. Data were not available in the OTA data base to assess the importance of this assumption, but it is known to be significant.

Development of Additional Processes Applicable to Carbonate Reservoirs

Although carbonate reservoirs represent approximately 28 percent of the initial oil in place in the United States,[41] the CO_2 miscible process is the only EOR process currently applied to such reservoirs, There is a possibility of using steam flooding in some carbonate reservoirs,[42] and other processes or process modifications should

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[39] ERDA Workshops on Thermal Recovery of Crude Oil, University of Southern California, Mar. 29-30, 1977.

[40] *Technical Plan for a Supplementary Research Program To Support Development and Field Demonstration of Enhanced Oil Recovery,* for U.S. Energy Research & Development Administration, Washington, D. C., GURC Report No. 154, Mar. 17, 1977.

[41] *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 7975,* Joint publication by the American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, Vol. 30, May 1976.

[42] *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

be tested for carbonate reservoirs because of the possibility of CO_2 shortages and because of the high cost of delivering CO_2 to areas that might not be served by pipelines.

Operating Problems

Operating problems of EOR are more severe, less predictable, and certainly less easily controlled than operating problems one faces in a plant making a new chemical product, but the industrial sector is equipped to solve such problems. For example, steam is now generated from high-salinity brines, a process that once seemed to pose serious technical problems. Most such problems, however, must be solved within the next 6 to 8 years if the potential production represented by OTA's advancing technology case is to be achieved.

Some problems exist where Government assistance could be beneficial. Design of steam generators for steam-drive projects that will meet environmental pollution-control standards and use cheaper alternate fuels (heavy crudes, coal, etc.), as well as large-scale steam generation, are areas that have been recently highlighted.[43] Equipment for retrofitting existing generators to permit them to meet new standards and lower their unit pollution level is also needed.

Process Field Tests

The current ERDA field testing program is a vital step in accelerating EOR process commercialization, If the upper targets of any of the recent predictions of EOR potential are to be achieved, a significant increase is needed in the rate of technical progress. To achieve this, the level of field tests needs to be significantly increased. **While** OTA did not attempt to estimate the optimal number, a study by the Gulf Universities Research Consortium (GURC) estimated 100 as a target group.[44] It is important that ERDA-sponsored field tests be part of an EOR research strategy designed to complement industry's efforts and to provide information that can be generalized to a variety of classes of reservoirs, The status of current field tests taken from the Lewin ERDA report[45] is shown in table 25.

There are at least three levels of field tests: minitests, single- or multi pattern-pilot tests, and fieldwide commercial testing.

Single- and multipattern-pilot tests should be directed at determining potential economic success and to thoroughly defining the technical performance. To maximize the value of such field tests, extensive pre- and post-test well coring, logging, fluid analysis, and laboratory tests are required to understand the process well enough to provide a strong knowledge base for operating at full scale in test reservoirs. Data acquisition is expensive and time consuming, and the record indicates that too little data are being gathered. Government support for such activities may be required if the postulated rate of technological advance is to be achieved.

Special consideration should be given to testing more than one process in a reservoir and to undertaking processes in reservoirs that offer new ranges of application of the process.

There is some current concern about the relative merits of minitests (one to two well tests at small well spacing) compared with larger single- or multipattern-pilot tests. Both can be helpful. The minitest is faster, less expensive, and may be helpful in initial process or reservoir screening. However, its lower cost and greater simplicity do not substitute for the greater degree of understanding that can come from multi pattern tests.

The number of projects that should be undertaken for fieldwide commercial demonstration is not easily determined. **A case** can be made **for at least one such** test for every major process that has not yet reached commercialization. The options of cost sharing, risk sharing, and/or support through special price **or tax** provisions should all be considered. Considerations of the merits of such alternatives, the scale of operations, and the applicable processes were outside the scope of

[43] ERDA Workshops on Thermal Recovery of Crude Oil, University of Southern California, Mar. 29-30, 1977.

[44] *A Survey of Field Tests of Enhanced Recovery Methods for Crude Oil*, for FEA and the National Science Foundation, Washington, D. C., GURC Report No. 140-S, Nov. 11, 1974.

[45] *Research and Development in Enhanced Oil Recovery*, Lewin & Associates, Inc., Washington, D.C. Part 1, p. III-2, November 1976.

Table 25
Field Activity in Enhanced Oii Recovery

Technique	Number of EOR Proiects						Acreage under current development
	Technical pilots		Economic pilots		Fieldwide development		
	Total	Current	Total	Current	Total	Current	
Steam drive. ., ...	17	13	15	14	15	15	15,682
In situ combustion	17	3	6	5	19	10	4,548
CO_2 miscible and nonmiscible.	5	4	6	6	2	2	38,618
Surfactant/polymer.	12	10	7	7	2	2	1,418
polymer-augmented waterflooding	3	0	14	9	14	11	14,624
Caustic-augmented waterflooding	5	1	2	0	0	0	63
Hydrocarbon miscible . .	9	7	6	5	10	8	56,782
Totals.	68	44	57	47	62	48	131,735

"From *Research and Development in Enhanced Oil Recovery,* Final Report, Lewin & Associates, Inc., Washington, D. C., ERDA 77-20/1,2,3, December 1976.

this study. However, the issue **needs to be addressed within** the next year or two. This test program is a facet of the Government program that deserves a major emphasis.

Reservoir Characteristics

Uncertainty concerning the physical and chemical nature of an oil reservoir is one of the most severe technological barriers to EOR processes.[46] Not only are reservoirs significantly different among themselves, even within the same geological class, but the place-to-place variations in thickness, porosity, permeability, fluid saturation, and chemical nature can be discouragingly large. The present ability to describe, measure, and predict such variability is extremely limited. Knowledge to measure and predict this variability within a reservoir is vitally important for forecasting fluid movement and oil recovery efficiency. Research efforts have so far been directed toward studying portions of individual reservoirs intensively, with little attention given to generic solutions.

Any major governmental research effort to accelerate oil production from EOR processes should include development of methods to measure, describe, and predict variations in properties throughout a reservoir. Extensive field and laboratory studies are warranted.

Raw Materials Availability

Enhanced oil recovery processes use both natural and manufactured raw materials.. Short-term shortages of manufactured materials could exist for all EOR processes if a vigorous national program were launched to produce EOR oil.

The supply of two natural resources, fresh water and CO_2, may limit ultimate recovery from steam injection, surfactant/polymer, and CO_2 miscible processes. Local shortages may develop for adequate supplies of fresh or nearly fresh water in some areas in which polymer flooding or surfactant/polymer flooding is initiated. Most areas of known fresh water shortage either have or are developing criteria for allocation of the scarce supply among competing classes of use. A major technological challenge for EOR lies in development of economic means for using water with higher saline content for all processes in which water is needed. The problem seems to have been solved for steam generation. Brine of up to 20,000 ppm can be used successfully.

[46] *Technical plan for a Supplementary Research Program To Support Development and Field Demonstration of Enhanced Oil Recovery,* for U.S. Energy Research and Development Administration, Washington, D. C., GURC Report No. 154, Mar. 17, 1977.

Carbon dioxide availability is central to any major expansion of CO_2 flooding. As mentioned previously, the quantity needed (a total of 53 Tcf in the advancing technology-high-process performance case at world oil prices) is a volume almost three times the annual volume of natural gas consumed in the United States.

The economic potential of CO_2 flooding is so great that a Government effort to accelerate EOR production should include not only locating natural sources of carbon dioxide but also exploring ways to produce it economically from large-scale commercial sources. Locations of known, naturally occurring CO_2 sources are summarized in the recent NPC study of EOR.[47] The magnitude of the reserves of CO_2 at these locations is not known. ERDA is currently involved in a nationwide survey of CO_2 availability.

Human Resources

Shortages of technically trained people to operate EOR projects may exist temporarily if a major national EOR effort is undertaken. National projections of needs for technically trained people have not been highly accurate. Data are not readily available on industrial needs since many firms do not make formal, continuing, long-range personnel forecasts. The efforts of ERDA and other agencies in national manpower forecasting could be encouraged.

All EOR processes are extremely complex compared to conventional oil recovery operations. Because of this technical complexity, highly competent personnel must be directly involved in each EOR project on a continuous basis at the managerial, developmental, and field operations level. Without close monitoring by qualified technologists, the odds for success of EOR projects will be lower, There currently is a mild short-term shortage of persons to work on EOR projects. National forecasts[48] of the number of available college-age students (all disciplines) indicate a significant enrollment decline over the period of greatest potential EOR activity. The supply of technical people (engineering, science, and business) available for EOR operations will crucially depend upon the economic climate in other sectors of the economy. In a generally favorable economic climate, increasing competition for qualified personnel could develop.

Environmental Effects

For most EOR processes and in most geographical areas, accommodation to environmental protection regulations will not be a critically restrictive requirement. Details of environmental impacts and an estimate of their severity and magnitude are described in chapter VI of this report. The environmental effects that pose major technological problems include the need for emission controls in California thermal EOR projects, the possibility of fresh water shortages, and the need to protect ground water.

The need to develop an economically acceptable means of meeting the air pollution requirements for thermal processes has become critical in California. Further expansion of the thermal process in California awaits this development.

The requirements placed on EOR processes by the Safe Drinking Water Act (P.L. 93-593) are critical for their long-term development. Accommodation to the Safe Drinking Water Act is not so much a technological problem as it is a human and administrative matter. The need is one of establishing acceptable guidelines that will protect fresh water sources and still allow EOR processes to proceed. The record of compatibility of these two goals through the long period of secondary recovery in the United States suggests that this can be accomplished. This is discussed further in chapter VI.

The Rate of Technological Evolution

All estimates of potential recovery from application of EOR processes are based on a postulated rate of technological evolution. There is consensus among personnel in industry, Government, and academic institutions who are

[47] *Enhanced Oil Recovery,* National petroleum Council, December 1976.

[48] *Projection of [durational Statistics to 7985-86,* National Center for Educational Statistics, Publ. NCES 77/402, p. 32, 1977.

knowledgeable **in enhanced** oil recovery processes that much research and field testing is necessary to bring EOR technology to the point where commercialization is possible for all processes except steam displacement.

The suggested components of research and development programs to stimulate EOR production have received significant appraisal and modification within the last 4 years. Between 1973 and March 1977, the Gulf Universities Research Consortium (GURC) issued a series of five reports[49,50,51,52,53] detailing the need **for field tests, their number and character, and the basic research needs.** In addition, Lewin and Associates, Inc,[54] prepared a major study for ERDA which recommends specific research targets (process/reservoir type). Further details of the ERDA program are outlined **in the** ERDA Management Plan for EOR.[55]

The GURC and Lewin documents represent compilations of existing industrial viewpoints concerning research targets and types of programs that are appropriate. This gathered consensus has been supplemented by a **series of ERDA-sponsored workshops on ERDA research** targets[56,57] at which modifications to the program were suggested through public forums.

Although there is agreement concerning general research and development needs, there is a decided difference of opinion regarding the factors which will stimulate this needed research and development. The Lewin ERDA study[58] proposed an extensive Government research and development program, justified in part by results of an industry survey which indicated that research would not be greatly accelerated within the current set of constraints (economic, technical, and institutional). The National Petroleum Council's EOR study concluded that "Government policy with respect to oil price and other factors influencing EOR profitability is the dominant factor in establishing the level of R&D funding and the rate of evolution of technology. "

The OTA assessment did not attempt to resolve these positions because there appeared to be no meaningful way to predict what industry would do a) if the price of oil produced by some EOR processes was allowed to rise to free market prices as proposed by FEA, orb) if the price of all EOR oil were decontrolled. as proposed in the President's National Energy Plan.

The ERDA Programs

The Energy Research and" Development Administration has developed programs which are directed at stimulation of research and development of EOR processes. The general thrust of the ERDA programs, including field testing and continued industry/Government interaction, is good.

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i'~P/armi ng *Criteria Relative to* a *National RDT&E Program Directed to the Enhanced Recovery of Crude Oil and Natural Gas,* for U.S. Atomic Energy Commission, Washington, D. C., GURC Report No. 130, Nov. 30, 1973.

50*An* I*nvestigation of Primary Factors Affecting Federal Participation in R&D Pertaining to the Accelerated Production of Crude Oil,* for the National Science Foundation, Washington, D. C., GURC Report #1 40, Sept. 15, 1974.

51A *Survey* of *Field Tests of Enhanced Recovery Methods for Crude Oil* (supplement to GURC Report No. 140), for the National Science Foundation and the Federal Energy Administration, Washington, D. C., GURC Report No. 140-S, Nov. 11, 1974.

52*Preliminary Field Test Recommendations* and *Prospective Crude Oil Fields or Reservoirs* for High Priority *Field Testing,* for U.S. Energy Research and Development Administration, Washington, D. C., GURC Report No. 148, Feb. 28, 1976.

53*Technical Plans for a Supplementary Research program to Support Development and Field Demonstration of Enhanced Oil Recovery,* for U.S. Energy Research and Development Administration, Washington, D. C., GURC Report No. 154, Mar, 17, 1977.

54*Research and Development in Enhanced Oil Recovery,* Lewin & Associates, Inc., Washington, D.C. Part 1, p. III-2.

55*Management Plan for Enhanced Oil Recovery, ERDA,* Petroleum and Natural Gas Plan, ERDA 77-15/1, p. II-1, February 1977.

56ERDA Workshops on Thermal Recovery of Crude Oil, University of Southern California, Mar. 29-30, 1977.

57EOR Workshop on Carbon Dioxide, sponsored by ERDA, Houston, Texas, April 1977.

58*Research* and *Development in Enhanced Oil Recovery,* Lewin & Associates, Inc., Washington, D. C., Part 1, p. III-2.

The ERDA management plan for EOR[59] is directed at maximizing production in the mid-1980's. However, short-term needs should not overshadow long-term national needs of increasing oil **recovery. The OTA analysis indicates that a long-range program is needed to stimulate the development** of processes, such as the surfactant/polymer process, which have the potential for greater oil recovery in the mid-1990's,

There does not seem to be adequate basic and applied research in the ongoing ERDA program. This has been recognized by ERDA, and an extensive research program has recently been outlined by GURC[60] **for** ERDA. This research program supplements the programs outlined in the ERDA management plan.[61]

The largest amount of basic and applied research has come from the integrated major oil companies and the service sector of the petroleum industry. The largest amount of expertise also resides in the industry. Basic and applied research done by industry and research institutions should be coordinated so that Government programs complement rather than duplicate programs underway in industry. This subject does not seem to be covered formally in the ERDA documents, and is particularly crucial since even under Government sponsorship a large portion of the basic and applied research is likely to be **done** in industry laboratories and oilfields.

The OTA assessment did not determine the level of ERDA or industry effort required to achieve the postulated technological advances or the cost of the necessary research and development. (Other studies have shown that the cost of research and development is on the order of a few cents per barrel of ultimate recovery.) However, the level of effort and funding in R&D must clearly be significantly increased over current levels by both industry and Government in order for the evolution of technology to approach the technological advances postulated in this assessment.

[59] *Management plan for Enhanced Oil Recovery,* ERDA, Petroleum and Natural Gas Plan, ERDA 77-1 5/1, p. 11-1, February 1977.

60 *Technical Plans for a Supplementary Research Program to Support Development and Field Demonstration of Enhanced Oil Recovery,* for U.S. Energy Research and Development Administration, Washington, D. C., GURC Report No. 154, Mar. 17, 1977.

61 *Management Plan for Enhanced Oil Recovery,* ERDA, Petroleum and Natural Gas Plan, ERDA 77-1 5/1, p. 11-1, February 1977.

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IV. Impacts of Price and Tax Policies on Oil Recovery

IV. Impacts of Price and Tax Policies on Oil Recovery

Policy Considerations

With the advent of a new technology like enhanced oil recovery (EOR), two related factors often inhibit expansion of output. First, even with certainty of information about prices, costs, and production, careful analysis may indicate that production will not be profitable for early operators. prices may be too low or production experience may have been inadequate to reduce costs or increase efficiency sufficient to yield an acceptable return on invested capital. Second, as in any market situation, there will be uncertainty about many variables that can affect profitability. In the case of EOR, technical and economic uncertainty, coupled with some degree of aversion to risk by potential operators, can inhibit the speed and extent of process development.

Proposed public policy alternatives are, in essence, attempts to reduce the effects of these two factors on the private decision process, modify private market decisions, and remove barriers to EOR development. Although these two factors are obviously interdependent, the artificial distinction will be maintained for purposes of this analysis. First, the report evaluates alternative public policy options designed to foster private-sector development of enhanced recovery processes under the *assumption* **of information certainty. Point projections of production, price, and cost profiles for selected reservoirs** will be used. A second analysis, using subjective probability distributions of key input variables, describes the impact of policy alternatives designed to alleviate economic uncertainty.

Policy Options

A number of public policy alternatives have been suggested which could influence the development of EOR techniques, Implementation of these alternatives may affect private sector decisions on the development of specific EOR reservoirs or modify decisions regarding which process should be installed. Some policy options also may alter constraints which would limit the amount of EOR production nationally. Regardless of their specific focus, most public policy changes can be expected to influence the degree of uncertainty perceived by the private sector in future EOR activities.

A number of these potential public policy actions will be analyzed and evaluated. The principal proposals can be classified as:

1) alternative regulated and/or market price levels;
2) price and/or purchase guarantees for EOR over the lifetime of a producing facility;
3) alternative taxation policies, including changes in depreciation methods, investment tax credit rates, and expensing rules for various categories of investment and operating costs; and
4) public investment subsidies-Government payment of a percentage of private investment costs.

In addition, the effects of these alternative strategies can be determined under alternative leasing systems when the reservoirs being considered are located on the public domain.[1] For

[1]Another policy option which could be considered for reservoirs located on the public domain is altering the lease terms to encourage enhanced oil recovery installations at an optimal point in the production time horizon. Analysis of this option, however, requires data not only on EOR costs and production profiles but on the synergistic effects with primary and secondary production. Since little experience is available on these elements, evaluation of the option would be difficult, if not impossible, at this time.

analytical purposes, OTA **examined the various options** in conjunction with several leasing systems, including the current system and others that could be used in the future. These systems include:

1) The current cash bonus system;

2) Higher fixed royalty rate plus cash bonus; and

3) Fixed-rate profit share plus cash bonus.

The analysis was conducted under five different price assumptions for enhanced oil production:

1) The current regulated upper tier (new oil) price of $11.62 per barrel;

2) The current price of foreign crude oil landed in the Eastern United States—$1 3.75 per barrel (in 1976 dollars);

3) A price approaching the estimated cost of synthetic fuels—$22 per barrel;[2]

4) An intermediate price between the world oil ‘price and the synthetic fuels price—$1 7 per barrel; and

5) A rising real world oil price initially set at $13.75 per barrel and projected to rise at a 5-percent annual rate.

The first four alternatives assume a constant real price and the fifth alternative assumes a rising real price.

For each EOR **process, baseline evaluations were carried out using these alternative price** levels and currently permitted tax procedures (including the 10-percent investment tax credit, expensing of injection chemicals, and Unit of production depreciation). Then, the following policy alternatives were analyzed:

1) Price subsidies of $1 and $3 per barrel;

2) Price guarantees of $13.75 per barrel;

3) Investment tax credit of 12 percent compared with the current 10 percent;

4) Capitalization and subsequent depreciation **of** injection chemical costs;

5) Use of an augmented accelerated depreciation method; and

6) Government investment subsidy of 15 percent of initial capital investment.

Since several of these options (price subsidies and guarantees) are designed to reduce uncertainty, they were not evaluated under the assumption of information certainty.

Alternative leasing systems for public domain lands were tested with various options, including the current cash bonus—fixed royalty system, a cash bonus system with a 40-percent fixed royalty, and an annuity capital recovery-profit share system with a cash bonus bid. In this profit share system, investment costs are converted to an annuity over 8 years of 8-percent interest, and the annuity is subtracted from net profits before the Government share of 50 percent is taken. j

Analytical Approach

All reservoirs in a selected sample were tested, using cost and production profiles from the high-process performance case discussed in chapter III. As a check on these results, data from the low-process performance case were also analyzed. individual EOR processes were evaluated sepa-

[2]This price was **obtained from the report of the** Synfuels **Interagency Task Force.**

‘Other leasing systems have been suggested and could be evaluated. For example, variable rate options for both royalty and profit share systems may be desirable alternatives. However, the systems chosen appear to cover a range of possible results.

rately using baseline values and then using the policy options discussed above.[4] The entire analysis was conducted using a Monte Carlo discounted cash flow simulation model (Tyner and Kalter, 1976), modified to handle the EOR decision process as viewed by the private sector.

Analysis of Government Policy Options

Reservoir Sample

For purposes of policy analysis, a sample of up to 50 of the reservoirs assigned to each EOR process (see previous discussion) was selected for initial evaluation. Separate samples for onshore and offshore areas were drawn from reservoirs assigned to the CO_2 process. Sample selection was based upon a number of criteria including regional location, reservoir depth, residual barrels of oil per acre (available for tertiary production), reservoir size in acres, and, in the case of offshore fields, water depth, For each EOR process evaluated, fields covering a broad range of these characteristics were included.

After reviewing the range of values taken on by the various selection criteria, it was decided that a sample of 25 reservoirs for each EOR process would be adequate to cover the circumstances affecting economical development and provide an appropriate test of the various policy options. The only exception to a sample number of 25 was the case of onshore CO_2 where substantial EOR production was expected. Table 26 displays the number of reservoirs assigned to each process, the number selected for the sample, and the percentage of the reservoir data base sampled.

Analysis Assuming Information Certainty

Price analysis

Given the sample selection, the first step in the analysis was to test the potential for profitable EOR development at various price levels under conditions of information certainty. Using production profiles, investment costs (and **timing), and operating costs developed for the high-process performance case, these tests were conducted under the assumptions that private industry would require a 10-percent net after tax, rate of return on invested capital and that currently permitted tax procedures (State and Federal) would be governing. Thus, a 10-percent investment tax credit, expensing of EOR injection costs, depreciation based on the rate of resource** depletion, and current State and Federal income tax rates *were* used.

Table 27 displays the number and percent of each EOR process sample that would be developed at various price levels under these conditions, as well as the percentage of potential EOR production (gross production less that used for EOR purposes) that would result from those developed. For example, development ranges from 6 percent of the fields at $11.62 per barrel for steam to 95 percent of all fields assigned to

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4Reservoirs subject to more than one EOR process were not evaluated with respect to the impact of policy options on each process or on process selection. The impact of alternative price levels and decision criteria on process selection was discussed in a previous section but data were not available to carry out a detailed analysis here. Since most policy options were analyzed at the world oil prices, this procedure should not affect the results (process selection was generally carried out at this price level).

Table 26
Number and Percent of Reservoirs Sampled by EOR Process

	Onshore					Offshore*
	Steam	In Situ	Surfactant	Polymer	CO_2	CO_2
Total reservoirs assigned.	20	20	92	20	190	294
Sample size	20	20	25	20	50	25
Percent sampled	100	100	27	100	26	9

● All offshore reservoirs were assigned to the CO_2 recovery process.

Tabie 27
EOR Reservoir Development and Production by Process and Price Levei

Process and price range (per barrel)	Sample size	Number developed	Percent developed	Percent potential production developed	Sample price elasticity of supply
Steam					
$11.62	20	6	30	41	
13.75	20	9	45	47	.99
17.00	20	11	55	75	3.10
22.00	20	14	70	85	,62
In Situ					
$11.62	20	14	70	89	
13.75	20	16	80	96	.52
17.00	20	18	90	100	.19
22.00	20	18	90	100	.00
Surfactant					
$11.62, ...	25	14	56	77	
13.75	25	19	76	85	.70
17.00. , ., . .	25	19	76	85	.00
22.00	25	22	88	94	.46
Polymer					
$11.62	20	14	70	94	
13.75	20	17	85	99	.32
17.00	20	17	85	99	.00
22.00	20	19	95	100	.05
CO_2--Onshore					
$11.62	50	12	24	22	
13.75	50	22	44	27	1.52
17.00	50	32	64	50	4.26
22.00. , ...	50	37	74	71	1.87
CO_2-Offshore					
$1"1 .62	25	9	36	24	
13.75	25	9	36	24	.00
17.00	25	15	60	'35	2.21
22,00	25	19	76	50	1.99
Total					
$11.62	160	69	43	46	
13.75	160	92	58	52	.88
17.00	160	112	70	69	1.78
22.00	160	129	81	82	.81

polymer at $22 per barrel. production ranges from 22 percent of the total possible for onshore CO_2 at $11.62 per barrel to 100 percent for polymer and in situ at $22 per barrel. Current world prices of $13.75 per barrel result in up to 99 percent of possible production from the polymer process, and up to 24 percent of possible EOR offshore oil production for those reservoirs assigned to the CO_2 process. Overall, 43 to 81 percent of the sample reservoirs are developed over the price range analyzed, with 46 to 82 percent of possible EOR oil being produced,[5]

Of perhaps greater interest, however, is the price elasticity of supply (i.e., the percentage change in production for each 1 -percent change in price) Table 27 also lists these values (arc elasticities) for the sample over the price range analyzed.[6] Individual EOR processes, as well as total production from all processes, are shown. It is obvious that the price elasticities vary across both the process and the range of price changes. in the $11.62 to $22 per barrel range, the CO_2 and steam processes are price elastic. This is also true of all processes combined. In situ, surfactant, and polymer are, however, price inelastic to the point where higher prices will have little impact on production.

All processes, except offshore CO_2, exhibit the greatest price elasticity in the low and/or middle price ranges (to $17 per barrel). Offshore CO_2 exhibits *its* greatest elasticity over the middle price range ($13.75 to $17 per barrel), with substantial elasticity above $17 per barrel. These results suggest the greatest price impact on production will take place in the range of real prices from $11.62 per barrel to approximately $17 per barrel, except in the high-cost offshore regions. With real oil prices expected to increase in the future, an effective method for encouraging EOR development would be to allow prices for EOR oil to rise with the world price. This conclusion is further supported by the fact that those EOR processes with the greatest production potential also have the highest price elasticity.

Of the 31 fields (31 of 160 sample reservoirs) which did not develop at a $22 per barrel price, 21 developed at $27.50 per barrel or below, 6 between $27.50 and $50 per barrel, 2 between $50 and $75 per barrel, and 2 could not be developed unless price exceeded $75 per barrel. As a result, 94 percent of the potential EOR reservoirs in the sample can be developed at prices below $27.50 per barrel. Overall price elasticity is positive (1 .35) in the range of $22 to $27.50 per barrel, but almost zero above $27.50 per barrel. Some fields in the steam, in situ, and surfactant processes could not be developed at prices below $50 per barrel. These processes use a portion of the recovered oil in the recovery process, so higher product price also means higher production cost.

It could be dangerous to generalize from the sample (although the steam and in situ samples included almost all assigned reservoirs), and the supply elasticities calculated from the sample were therefore compared with those based upon all reservoirs assigned to EOR processes in both the low- and high-process performance cases. Such a comparison cannot be precise because of the different approach used in the overall analysis to address economic calculations. Furthermore, the policy sample contains a greater proportion of marginal fields than does the total data set.

In general, the results displayed in table 28 indicate that the tendencies apparent from the sample are supported when looking at the entire high-process performance data base, Surfactant becomes price elastic, along with CO_2 and steam, but onshore CO_2 appears somewhat less price sensitive and offshore CO_2 somewhat more price

[5] Using production estimates based upon the low-process performance case would substantially reduce these values. For example, the surfactant process at world oil prices would be implemented on only two reservoirs in the sample (8 percent) and result in 7 percent of the potential net production. Similar calculations could be shown for other processes and price levels. However, the object ot this section is an evaluation of policy options. For this purpose, the high-process performance case is used as a basis with digressions to other cases only if policy conclusions would be affected. Also, the values change considerably when the analysis is conducted at the lower tier (old oil) price of $5.25 per barrel. At this price only 8 percent of the reservoirs with 14 percent of total possible production were developed.

[6] The elasticity formula used for all calculations was $(Q_1 - Q_0)/Q_0 \div (P_1 - P_0)/P_0$. Note that these values relate to ultimate net production and, thus, give no indication of the sensitivity of production profiles (or timing) to price.

sensitive than in the sample. No evidence is apparent which would argue for a change **in the previously discussed conclusions. As would be expected, the low-process performance case showed higher price elasticities** for a number of the processes. Only in situ remained price inelastic overall, while the price elasticity of steam dropped.

Analysis of Other Policy Options

Given the potential impacts of price on EOR development, the next question under the assumption of information certainty is whether other public policy options would change EOR economics. To answer this question, OTA analyzed four possible policy changes (three tax considerations and a public investment subsidy to encourage EOR development).

The tax options include the use of a 12-percent investment tax credit (2 percent more than the current rate), accelerated depreciation using the double declining balance method, and an option **in which injection costs are 100** percent depreciated rather than expensed. The latter option was conducted to evaluate industry's contention that the Internal Revenue Service must

Table 28
Price Elasticity of Supply Comparison

Process and price range (per barrel)	Policy analysis sample	OTA total reservoir assignment	
	High-process performance case	High-process performance case	Low-process performance case
Steam			
Overall ($11 .62-22.00)	2.32	2.42	1.92
$11.62 -13.75	.99	1.15	1.23
$13.75 -22.00	2.18	2.18	1.60
In situ			
Overall ($1 1.62-22.00)	.25	.25	.71
$11.62 -13.75	.52	.76	1.08
$13.75 -22.00	.10	.00	.38
Surfactant			
Overall ($1 1.62-22.00)	.48	1.47	12.93
$11.62 -13.75	.70	2,51	8.39
$13.75 -22.00	.28	.59	5.57
Polymer			
Overall ($1 1.62-22.00)	.11	.00	1.06
$11.62 -13.75	.32	.00	3.23
$13.75 -22.00	.06	.00	.00
CO_2-Onshore			
Overall ($11.62-22.00)	4.64	2.49	5.33
$11.62 -13.75	1.52	3.34	2.03
$13.75 -22.00	4.22	1.16	4.46
CO_2-Offshore			
Overall ($1 1.62-22.00)	2.26	7.06	—
$11.62 -13.75	.00	3.23	—
$13.75 -22.00 ...,	2.84	5.04	.
All processes			
Overall ($1 1.62-22.00)	1.70	2.02	4.50
$11.62 -13.75	.88	2.46	2.42
$13.75 -22.00	1.56	1.10	3.39

Table 29
EOR Development by Process and Policy Option

Process	Sample size	Number of Reservoirs Developed				
		$13.75 per barrel	12-percent investment credit	Accelerated depreciation	Depreciate injection costs	15-percent investment subsidy
Steam	20	9	9	9	6	9
In situ	20	16	16	17	16	18
Surfactant	25	19	19	19	4	19
Polymer.	20	17	17	17	15	17
CO_2-Onshore	50	22	22	22	13	22
CO_2-Offshore ., . . .	25	9	9	9	9	10
Total	160	92	92	93	63	95

permit the expensing of injection costs if EOR is to be economically viable. Depreciation was assumed to take place over the remaining production period in proportion to production. The investment subsidy option calls for the Government to pay 15 percent of all initial EOR capital investments (deferred investments and injection costs are paid fully by the producer).

Table 29 displays the result of these tests. All evaluations assumed current world market prices ($1 3.75 per barrel). As can be seen, the various options have relatively minor impacts on development and, consequently, on production. In fact, the 12-percent investment tax credit **results in no new development,** while the accelerated depreciation option adds one reservoir to the in situ process and increases total net production by only two-tenths of 1 percent. On the other hand, the requirement that EOR injection costs be 100-percent depreciated results in 30 (32 percent) fewer sample reservoirs being developed with a 29-percent reduction in total production. The reduced production is **concentrated** in surfactant, with some impact on the steam, polymer, and onshore CO_2 processes. The only policy option at all effective in encouraging development appears to be a 15-percent investment subsidy which would add three developed reservoirs at current world prices and result in a 1 -percent increase in net production. T

The various options do change the amount of above normal (1 O-percent rate of return) profit that can be expected from developed fields. Depreciation of injection costs would tend to reduce rates of return and the other options would increase them. If the introduction of EOR to potential reservoirs is paced on the basis of rates of return (as assumed previously), this change could have an impact on aggregate production profiles and the timing of recovery. The exact impact is impossible to quantify since firms will have different decision criteria and schedules for EOR initiation based on those criteria.

For policy analysis, these results need to be compared with the costs of the respective policies. In the case of a 12-percent investment tax credit, the Government revenue loss is not offset by additional tax revenues because no new output results. The accelerated depreciation option adds one additional reservoir, increasing production by more than 28 million barrels. At the same time, Government revenue actually increases due to the higher production and resulting tax receipts. The increase per barrel of production, however, is slight-less than 1 cent per barrel.

[7]Similar results were obtained when analyzing the low-process performance case. The number of reservoirs that developed at a 10-percent rate of return was obviously reduced by a substantial degree. However, the various policy options have little impact on changing these decisions. Taking surfactant as an example of a process which is often marginal, the various options resulted in only one addition to the two fields developed under free market conditions (see footnote 4). That development occurred when a 15 percent investment subsidy was introduced. Required depreciation of Injection costs, however, did not affect the decision to develop.

As would be expected, requiring the depreciation of injection costs increased Government revenue while the 15-percent investment subsidy reduced it. However, the impacts per barrel of incremental production were quite small.

In summary, it appears that no policy option is either very powerful in encouraging new production or very expensive in terms of Government cost per barrel produced. In fact, little appears to be gained (or lost) by attempting to accelerate EOR development at a pace faster than that likely to occur in current institutional setting. The question remains, however, whether such policy options are worth potential distortions in efficiency under conditions of information uncertainty. This question is explored in the next section.

Analysis Assuming Information Uncertainty

To evaluate the question of uncertainty in production, cost, and price values, the same sample of reservoirs was used in conjunction with subjective probability distributions on the key input variables. Table 30 lists the variables and the distributions used. The resulting range in production from the reservoirs was substantially less than that resulting from the high- and low-process performance assumptions discussed in chapter III. This result indicates that the degree of uncertainty implicit in the cost and production distributions was less than that incorporated in the two advancing technology cases. As a result, the policy tests can be considered conservative, in that a policy which will not affect development under these assumptions is unlikely to have any impact in practice.

Table 30
Input Variables and Subjective Probability Distributions Used for Monte Cario Simulations

Variable	Value
Price	
Original value ($/bbl.)	13.75
Mean of price change distribution	0.00
Standard deviation of price change distribution	0.01
Production	
Triangular contingency distributions	
Minimum	-.30
Most likely	-.10
Maximum	0.05
Investment and operating cost	
Triangular contingency distributions	
Minimum	-.05
Most Likely	0.00
Maximum	0.10

(Number of Monte Carlo Iterations: 200)

Options Designed To Alleviate Uncertainty

The effects of uncertainty were evaluated at the current world oil price. Because of the minor impacts exhibited by the tax options in the previous analysis, they were dropped from further consideration. Two other options, designed to reduce uncertainty, were added: (1) a price guarantee whereby the Government would assure a market price that did not fall below $13.75 per barrel; and (2) an actual price subsidy (payment by the Government over and above market price) of $3 per barrel of EOR oil produced.[8] In all evaluations, current tax rules and a 10-percent rate of return were assumed. Table 31 summarizes these evaluations.

The simulations provide interesting insight into the potential profitability of EOR development. Overall, it appears that up to 23 percent of the developable EOR reservoirs (and 23 percent of the producible oil) would be available at current market prices with very low risk of a less-than-normal profit to the operator. The remainder of the fields with some chance of profitability are spread more or less uniformly over the probability range of less-than-normal profit categories. However, because of variations in reservoir size, the remaining recoverable oil is not distributed uniformly, but is concentrated in the 26 to 50 percent and 75 to 99 percent chance-of-loss categories. Only 66 percent of the sample's producible EOR oil has some probability of being profitably exploited under the conditions simulated.

The policy options analyzed have little effect on these results. Only the $3 price subsidy adds a

[8] A $1 per barrel subsidy was also evaluated but is not displayed because of its neglible impact.

Table 31
Monte Carlo Simulation of Policy Option Impacts in Reducing Uncertainty
(Analysis Based on High-Process Performance)

EOR process and policy *	Sample size	Number of reservoirs developed						Percent potential net production developed					
		Probability of less-than-normal profit						Probability of less-than-normal profit					
		0 percent	1-25 percent	26-50 percent	51-75 percent	76-99 percent	Total	0 percent	1-25 percent	26-50 percent	51-75 percent	76-99 percent	Total
Steam													
Base case	20	3	1	2	—	4	10	31	1	8	—	29	69
Price guarantee	20	3	1	2	—	4	10	31	1	8	—	29	69
Price subsidy	20	3	3	2	1	3	12	31	9	4	2	35	81
Investment subsidy	20	3	3	—	1	3	10	31	9	—	2	27	69
In situ													
Base case	20	10	2	—	2	4	18	69	1	—	19	11	100
Price guarantee	20	10	2	1	2	3	18	69	1	9	13	8	100
Price subsidy	20	11	2	3	2	—	18	69	11	17	3	—	100
Investment subsidy	20	11	1	3	1	2	18	69	1	22	5	3	100
Surfactant													
Base case	25	2	4	6	3	4	19	1	16	49	11	8	85
Price guarantee	25	2	4	7	2	4	19	1	16	50	10	8	85
Price subsidy	25	2	12	4	1	1	20	1	76	8	—	3	88
Investment subsidy	25	2	4	8	3	2	19	1	16	60	2	6	85
Polymer													
Base case	20	11	3	—	1	2	17	78	16	—	2	2	98
Price guarantee	20	11	3	—	1	2	17	78	16	—	2	2	98
Price subsidy	20	14	2	1	—	—	17	94	3	2	—	—	99
Investment subsidy	20	11	3	1	2	—	17	78	16	2	2	—	98
CO_2—Onshore													
Base case	50	4	3	4	4	7	22	12	2	5	11	11	41
Price guarantee	50	4	4	3	4	7	22	12	4	3	11	11	41
Price subsidy	50	9	11	2	2	7	31	16	22	2	1	6	47
Investment subsidy	50	4	6	4	5	6	25	12	6	9	10	5	42
CO_2—Offshore													
Base case	25	7	2	—	—	—	9	21	4	—	—	—	25
Price guarantee	25	7	2	—	—	—	9	21	4	—	—	—	25
Price subsidy	25	9	—	—	3	4	16	24	—	—	7	7	38
Investment subsidy	25	7	2	—	—	2	11	21	4	—	—	6	30
Total													
Base case	160	37	15	12	10	21	95	23	5	14	8	16	66
Price guarantee	160	37	16	13	9	20	95	23	6	14	7	16	66
Price subsidy	160	48	30	12	9	15	114	24	26	5	2	15	72
Investment subsidy	160	38	19	16	12	15	100	23	9	19	6	13	70

*Base case assumes a $13.75 per barrel oil price, price guarantee guarantees a $13.75 per barrel price, price subsidy is $3.00 per barrel of EOR oil, and investment subsidy is 15 percent of all initial EOR capital investments.

significant number of reservoirs to those potentially developed (20 percent), but this results in only a 6-percent increase in potential oil production. The impact is concentrated in the CO_2, steam, and surfactant processes. The 15-percent investment subsidy adds 5 percent to the potential reservoir development but only 4 percent additional oil. Only CO_2 processes were affected, however. In most cases, reservoirs added to those that would be potentially developed are in the high-risk (76 to 99 percent chance of loss) category.

All options, however, have some impact on reducing the risk of development for those reservoirs that are potential candidates under current market conditions. Again, the most successful policy in this regard is the $3 per barrel price subsidy with 55 percent of the potential production classified below 50-percent probability of a less than normal profit. This is a 31 -percent improvement over the base case and compares to a 2-percent improvement for the price guarantee option and a 21 -percent gain for the investment subsidy.

The impacts of the various policy options on individual EOR processes are similar to the overall results, with the greatest addition to potential EOR reservoirs and total production resulting from the price subsidy option. The reduction in risk for potential production (from the base case) **is greatest** for the onshore CO_2 process, followed by in situ combustion and surfactant flooding.

Although increases in potential EOR **production (from all risk categories) do not appear substantial for any of the options designed to reduce uncertainty, the possibility of changing the risk of development for those reservoirs included** in the base case warrants further investigation of a price subsidy. To accurately assess this option the potential benefits of increased EOR production must be balanced against Government costs. However, both the extent of increased production and the corresponding costs are difficult to quantify. Since the decision to recover EOR oil depends on a producer's risk-preference function, one must ascertain the appropriate decision rule used by the private sector in making development decisions before an accurate assessment can be made. Given that these decision rules will vary among firms and may change for a given firm with implementation of a policy subsidy, Government cost is difficult, if not impossible, to quantify. The cost of the $3 subsidy to all produced EOR oil will be offset to some extent by an increase in Federal tax revenue and, in the case of offshore fields, higher royalty collections. Without knowledge of the impacts under varying risk conditions and decision criteria, the magnitude of this change can only be an educated guess, For a range of possible conditions, the net present value cost of the subsidy appears to be in the area of $1.50 to $2 per barrel.

Analysis Assuming a Rising Real Price

The preceding analysis assumes that EOR oil will be priced at $13.75 per barrel and that such a price will continue, in real terms, throughout the productive life of an EOR project. Evaluation of this assumption could lead to the conclusion that the results discussed above are an inaccurate representation of future reality, If EOR oil prices are deregulated and world market prices maintain a moderate, but consistent, real growth rate, much of the uncertainty exhibited in the profitability of EOR projects may be eliminated.

To test this possibility, an analysis was performed on the sample which assumed an average annual real price increase of 5 percent (randomly selected from a normal price change distribution with a standard deviation of 3 percent). Table 32 displays the price deregulation impact and, compares it to the $13.7s price base case and **the** $3 price subsidy situation (from table 31). It can be seen that the rising price scenario test equal led or exceeded the results of the price subsidy in reducing uncertainty for all EOR processes. Overall, price deregulation led to a 34-percent increase in field development over the base case and an 11 -percent increase over the price subsidy analysis. Moreover, substantial shifts in the uncertainty category occurred for fields which were formerly in high-risk categories (greater than *50*-percent chance of loss). Price deregulation has a significant impact in all EOR processes except **in situ combustion.**

Thus, if a moderate annual increase in real oil prices obtained for EOR production could be expected with a high degree of assurance, special Government policies to reduce uncertainty may not be required. An equal or greater impact could be obtained with simple price deregulation.

Table 32
Monte Carlo Simulation of EOR Oii Price Deregulation
(fixed $13.75 per barrel price, and a $3.00 per barrel subsidy)

EOR process and policy	Sample size	Number of reservoirs developed — Probability of less than normal refit: 0 percent	1-25 percent	26-50 percent	51-75 percent	76-99 percent	Total percent
Steam							
Base case.	20	3	1	2	—	4	10
Price subsidy. ... , ...	20	3	3	2	1	3	12
Price deregulation*.	20	3	5	3	2	—	13
In situ							
Base case.	20	10	2	—	2	4	18
Price subsidy.	20	11	2	3	2	—	18
Price deregulation*.	20	11	5	—	2	—	18
Surfactant							
Base case.	25	2	4	6	3	4	19
Price subsidy.	25	2	12	4	1	1	20
Price deregulation*.	25	6	13	—	1	2	22
Polymer							
Base case.	20	11	3	—	1	2	17
Price subsidy.	20	14	2	1	—	—	17
Price deregulation*.	20	14	3	—	—	2	19
CO_2 onshore							
Base case	50	4	3	4	4	7	22
Price subsidy	50	9	11	2	2	7	31
Price deregulation*	50	18	5	4	6	4	37
CO_2-Offshore							
Base case	25	7	2	—	—	—	9
Price subsidy	25	9	—	—	3	4	16
Price deregulation*	25	9	—	—	3	6	18
Total							
Base case	160	37	15	12	10	21	95
Price subsidy	160	48	30	12	9	15	114
Price deregulation* . .	160	61	31	7	14	14	127

*Assumes an annual price change distribution which is normal with a S-percent mean and a 3-percent standard deviation

Impact of Alternative OCS Leasing Systems

With the current widespread interest in OCS leasing activity, increased attention has **been** focused on alternative leasing systems. The United States currently uses, almost exclusively, a cash bonus leasing procedure in which the winning bidder for an OCS **lease** is the firm which **offers the Government the highest front-end payment** for exploration and development rights (the **cash bonus). This bid amount is not refundable** if recoverable resources are not found and, therefore, has no impact on subsequent development and production decisions (including the use of EOR technology). **In addition to the cash bonus, a royalty on gross production value of**

16.67 percent is paid to the Government by the producer. The previous analysis of policy options assumed this leasing method was in use for offshore CO_2 cases.

However, because of the substantial uncertainty that exists in offshore development and the capital requirements of cash bonus bidding, alternative systems have been proposed that would shift some of the risk to the Government, reduce capital requirements, and encourage competition.[9] As a result, Government revenue could increase with little or no loss in production. Such alternative leasing systems make greater use of contingency payments (which produce Government revenues based on the value of production) and usually employ a higher royalty rate or a profit-share technique. The cash bonus is retained as the bid variable to alleviate problems of speculation. The higher contingency payments, however, act to reduce the magnitude and importance of the bonus.

The viability of EOR under the alternative leasing systems was evaluated by comparing the profit share and higher royalty rate systems described above with the current system. Table 33 details the results of this analysis. It is clear that high fixed royalties will inhibit EOR development by increasing the risk of less-than-normal profits and by making some fields uneconomical for EOR development. These results confirm earlier studies on the impact of high royalties for primary and secondary production.[10] However, the profit-share system also has a tendency to increase the risk of a less-than-normal profit. This result is at variance with previous results on primary and secondary production and indicates that a profit-share rate of so percent is too high for EOR development on marginal fields. One option **in both situations** would be the use of a variable-rate royalty or profit-share approach, so that rates would be reduced automatically for marginal fields and increased in situations of higher productivity. If experiments with new leasing systems are contemplated, the effects of leasing systems on EOR production as well as primary and secondary production should be evaluated.

Administrative Issues

All of the policy options analyzed **in this section would provide special incentives** for production of oil using enhanced recovery techniques. The implementation of any **such incentives will** require administrative decisions concerning the qualification of particular projects or types of projects for the incentives. Those policies involving special price incentives will also require a further judgment about what portion of the oil produced from a field can be attributed to the EOR process, and what part would have been produced anyway by the continuation of primary and secondary techniques. The problem is to define this EOR increment in such a way that special incentives will encourage the application of EOR processes without significantly distorting decisions concerning primary and secondary production.

These problems will have to be dealt with if proposed price incentive policies are to be adopted. In 1976, Congress amended the Emergency Petroleum Allocation Act (through provisions in **the** Energy Conservation and Production Act) to direct the President to modify oil pricing regulations to provide additional price incentives for bona fide EOR techniques. Since then, FEA has published proposed regulations for comment and has held several public hearings on the subject. The basic approach proposed by FEA is to apply price incentives only to the increment of production attributable to an EOR process. The same approach is implied in the president's April 1977 National Energy Plan, which called for decontrol of the price of oil produced with EOR techniques.

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[9] Robert J. Kalter and **Wallace E.** Tyner, *An Analysis of* **Selected OCS** ***Leasing Options.*** Report to the Office of Technology Assessment, U.S. **Congress, June 1975.**

[10] Robert J. Kalter, **Wallace E.** Tyner, **and Daniel** W. **Hughes,** ***Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf,*** **Department of Agricultural Economics Research Paper 75-33, Cornell University, 1975.**

Decisions concerning the qualification of processes and production levels for special incentives involve highly technical judgments which will require personnel competent in EOR techniques. Such personnel do not at present exist in Government in the numbers required. The number of people available in the job market is quite limited and industry demand is large. While consultants might be used, this practice could raise potential conflict of interest problems, because consultants **must, in the long run, depend upon industry for their support.** An alternative approach, supported by industry in comments on FEA proposals, would be simply to apply price incentives to all oil produced from a field to which an EOR process was applied. While this would avoid the problem of defining an EOR increment, there would remain the problem of defining the level of effort required for a project to qualify as a bona fide EOR process, and monitoring to ensure that that effort is in fact maintained.

A more detailed analysis of the advantages and disadvantages of these and other incentive pricing options was beyond the scope of OTA's assessment of the potential contribution of EOR processes to national reserves. Because of the importance and complexity of the associated issues, however, Congress may wish to examine the problem of defining and monitoring EOR operations, and possibly hold oversight hearings on the proposed FEA pricing regulations for EOR production. If defining EOR incremental oil production and monitoring EOR operations are found to be critical issues, a mechanism could be developed whereby bona fide EOR projects could be certified and monitored. Certification and monitoring of EOR operations could be performed by the operator, a State regulatory group, a Federal agency, or a combination of Federal, State, and producer interests.

Table 33
Monte Carlo Simulation of OCS Leasing Systems and EOR Potential

EOR process and OCS leasing system	Sample size	Probability of less-than-normal profit					
		o percent	1-25 percent	26-50 percent	51-75 percent	76-99 percent	Total percent
		Number of fields developed					
CO_2-Offshore							
Current.	25	7	2	—	—	—	9
40-percent royalty	25	2	1	1	1	3	8
50-percent profit share	24	4	3	2	—	—	9
		Percent potential net production developed					
CO_2-Offshore							
Current.	25	21	4	—	—	—	25
40-percent royalty	25	3	6	4	1	9	23
50-percent profit share .	25	13	8	4	—	—	25

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V. Legal Aspects of Enhanced Oil Recovery

V. Legal Aspects of Enhanced Oil Recovery

Method of Approach

This chapter of OTA's assessment of enhanced oil recovery (EOR) examines legal impacts on EOR processes arising from Federal and State statutes, regulations, and other laws. It seeks to identify existing and potential constraints on the employment of EOR techniques to obtain additional oil beyond primary and secondary production.

Federal and State laws and regulations were collected and studied in detail; the legal literature relating to enhanced recovery in treatises and law reviews were reviewed; and the recent studies for, or by, the Energy Research and Development Administration (ERDA), the Federal Energy Administration (FEA), the National Petroleum Council (NPC), the Environmental Protection Agency (EPA), the Gulf Universities Research Consortium (GURC), and the Interstate Oil Compact Commission-together with other technical literature—were examined. With the cooperation of the Interstate Oil Compact Commission, questionnaires regarding EOR regulation and associated problems were sent to 18 large producing companies, about 240 smaller producers, 34 State regulatory commissions, and to appropriate officials in the Department of the interior. Responses were received from 15 of the large producers, 67 of the smaller producers, and 32 of the State commissions. In addition, calls were made to or personal discussions were held with selected individuals with knowledge in the field of enhanced recovery. Information from all of these sources was used in completing this segment of the EOR assessment. A more detailed discussion of legal aspects of EOR activity is presented in appendix C of this report.

Legal Issues in EOR Development

The law affects enhanced recovery of oil operations in many ways. Based upon the responses to questionnaires, price controls on crude oil constitute the most significant legal constraint to enhanced recovery operations. Approximately 65 percent of all producers responding to the questionnaire indicated that removal of price controls would make more projects economically feasible or more attractive.

A second important problem area for enhanced recovery appears to be the establishment of operating units. In order to be able to treat a reservoir without regard to property lines, it is necessary that a single party have control over the entire reservoir or that the various parties who own interests in the reservoir integrate their interests either voluntarily or through a requirement by the State. Integration of these interests is referred to as unitization, and problems with unitization were cited by producers with the second greatest frequency after price controls as an EOR constraint. The difficulties surrounding unitization can be better explained by providing a brief background on the basic principles of oil and gas law. It should be noted that most problems associated with enhanced recovery methods apply to waterflooding as well. Therefore, problems with unitization agreements and possible contamination of ground water are not unique to enhanced oil recovery.

The right to develop subsurface minerals in the **United States originally coincides with** the ownership of the surface. The owner of land may, however, sever the ownership of the surface from ownership of the minerals. A variety of interests may be created, including mineral and royalty interests on all or part of a tract, undivided fractions of such interests, and leasehold interests. The owner of the minerals normally does this because he is unable to undertake the development of the minerals himself because of the great expense and risk of development operations. To obtain development without entirely giving up his interest he will lease to another party the right to explore for and produce the minerals. The lessee will pay a sum of money for the lease and will promise to drill or make other payments, and if there is petroleum to pay the value of a portion of the production to the lessor. Should certain of the terms of the lease not be met, the lease will terminate and the interest will revert to the lessor.

In the lease transaction the lessee has both express and implied rights and duties. These often have a significant impact on enhanced recovery activities. Among these rights of the lessee is the right to use such methods and so much of the surface as may be reasonably necessary to effectuate the purposes of the lease, having due regard for the rights of the owner of the surface estate. This would generally include the right to undertake enhanced recovery operations. Some authorities have asserted that there is a duty for a lessee to undertake enhanced recovery. In general, the lessee has a duty to develop the lease as a prudent operator and to do nothing to harm the interest of the lessor. Without the express consent of the lessor, the lessee does not have the right or the power to unitize the interest of the lessor.

In order to undertake fieldwide recovery operations (waterflood or EOR), it is generally necessary to secure the consent of all or most of the various interest owners in the field through a unitization agreement. It may take many months or even years for the parties to reach such agreement. The principal difficulty lies in determining the shares of risk and/or production from the operations. The producing State governments allow voluntary unitization and provide the parties an exemption from possible application of the antitrust laws. Most producing States also provide for compulsory joinder of interest owners in the unit once a certain percentage of interest owners have agreed to unitization. This percentage ranges from a low of 50 percent to a high of 85 percent as shown in table 34. In the absence of such legislation, or where the necessary percentage of voluntary participation cannot be achieved, the undertaking of enhanced recovery operations can result in substantial liability for the operator due to possible damage to conjoiners.

Once agreement for unit operations has been reached, it is necessary for the operator or other parties to go before a State commission for approval of the unit. The commission will require the submission of a detailed application describing the unit and its operations, the furnishing of notice of the application to other parties who might have an ‘interest in the unit operation, the opportunity for hearing on the application, and the entry of an order establishing the unit when the other steps have been completed. The problems with unitization arise from the difficulties in securing the voluntary agreement of different interest owners, and generally not from the State regulatory procedures.

Prior to undertaking injection programs for enhancing production of oil, each State requires the operator to secure a permit for the operation. The procedure for this is similar to the procedure for approval of unitization and sometimes may be accomplished in the same proceedings. There is little indication that these regulatory activities significantly restrict or hinder enhanced recovery of oil with the possible exception of one or two jurisdictions. The procedures could well change under regulations promulgated by the Environmental Protection Agency pursuant to the Safe Drinking Water Act. Producers and others have indicated that such Federal regulations could have an important adverse impact on enhanced recovery.

Once enhanced recovery projects have commenced, a variety of legal problems can arise. Operators in some States will face the prospect of liability to parties who refuse to join a unit when enhanced project operations reduce the production of such non joiners. There is also the prospect of liability to governmental agencies and the possibility of shutting down of operations for environmental offenses. Operators may have difficulty in acquiring adequate water supplies for EOR projects or be subject to a cutting off of supplies owing to the water rights doctrines followed in some States. Problems such as these can interfere with the operation of enhanced recovery projects or even prevent their being started.

Table 34
Comparative Chart of Aspects of Unitization Statutes

State	Percent working or royalty int. req'd. (vol. = voluntary only)	Proof or findings required: Inc. ult. recovery	Proof or findings required: Prevent waste	Proof or findings required: Protect corr. rights	Proof or findings required: Add. cost not over add. recov.	Unit area Part or All of - Single or Multip, -pools	Water rights doctrine R-riparian PA-prior appropriate ion D-dual system
Alabama	75	Yes	Yes	Yes	Yes	PAM	R
Alaska . . .	62.5	Yes	Yes	Yes	Yes	PAS	PA
Arizona . .	63	Yes	Yes	Yes	Yes	PAS	PA
Arkansas ...	75	Yes	Yes	Yes	Yes	PAS	R
Cdllfornia Subdence.	65	No	No	Yes	Yes	PAM	D
California Townsite*	75	Yes	—	Yes	Yes	AS	D
Colorado	80	Yes	—	Yes	Yes	PAM	PA
Florida	75	Yes	Yes	Yes	Yes	PAM	R
Georgia	None	.	—	—	—	PAS	R
Idaho ... , ...	vol.	—	Yes or Yes		—	PAM	PA
Illinois	75	Yes	Yes	Yes	Yes	PAM	R
Indiana ., ...	None	Yes or Yes			Yes	PAS	R
Kansas	75	Yes	Yes	Yes	Yes	PAS	D
Kentucky.	75	Yes	Yes	Yes	YeS	PAM	R
Louisiana Subsection B.	None		Yes			PAS	R
Louisiana Subsection C	75	Yes	Yes	Yes	Yes	AM	R
Maine	85-W - 65-R	Yes	—	—	Yes	PAM	R
Michigan.	75	Yes	Yes	Yes	Yes	PAM	R
Mississippi	85	Yes	Yes	Yes	Yes	PAM	D
Missouri	75	Yes	Yes	Yes	Yes	PAS	R
Montana	80	Yes	—	Yes	Yes	PAM	PA
Nebraska.	75	Yes	Yes	Yes	Yes	PAM	D
Nevada..,......,., .	62.5	Yes	Yes	Yes	Yes	PAS	PA
New Mexico . . . ., . .	75	Yes	Yes	Yes	Yes	PAS	PA
New York	60	Yes	—	Yes	Yes	PAS	R
North Dakota	80	Yes	Yes	Yes	Yes	PAM	D
Ohio	65	Yes	—	Yes	Yes	PAS	R
Oklahoma.	6.3	Yes	Yes	Yes	Yes	PAS	D
Oregon	75	Yes	Yes	Yes	Yes	PAM	D
South Dakota	75	Yes	Yes	Yes	Yes	PAM	D
Tennessee	50						R
Texas.	vol.	—	Yes	Yes	Yes	PAM	D
Utah.	80	—	Yes	Yes	Yes	PAS	PA
Washington	None	Yes	Yes	Yes	Yes	AM	D
West Virginia	75	Yes	Yes	Yes	Yes	AS	R
Wyoming	80	Yes	Yes	Yes	Yes	PAM	PA

"See appendix C
Adapted in part from Eckman, 6 Nat Res. Lawyer 384 (1973).

Policy Options

The factor most often identified by producers as a constraint to EOR activities was Federal price controls. A large majority of both independent and large producers felt that price controls were inhibiting EOR projects. For example, one Oklahoma independent stated: "We see no point in 'enhancing' anything until it reaches the stripper qualification [exempt from price controls]. This makes no engineering sense, but this is what has been forced upon us by a myriad of political decisions." Although price options are taken up in another segment of the EOR assessment, the price constraint is mentioned in order to place the other factors identified in perspective. However, it should be noted that differing treatment of interest owners producing from the same reservoir does act to discourage unitization. Because of current price regulations (upper- and lower-tier prices), producers in the same unit may not receive the same price for their oil. To avoid this, it is suggested that whatever price, taxation, or subsidy determinations are made should not place an interest owner in a worse position than before unit operations were undertaken, and should operate in such a way that each interest owner will receive the same benefits that other similarly situated interest owners in the field receive.

The second most important area now causing problems for enhanced recovery operations is the difficulty in joinder of parties for fieldwide operations. Owners of relatively small interests in a reservoir in many States can effectively prevent the majority from undertaking enhanced recovery operations. The problem appears to be greatest in Texas, which has no compulsory unitization statute. In other major producing States which have compulsory unitization statutes, the percentage of voluntary participation required may be so high as to make unitization of some reservoirs difficult or impossible. To overcome these problems, the Federal Government could recommend that each State adopt a compulsory unitization statute requiring that 60 percent of the working interest and royalty owners consent to unitized operations before the remaining' interest owners would be compelled to participate. This could be easily incorporated in existing unitization legislation in each State.

Alternatively, the Federal Government could require that States adopt such features in their unitization statutes before the States can qualify for administrative support or to avoid having a Federal agency take responsibility for unitization and enhanced recovery regulation,

While it is likely that this would be a constitutional exercise of Federal authority under the commerce clause, such a major step probably would encounter considerable opposition at the State level. In any case, the desirability of strong regulations to encourage unitization would depend on a more detailed reservoir-by-reservoir analysis of the extent to which unitization problems are in fact an obstacle to a significant amount of potential EOR activity.

The Federal Government could also recommend to the States that they, by statute, exempt producers from liability for any damages caused by State-approved enhanced recovery operations not involving negligence on the part of the producer. This would remove a constraint to the operations and would act as an incentive to unitize for parties who might otherwise remain out of the unit.

As to regulatory requirements and practices, there were only two important areas of concern for producers: environmental requirements in California and the potential impact of the regulations issued by EPA under the Safe Drinking Water Act. Congress might consider reviewing the effects of various environmental laws and regulations on the production of petroleum. Congress might also consider reviewing EPA's authority and actions under the Safe Drinking Water Act to see if the proposed regulations would unduly restrict enhanced recovery projects. producers did not complain of State EOR practices and a number indicated that State commissions are most helpful. With respect to Federal lands, several producers indicated that the Bureau of Indian Affairs and the U.S. Geological Survey had delayed the initiation of projects for long periods of time. Congress might consider directing the Department of the Interior to survey Federal lands for their EOR potential and to review its policies on EOR.

VI. Environmental Issues

VI. Environmental Issues

Physiographic Regions

For the purpose of this assessment, the continental United States was divided into four general types of physiographic regions, each of which has certain specific characteristics and vulnerabilities to environmental damage. The four physiographic regions are: 1) the Continental Shelf which includes the broad, shallow gulf coast shelf, the steeper sloping Atlantic shelf, and the narrow steep-edged pacific coast shelf; 2) the Coastal Plains adjoining the Pacific Ocean, Atlantic Ocean, and the Gulf of Mexico, particularly those of California, Texas, and Louisiana; 3) the Interior Basins, such as the Great Plains, Great Lakes, and the central valley of California; and 4) the Rocky *Mountains* and other mountainous regions.

Continental Shelf

The Continental Shelf, a shallow, flat, submerged land area at the margin of the continent, slopes gently downward away from the shoreline. The width of the shelf ranges from less than 5 miles along portions of the southern California coastline, to a few hundred miles along parts of the gulf coast. The topography of a shelf is highly dependent on its location; the Atlantic Continental Shelf is relatively flat and shallow compared to the deeper southern California borderland which has a series of parallel steep-walled ridges and subsea canyons.

Hazards common to all Continental Shelf oil recovery operations include tidal action, wave action, storm waves, and collisions with ships. In addition, hurricanes in the gulf and Atlantic coasts, landslides and earthquakes in the southern California borderland, difficulty of control, and unstable bottom substrate pose further hazards.

Coastal Plains

The Coastal Plains along the Atlantic and gulf coasts are as much as 100 to 200 miles wide, and make up nearly 10 percent of the land in the contiguous 48 states. With minor exceptions, the variance in elevation is less than 500 feet and for more than half of the Coastal Plains is less than 100 feet. This low topographic relief results in extensive marshy areas. Coastal marshes, estuaries, and near-shore waters are all considered part of the Coastal plains area. In contrast, the coastal plain in California is narrow, limited by the coastal mountains, and has a poorly developed marsh system.[1]

The geologic formations are quite young, usually Cretaceus, Tertiary, and Quaternary in age. These sedimentary deposits represent various onshore, nearshore, and offshore environmental depositions. The formations generally dip gently seaward and outcrop in belts roughly parallel to the inner and outer edges of the Coastal Plains.[2]

Although many coastal wetlands have been designated as wildlife refuges and recreation areas, large parts of the Nation's Coastal Plains are covered by major population centers. In the arid Southwest, Coastal Plain inhabitants rely heavily on local ground water supplies. The U.S. Coastal Plains which have the potential for the greatest EOR activity are those of southern California, Louisiana, and Texas.[3]

Interior Basins

The Interior Basins include all land areas of the United States except the mountainous areas and the Coastal Plains. Within the interior drainage basins, there are geologic basins which may contain large quantities of oil entrapped beneath the surface. Generally; the geologic formations are older than those in the Coastal Plains.

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[1] Charles B. Hunt, *Physiograph y of the* United *States,* W. H. Freeman and Company, San Francisco, Calif. 1967.

[2] Ibid.

[3] *Enhanced Oil* Recovery, National Petroleum Council, December 1976.

Some EOR activity is expected to take place in the Interior Basins, particularly those of the mid-continent and central California. Typically, the urban centers and farm areas of these basins depend heavily on local ground water supplies. The ground water aquifers of these basins are recharged by local rivers and by runoff from bordering mountains.

Mountain Ranges

The mountainous areas are rich in timber and minerals. Some EOR operations are anticipated in the Rocky Mountains, particularly in Wyoming. These mountain areas offer diverse benefits to society since they are prime wildlife and recreational areas; with their relatively high snowpack, they are frequently a major source of ground water for adjacent plains. These generally are remote unpopulated areas, where direct EOR impacts on the human population are limited but where adverse impacts on the natural environment can be significant.

Causes of Environmental Effects

The following elements and processes are common to all EOR methods: a recovery fluid; an injection system; surface processing; and disposal of spent materials.

The processes and the materials used within the confines of the system pose no environmental threat. Environmental problems result only when the materials are allowed to escape. The following mechanics may be responsible for such escape:

1) Transit Spills—Spills which may occur when material is being prepared at or transported to the field site.
2) Onsite Spills—Spills which may occur at the field site from surface lines and/or storage facilities.
3) Well System Failure--Escape of materials which may occur from failure of the injection or producing well due to casing leaks or channeling.
4) Reservoir Migration--Fluid may migrate outside of the confining limits of a reservoir through fractures or through a well bore which interconnects reservoirs.
5) Operations—The effects caused by routine activities and by the support facilities and activities associated with EOR production. To determine environmental problems during operations, the effect of each of the following must be considered: disposal of spent material; consumption of site-associated natural resources; discharge emissions; fugitive emissions; and off site supply and support efforts.

A simple matrix model was developed to compare the relative significance of environmental impacts from spills, well failure, reservoir leaks, and operations from thermal, miscible, and chemical EOR methods in each of the four physiographic regions. The matrix reflects a subjective assessment and relative ranking of the significance of potential impacts from negligible or nonexistent (1), to potentially significant (4). The values assigned on table 35 are comparable only when applied to a specific EOR process and environmental component such as thermal and air.

Table 35 relates to potential hazards from each EOR project by physiographic area. To **suggest** possible total impact of each EOR process, table 36 was developed. This matrix attempts to predict the relative degree of development of the EOR method as a function of the physiographic area. Should time and/or experience indicate different values, they could be substituted without invalidating the matrix presented.

By selecting the appropriate value from table 36 and multiplying it by the value for the same process and physiographic area on table 35, an estimate of the weighted environmental impact of any or all effects can be calculated. Table 37 is

Table 35
Matrix Evaluation of Relative Potential for
Environmental Impacts for Enhanced Oil Recovery
Impact Model Showing Relative Impacts of Process-Effect and Environmental Components

Process	Process of effect	Air				Water				[illegible]				Biota			
		CS	CP	IB	MT	CS	CP	IB	MT	CS	CP	IB	MT	CS	CP	IB	MT
Thermal	Spills	1	1	2	1	1	2	2	2	-	-	1	-	1	2	1	2
Steam	Well Failure	1	2	2	1	1	2	2	2	-	-	1	-	1	1	1	1
In Situ	Reservoir Leaks	1	1	2	1	1	2	2	2	-	-	1	v	1	1	1	1
Hot Water	Operational	2	4	3	2	2	3	4	3	-	-	1	.	2	4	4	4
Miscible	Spills	1	2	2	1	1	2	1	1	-	[illegible]	1	[illegible]	1	2	1	1
CO_2	Well Failure	1	2	2	1	1	2	2	2	-		1	-	1	2	2	2
Hydrocarbons	Reservoir Leaks	1	1	1	1	1	2	2	2	-	[illegible]	1	[illegible]	1	1	1	1
	Operational	2	3	3	2	2	2	3	2	-	[illegible]	2	[illegible]	2	4	3	3
Chemical	Spills	1	1	1	1	2	4	3	4	.	~	1	-	2	4	3	4
Polymer	Well Failure	1	1	1	1	2	3	2	3	.	-	1	-	2	3	2	3
Surfactant/	Reservoir Leaks	1	1	1	1	2	2	2	2	.	-	1	-	2	2	2	2
Polymer	Operational	2	2	2	2	2	3	4	3	r	m	2	-	2	4	4	4

Scale Units: From 1 negligible or nonexistent, to 4 the most significant.

CS - Continental Shelf; CP - Coastal Plains; IB - Interior Basins; MT - Mountains

EMARKS: Spills - Includes both onsite and transit spills of materials used in process.
Well Failure - Includes leaks from well system of EOR materials.
Reservoir Leaks - Includes the migration from the zone that the EOR process is operative into the external system.
Operational - Includes disposal of spent material, consumption of site natural resources, discharge emissions, and offstie supply of EOR materials.

the sum of each environmental component in a physiographic area times the appropriate value from table 36. After determining the value for each of the physiographic areas for an EOR process, they are total led and the value transferred to table 37.

The values in table 37 suggest possible relative environmental impacts. For example, chemical EOR projects may have the greatest potential for environmental impacts and thermal the least, or the biota may be the most impacted and land the least. Sweeping conclusions should be drawn with caution, however, because individual sites and production conditions for EOR, and thus possible environmental impacts, vary significantly from setting to setting.

Tabie 36
Potential Distribution of Environmental Impacts for Enhanced Oii Recovery

(Prediction of the Relative Degree of Development of the EOR Method as a Function of Physiographic Areas)

Method	Physiographic Area			
	Continental Shelf	Coastal Plain	Interior Basin	Mountains
Thermal. . .	1	4	2	2
Miscible . .	1	3	3	2
Chemical. .	1	3	4	2

SCALE UNITS: 1 - Improbable; 2- Negligible; 3- Moderate; 4- Significant; 5- Extensive

Table 37
Cross Plot of Environmental Impacts for Enhanced Oil Recovery

(This Model Cross Plots the Impact Matrix With the Distribution Model To Obtain a Relative Analysis of the Total Process Impacts)

Method	Environmental Components				
	Air	Water	Land	Biota	Total
Thermal .	65	79	36	67	247
Miscible .	63	67	46	88	264
Chemical	50	112	50	117	329
Total. . . .	178	258	132	272	

Potential Impacts on the Environment

There are at least seven media in which EOR operations could have environmental impacts: air, surface water, ground water, land use, seismic disturbances and subsidence, noise, and biological and public health. While each of the four physiographic regions can experience environmental repercussions in these seven media, certain types of impacts will be far more important in some regions than in others. For example, air pollution is a concern primarily in urbanized portions of the Coastal Plains and in Interior Basins where air quality is already in violation of Clean Air Act standards.[4] Similarly, land-use conflicts arise in heavily populated areas where land values tend to be high and multiple-potential uses exist for a given parcel of land. Ground water use and pollution is a grave concern in areas where ground water is a principal component of the water supply, such as in central and coastal California. Surface water pollution is important in areas with high surface runoff and at sites adjacent to surface water bodies. Noise is a concern in both urban and open areas, although natural ecosystems differ widely in their sensitivity to noise.

The matrix described previously attempts to identify the physiographic regions most likely to experience each type of environmental impact. The most likely means of generating these impacts are discussed below. Although some effort is made to quantify these impacts, it is not possible to do so precisely with the data available.

Air Quality Impacts

While all EOR methods (thermal, miscible, and chemical) can cause air pollution, thermal methods are most likely to generate air pollution impacts. Steam and hot-water flooding rely on steam generators. These generators usually use the fuel supply available on location (oil being

[4] *Monitoring and Air Quality Trends Report,* U.S. Environmental Protection Agency, Office of Air and Waste Management, 1976.

the most common fuel source), and emit sulfur dioxide (SO_2), oxides of nitrogen (NO_x), hydrocarbons, carbon monoxide (CO), carbon dioxide (CO_2, and other combustion products from exhaust pipes, In situ combustion can release these same compounds as fugitive emissions and as exhaust from high volume air compressors. These types of impacts from thermal EOR activities are likely to be localized and to be significant primarily in areas that are already in violation of, or are near the limits of, the Federal Ambient Air Quality Standards. In addition, NO_x released together with hydrocarbons escaping from the oil production process constitute a mixture with the potential to generate oxidant far downwind from the point of release. Further, nondegradation requirements may become important in remote areas.

The following sections discuss the mechanisms by which air quality impacts are generated and attempts to assess environmental air quality effects of various EOR methods in the four physiographic regions. The impact estimates are based on data which are now available. As more data become available, more meaningful projections of air pollution impacts will be possible.

Air Pollution Impacts of Thermal Recovery Methods

Although some estimates of the air pollutant emissions from steam flooding projects are available, there are very few quantitative data. Estimates of air pollution impacts of steam flooding can be made if both the amount of fuel to be burned and the emissions per unit volume of the fuel burned are known. Emissions from the oil production, (i.e., hydrocarbons, hydrogen sulfide (H_2S), and other emissions escaping from the production wells), are in addition to these exhaust gases.

Emission factors for fuel oil combustion are shown on table 38. Most thermal EOR processes will burn fuel oil or comparable petroleum products and will fall into the residual oil classification. The powerplant classification would apply only to the largest boilers used in EOR. Oxides of nitrogen (NO_x) emissions from powerplants and other large sources are higher because of the higher combustion temperatures encountered, while hydrocarbon and particulate emissions are lower because of better combustion regulation and more efficient burner designs

Table 38
Emission Factors for Fuel Oil Combustion
(Pounds Emitted per 1,000 Gallons Burned)

Pollutants	Power-plant	Residual oil	Domestic sources
Aldehydes, ., ...	1	1	2
Hydrocarbons	2	3	3
co.	3	4	5
NO_x (as NO_2.	105	40-80	12
SO*	157 S*	157 s"	142 S*
Particulate	8	23	10

S•= Percent sulfur in oil

Steam generator emissions in pounds emitted per 1,000 barrels of oil produced can be calculated from table 38 using the values given for residual oil. The results of this calculation are given in table **39.** Estimates in table 39 are based on the consumption of 0.3 barrel of oil for every 1.0 barrel of gross production. This level of consumption approximates commercial-scale steam generator operations in the San Joaquin Valley in California. The emission factors presented in table 39 are estimates only and do not necessarily portray accurate emissions of in-field EOR steam generators. The figures in the table can be linearly scaled to account for variations in consumption.

Recently, there has been serious consideration of use of coal as an inexpensive fuel to provide steam for thermal recovery, including use in California. Use of coal could cause somewhat higher emissions in every category.

Table 39
Steam Generator Emissions
[Pollutants Emitted per 1,000 Barrels of Gross Oil Produced)

Hydrocarbons	40 lbs
SO*	4,000 lbs
NO,. . . . . . . , ...	800 lbs
Particulate. , , , ... , , ... , ., ... , ...	280 lbs

•For crude containing 2 percent sulfur, without flue gas desulfurization.

NOTE: This table assumes that 0.3 barrel of fuel oil is burned for every 1.0 barrel of gross production. Due to a shortage of data, fugitive **emissions are excluded for** the **analysis.**

[5] J. A. Eldon and J. A. Hill, "Impacts of OCS Oil Development on Los Angeles Air Quality, " In *Southern California Outer Continental Shelf Oil Development: Analysis of Key Issues*, U. C.L.A. Environmental Science and Engineering Program, Los Angeles, Calif., 1976.

The new performance standards for fuel oil combustion were not used in making this calculation because oilfield steam generators rarely exceed the 250 million British Thermal Units (Btu) per hour capacity covered by these regulations.

A probable density of steam generators, and a level of steam generation required for a given well production rate, must be considered in order to estimate the overall pollution impact of a steam flood project.

The total emission rates from a field can be calculated using data in table 39. The resulting emission estimates can then be used in the evaluation of the impact of steam flood EOR on any specific region. As an example, the Wilmington Oil Field produced 67 million barrels of crude oil in 1973[6] by primary production; the field may eventually be a candidate for EOR. Steam flooding may be applicable due to the low American Petroleum Institute (API) gravity (high density) and high viscosity of California crude, and the considerable thickness of the oil-bearing stratum. The production of 30 million barrels per year by steam flooding (a potential for the Wilmington field) would involve the combustion of some 9 million barrels per year of fuel in the field steam generators. With the emission factors developed above, this combustion rate corresponds to the air pollutant emissions rate given in table 40.

Table 40
Projected Emissions from Steam Flooding of a Major Oil Field Compared to Los Angeles County Emissions

Pollutant	Emissions from a 30 million bbl/year field	Los Angeles County Total
NO_x	32 tons/day	1,000 tons/day
Particulate . .	12 tons/day	120 tons/day
SO_2	81 tons/day*	300 tons/day
Hydrocarbons.	2 tons/day	1,000 tons/day

*An 011 sulfur content of 2 percent was assumed

Table 40 also shows the total current emissions for Los Angeles County. Enhanced oil recovery emissions calculated for this example, with the exceptions of hydrocarbons and oxides of nitrogen, would be a significant fraction of the total emissions of Los Angeles County, Extensive exhaust gas scrubbing, consumption of low-sulfur fuel oil, and reduced scale of operation would be necessary in order to reduce SO_2 emissions to acceptable levels. Although these processes could reduce the emissions to lower levels, the resultant emissions will still be significant, at least on a local scale, since they are released into a heavily polluted airshed. Furthermore, they are released from a relatively small source area by comparison with the entire county, and could produce substantial impacts along a downward trajectory over a heavily populated region.

Emissions from in situ combustion are highly dependent on the oil formation, the type of crude oil, and the manner in which the project is operated. The high density of the crude oil in California and low economic returns experienced thus far indicate a low potential for in situ combustion, even though most oilfields in California can be spontaneously ignited by unheated air injections alone. To date, there are very few data available regarding the emissions from in situ combustion projects. It is anticipated that in order to meet air-quality pollution-control standards, especially in some areas of southern California, gas collection and treatment systems will be required,

In situ combustion and steam flooding are expected to have the greatest air-quality impacts in regions of low inversions, low wind speeds, and already polluted air, such as California's coastal plains and central valley. In remote mountainous regions, if background air quality is generally good and meteorological dispersion is favorable, a smaller impact may be expected. It should be noted, however, that high mountain valleys often experience severe inversions and air stagnation. Furthermore, nondegradation standards may apply for mountainous recreational areas. Thus air pollution impacts cannot be disregarded for such areas. While light air-pollution emission over the Continental Shelf would normally be considered inconsequential, there are areas in which these emissions must be carefully controlled, as in the southern California borderland. Any emissions released there have a high probability of being transported to shore, where they will contribute

[6] *California Oil and Gas Fields,* Vol. 2, California Division of Oil and Gas, Report No. TR12, 1974.

to an already serious air pollution problem.[7] Due to the low thermal and mechanical turbulence of air over water, dispersion of air pollutants over water is much slower than over land.[8] The Atlantic coast is just the reverse of the California situation in that the prevailing winds are from the west, so that emissions generated along the coast usually would be transported out over the Atlantic Ocean. The gulf coast tends to be a combination of the Atlantic and Pacific coast situations; depending upon the time of the year, the prevailing wind direction can be either from the north or the south.

Air Pollution Impact of Miscible Flooding Recovery Methods

Because miscible flooding does not involve high rates of either fuel combustion or in situ combustion, it is probable that CO_2 injection will have a much smaller air-quality impact than will the thermal methods discussed earlier. However, if hydrogen sulfide (H_2S) is injected into a reservoir and subsequently escapes, poisoning of humans and wildlife could result. There have been instances of this in the past. However, it is very unlikely that H_2S will be used as a primary constituent in any future major gas injection projects. Carbon dioxide is nontoxic, but capable of causing suffocation if concentrations are high enough. It will most likely be obtained from industrial activities (coal gasification), or natural reservoirs. The main air pollution impact resulting from CO_2 recovery methods will be the release of hydrocarbons and H_2S from formations into which CO_2 is injected. An important air quality concern is that CO_2 combined with H_2S in a gas mixture might have inadequate buoyance to disperse quickly, With the reduced buoyance, H_2S remains concentrated at ground level long enough to pose a threat to human and animal life because of its toxicity. Such effects are difficult to quantify without detailed information concerning concentrations of H_2S and CO_2 that would be emitted from gas injection recovery projects.

Because there has been considerable concern and a large degree of misunderstanding about H_2S and its potential safety and health threat to humans, the environment, and to equipment, further discussion is warranted. Concern has been generated to a large degree from an incident that occured at Denver City, Tex., in 1975, which resulted in nine fatalities. Hydrogen sulfide is toxic, flammable, explosive, corrosive, and may be naturally present in reservoirs. The concentration of H_2S which constitutes a harmful quantity depends upon the subject being considered, whether humans, the environment, or equipment. Therefore, regulations have been adopted by various governmental agencies to require all stages of H_2S operations to conform to safety and environmental standards.[9] Smith, the principal author of Texas Rule 36 which regulates this injection method, states that a dangerous condition would prevail if leaks of a certain volume exist, weather conditions complimentary to gas cloud ground accumulation exist, and persons unaware of the situation are present.[10] Texas Rule 36 and regulations adopted by other States have been formulated to prevent the above conditions from occurring. Hydrogen sulfide emission can be associated with normal oil production and is not necessarily complicated by any of the EOR processes, although the amounts encountered would be amplified by increased production. Therefore, while the H_2S problem exists for oil production in general, excessive concern for magnified H$ problems related to EOR is unwarranted.

Air Pollution Impacts of Chemical Recovery Methods

Chemical recovery methods do not produce emissions during application. Any air quality emissions from chemical EOR methods would be

[7] J. A. Eldon and J. A. Hill, "Impacts of OCS Oil Development on Los Angeles Air Quality, " In *Southern California Outer Continental Shelf Oil Development: Analysis of Key Issues,* U. C.L.A. Environmental Science and Engineering Program, Los Angeles, Calif., 1976.

[8] P. Michael, G. S, Raynor, and R. M. Brown, "Atmospheric Dispersion from an Offshore Site," in Physical Behavior of *Radioactive Contaminants* in the Atmosphere, p. 91, International Atomic Energy Agency, Vienna, 1974.

[9] *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

[10] C. D. Ehrhardt, Jr., "Environmental and Safety Regulations in Sour Gas and Crude Operations, " in Society of *Petroleum Engineers of AIME Paper Number SPE 5191, 1974.*

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indirect, in that they would occur from the production of various chemicals and the power generation required in the pumping process. In the case of the chemicals, air pollution impacts from production plants are already covered by existing air quality control regulations. Some light hydrocarbons, ethers, or alcohols are expected to be used in chemical recovery methods. These would presumably be derived from petroleum refineries whose air pollution emissions are of concern, but these may not be new emissions arising solely from EOR. If EOR were not utilized, the same refineries would very possibly manufacture other petrochemical products from the same raw materials. Therefore, the air pollution impacts of the chemical recovery methods "will be secondary in nature and covered by existing EPA State regulations.

Surface Water

Enhanced oil recovery methods will require significant quantities of water over and above primary recovery methods. It is anticipated that the EOR fresh water requirements would be higher than the demand in present techniques of waterflooding. A review of the literature did not provide firm data on the amount of water required for EOR. In order to quantify the water requirement, it is assumed in this assessment that one to six barrels of fresh water is needed for each barrel of oil recovered, This quantity of water consumption would have a greater effect on the environment in most regions than any other EOR impact.

As shown in figure 14, California, Texas, and western Louisiana are areas where water use is high and supplies short.[11] In fact, severe shortages are predicted by the year 2000. Although large quantities of water are required for EOR, the environmental impact on surface waters from EOR activities is anticipated to be only slightly greater than that from secondary recovery (waterflood) methods. The extent of hydrologic environmental effects will depend upon the characteristics and previous development of a reservoir. Geographic location, reservoir depth, and condition of the wells are factors which determine the potential adverse impacts of EOR activity on the hydrologic environment. The main environmental impact on the surface waters will be the actual consumptive use of the water. In semiarid areas, water may be required which is now being used for agriculture or other purposes.

Of the three EOR methods considered, chemical methods have the greatest potential for adverse impacts on surface water resources because water consumed (fresh water) 1) would be equal to or greater than for miscible or thermal EOR methods used, and 2) spills of concentrated chemicals would be environmentally more detrimental to water supplies than spills or emissions from other EOR processes. The likelihood that well failures or reservoir leakage due to breakdown of the reservoir would lead to contamination of surface waters is considered to be minimal.

The environmental effects on surface water of thermal EOR methods will be greater than those of miscible methods but less than those from chemical processes. As with chemical EOR methods, fresh water consumption in routine operations will have the greatest impact on the environment. Past experience has shown that spills, well fractures, and reservoir leakage are infrequent and basically nondetrimental during thermal EOR operations.

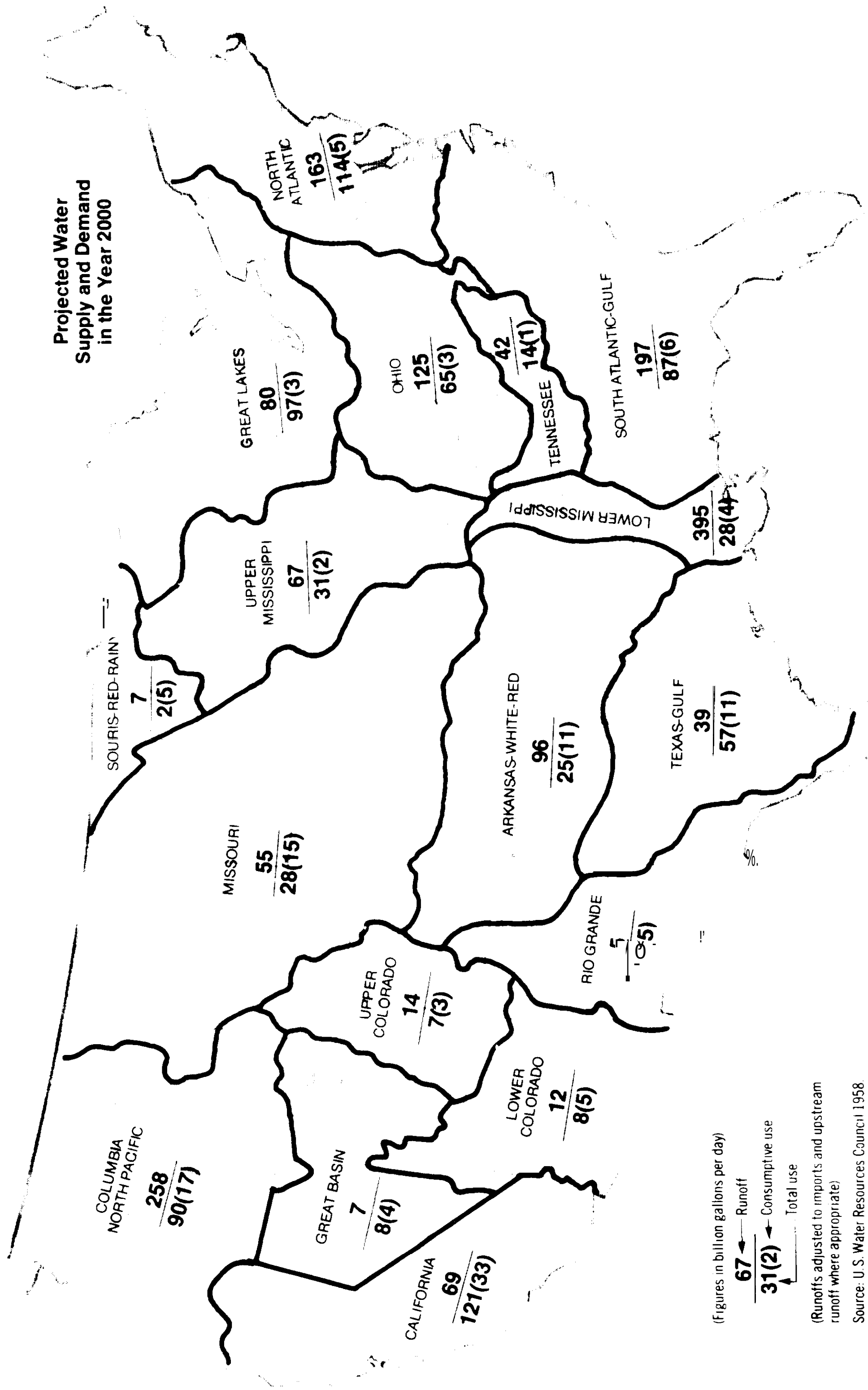
Miscible EOR methods will have the smallest environmental effect on surface water. As with the previous two methods, the quantities of water consumed in this EOR process—which presumably would be diverted from farming and other activities—would constitute the greatest environmental impact.

Surface water requirements will be largest for EOR activity in the Interior Basins, smaller in the Coastal Plains, and smallest on the Continental Shelf where few EOR projects are expected to occur.

Within the Continental Shelf area, it is anticipated that routine operations would cause the most environmental damage. Chemical spills, well failure, and reservoir leakage are thought to

[11] Water Information Center Publication, *Water Atlas of the United States,* Water Information Center, Inc., Port Washington, N. Y., 1973.

Figure 14. Water Use and Supplies



be the only mechanisms by which environmental effects would occur other than those which are a part of routine operations.

On the Coastal Plains, consumptive water use would frequently have the greatest environmental impact from EOR production. One exception to this would be chemical spills which could occur in this environmentally sensitive physiographic area. Thermal EOR methods might have a slightly greater environmental impact than miscible EOR methods. For regions where air quality already is poor, of course, air pollution impacts from thermal methods could be substantial.

Interior Basins would most likely be affected by chemical EOR methods. Miscible EOR methods would have the least environmental impact of the three EOR methods. Almost without exception, the greatest environmental effect on the Interior Basins would be water use. As with the Coastal Plains, the Interior Basins could also experience a significant environmental impact from chemical spills, primarily in transit to the injection well sites. The mountainous geographic areas might be relatively less affected even though they are environmentally sensitive areas.

Ground Water

potential for ground water contamination resulting from fluid injections associated with EOR operations appears minimal. This conclusion is supported by the lack of ground water contamination problems associated with conventional waterfloods. Only 74 ground water injection problems resulted from operating 44,000 injection. wells in Texas between 1960 and 1975 (an incidence rate of 1.1/10,000 per year); only 3 of these occurred during the last decade (an incidence rate of .02/10,000 per year). Similar safe operating records exist in the other major oil-producing States with large numbers of waterfloods. Because EOR injection operations are basically the same as waterfloods, often using the same injection wells in the same formations, an increase in the rate of ground water contamination is not expected. In fact, it is anticipated that the safety record will improve because EOR injection fluids are more costly than the water now used in waterfloods and operators could be expected to take additional precautions to prevent loss of these fluids during the EOR process.

As with surface waters, use of water from aquifers for EOR operations could put a strain on freshwater supplies in areas where reserves were limited. In areas where the rate of consumption exceeds the rate of recharge, the impacts would be severe. Recent field tests indicate that brine-tolerant EOR processes are feasible, and could significantly reduce the impact of EOR operations on freshwater aquifers if used.

Land Use

The impact of EOR operations on land use will not be significant. Additional surface facilities required for EOR activities will be relatively small, even for large projects. Relatively few additional flow lines and pipelines will be needed outside of the reservoir area, except in the case of CO_2 injections. Where large quantities of CO_2 are required, pipelines will be required to deliver economically the CO_2 to the project sites. Construction of these pipelines poses potential environmental hazards.

For some EOR projects additional wells will be drilled, and redrilling of wells will occur in older fields. These activities will cause minor disturbances for short periods but no long-term impacts will be evident, provided care is taken in the field development.

Geologic Hazards

Potential geologic hazards connected with EOR methods are subsidence and possible seismic activity. A great deal of subsidence data associated with primary oil recovery have been collected in the Long Beach, Calif., area.[12] When compared with primary recovery methods, it is anticipated that subsidence actually will be reduced during EOR operations. The reason for this reduction is that fluids will be left in the

[12] M. N. Mayuga, and D. R. Allen, "Long Beach Subscidence," *Focus on Environmental Geology,* R. W. Pank, Oxford University Press, New York, N. Y., p. 347, 1973.

reservoir after the oil is removed, except when in situ thermal methods are used.

There has been some research relating seismic activity to the use of secondary recovery methods. Results of this research imply that seismic activity will not be increased by EOR methods. The Rocky Mountain Arsenal near Denver, Colo., conducted deep well injections which resulted in an increase in seismic activity in the Denver Area[13] It should be noted, however, that these injections were generally made into deep crystalline rock which did not ordinarily contain fluids. Injected fluid acted as a lubricant to the existing stress zone which is believed to have caused the increased seismic activity. Obviously, oil recovery from reservoirs would not be considered analogous to the Rocky Mountain Arsenal situation.

Noise

Although the compressors and other equipment used in EOR generate high levels of noise, it is unlikely that this noise will cause any serious environmental impact. The loudest noises, such as those which would accompany preparation for the fracturing of the reservoir or injection of steam in a cyclic steam process, are of short duration. In regions where the local biota or human population would be adversely affected by noise, maximum muffling and noise abatement procedures will need to be imposed. Occupational Safety and Health Act (OSHA) regulations will serve as a standard for safeguarding humans.[14]

Biota

Enhanced oil recovery technologies present a variety of potential biological effects. These are summarized according to relative significance in table 35, and most do not appear very serious. While some do pose potentially significant problems, most can be adequately addressed and avoided.

Many areas where EOR activities would take place have already undergone primary and secondary development, and environmental impacts will therefore not result from EOR activities alone. Some of the potential impacts are common-to all processes, while others are the result of or dependent upon a particular process. Table 41 identifies the activities that might be expected to create biological impacts.

Table 41
Potential Biological Impacts Resulting From EOR

Process - Independent Impacts	
	Consumption of water
	New well drilling (land-use/habitat impacts)
	Extended time frame of activities
	Pipeline to provide water
	Increased refinery effluents
Process - Dependent Impacts	
Thermal:	**Air emissions**
	Cooling and consumptive water use
	Energy source
Miscible:	**Air emissions**
	Pipeline and source of CO_2
	pH changes
Chemical:	**Manufacturing, handling, and disposal of chemicals**

Process Independent Impacts

Probably the most significant potential adverse biological impact of EOR will result from the increased water consumption associated with this technology. Because fresh water (rather than saline water) is generally required, EOR process consumption of water will not only compete directly with domestic, agricultural, and other industrial uses, but could result in a localized drawdown of surface water, severely affecting aquatic flora and fauna within the area of the drawdown.

The Interior Basin and Mountain regions may be the most seriously affected by this consumptive use of water. Interior Basin areas already face some of the most serious water allocation problems, and wetland or aquatic ecosystems have already been substantially affected in many parts of this zone. While they have not experienced the same demands for water use, Mountain wetland areas are comparatively more

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[13] **"Geophysical and Geological Studies of the Relationships between the Denver Earthquakes and the Rocky Mountain ARsenal Well-Part A,"** *Quarterly of the Colorado School of Mines,* **Vol. 63, No. 1, 1968.**

[14] A. P. G. Peterson **and E, E. Cross, Jr.** *Handbook Of Noise Measurement,* **General Radio Corp, 7th Ed., 1974.**

fragile and vulnerable to drawdown. Also, consumptive use of water in the Coastal Plains could increase salt water intrusion, and significantly alter coastal wetland communities.

Potentially serious impacts may also result from new well drilling activity. Because EOR techniques will always be applied in areas of previous drilling activity, support facilities and access roads will generally be available. However, depending on the density of facilities needed for EOR, new construction may be significant. In the past, significant impacts have resulted from well drilling activities in wetland and aquatic areas, particularly in the Coastal Plains and mountain areas. These impacts have generally resulted from loss of habitat associated with a well drilling site, or from alterations (such as canals, ditches, and roads) to provide access. Canals used as access for drilling operations in coastal areas have caused significant adverse effects on shallow aquatic habitat and on marsh wetlands. These impacts have largely been caused by alteration of the hydroperiod and the fresh water—salt water interface. The changed salinity regimes which have resulted have caused severe alteration of wetland types as well as the fauna inhabiting them. The activities associated with construction of access to sites in the Coastal Plains, particularly dredging and filling, have also created substantial impacts.[15] The resulting changes may be permanent.

Because of the fragile nature of mountain ecosystems and the long times they frequently need to recover from impacts, road construction in Mountain regions also poses a threat of significant impact.

"These impacts are not a necessary consequence of new well drilling activity. Although potentially significant, most can be avoided by a thorough initial understanding of the system which may be disturbed, followed by careful construction and drilling practices. Because EOR activity occurs in areas of previous activity, economics dictate that maximum usage will generally be made of existing roads, facilities, and other structures,

Although EOR techniques may, on occasion, permit more rapid production of oil, they will generally extend the time during which production activities take place by 10 to 20 years. This will result in continued traffic, noise, dust and air emissions, and other actions of potential impact on biota. These will not usually be important, since the areas will already have been subject to primary recovery activity and because the remaining biota often will have adapted to man's routine activities after an initial period of displacement or disturbance. Some exceptions include activities adjacent to or otherwise affecting breeding and nesting areas or migratory routes. Some particular species (frequently endangered species) are not compatible with man's activities. Continued operations might preclude their return or survival in localized areas, although this would be an infrequent occurrence.

Because EOR processes will often require new or increased supplies of water, or water of different quality, the construction of water supply pipelines could also affect the biological environment. Such activity will result in direct loss of some habitat, and could affect the biota in other ways. For example, construction of pipelines across wetlands may be accompanied by the digging of a ditch, canal, or diked road; these would interrupt or alter the surficial sheetflow of water. Again, these impacts can be reduced through careful route selection and methods of construction. Frequently, pipelines will already exist to deliver water to production fields. It may be possible to use the opportunity created by new construction to rectify problems caused by existing pipelines.

Process Dependent Impacts

Each EOR process could have some specific biological impact. It appears that some of these will be of less significance than the potential impacts previously described. All of the EOR processes will result in air and water emissions, which must be controlled to be in compliance with the applicable air and water quality standards. However, it is important to recognize that attainment of standards will not avoid all biological impacts.

[15]Edward T. LaRoe, *Effects of Dredging, Filling, and Channelization on Estuarine Resources*, pp. 134-144; "Proceedings, Fish and Wildlife Values of the Estuarine Habitat, A Seminar for the Petroleum Industry," p. 184, U.S. Department of the Interior, Fish and Wildlife Service, 1973.

Therrnal.-Steam injection processes will have large demands for water, creating a potential for increased impacts caused by water consumption and the need for water pipelines.[16] Steam injection will also require substantial energy for steam generators and compressors. Existing facilities are usually powered by onsite generators fueled by petroleum products (oil or gas) produced at the well. These are noisy and air polluting. If EOR operations become widespread, the industry might desire to switch to electrically powered air compressors and other equipment. The off site production and supply of electricity (very likely from coal) could result in off site biological effects which would vary in significance with the type and location of power generation.

The air emissions produced by both steam injection and in situ combustion thermal EOR techniques WIll pose potentially slgnificant biological impacts. If uncontrolled, the impacts of these emissions could be most severe in the California coastal plain and Interior Basin areas because these areas not only appear the most likely regions for use of thermal EOR techniques but also have dirtier air than most other regions. The most critical effects would be on humans and vegetation, although the chronic effects on wildlife could also be significant. Air pollutants from EOR operations can probably be controlled; however, there has been little applied research in this direction to date. It is reasonable to expect that a serious research effort would make possible considerably reduced impacts.

Thermal projects also need to dispose ot heated water after it has been used for coo!ing. If discharged into surface waters, hot water can lead to changes in marsh and aquatic plant and anirnal life and promote the growth of phytoplankton algae, including blue-green algae, which can harm natural flora, fish, and wildlife. The thermal impact could be avoided by the use of cooling ponds, which could create localized air impacts of generally small consequence. Well failures or reservoir leakage could also result in the release of thermal pollutants; however, the impact of such discharge would generally be very localized and of little significance.

Thermal EOR processes frequently result in recovery of large amounts of oil-associated water, which is usually reinfected.1’ However, if the water is not reinfected and is discharged without treatment, the chronic release of this water, with entrained oil and traces of heavy metals, could adversely affect aquatic biota.

Thermal processes will also produce solid waste material, including fly ash from scrubbers used to control air emissions. The most direct impact will be in the need for land area to dispose of solid wastes (and the loss of habitat which that may cause). Shipment of material to suitable sites will cause some adverse impacts. Biological impacts of an efficiently designed and operated system can be kept small.

Miscible.--+robably the most significant potential biological impacts resulting from the CO_2 miscible EOR process will be those relating to the supply and transportation of CO_2. For EOR use, CO_2 will originate from CO_2 wells, or as a byproduct of other industrial activity. It will usually be transported to the field by pipelines, although in small projects CO_2 may be transported by refrigerated truck or tank car. While CO_2 itself is not toxic, the activities associated with its collection and transportation may have adverse biological impacts. Carbon dioxide pipelines can have the same biological impacts discussed for water pipelines above. The primary areas presently identified for CO_2 production are the Four Corners area, the northeast New Mexico-southeast Colorado area, central Mississippi, Texas, Utah, and Wyoming. These areas, and places along the pipeline routes to Texas, will have the most significant potential for impact, but the impacts will be localized That is, they will be restricted to the immediate area of CO_2 production and the pipeline route.

As with thermal processes, miscible processes will result in increased air emissions. The release of CO_2 itself would not have adverse biological effects, although adverse effects could result

[16] *Enhanced Oil Recovery,* National **Petroleum Council, December 1976.**

[17] Ibid

from the release of other gaseous contaminants, such as H_2S. If properly treated, or if reinfected, these emissions will have insignificant impacts.

1 he release of CO_2 under pressure to aquatic systems, as might occur with well failures or reservoir leakage, could result in a decrease in pH of the water body. The biological significance of this pH change would depend on the size of the water body, amount of CO_2 released, and the duration of release. However, aquatic life, especially freshwater fish, is particularly susceptible to increased acidity. While the potential for such an occurrence is extremely small, the impact, if it occurred, could be locally significant.

Chemical.-Although several chemicals that could be used in EOR processes have been described in literature, it appears in practice that only a few will actually have extensive use. Table 42 lists chemicals described in patent literature. Chemicals commonly used include broad spectrum petroleum and synthetic petroleum sulfonates; alcohols; polyacrylamide and polysaccharide polymers; sodium dichlorophenol and sodium pentachtorophenol; sodium hydroxide and sodium silicate.[18] These do not appear particularly hazardous in the concentrations used, nor do they become concentrated in food chains. However, the manufacturing, handling, and disposal of these chemicals pose potential biological impacts.

If chemical flooding methods are widely adopted, there must be a substantial increase in the production of some of these chemicals, especially the surfactants. Expanded manufacturing capacity could result in localized adverse impacts through loss of habitat and potential air and" water emissions.

Transportation of the chemicals commonly used for EOR operations is not likely to pose a major hazard. Many are frequently shipped as solids, which reduces the potential for a spill. Small spills of liquids, both during transportation

[18] *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

Table 42
Potential Chemicals Used in Chemical Flooding

Chemicals Proposed for *Surfactant Flooding:*
- **Broad spectrum petroleum sulfonates**
- **Synthetic petroleum sulfonates**
- * **Sulfated ethoxylated alcohols**
- * **Alcohols**
- " **Ethoxylated alcohols**

Chemicals Proposed as Bactericides:
- * **Sodium dichlorophenol**
- * **Sodium pentachlorophenol**
- **Formaldehyde**
- **Gluteraldehyde**
- **Paraformaldehyde**
- **Alkyl phosphates**
- **Alkylamines**
- **Acetate salts of coco diamines**
- **Acetate salts of coco** amines
- **Acetate salts of tallow diamines**
- **Alkyldlmethl ammonium chloride**
- **Coco dlmethyl ammonium chloride**
- **Sodium salts of phenols**
- **Substituted phenols**
- **Sodium hydroxide**
- **Calcium sulfate**

Chemicals Proposed for *Alkdline Flooding:*
- * **Sodium hydroxide**
- * **Sodium silicate**
- **Ammonium hydroxide**
- **Sodium carbonate**
- **Potassium Hydroxlde**

Chemicals Proposed *for Mobility Control:*
- * **Polyacrylamide**
- * **Polysaccharide**
- **Aldoses B Series**
- **Aldoses L Series**
- **Car boxy methylcellulose**
- **Carboxyvinyl polymer**
- **Dextrdns**
- **Deoxyribonucleic acid**
- **Ketoses B Series**
- **Ketoses L Series**
- **Polyethylene oxide**
- **Polyisobutylene in benzene**
- **Conjugated saccharides**
- **Disaccharides**
- **Monoosaccharides**
- **Tetrasaccharldes**

Chemicals Proposed as Oxygen **Scavengers:**
- **Sodium hydrosulfite**
- **Hydrazine**
- **Salts of bisulfite**

"Most commonly used
The above table was modified from *Enhanced 011 Recovery,* National Petroleum Council, December 1976.

and onsite use, are to be expected, but the biological impact will be limited since they are primarily of low toxicity.

Even though tests have shown that chemicals common l y used i n EOR processes have a 10 w acute toxicity, the long-term effect of such chemicals on the environment has not been evaluated. Not until such long-term studies have been conducted on the chemicals used in EOR processes can the potential for adverse environmental impacts be dismissed.

Disposal of produced water containing the chemicals will pose another potential water-quality impact. Most chemicals will be absorbed within the reservoir and the amount produced will be small. Although the chemicals are not particularly toxic, some (particularly the polysaccharide polymers) could act to increase biological oxygen demand (BOD) in the receiving water and this would adversely affect fish species. Potential biological impact can be avoided by disposing of chemically laden produced water by either relnjecting it into the oil-producing reservoir, injecting it into other saline aquifers, or treating it to remove contaminants before disposal into surface waters.

Appendixes

Appendix A

Oil Resource for Enhanced Recovery Projections

Contents

LIST OF TABLES

LIST OF FIGURES

OTA Data Base

The oil recovery projections for enhanced oil recovery (EOR) processes were determined from the results of reservoir-by-reservoir simulations. The accuracy of this approach depends on the extent, representativeness, and accuracy of the reservoir data file. In earlier work, Lewin and Associates, Inc., collected detailed data on 245 reservoirs in three States, California, Louisiana and Texas. The Office of Technology Assessment (OTA) contracted with Lewln and Associates, Inc., to expand this data base to include all major oil-producing States and at least 50 percent of the remaining oil resources. The expanded data base, referred to as the OTA data base, covers a broad range of geographic locations and reservoir types as well as the largest 300 domestic reservoirs on which public data are available.

This appendix describes the development and content of the OTA data base. Sources of data are documented by geographic region.

Reservoir Selection

A list of the largest oilfields (measured by cumulative production plus remaining reserves) was constructed from available data.[1] The exponential distribution of the size of the Nation's oilfields—the largest 300 fields provide over two-thirds of the Nation's production-suggests that the preponderance of tertiary recovery opportunities lies in the major fields.

Data collection, therefore, began by focusing on the largest fields and the largest reservoirs within these fields. Smaller fields and reservoirs were added to the file to increase the proportion of each State's oil covered by the data base. Thus, the OTA data base contains reservoirs and fields of varying size, although the preponderance of the reservoirs is quite large (over 50 million barrels cumulative production plus remaining reservoirs). An analysis was conducted to ascertain whether the preponderance of large fields renders the data base unrepresentative. No systematic bias was introduced by the number of larger fields.

Selection of Data Items

The data items included in the file were established by the three key tasks involved in EOR analysis, namely to:

1. Screen fields and reservoirs at two levels: (a) favorable or unfavorable to tertiary recovery; and (b) for the favorable reservoirs, the most preferred tertiary technique.
2 Calculate the oil in place and amount to be recovered through primary, secondary, and tertiary methods-based on actual reservoir parameters and production histories.
3 Calculate investment and operating costs of the preferred tertiary technique--based on region, reservoir, and crude oil characteristics.

Detailed data were collected concerning formation and crude oil characteristics, production histories, and original (OOIP) and remaining oil in place (ROIP). Figure A-1 is a copy of the form used to display data for each field and its producing reservoir(s). Complete reservoir data (as shown on the form) were available for only a few reservoirs. Although there are many data missing, complete volumetric and production data were available for each reservoir in the OTA data base.

Data Collection

A three-step approach was used in collecting the reservoir data:

1, Identification of Data Sources

National level data were available for fields through the American Petroleum Institute (API) and the U.S. Geological Survey (USGS)-sponsored Oil Information Center. However, little was available for reservoirs within these fields. Detailed data on reservoirs were gathered from State agencies, State-level private organizations, and general publications. In this step, the available data sources were cataloged and evaluated as

Figure A-1. Big Fields Reservoir

REPORT RUN DATE *

IDENTIFICATION

FIELD: RESERVOIR: CURRENT SCREEN:

LOCATION: REGION: BASIN: COUNTY(S):

FORMATION: RESERVOIR ID: FIELD ID:

RESERVOIR CHARACTERISTICS

DEPTH:	VISCOSITY:	SCW:	STRUCTURE:
BOTTOMHOLE TEMP:	API GRAVITY:	SOI:	
PRESSURE-SATURATION BP•	SALINITY-CONNATE-WATER:	STB SOI:	GEO AGE:
PRESSURE-ORIG:	SALINITY-PRODUCED-FLUID:	SOC:	
PRESSURE-LATEST:	CALCIUM:	STB SOC:	LITHOLOGY:
DIP:	MAGNESIUM:	SOR P/S:	FRACTURES:
GROSS PAY THICKNESS:	GAS CAP-ORIG:	STB-P/S SOR:	FAULTING:
AVG NET PAY THICKNESS:	GAS CAP LATEST:	FVF-ORIG:	COMPLEXITY:
NUMBER PAY ZONES:	GOR-ORIG:	FVF-LATEST:	LENTICULARITY:
POROSITY:	GOR-LATEST:	OST: 1	HETEROGENITY:
AVG PERMEABILITY:			CLAY CONTENT:
			TURBIDITES:

DEVELOPMENT HISTORY

PRIMARY YEAR SECONDARY YEAR TERTIARY YEAR

LATEST EOR YEAR:
LATEST EOR STAGE:
LATEST EOR ACRES:

RESERVOIR ACRES-TOTAL:	FIELD ACRES-TOTAL:	CURRENT OPERATORS
RESERVOIR ACRES-LATEST:	FIELD ACRES-LATEST:	
RESERVOIR PRODUCING WELLS-TOTAL:	FIELD PRODUCING WELLS-TOTAL:	
RESERVOIR PRODUCING WELLS-LATEST:	FIELD PRODUCING WELLS-LATEST:	
RESERVOIR INJECTION WELLS-TOTAL:	FIELD INJECTION WELLS-TOTAL:	
RESERVOIR INJECTION WELLS-LATEST:	FIELD INJECTION WELLS-LATEST:	

PRODUCTION HISTORY

RESERVOIR ORIG OIL-IN-PLACE:	FIELD ORIG OIL-IN-PLACE:
RESERVOIR CUMULATIVE PRODUCTION TO 1-1-75:	FIELD CUMULATIVE PRODUCTION TO 1-1-75:
RESERVOIR ESTIMATED ULTIMATE P/S PRODUCTION:	FIELD ESTIMATED ULTIMATE P/S PRODUCTION:
RESERVOIR RESIDUAL OIL-AT-ABANDONMENT:	FIELD RESIDUAL OIL-AT-ABANDONMENT:
RESERVOIR ANNUAL PRODUCTION	FIELD ANNUAL PRODUCTION
1974	1974
RESERVOIR PRODUCTION DECLINE RATE:	FIELD PRODUCTION DECLINE RATE:

to their completeness and reliability. From this evaluation, priorities were assigned to the identified sources.

2. State Procedures

For each State, detailed procedures were developed which described the data to be collected from each source, the sequence of using the sources, and decision rules for any estimates or averaging necessary to complete the data collection forms.

3. Estimation and Calculation of Missing Data Items

After' rigorously examining and cataloging all available data sources, some of the data remained missing. When these data were critical to the analysis, they were estimated using engineering formulas and empirical correlations. All data were edited for volumetric consistency, a requirement of later steps in the analysis.

Application of this procedure required numerous followup contacts with Federal and State sources to elicit additional data, to verify interpretations, or to procure additional suggestions regarding data sources.

Data Coverage

Table 6 in Chapter III shows the scope and coverage of the OTA data base. The 19 States included account for 96 percent of the oil remaining in domestic reservoirs. The individual reservoirs in the data base account for over half of the Nation's remaining oil, The percentage coverage of each State is also relatively high. In only one case was the coverage less than 20 percent of the State's residual oil. For only two States did the coverage fail to reach 30 percent. Thirteen of the 19 States had coverage of 40 percent or greater. Based on the coverage and diversity of the reservoirs in the OTA data base, an extrapolation to the full United States appears justified.

The States for which the coverage is lowest, especially Kansas, Oklahoma, Pennsylvania, and West Virginia, are States which collect only limited information,

Fields and Reservoirs in the OTA Data Base

Field	*Reservoir*
Alabama	
Citronella	Rodessa
Gilbertown	Eutaw
Alaska	
Granite Point	Middle Kenai
McArthur River	Hemlock
Middle Ground Shoal	Hemlock E,F,G Pools
Prudhoe Bay	Kuparuk River
	Lisburne
	Prudhoe Oil Pool
Swanson River	Hemlock
Trading Bay	Middle Kenai
	Middle Kenai G–Hemlock, North
Arkansas	
Magnolia	Smackover
Smackover	Old
Schuler	Jones
California	
Coastal	
Cat Canyon	Old Area Pliocene
	Sisquoc Area Others
	Los Flores
Dos Cuadras	Federal Offshore
Elwood	Vaqueros
Orcutt	Monterey Point Sal
Rincon	Hobson-Tomson-Miley
	Padre Canyon Others
	Oak Grove Others
San Ardo	Lombardi
Santa Maria Valley	Main
South Mountain	Sespe Main
Ventura	C Block
	D-5, D-6 East
Ventura	D-5, D-6 North
	D-7, D-8
Los *Angeles*	
Beverly Hills	East Area Miocene
Brea Olinda	Olinda Area
	Brea Area
Coyote East	Anaheim
Coyote West	Main 99 Upper West
	Main 99 Upper East
Dominquez	First East (Abandoned)
	First East Central
	First West Central
	East Cooperative
	3 and 4 NW Central
	3-4-5 East
	West Unit

96-594 0- 78 - ~

Field	Reservoir
Huntington Beach	North Area Tar Bolsa
	South Area Upper Main
Inglewood.	Vickers
Long Beach.	Old Area Upper Pools
Montebello, ...	Baldwin
Richfield	East and West Area
Santa Fe Springs.	Main Area Others
Seal Beach	South Block Wasam
	Alamitos
	North Block McGrath
Torrance	Main
Wilmington	Tar
	Upper Terminal
	Ranger
	Lower Terminal
	Ford

San Joaquin

Field	Reservoir
Belridge South	Tulare
Buena Vista , ...	Upper Hills
	Front Area
Coalinga	Temblor
Coles Levee North.	Richfield Main Western
Cuyama South	Main Area Homan
Cymric	Tulare
	Carneros
	Oceanic (all)
Edison , ...	Schist Main Upper
	Vedder Freeman
Elk Hills.	Upper Main
Fruitvale	Chanac-Kernco Main
Greeley	Rio Bravo-Vedder
Kern Front.	Main
Kern River.	Kern River Sands
Kettleman Dome North. . . .	Temblor
Lost Hills.	Main
McKittrick.	Upper Main
Midway-Sunset	Potter
Mt. Peso	Vedder
Rio Bravo	Vedder-Osborne-Rio Bravo

Colorado

Field	Reservoir
Adena	J-Sand
Akron, East ... , ...	D-Sand
Azure.	D-Sand
Badger Creek	D-Sand
Bijou	D-Sand
Bijou, West, ...	D-Sand
Black Hollow . . . . , . . .	Lyons
Bobcat.	D-Sand
Boxer.	D-Sand
Buckingham	D-Sand
Divide	D-Sand
Graylin, NE	D-Sand
Jackpot	D-Sand
Little Beaver	D-Sand
Little Beaver, East. , , ...	D-Sand
Phegley	D-Sand
Pierce	Lyons
Plum Brush Creek	J-Sand
Rangely	Weber
Saber.	D-Sand

Florida

Field	Reservoir
Sunoco-Felda	Roberts
Jay ., ...	Smackover
Blackjack Creek	Smackover

Illinois

Field	Reservoir
Clay City Consolidated. . . .	Aux Vases
	McClosky
Dale Consolidated.	Aux Vases
Lawrence	Cypress
Louden	Cypress
Main Consolidated	Pennsylvanian
New Harmony	Cypress
Salem Consolidated	Benoist
Robinson, ...	Robinson

Kansas

Field	Reservoir
Bemis-Shutts.	Arbuckle
Blankenship	Bartlesville
Big Sandy	Bartlesville
Burket	Bartlesville
Bush City	Squirrel
Chase Silica	Arbuckle
Cunningham.	Lansing-Kansas City
Edna.	Bartlesville
El Dorado	Admire
Fairport	Arbuckle
Fox-Bush-Couch.	Bartlesville
Gorham.	Arbuckle
Hall-Gurney	Lansing-Kansas city
Hep[er	Bartlesville
Hollow-Nikkei	Hunton
Humboldt-Chanute	Bartlesville
Iola	Bartlesville
Kraft-Prusa	Arbuckle
Lament	Bartlesville
Madison	Bartlesville
McCune	Bartlesville
Moran, Southwest	Bartlesville
Rainbow Bend	Burgess
Ritz-Canton	Mississippian
Sallyards	Bartlesville
Thrall-Aagard	Bartlesville
Trapp.	Arbuckle
Virgil	Bartlesville

Louisiana (North)

Field	Reservoir
Caddo Pine.	Nacatoch
	Annona
	Paluxy

Field	Reservoir
Haynesvil[e	Buck
	Pettit Lime
	Camp
	Smackover
Homer	Homer (all)
Rodessa	Rodessa (all)
Delhi	Delhi (all)

Louisiana (South)

Field	Reservoir
Avery Island	Medium
	Deep
Bay St. Elaine	Deep
	Deep
Bayou Sale	Deep
Caillou Island	Medium
	Medium
	Deep
Cote Blanche Bay West	Medium
	Medium
Cote Blanche Island	Deep
	Deep
Garden Island Bay	Shallow
	Shallow
	Medium
	Medium
Grand Bay	Medium
	Medium
Hackberry West	Medium
Lake Barre	Deep
	Deep
Romere Pass	Medium
Timbalier Bay	Medium
Lake Pelto	Deep
	Deep
Lake Washington	Shallow
	Medium
	Deep
Paradis	Deep
West Bay	Medium
Weeks Island	Deep
	Deep
Quarantine Bay	Medium
	Medium
Venice	Medium
	Medium

Mississippi

Field	Reservoir
Baxterville	Lower Tuscaloosa Massive
Bay Springs	Lower Cotton Valley
Cranfield	Lower Tuscaloosa
Eucutta East	Eutaw
Heidelberg	East Eutaw, (2) West Eutaw
Little Creek	Lower Tuscaloosa
Mallalieu, West	Lower Tuscaloosa
McComb	Lower Tuscaloosa
soso	Bailey
Tinsley	Woodruff Sand
Yellow Creek, West	Eutaw

Montana

Field	Reservoir
Bell Creek	Muddy
Cabin Creek	Interlake-Red River
Cut Bank	Kootenai
Deer Creek	Interlake
Gas City	Red River
Glendive	Red River
Little Beaver	Red River
Little Beaver, East	Red River
Monarch	Interlake-Red River
Outlook	Winnepegosis-Intedake
Pennel	Interlake-Red River
pine	Interlake
Poplar, East	Madison
Richeu, Southwest	Interlake-Red River
Sand Creek	Interlake-Red River

New Mexico

Field	Reservoir
Allison	Pennsylvanian
Caprock	Queen
Caprock, East	Devonian
Cato	San Andres
Chaveroo	San Andres
Corbin	Abo
Denton	Wolfcamp
	Devonian
Empire-Abe	Abo
Eunice-Monument	Gray burg-San Andres
Hobbs	San Andres-Grayburg
Lea	Devonian
Lusk	Strawn
Maljamar	Gray burg-San Andres
Milnesand	San Andres
Vacuum	Gray burg-San Andres
	Glorieta
	Abo Reef

North Dakota

Field	Reservoir
Antelope	Madison
Beaver Lodge	Madison
	Devonian
Blue Buttes	Madison
Capa	Madison
Charlson	Madison
Tioga	Madison

Oklahoma

Field	Reservoir
Star	Upper Misener-Hunton
Washington, East-Goldsby, West	Osborne
Sho-vel-tum	Pennsylvanian-Deese
Elmwood, West	Upper Morrow "A"
Elk City	Hoxbar
Salt Fork, Southeast	Skinner
Dover Hennessey	Meramec
	Manning
Red Bank	Dutcher
Putnam	Oswego

Field	*Reservoir*
Stroud	Prue
Eola-Robberson	Pontotoc
Avant & West	Bartlesville
Bowlegs	Gilcrease
Burbank, North	Burbank
Carleton, Northeast	Atoka-Morrow
Cement	Medrano Sand, West
Cheyenne Valley	Red Fork
Cushing	Bartlesville
Dibble, North	Osborne
Delaware-Childers	Bartlesville
Earlsboro	Earlsboro
Edmond, West	Hunton
Flat Rock	Bartlesville
Healdton	Hoxbar
Lindsay, North	Bromide
Mustang	Hunton Bois D'Arc
North Northwest-Verden	Marchand
Oakdale Northwest	Red Fork
Oconee, East	Oil Creek
Oklahoma City	Wilcox
	Oil Creek-Lower Simpson
Red River, West	Gunsight
Seminole	Upper Wilcox
Stanley Stringer, North	Burbank

Pennsylvania

Bradford	Third Bradford
Fork Run	Cooper
Foster-Reno-Oil City	Venago First
Kane	Kane
Sartwell	Third Bradford
	Sartwell

Texas

District 1

Big Wells	San Miguel
Darst Creek	Buda-Edwards
Luling-Branyon	Edwards
Salt Flat	Edwards

District 2

Greta (all)	4400
Lake Pasture	H-440
	569
Refugio	Refugio-Fox
Tom Oconnor	Catahoula-Frio-Miocene
West Ranch	41-A

District 3

Field	*Reservoir*
Thompson	Frio
Barbers Hills	Frio-Miocene
Columbia West	Miocene
Conroe	First Main Cockfield
Dickinson-Gillock	Frio 8300-8800
	Frio 9000-9300
Goose Creek	Miocene
Hastings East & West	Frio
High Island	Miocene
Hull Merchant	Yegua
Humble (all)	Miocene
Old Ocean	Armstrong
Oyster Bayou	Frio-Searbreeze
Pierce Junction	Frio
Sour Lake	Frio
Spindletop	Caprock-Miocene-Frio
Tomball	Cockfield
Webster	Frio
Magnet Withers	Frio
Anahuac	Frio

District 4

Alazan North	Frio
Aqua Dulce-Stratton	Frio-Vicksburg
Borregos	Combined Zones
Government Wells North	North
Kelsey	Multiple Zones 5400-6400
Plymouth	Frio
Saxet	Het.-Mio
Seeligson	Combined Zones
T-C-B	Zone 21 -B
White Point East	Frio

District 5

Mexia	Woodbine
Powell	Woodbine
Van	Woodbine

District 6

Fairway	Lime
Neches	Woodbine
New Hope	Bacon Lime
	Pittsburg
Quit Man	Paluxy
Talco	Paluxy
East Texas	Woodbine
Hawkins	Woodbine

District 7-B

Eastland Co	Strawn
Stephens Co.	Caddo

District 7-C

Big Lake	Queen
Jameson	Strawn
	Pennsylvanian
McCamey	Grayburg
Pegasus	Pennsylvania
	Ellen burger

District 8

Andector	Ellen burger
Block 31	Crayburg
	Devonian
	Ellen burger
Cowden North	Grayburg
	Deep
Cowden South	San Andres-Grayburg
	Canyon
	Ellen burger

Field	*Reservoir*
Crossett	Devonian
Dollarhide	Ellen burger
	Devonian
Dora Roberts	Ellenburger
Dune	Permian-San Andres
Emma	Gray burg-San Andres
	Ellen burger
Foster	Gray burg-San Andres
Fullerton	San Andres
	Clear Fork
	8500
Goldsmith	San Andres-Grayburg
	5600 Clear Fork
Harper	Permian
	Devonian
	Ellenburger
Headlee	Ellen burger
Hendrick	Yates-Seven Rivers
Howard-Glasscock	Yates-Seven Rivers-Queen
	San Andres-Grayburg
	Glorieta
Iatan East	San Andres
Johnson	Gray burg-San Andres
Jordan	Permian
	Ellenburger
Kermit	Permian-Yates
Keystone	Colby
	Ellenburger
McElroy	Crayburg
Means	Gray burg-San Andres
Midland Farms	Grayburg
	Ellenburger
Parks	Pennsylvanian
Penwell	San Andres
	Glorieta
Sand Hills	Tubbs
Shafter Lake	San Andres
	Devonian-Wolfcamp
	Ellenburger
Spraberry Trend	Spraberry
TXL	Tubb
	Pennsylvanian
University Waddell	Devonian
Waddell	Gray burg-San Andres
Ward Estes North	Yates-Seven Rivers
Ward South	Yates-Seven Rivers
Yates	Gray burg-San Andres

District 8-A

Anton Irish	Clearfork
Cogdell	Canyon Reef
Diamond M	Canyon Lime
Kelly Snyder	Cicso
	Canyon Reef (Watered)
	Canyon Reef
Levelland	San Andres
Prentice	Glorieta
	Clearfork 6700

Field	*Reservoir*
Russell	Glorieta
	Clearfork
	Devonian
Salt Creek	Canyon Reef
Seminole	San Andres
Slaughter	San Andres
Wasson	San Andres
	Clearfork
Welch	San Andres

District 9

Archer Co. Reg.	Strawn-Gunsight
Cooke Co. Reg.	Strawn
Hull Silk Sikes.	Strawn 4300
KMA	Strawn
Walnut Bend	Huspeth
	Walnut Bend
	Winger
Wichita Co. Reg.	0-2100
Wilbarger Co. Reg.	Dyson-Milham
Young Co. Reg.	Gunsight

District 10

Panhandle	Carson
	Gray
	Hutch inson

Utah

Altamount-Bluebell	Green River
Aneth	Desert Creek
McElmo Creek	Desert Creek
Ratherford	Desert Creek
White Mesa	Desert Creek
Bridger Lake	Dakota

West Virginia

Greenwood	Big Injun
Griffithsville	Berea

Wyoming

Big Muddy	Wall Creek
Big Sand Draw	Tensleep
Bonanpa	Tensleep
C-H Field	Minnelusa
Cottonwood Creek	Phosphoric
Dillinger Ranch	Upper Minnelusa B
Elk Basin	Embar-Tensleep
Frannie	Tensleep
Gailand	Combined
	Tensleep
Grass Creek	Curtis
	Embar-Tensleep
	Frontier
Hamilton Dome	Tensleep
Hilight	MuddY-MinnellJsa
Lance Creek	Leo
	Sundance

Field	*Reservoir*
Little Buffalo Basin	Tensleep
Lost Soldier	Combined
	Tensleep
Oregon Basin	North Tensleep
	South Tensleep
Salt Creek	Wall Creek
Smemlek, West	Minnelusa B
Steamboat Butte	Tensleep
Wertz	Tensleep
Winkleman Dome	Tensleep

Offshore Fields in Louisiana

Field	*Reservoir*
Bay Marchand 002	3600’ D
	3650’ (L) D
	3650’ (U) D
	4900’ D
	7100’ F
	7600’ MS
	7900’ D
	81 75’ B
	8200’ F
	8200’ BUQ
	8300’ BU
	8300’ EE
	8500’ B
	8550’ B
	8700’ BU
	8750’ BUW
	9100’ c
	9200’ B
	9600’ B
	RA
	RA
	RD
Bay Marchand Block 2	BM 4350 D VU
	BM 4500 MLD VU
	BM 5000 D VU
	BM 4800 RD VU
	4800 AB VU
Eugene Island 126	2A-RF-B
	2A-RF-c
	2B (1) RF A
	2B (1) RF-BVU
	2B (U) RJ
	2B (U) RL-C
	C-1 RF
	C-1 RN
	D-1 RF A
	D-1 RF SU
	E-2 RF SU
	F-1 RF SU
	IM RF-B
	IM RL-A
	IM RL-SU
Eugene Island 175	RA
	RA
	RA
	RB
	RD
	RB
	FB-D
	FB-D
	FB-A
	RB
	RC
	RA
Eugene Island 276	P RA SU 1 W
	P RA SU IW
	U RA SU 1 W
	U3 RA SU 1 W
	VH 10 DE* 1
	Crist Sub 3A RA
	Tex (P) 1 RF
Eugene Island Block 330	LF FBB 1
	7300 S1 ● 1
	FBB
	RA
	FBA
	FBA
	RA
	Seg. A
	Seg. 1
	Seg. 3
	GA-2
	HB-1
	Seb. I
	B
	FBA
	FBB
	FBB
	FB
	FC
	FSI
	L RA
	L RB
	L RC
	L RE
	L RF
	LF FBA 1
Grand Isle Block 16	B-2 RC 1A
	B-2 RE 1 W
	B-4 RC
	B-4 RE
	B-4 RT
	BF-2 RE UC
	C-1 REF IW
	C-4 A RN
Grand Isle Block 43	G-1
	F-2
	c-l
	R-2
	C-1
	G-2

Field	Reservoir
	S-1
	R5
	D-1
	R-1
	S-1
	R1
	I-I
	F-1
	R-6
	F-1
	I-8
	E-6
Grand Isle Block 47	A-6
	A-6
	A-3
	A-2
	A-1
Main Pass Block 35	G2 RA SU
	K2 RA SU
	LO RA SU
	L2 RA SU
	N RA SU
	O RA SU
	R2 RA SU
Main Pass Block 41	RD SU
	RA SU
	RA SU
	RB SU
	RA SU
	RB SU
Main Pass 41	A
	D
	D
	A
	A
	A
	A
	t
	A
	F
	A
Main Pass Block 69	RB SU
	RA VU
	RC VU
	RH SU
	RB SU
Main Pass 144	RI
	6250
	6250L
	6900
	7250
	7500
	7525
Main Pass 306	AB 28/29
	C45
	B 44/45
	AB4
	44/45
	A-213
	A-4
	A-FB-1
	A-2
	A-3
	5AF81
	44/45
	FB-I
	FB-111
	2/3
	4
	29
	42
	44/45
Ship Shoal 204	D-1
	FB5
	FB4
	FB5
	RA
	BRA
	RA & BRA
	RB
Ship Shoal 207	AI
	RA
	RA
	RE
	RB
	RG
	RA
	RA
	RF
	RA
	RC
	RG
Ship Shoal 208	RC
	PA
	ARA
	RA
	FB-3
	FB-4
	FB-3
	FB-4
	FB-4
	FB-3
	FB-4
	FB-3
	FB-4
	FB-4
	RA
	RC
South Pass Block 24	4 RB SU
	8200 T SU
	8400 RA SU
	8600 RA SU
	8800 RD SU
	M2 RA SU
	NA RA SU
	02 RA SU
	P-Q RA SU
	Q RA SU

Field	*Reservoir*
	Q RB SU
	Q RC SU
	Q RE SU
	R2 RA SU
	SRA SU
	S RC SU
	T RA SU
	T RB SU
	T RC SU
	T RD SU
	T1 RB SU
South Pass Block 24	T1 A RB SU
	TIA RB SU
	U2 RA SU
South Pass Block 27	RA SU
	v u
	RB SU
	RA SU
	RA SU
	RA SU
	RB SU
	RC SU
	RD SU
	RB SU
	RC SU
	RD SU
	RE SU
	RC SU
	RA SU
	RB SU
	RA SU
	RA SU
	RB SU
	RA SU
	RA SU
	RB SU
	RC SU
	RD SU
South Pass 27	Pliocene
	10 D
	F 32 UP
	F 32 UP
	F 13 AUp
	F 13 AD
	RBSU
	10 UP
	RESU
	RASU
	6 UP
	RESU
	RESU
	F 13 AU
South Pass 61 ... ,	RM
	RN
	RQ
	RR
	RN
	RM
	RA

Field	*Reservoir*
	RC
	RB
	RC
	RD
South Pass 62	RA
	RA
	RB
	RC
	RA
	RA
	RA
	RC
	RA
	RD
South Pass 65	RA
	RG
	RB
	RC
	RB
	RC
	RD
	RE
	RA
	RB
Ship Shoal 208	RA
South Marsh Island 73	B-35-K
	B-65-G
	C-5-6
Timbalier Bay Block 21.	DC
	Su
	I
	IIIB
	ZX3
	3X2
	DC
	Clc
	BID
	BSC
	DC
	DC
	DC
	DC
	EB
	TE
	BSU
	DC
	DC
W. Delta Block 30	A-1 Res. F
	A-2 Res. D
	A-3 Res. D
	C-45 and Res. Q
	D-6 Res. BB
	E RASU
	G RASU
	G-4 Res. C-1
	C-4. Res. E-1
	I RASU
	IF Res. C-2
	IM Res. C-10

Field	*Reservoir*
	P-1 Res. F
	P-2 Res. F
	P-45 Res. F
	P-6 Res. F
	6100 Res. E
	6300' Res. G-A-2 Res. F
	6400' Res. G-A-3 Res. F
	71 50' Res. E
	8500 Res, C
W. Delta 73.	RA
	FBI
	FB2
	RA

Field	*Reservoir*
	RA
	RA
	RA
W. Delta 79. ., ...	D2R6S
	SFFO
	NFF
	NFF
	I
	I
	II
	III
	Iv

Documentation of Data Sources

Data needed for individual reservoirs were obtained from many sources. Sources of data are summarized by State in the *Bibliography* beginning on page 129. The entries in this bibliography include 10 categories of data. Specific data items in each category are identified in the following section. These categories indicate the type of information sought. As indicated in the Selection of *Data Items* on page 111, there are many gaps in the specific data items under each category. Data which were available for essentially all reservoirs in the data base are indicated with an asterisk.

Geology
- * Structure name
- Geologic age
- Lithology
- Fractures
- Faulting
- Complexity
- Continuity
- Lenticularity
- Heterogeneity
- Clay content
- Turbidities

Reservoir condition
- * Depth
- * Bottom hole temperature
- Pressure
- Dip
- * permeability
- Gas cap

Reservoir volume
- * Net pay thickness
- * Number of zones
- * Porosity
- * Acres

Saturations
- * Connate water saturation
- * Initial oil saturation
- Current oil saturation
- Residual oil saturation after primary and secondary recovery

Water characteristics
- Salinity
- Calcium
- Magnesium

(il/ characteristics
- * Gravity
- * Viscosity (reservoir conditions)
- * Formation volume factors
- Gas/oil ratio

Oil volume - resources/reserves
- * Original oil in place
- * Estimated primary/secondary recovery
- * Remaining reserves

Oil volume - production history
- * Cumulative production
- * Annual production
- Production decline rate

Field development - conventional
- * Discovery year
- * primary drive type
- * Type of secondary recovery
- * Year of secondary initiation
- * Total wells drilled
- * Latest active wells
- Current operator(s)

Field development - EOR
- Type of EOR process
- Year of initiation
- Current stage of development
- Acres under development

Bibliography

Following the State-by-State charts is a bibliography providing the full citation for each source by State.

Documentation of Data Sources for Big Fields Reservoir File

	State and Source	Geology	Reservoir Condition	Reservoir volume	Saturations	Water characteristics	Oil characteristics	Oil volume: Resources/reserves	Oil volume: Production history	Field Development: Conventional	Field Development: EOR
	Alabama										
1	American Association of Petroleum Geologists	●	●	●		......			●	●	
~	American Petroleum Institute					......		●			
1	Bureau of Mines					●					
4	International Oil Scouts Association		●	●		......			●	●	
5	Mississippi Geological Society	●	●	●	●	......	●	•		●	
6	Oil & Gas Journal				●	......		●	●		
7	Society of Petroleum Engineers of AIME					......	●				
	Alaska										
1	Alaska Division of Oil & Gas	●	●	●	●	......	●	●	●	●	
2	Alaska Geological Survey	●	●	●		......	●			●	
i	American Association of Petroleum Geologists	●	●	●		......	●		●	●	
4	American Petroleum Institute — a				●	......		●			
	American Petroleum Institute — b					......		●			
5	Bureau of Mines		●		●	......					
b	Federal Energy Administration	●	●	●	●	......	●	●		●	
7	International Oil Scouts Association		●	●		......			●	●	
8	Mortada International	●	●	●	●	......	●			●	
9	Oil & Gas Journal					......		●	●		
10	Petroleum Data System of North America		●	●	●	......	●			●	
11	Society of Petroleum Engineers of AIME					......	●				
	Arkansas										
1	Arkansas Oil & Gas Commission		●	●	●	......		●	●	●	
2	Bureau of Mines — a	●		●	●	......	●	●			●
	Bureau of Mines — b					●					
	Bureau of Mines — c	●	●	●	●	......	●	●		●	
3	Gulf Universities Research Consortium	●	●	●		......	●				
4	International Oil Scouts Association		●	●		......	●			●	
5	Interstate Oil Compact Commission	●	●			......		●		●	
6	Oil & Gas Journal					......		●	●		
7	Society of Petroleum Engineers of AIME — a		●			......	●				
	Society of Petroleum Engineers of AIME — b	●	●	●	●	●					●
	California										
1	American Petroleum Institute — a					......		●	●		
	American Petroleum Institute — b					......		●	●		
2	American Association of Petroleum Geologists	●	●	●		......	●	●		●	
3	California Division of Oil and Gas	●		●		●		.		●	●
4	Conservation Commission of California Oil Producers		●			......	●		●	●	
5	Energy Research and Development Administration — a	●	●	●		......	●	●	●	●	●
	Energy Research and Development Administration — b			●		......					
6	Federal Energy Administration	●	●	●	●	......	●	●	●	●	
7	Gulf Universities Research Consortium	●	●	●		......	●				
8	National Petroleum Council — a	●	●	●		......	●	●	●	●	
	National Petroleum Council — b	●				......	●				
9	Oil and Gas Journal — a		●			......	●				●
	Oil and Gas Journal — b					......		●	●		

State and Source	Geology	Reservoir Condition	Reservoir volume	Saturations	Water characteristics	Oil characteristics	Oil volume: Resources/ reserves	Oil volume: Production history	Field Development: Conventional	Field Development: EOR
10 Petroleum Data System of North America	●	●	●	●	......	●			●	
11 Society of Petoleum Engineers of AIME — a	●	●	●	●	......	●	●	●	●	●
Society of Petroleum Engineers of AIME — b		●		●	......	●				
Society of Petroleum Engineers of AIME — C	●	●	●	●	●	●	●		●	
Society of Petroleum Engineers of AIME — d	●	●	●	●	●	●	●		●	●
12 12. Miscellaneous Petroleum Periodicals					......		●	●		
Colorado										
1 American Petroleum Institute					......		●			
2 Bureau of Mines	●	●	●		......	●	●		●	
3 International Oil Scouts Association			●		......	●	●	●	●	
4 Petroleum Data System of North America		●	●	●	●				●	
5 Rocky Mountain Association of Petroleum Geologists — a	●	●	●	●	●	●	●	●	●	
Rocky Mountain Association of Petroleum Geologists — b					●					
6 Society of Petroleum Engineers of AIME				●	......	●				
Florida										
1 American Association of Petroleum Geologists	●	●	●	●	......	●	●	●	●	
2 American Petroleum Institute					......		●			
3 Federal Energy Admininstration	●	●	●	●	......	●	●	●	●	
4 International Oil Scouts Association			●		......	●				
5 Oil and Gas Journal					......		●	●		
6. Society of Petroleum Engineers of AIME — a					......	●				
Society of Petroleum Engineers of AIME — b	●	●	●	●	......	●	●	●	●	
Illinois										
1 Bureau of Mines	●		●	●	●	●				●
2 Gulf Universities Research Consortium	●	●	●		......	●				
3 Illinois and Indiana-Kentucky State Geological Societies	●	●	●		......	●	●	●		
4 Illinois State Geological Survey — a		●	●		......	●				
Illinois State Geological Survey — b	●	●	●	●	......	●		●	●	
5, International Oil Scouts Association			●		......	●		●	●	
6. Oil and Gas Journal — a					......	●				●
Oil and Gas Journal — b					......		●	●	●	●
7. Petroleum Data System of North America	●	●			......	●			●	
8 Society of Petroleum Engineers of AIME — a	●	●	●		......	●			●	●
Society of Petroleum Engineers of AIME — b					......				●	●
Kansas										
1 American Association of Petroleum Geologists — a	●		●		......				●	
American Association of Petroleum Geologists — b	●	●	●		●	●		●		
American Association of Petroleum Geologists — c	●	●	●		......	●			●	
2 American Petroleum Institute					......		●			

State and Source	Geology	Reservoir condition	Reservoir volume	Satura-tions	Water charac-teristics	Oil charac-teristics	Oil volume		Field Development	
							Resources/ reserves	Produc-tion history	Conventional	EOR
3 Bureau of Mines — a.	●	●	●	●	●	●			●	
Bureau of Mines — b				●	●		',			
4 Energy Research and Development Administration	●	●	●		......			●		
5 International Oil Scouts Association		●	●		......	●		●	●	
6 Kansas Geological Survey — a		●	●		......	●		●	●	
Kansas Geological Survey — b	●	●	●		......	●			●	
Kansas Geological Survey — c	●	●		●	......	●		●	●	
Kansas Geological Survey — d	●			[illegible]	......				●	
7 National Petroleum Council			●		......			●		
8 Oil and Gas Journal — a		●	●		......	●				●
Oil and Gas Journal — b					......		●	●		
9 Petroleum Data System of North America	●	●	●		......				●	
10 Society of Petroleum Engineers of AIME — a		●	●	●	......	●	[illegible]			
Society of Petroleum Engineers of AIME — b	●	●	●	\	......					●
Society of Petroleum Engineers of AIME — C	●	●		●	●		●	●		●
11 Miscellaneous Petroleum Periodicals	●	●	●	●	......	●			●	
Louisiana (Onshore)										
1 American Petroleum Institute — a and b					......		●	●		
2 Bureau of Mines					●				\ \ \ \	
3 Louisiana Department of Conservation — a		●	●	●	......	●	●		●	●
Louisiana Department of Conservation — b			●		......		[illegible]		●	
4 Oil and Gas Journal — a		●			......	●				●
Oil and Gas Journal — b					......		●	●		
5 Society of Petroleum Engineers of AIME — a	●	●	●	●	●	●	●	●	●	ž
Society of Petroleum Engineers of AIME — b	●	●	●		......		[illegible]		●	●
6 Society of Production Well Analysts					●			[illegible]		
7 National Petroleum Council	●	●	●		......	●	●	●	●	
Louisiana (Offshore)										
1 U S Geological Survey	●	●	●	●	......	●	●	●	●	
Mississippi										
1 American Association of Petroleum Geologists	●	●	●	●	......	●			●	
2 American Petroleum Institute					......		●			
3 Bureau of Mines — a	●				●					
Bureau of Mines — b		\		\	......		●			
4 Federal Energy Administration		●	●	●	......	●	●		●	
5 Gulf Universities Research Consortium		●	●	●	......	●	[illegible]	●	●	
6. International Oil Scouts Association		●	●		......	●	\ \ \ \ \	●	●	
7 Mississippi State Oil and Gas Board	●	●	●	●	......	●	●	●	●	●
8 Oil and Gas Journal — a					......	●				●
Oil and Gas Journal — b					......		●	●		
9 Society of Petroleum Engineers of AIME					......	●				
Montana										
1 American Association of Petroleum Geologists		●	Q		.....				\ \ \ \	
2 Bureau of Mines	●	●	●	●	......	●			●	
3 Gulf Universities Research Consortium		●	●		......	●	[illegible]		●	

State and Source	Geology	Reservoir condition	Reservoir volume	Saturations	Water characteristics	Oil characteristics	Oil volume		Field Development	
							Resources/ reserves	Production history	Conventional	EOR
4 International Oil Scouts Association	●	●	●		......			●	●	
5 Montana Oil and Gas Conservation Commission	●	●	●	●	......	●	●		●	
6 Oil and Gas Journal					......		●	●	●	
7 Society of Petroleum Engineers of AIME — a					......	●				
Society of Petroleum Engineers of AIME — b	●	●	●		......	●			●	
8 U.S. Office of Oil and Gas	●		●		......					
9. Landes, *Petroleum Geology of the U.S.*	●	●	●	●	......		●			
10 Ver Wiebe, *North American Petroleum*	●				......					
New Mexico										
1. American Association of Petroleum Geologists			●		......					
2 American Petroleum Institute					......		●			
3 Federal Energy Administration	●	●			......					
4 Gulf Universities Research Consortium	●	●	●		......	●			●	
5 Interstate Oil Compact Commission		●	●		......			●	●	
6 International Oil Scouts Association		●	●		......	●		●	●	
7 National Petroleum Council			●	●	......					
8 Oil and Gas Journal					......		●	●	●	
9 Petroleum Data System of North America	●	●	●	●	●	●			●	
10 Phifer Petroleum Publications	●	●	●	●	......	●				
11 Roswell Geological Society	●	●	●	●	●	●			●	
12 Society of Petroleum Engineers of AIME — a		●	●	●	......	●				
Society of Petroleum Engineers of AIME — b		●	●	●	......	●			●	●
13 Personal Communication			●	●	......					
North Dakota										
1 American Petroleum Institute					......		●			
2 Bureau of Mines	●	●	●	●	......	●			●	
3 International Oil Scouts Association		●	●	●	......	●		●	●	
4 North Dakota Geological Survey — a	●	●	●	●	●	●			●	
North Dakota Geological Survey — b		●	●	●	......	●		●	●	
5 Oil and Gas Journal — a					......		●	●		
Oil and Gas Journal — b		●			......					●
6 Society of Petroleum Engineers of AIME					......	●				
7 Personal Communication	●	●	●	●	......	●		●	●	
Oklahoma										
1 American Association of Petroleum Geologists	●	●	●	●	......	●	●		●	
2 American Petroleum Institute — a and b					......		●	●		
3 Bureau of Mines	●	●	●	●	●	●	●			
4 Energy Research and Development Administration	●	●	●	●	●	●	●	●	●	●
5 Gulf Universitites Research Consortium	●	●	●		......	●				
6 International Oil Scouts Association			●		......	●		●	●	
7 Interstate Oil Compact Commission					......				●	
8 National Petroleum Council			●		......				●	
9 Oil and Gas Journal — a		●			......	●				●
Oil and Gas Journal — b		●			......		●	●		

	State and Source	Geology	Reservoir condition	Reservoir volume	Satura- tions	Water charac- teristics	Oil charac- teristics	011 volume		Field Development	
								Resources/ reserves	Produc- tion history	Conventional	EOR
10		●	●	●	●	......	●	●		●	
11		●	●	●	●	......	●				●
12						......			●		
13			●		●	......	●				
		●	●	●	●	●	●	●	●	●	●
		●	●	●		......	●	●	●	●	●
1						......		●			
2		●	●	●	●	......	●	●		●	
3			●	●		......		●		●	●
4		●	●			......					
5				●		......				●	
6						......		●	●		
7			●			......	●				
			●			......					
8		●		●		......				●	
9		●	●	●	●	●			●	●	
10			●	●	●	●				●	
	Texas										
1	American Association of Petroleum Geologists — a	●	●	●		......	●	●	●	●	
	American Association of Petroleum Geologists — b	●	●	●		......	●	●	●	●	
2	American Petroleum Institute — a					......		●	●		
	American Petroleum Institute — b					......		●	●		
3	Bureau of Mines					●					
4	Federal Energy Administration	●	●	●	●	......	●	●	●	●	
5	Gulf Universities Research Consortium — a	●	●	●		......	●	●	●		
	Gulf Universities Research Consortium — b					......					●
6	International Oil Scouts Association			●		......	●		●	●	
7	National Petroleum Council — a					......			●	●	
	National Petroleum Council — b	●	●	●		......	●	●	●	●	
8	Oil and Gas Journal — a		●	●		......	●				●
	Oil and Gas Journal — b					......		●	●	●	
9	Petroleum Data System of North America	●	●	●	●	......	●			●	
10	Society of Petroleum Engineers of AIME — a		●	●	●	......					
	Society of Petroleum Engineers of AIME — b	●	●	●	●	●	●	●	●	●	●
	Society of Petroleum Engineers of AIME — c	●	●	●	●	●	●	●	●	●	●
	Society of Petroleum Engineers of AIME — d	●	●	●	●	●	●	●	●	●	●
11	Texas Railroad Commission — a					......			●	●	
	Taxas Railroad Commission — b		●	●		......					
	Texas Railroad Commission — c	●	●	●	●	●	●	●	●	●	
	Texas Railroad Commission — d		●	●		......	●	●	●	●	●
	Utah										
1	American Association of Petroleum Geologists	●	●	●	●	......				●	
2	American Petroleum Institute					......		●			
3	Bureau of Mines	●	●	●	●	......	●			●	

State and Source	Geology	Reservoir condition	Reservoir volume	Saturations	Water characteristics	Oil characteristics	Oil volume: Resources/ reserves	Oil volume: Production history	Field Development: Conventional	Field Development: EOR
4		●	, ,	, . .	. ,				●	
5.	●	●	●	●	●	●	●		●	
6		●	●			●		●	●	
7	[illegible]						, .	●		
8		●	●				●		●	
9				●		●				
10	●	●	●	●		●	●	●	●	●
	[illegible]	●		●		[illegible]			●	
1							●			
2.		●	●						[illegible]	●
3.			●						●	
4.		, . .	●						●	
5.	●	●	●	●	●			. , .	●	
6.	●	●	●	●		●		●	[illegible]	
Wyoming										
1. American Petroleum Institute			[illegible]				●	, .		
2. 8ureau of Mines	●	●	●		●	●			●	
3. Federal Energy Administration		●	●			[illegible]	●	●	●	
4 Gulf Universities Research Consortium	●	●	●			●			[illegible]	
5 International Oil Scouts Association		●	●		, . .	●		●	●	
6 National Petroleum Council.									●	
7 011 and Gas Journal —a.		.,		[illegible]			●	, .		
Oil and Gas journal — b.								. .		●
8. Society of Petroleum Engineers of AIME — a ,..		●	●	●		●	.			
Society of Petroleum Engineers of AIME — b . . .	●	●	●	●		●		,,	[illegible]	
Society of Petroleum Engineers of AIME — c	●	●	●	●	●	●	●		●	●
9. Wyoming Geological Association.	●	●	●	●		●	●		●	
10 Wyoming 011 and Gas Conservation Commission					●			●	●	
11 Miscellaneous Petroleum Periodicals.	●	●				●		. .		

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Analysis of Reservoirs in Data Base To Determine Amount and Distribution of Remaining Oil

Distribution of the Original Oil in Place

Reservoirs frequently taper out near the perimeter of the productive acreage. The OTA data base did not contain data which would approximate variation of thickness or oil saturation with a real position. For the purposes of this study it was assumed that 95 percent of the original oil in place was contained in 80 percent of the reservoir acreage.[2] All enhanced oil recovery (EOR) projects were developed in this "richer" portion of the reservoir. This assumption was implemented in individual reservoir calculations by increasing the net oil sand in the richer portion of the reservoir.

Volume of Oil Remaining

The oil resource for EOR processes is the oil which is not recovered by primary and secondary methods. The OTA data contained estimates of the original oil in place as well as the reserves attributed to current operations. Reserves were considered to be the maximum attainable from each reservoir without application of enhanced recovery methods. It was assumed that regions which could be waterflooded economically have been or are now under development. Thus, infill drilling would be considered to accelerate the production of known reserves rather than to add new reserves.

Distribution of the Remaining Oil Resource

Two models were used to approximate the distribution of the oil resource which remains for potential recovery processes.

Reservoirs With Limited Waterflood Response

Reservoirs which were candidates for thermal recovery processes were those where waterflooding has not been applied successfully over an appreciable portion of the reservoir. The oil resource at the beginning of thermal recovery operations was assumed to be distributed uniformly throughout each reservoir. The average oil saturation at this point was computed using equation 1A, which represents a material balance over the reservoir volume.

$$S_{o2} = (N - N_p)\left(\frac{B_o}{B_{oi}}\right)(S_{oi}) \qquad 1A$$

where

- S_{o2} = material balance, average oil saturation
- S_{oi} = oil saturation in the reservoir at discovery
- N = estimated initial oil in place, stock-tank barrels
- N_p = ultimate oil recovery by primary and secondary methods in **stock-tank barrels**
- B_{oi} = oil formation volume factor at initial pressure. Ratio of volume occupied by the oil at reservoir conditions to the volume of oil which would be recovered at the surface at stock-tank conditions
- B_o = oil formation volume factor at the reservoir pressure which exists when N_p stock-tank barrels are produced.

The OTA data base did not contain values of B_o for every reservoir but since reservoir temperatures were available the value of B_o was set at the value corresponding to thermal expansion at reservoir temperature. Equations 2A and 3A derived from the correlations of Katz[3] were used to estimate B_o:

[2] *Research and Development In Enhanced Oil Recovery,* **Final Report, The Methodology, U.S. Energy Research and Development Administration, Part 3 of 3, p. V-4,** *ERDA 77-2013,* December 1976.

[3] **1. W. Amyx,** D.M. Bass, **and** R.L. **Whiting,** *Petroleum Reservoir Engineering* **p. 429,** McGraw Hill Book Company (1960).

$$B_o = 1 + \alpha\,(T_R - 60) \qquad \text{2A}$$

$$\alpha = 0.000288 + 8.04111 \times 10^{-6}\,API - 1.890 \times 10^{-7}\,(API)^2 \qquad \text{3A}$$

where

API = stock-tank oil gravity in degrees API
T_R = reservoir temperature, "F.

There were insufficient data to estimate changes in B_o from dissolved gas.

Several large reservoirs in California do not have uniform oil saturation in all portions of the reservoir. Reservoirs which were known to have oil saturation distributions were identified by members of the Technology Task Force of the National Petroleum Council (NPC) study. These data were available for the OTA study. However, it was not feasible to subdivide the reservoirs in the economic model. Subdivision of the reservoirs would change the price versus ultimate recovery projections but would not alter the ultimate recovery.

Reservoirs Under Natural Water Drive or the Waterflooding Process

The carbon dioxide (CO_2 miscible process and the surfactant/polymer process will probably be applied in reservoirs where waterflooding—either through natural water influx or water injection-has been successful. The entire reservoir volume is not swept by a waterflood. Consequently, there is a distribution of oil saturation which varies from essentially initial oil saturation in regions not swept by water to a residual oil saturation in the volume swept by the water.

The oil recovery models for both CO_2 miscible and surfactant/polymer processes assume that the processes will be contacting residual oil in some portions of the volume swept by the waterflood. It is necessary to estimate the volume of this region as well as the residual oil saturation. Although these two parameters are not known for every reservoir, it is possible to develop a relationship between them for certain situations.

The data base contains estimates of the initial oil in place, oil recovered by primary and secondary processes, and the formation volume factors at initiation and end of primary and secondary recovery. If these data are considered correct, the volumetric sweep efficiency and the average residual saturation in the region swept by water are related by equation 4A.

$$E_{vm} = \frac{\dfrac{N_p}{N} + \dfrac{B_{oi}}{B_o} - 1}{\dfrac{B_{oi}}{B_o}\left(1 - \dfrac{S_{orw}}{S_{oi}}\right)} \qquad \text{4A}$$

where

E_{vm} = volumetric sweep efficiency of the waterflood, fraction of the reservoir swept by the waterflood
S_{orw} = average oil saturation in the reservoir volume swept by the waterflood

Other terms were defined in equation 1A.

Equation 4A was derived from an overall material balance on the reservoir in which 1) all portions of the reservoir are considered hydraulically connected, 2) regions not swept by the waterflood are resaturated to the initial oil saturation at the current reservoir pressure, and 3) the rock pore volume is invariant with pressure.

Neither SO_{rw} nor E_{vm} were available in the data base. Estimates of S_{orw} on a geological and regional basis were made in the NPC study on enhanced oil recovery using the study group's general knowledge of the reservoirs in the Lewin data base and experience in similar reservoirs which were not included in the data base. Based on this knowledge, a residual oil saturation of 20, 25, or 30 percent was assigned to each reservoir in Texas, Louisiana, or California which was a candidate for surfactant/polymer or $C0_2$ miscible processes.

The Office of Technology Assessment investigated the validity of these estimates through discussion with members of the NPC study group and review of the technical literature. Additional data were obtained from a committee preparing a book on residual oil saturations for the Interstate Oil Compact Commission.[4] Personal inquiries

[4] Personal communication with Lincoln Elkins, November 1976.

were made to companies and/or personnel who did not participate in the selection of specific values for the NPC study but who had knowledge of the properties of reservoirs in the NPC/Lewin data base.

The following conclusions were reached:

- There are a relatively small number of reservoirs where estimated values of the residual oil saturation have been confirmed with independent methods of measurement.
- Values of the residual oil saturation assigned by the NPC study group are consistent with the information which was available in the public literature and obtained through personal inquiry. Specific reservoirs within a region are likely to vary from the assigned values, but this variation is believed to be within the uncertainty of the estimates.
- The uncertainty in the residual oil saturation estimates is significant. The uncertainty is primarily due to inadequate measurement techniques and limited application of existing methods. As a result, it is not uncommon to find technical personnel in different operating divisions of the same company whose estimates of the residual oil saturation in a particular reservoir differ by 5 saturation percentage points.
- Residual oil saturations in the region swept by water are judged to be known with more certainty than the volumetric sweep efficiency, The OTA study group accepted the NPC assignment of residual oil saturation for those reservoirs which were also in the NPC base case. Reservoirs not in this category were assigned saturations indicated in table A-1 .

Two constraints were imposed on the volumetric sweep efficiencies computed from equation 4A using the residual oil saturations in table A-1.

> The maximum sweep efficiency of *a waterflood was considered to be* 90 *percent of the reservoir volume.* If the computed E_{vm} was larger than 0.9, the value of E_{vm} was set to 0,9 and the value of S_{ORW} was computed from equation 4A for the reservoir.

Table A-1
Average Oil Saturation in the Region Swept by Waterflood

Region	S_{orw}
Texas District 3.	0.20
South Louisiana, Offshore Texas Districts 1,2,4,5, and 6.	0.25
California, North Louisiana, the balance of Texas, and all other States. . . . . . , ...	0.30

> *The minimum volumetric sweep efficiency of a waterflood was considered to be 40 percent in California and 50 percent in all other reservoirs.* If the computed E_{vm} was less than the minimum value, the appropriate minimum was assigned to E_{vm} and the value of S_{orw} computed from equation 4A was assigned to the reservoir.

Consistency of Oil Resource Estimates With Those Implied by Other Studies

The approach used in the NPC study involved assignment of both volumetric sweep efficiency and residual oil saturation for each reservoir. This led to overstatement of the resource when the ultimate production data were also known. However, ultimate production data were not available to the NPC Technology Task Force for every reservoir in the NPC data base.

The initial oil in place (N) for reservoirs used in the NPC study was computed by OTA by inserting NPC-assigned sweep efficiencies and residual oil saturations in equation 4A. Ultimate production for each reservoir was included in the data base so that the initial oil in place could be computed from equation 4A. The resulting values of the initial oil in place were significantly different from values in the data base. Differences were particularly large (>10 percent) in California. The difference could be attributed to either overstatement of the initial oil in place or understatement of the ultimate production. Information gained from contacts with oil industry personnel familiar with certain reservoirs was used to reevaluate the methods used by Lewin and Associates, Inc., to determine the initial oil saturations. Revisions of this analysis led to the reduction of oil-in-place estimates by 3.5 billion barrels in California.

Reservoirs assigned to one set of OTA runs for CO_2 miscible and surfactant/polymer processes were analyzed to determine if there were large differences between the initial oil-in-place estimates in the data base and those computed by using NPC sweep efficiencies and residual oil saturations in equation 4A. Results extrapolated to national totals are summarized in table A-2.

The comparison in table A-2 indicates a difference of about 10 percent between estimates for the surfactant/polymer reservoirs. This is within the range of uncertainty. The difference approaches 30 percent for reservoirs which were CO_2 candidates. However, as indicated in the section on Discussion 01 *Results* (page 46) in chapter III, the effect on calculated oil recovery by the CO_2 miscible process was minimal.

Table A-2
Comparison of initial Oil in Place Computed for Estimates of Sweep Efficiency and Residual Oil Saturations

Reservoirs *in Surfactant/Polymer Economic Evaluation*	
Original oil in place from OTA data base . . . . ~	**51.2 billion barrels**
Original oil in place determined from material balance calculations using NPC sweep efficiency and residual oil saturations	**46.4 billion barrels**
Difference—surfactant/polymer reservoirs	**4.8 billion barrels**
Reservoirs **in CO_2 Miscible Economic Evaluation**	
Original oil in place in OTA data base	**93. s billion barrels**
Original oil in place determined from material balance calculations using NPC sweep efficiency and residual oil saturations	**130.0** billion barrels
Difference-CO_2 miscible reservoirs . .	36.5 billion barrels

Appendix B

Supporting Materials for Oil Recovery Projections From Application of Enhanced Recovery Processes

LIST OF TABLES

LIST OF FIGURES

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This appendix presents supplementary materials which were used to prepare oil recovery projections and to compute the costs to produce enhanced oil. It is organized into two sections, the first describing the technological assumptions for each enhanced oil recovery (EOR) process. For each process the "state of the art" of the technology is assessed. Models used to compute recoveries and production rates are presented in detail. Cost data which are specific to a process are documented. Results of calculations not presented in the body of the report are given.

The second section describes the economic model used in the OTA study. Cost data which are independent of the process are documented in this section.

Technological Projections

Surfactant/Polymer Flooding

State of the Art—Technological Assessment

The surfactant/polymer process involves two technologies. The first is the art of formulating a chemical slug which can displace oil effectively over a wide range of crude oil compositions, formation water characteristics, and reservoir rock properties. As used in this section the term chemical slug refers to all injected fluids which contain a surfactant mixed with hydrocarbons, alcohols, and other chemicals. Excluded from this definition is alkaline flooding,[1] a process in which surfactants are generated in situ by reaction of certain crude oils with caustic soda.

The second technology is the displacement of the injected chemical slug through the reservoir. This technology is governed by economic and geologic constraints. The cost of the chemical slug dictates use of small volumes in order to make the process economically feasible. The technology for displacement of the chemical slug through a reservoir relies on controlling the relative rate of movement of the drive water to the chemical slug. Effective control (termed mobility control) through process design prevents excessive dilution of the chemical slug. If mixed with displaced oil or drive water, the chemical slug would become ineffective as an oil-displacing agent. Control of the mobility of the chemical slug or drive water is accomplished by altering the viscosities or resistance to flow of these fluids when they are formulated. z

NOTE: All references to footnotes in this appendix appear on page 193.

Research to find chemicals which displace oil from reservoir rocks has been conducted in Government, industry, and university laboratories for the past 25 years. Research activity in the period from 1952 to about 1959 was based on the injection of dilute solutions of surfactant without mobility control .-3 Activity peaked with the advent of each new chemical formulation in the laboratory and declined following disappointing field results. In some tests, surfactants were injected into reservoirs with no observable response. in other tests, the response was so small that the amount of incremental oil recovered was almost unmeasurable. The cost of whatever incremental oil was produced was clearly uneconomic.

The period beginning in the late 1950's and extending into the present is characterized by major advances in formulation of the chemical slug and control of slug movement through a reservoir. Several laboratories developed formulations based on petroleum sulfonates which may displace as much as 95 percent of the oil in some portions of the reservoir which are swept by the chemical slug.[4,5] Addition of water-soluble polymer to drive water has led to mobility control between the drive water and chemical slug.[6]

Field tests of the different processes have produced mixed results. About 400,000 barrels of oil have been produced from reservoirs which have been previously waterflooded to their economic limit.[7,8,9] Oil from one test was considered~ economic. All other oil was produced under conditions where operations were uneconomic. Offsetting these technically successful tests[10] are several field tests which yielded considerably less incremental oil than anticipated." [11,12,13] The state of technology is such that honest differences of opinion exist concerning the reasons for disappointing field test results.[14,15]

The current ERDA program includes six large-scale, cooperative, field-demonstration tests. The fields and locations are summarized in table B-1. The first five projects are in fields which have been intensively waterflooded. In these tests, the principal objectives are to demonstrate the efficiency and economics of recovery from a successfully depleted waterflood using the surfactant/polymer process. The Wilmington reservoir contains a viscous oil. An objective of this project is the development of a surfactant/polymer system which will displace viscous oil economically.

Table B-1
ERDA Cooperative Field-Demonstration Tests of EOR Using the Surfactant/Polymer Process

Field	Location
El Dorado	Kansas
North Burbank	Oklahoma
Bradford	Pennsylvania
Bell Creek	Montana
Robinson	Illinois
Wilmington	California

Screening Criteria.—The screening criteria in table 7 of the main text reflect estimates of technological advances in the next 20 years as well as current technology inferred from past and ongoing field tests. For example, technological advances in temperature tolerance are projected so that reservoirs which have a temperature of 200° F can have a technical field test in 1985.

The OTA screening criteria coincide with those used by the National Petroleum Council (NPC)[16] with one exception. The OTA data base did not contain adequate water-quality data for all reservoirs. Consequently, reservoirs were not screened with respect to water quality.

The screening criteria were reviewed prior to acceptance. The review process included informal contacts with personnel who did not participate in the NPC study and an examination of the technical literature. The principal variables are discussed in the following sections.

The screening criteria are judged to be representative of the present and future technological limits. As discussed later, it is recognized that permeability and viscosity criteria have economic counterparts. However, the number of reservoirs eliminated as candidates for the surfactant/polymer process by either of these screening criteria was insignificant.

Current Technology (1976).--Current limits of technology are reflected by field tests which have been conducted or are in an advanced stage of testing. These are summarized in table B-2.[17] Field tests are generally conducted in reservoirs where variation in rock properties is not large enough to obscure the results of the displacement test due to reservoir heterogeneities. These reservoirs tend to be relatively clean sandstone with moderate clay content. A crude oil viscosity less than 10 centipoise is characteristic of most surfactant/polymer field tests. Reservoir temperatures range from 55° F to 169° F.

Reservoir Temperature.—Surfactants and polymers are available which tolerate temperatures up to about 170° F. Research on systems which will be stable at 200° F is underway in several laboratories. The rate of technological advance in this area will probably be related to the success of field tests of the surfactant/polymer process in lower-temperature reservoirs. Successful field tests will stimulate development of fluids for higher-temperature deeper reservoirs as potential applications in those reservoirs become a reality. The assumed timing of technological advances in temperature limitations appears attainable.

Permeability and Crude Oil Viscosity. -Permeability of the reservoir rock is both a technological and an economic factor. The surfactant/polymer process will displace oil from low permeability reservoir rock.[18] A minimum permeability based on technical performance of the process has not been established. Low permeability may correlate with high-clay content of the reservoir rock and corresponding high-surfactant losses through adsorption. The surfactant slug must be designed so that its integrity can be maintained in the presence of large adsorption

Table B-2
Summary of Surfactant Field Tests Being Conducted by Industry Without ERDA Assistance

Field	State	County	Operator	Process Type*	Area (Acres)	Start	Pay	Porosity (%)	Perm. (Md)	Depth (ft)	Reservoir °API	Oil (Cp)	Temp. (°F)	Salinity (ppm)	Comment
Robinson	Ill.	Crawford	Marathon	MSF	0.75-40	11/62	Robinson	20	200	1,000	35-36	7	72	HPW 18,150 ppm TDS (1 19-R)	6 tests
	Ill.		Marathon	MSF	4.3	5/70	Aux Vases			3,000					
Bingham	Pa.	McKean	Pennzoii	MSF	0.75-45	12/68	Bradford	18	82	1,860		5	68	2,800 Cl^-	2 tests
Goodwill Hill	Pa.	Waxyen	Quaker St.	MSF	10	5/71	First Venongo			600	40	4.5	55		
Benton	Ill.	Franklin	Shell	Aqueous	1-160	11/67	Tar Springs	19	69	2,100		4	86	77,000 ppm TDS	2 tests
Loudon	Ill.		Exxon	Aqueous solution	0.65	9/70	Chester Cypress	21	103	1,460		4	Est. 95	64,000 Cl^- 104,000 TDS	
Higgs Unit	Tex.	Jones	Union	SOF	8.23	8/69	Bluff Creek	22.9	500	1,870	37	4.3	95	54,000 cl–	
Big Muddy	Wyo.	Converse	Conoco	SF	1	8/73	Second Wall Creek	19.2	52	3,100	34	5.6	114	7,700 TDS, 20 ppm fractured, CA+ Mg	
Griffin Consol.	Ind.	Gibson	Conoco	SF	0.8	11/73	Upper Cypress	20	75	2,400	37				
Wichita Co. Regular	Tex.	Wichita	Mobil	LTWF	209	7/73	Gunsight	22	53	1,750	42	2.2	89	160,000 TDS	
Borregos	Tex.	Kleberg	Exxon	Aqueous solution	1.25	mid 60's	Frio	21	*400	5,000	42	0.4	165	33,000 TDS	
Guerra	Tex.	Star	Sun	SF	2.0		Jackson	33	2,500	2,270	36	1.6	122	20,000 TDS	
Bridgeport	Ill.	Lawrence	Marathon	MSF	2.5	9/69	Kirkwood	18	90	1,500	38-39	5.5	72		
Sayles	Tex.	Jones	Conoco	SF	2.5	/63	Flappen	21.7	457	1,900	38				
Montague	Tex.	Montague	Conoco	SF	2.5	/63	Cisco	24.2	394	1,200	27			150,000 TDS	
Loma Novia	Tex.	Duval	Mobil	SF	S.o	mid 60's									4% kaolinitc 5.5% montmorillonite
Salem	Ill.	Marion	Texaco	LTWF	5.8	4/74	U. Benoist	14.8	87	1,750	38	3.6	0.85	40,000cl–	
Sloss	Nebr.	Kimball	Amoco	SF	10.0	1/75	Muddy J.	17.1	93	6,250	34	0.8	165	2,457 TDS	
West Ranch	Tex.	Jackson	Mobil	LTWF	2.5	6J74	41A	31	950	5,700	32	0.7	169	60,000Cl^-	
La Barge	Wyo.	Sublette	Texaco	SF	1.7	1/75	Almy	26	450	700	26	17	60	1,017 Ca^{++} and Mg^{++}	

* Process Type normally refers to specific surfactant floods used, but is not intended to characterize actual differences: Aqueous-dispersion of sulfonate in water with very little oil in slug; MSF—micellar surfactant flood; SOF—normally considered "oil external" chemical slug; SF and LTWF—surfactant flood and low-tension waterflood *normally* similar to aqueous *systems.*

Source: *Enhanced 0// Recovery,* National Petroleum Council, December 1976, p. 97.

losses. As a result, larger slugs or higher concentrations may be needed with corresponding increases in costs.

Permeability, fluid viscosities, well spacing, and maximum injection pressure affect the rate at which a chemical slug can displace oil from a reservoir. Low permeability translates to low displacement rates or increased well density to maintain a specific rate. Both lead to higher process costs.

The same reasoning applies to crude oil viscosity. As viscosity increases, displacement rates decrease or well density increases. Mobility control in the surfactant/polymer process is attained by increasing the viscosities of the chemical slug and the drive water. Both of these changes require addition of expensive constituents to these fluids. Therefore both permeability and viscosity are constrained by economics.

It is known from laboratory tests that oil recovery by the surfactant/polymer process is a function of displacement rate. For example, more oil is recovered at an average displacement rate of 5 ft per day than at the rate of 1 ft per day[19] which exists in a typical reservoir. Rate effects in field size patterns may be revealed in the Marathon-ERDA commercial demonstration test.[20]

Water Quality .-Composition of the formation water is a critical variable in the surfactant/polymer process. Fluids under field tests can tolerate salinities of 10,000 to 20,000 ppm with moderate concentrations of calcium and magnesium, although reservoirs containing low-salinity flu ids are preferred. Some field tests are in progress in which preflushes are used to reduce salinity to levels which can be tolerated by the injected chemicals.[21,22] However, in one large field test[23] the inability to attain a satisfactory preflush was considered to be a major contributor to poor flood performance. Potential shortages of fresh water for preflushing and uncertainty in effectiveness of preflushes have stimulated research to improve salinity tolerance.

Technological advances were projected in the NPC study which would increase the salinity tolerance from 20,000 ppm in 1976 to 150,000 ppm in 1980 and 200,000 ppm in 1995. The OTA technical screen does not contain a similar scenario because salinity data were not available for all the reservoirs in the OTA data base. It does not appear that results would have been affected appreciably if the data were available in the data base to schedule technological advances in salinity tolerance.

Rock Type.—The surfactant/polymer process is considered to be applicable to sandstone reservoirs. Carbonate reservoirs are less attractive candidates because 1) the formulation of compatible fluids is more difficult due to interaction with calcium and magnesium in the rocks; 2) carbonate reservoirs frequently produce through small- and large-fracture systems in which maintenance of an effective surfactant slug would be difficult; and 3) there is a consensus among technical personnel that the CO_2 miscible displacement process is a superior process for carbonate reservoirs.

Reservoir Constraints.—Reservoirs with large gas caps which could not be waterflooded either by natural water drive or water injection are likely to be unacceptable. Also, reservoirs which produce primarily through a fracture system fall in the same category. However, there is the possibility of technological developments[24] which would restrict flow in the fracture system and perm t displacement of the surfactant slug through the porous matrix.

Oil Recovery Projections

The surfactant/polymer process is applied in a reservoir which has been previously waterflooded, There are different opinions among technical personnel concerning the volume of the reservoir which may be swept by the process. Some consider that the swept volume will be less than the volume swept by the waterflood, while others envision **more** volume swept by the surfactant/polymer process. The reasoning behind these viewpoints is summarized in the following subsections.

Swept Volume Less Than Water flood Sweep.—Residual oil saturations and volumetric sweep efficiencies attributed to waterflooding are frequently the result of displacing many pore volumes of water through the pore space. In contrast, the surfactant/polymer process can be approximated as a 1- to 2-pore volume process which may lead to a smaller fraction of the reservoir being contacted by the surfactant/polymer process.

Many reservoirs are heterogeneous. It can be demonstrated that heterogeneities in the vertical direction of a reservoir which have relatively small effect on the sweep efficiency of a waterflood may have large effects on the sweep efficiency of the surfactant/polymer process.[25] For instance, in a layered reservoir it may not be possible to inject enough surfactant into all layers to effectively contact the regions which were previously waterflooded.

Surfactant/Polynmer Swept *Volume Outside of Waterflood Region.*—The region outside of the volume swept by the waterflood contains a high oil saturation. in many surfactant processes, the viscosity of the injected fluids is much higher than water used in the previous waterflood. This could lead to increased volumetric sweep efficiency for the surfactant/polymer process. Davis[26] has presented data from a Maraflood™ oil recovery process test in the Bradford Third Sand of Pennsylvania. An increase of 7 to 10 percent in the volumetric sweep efficiency for the surfactant process over the previous waterflood was indicated in his interpretation of the data.

OTA Model.-The OTA model is based on the assumption that the region contacted by the surfactant/polymer process in most reservoirs is the region swept by the previous waterflood. The surfactant/polymer process displaces oil from the previously water-swept region by reducing the oil saturation following the waterflood (S_{orw}) to a lower saturation, termed S_{of}, which represents the residual oil saturation after a region is swept by the surfactant/polymter process. The oil recovery using this representation of the process was computed using equation 1 B for each pattern area,

$$N_{pc} = \frac{A_p h \phi E_{vm}}{B_o}(S_{orw} - S_{of}) \qquad \mathbf{1B}$$

where

N_{pc} = oil displaced by the chemical flood, stock-tank barrels
A_p = area of the pattern
h = net thickness of pay
9 = porosity, the fraction of the rock volume which is pore space
E_{vm} = fraction of the reservoir volume which was contacted by water and surfactant/polymer process determined by material balance calculations
B_o = ratio of the volume of oil at reservoir temperature and pressure to the volume of the oil recovered at stock-tank conditions (60° F, atmospheric pressure)

Residual oil saturations left by the chemical flood (S_{of} ranging from 0.05 to 0.15 have been reported in laboratory[27,28] and field tests.[29] A value of 0.08 was selected for the OTA computations.

The residual oil saturation following waterflood (S_{orw} for the high-process performance case was the oil saturation corresponding to the particular geographic region in table A-1 modified by the material balance calculation as described in appendix A, in the section on *Distribution of (the Remaining Oil Resource* on page 139. In the low-process performance model, the residual oil saturations following waterflood (S_{ORW}) were reduced by 5 saturation percent from the values in table A-1. This caused a decrease in recoverable oil which averaged 28.6 percent for all surfactant/polymer reservoirs. Due to the method of analysis, the process performance of a small number of reservoirs was not affected by this saturation change. Some reservoirs which had 90-percent volumetric sweep imposed by the material balance discussed on page 139 for the high-process performance case also had 90-percent volumetric sweep efficiency under low-process performance.

Pattern Area and Injection Rate.—Each reservoir was developed by subdividing the reservoir area into five-spot patterns with equal areas. The size of a pattern was determined using the procedure developed in the NPC study.[30] A pattern life of 7 years was selected. Then, the pattern area and injection rates were chosen so that 1.S swept-pore volumes of fluids could be injected into the pattern over the period of 7 years. The relationship between pattern area and the injection rate is defined by equation 2B.

where

i = injection rate, barrels per day
ϕ = porosity
h = thickness, feet
A_p = pattern area, acres

Maximum pattern area was limited to 40 acres.

Injection rates were constrained by two conditions. In Texas, California, and Louisiana, it was assumed that maximum rates were limited by well-bore hydraulics to 1,000 barrels per day, 1,500 barrels per day, and 2,000 barrels per day, respectively. Rate constraints in the reservoir were also computed from the steady-state equation for single-phase flow in a five-spot pattern given in equation 3B. The viscosity of the surfactant/polymer slug was assumed to be 20 times the viscosity of water at formation temperature. The lowest injection rate was selected. other parameters are identified after the definition of the equation.

$$i = \frac{3.541 \times 10^{-3} kh \Delta P}{\mu_{eff}\left\{\ln\left(\frac{d}{R_w}\right) - 0.619\right\}} \qquad 3B$$

where

i = injection rate, barrels per day
k = average permeability, millidarcies
h = average thickness, feet
ΔP = pressure drop from injection to producing well, taken to equal depth/2
μ_{eff} = effective viscosity of surfactant/polymer slug, or 20 times viscosity of water at reservoir temperature
ln = natural logarithm
d = distance between the injection and production well, feet, or $147.58 \sqrt{A_p}$
A_p = pattern area, acres
R_w = radius of the well **bore**

Development of Pattern.-Development of each five-spot pattern took place according to the schedule shown in table B-3. Drilling and completion of wells and installation of surface facilities were done in the first 2 years. The surfactant slug was injected during the third year with the polymer injected as a tapered slug from years 4 through 6. The oil displaced by the surfactant/polymer process as computed from equation IB was produced in years 5 through 9 according to the schedule in table B-3.

Table B-3
Development of a Five-Spot Pattern Surfactant/Polymer Process

Year of pattern development	Activity	Annual oil production % of incremental recovery
1	Drill and complete injection wells. Rework production well.	0
2	Install surface equipment.	0
3	Inject surfactant slug.	0
4	Inject polymer slug with average concentration of 600 ppm. Polymer concentration tapered.	0
5		10
6		26
7	Injection of brine.	32
8		20
9		12
	Total	100

Volumes of Injected Materials.—

Current technology

Surfactant Slug, . . 0.1 swept pore volume*
Polymer Bank. . . . 1.0 swept pore volume

Advancing technology case

Surfactant Slug. . . 0.1 swept pore volume
Polymer Bank, . . . 0.5 swept pore volume

● The swept pore volume of a pattern is defined by equation 4B.

$$V_p = E_v \sim A_p h \phi (7,758) \qquad 4B$$

= volume of pattern swept by the surfactant/polymer process, barrels

The volumes of surfactant and polymer approximate quantities which are being used in field tests. Volume of the surfactant slug needed to sweep the pattern is affected by adsorption of surfactant on the reservoir rock. The slug of 0.1 swept-pore volume contains about 36 percent more sulfonate than needed to compensate for loss of surfactant that would occur in a reservoir rock with porosity of 25 percent and a surfactant retention of 0.4 mg per gm rock. The OTA data base contained insufficient information to consider differences in adsorption in individual reservoirs. The effect of higher retention (and thus higher chemical costs) than assumed in the advanced technology cases is examined in the high-chemical cost sensitivity runs.

Composition and Costs of Injected Materials

The surfactant slug for all cases except the current technology case contained 5-wt percent petroleum sulfonate (100-percent active), 1-wt percent alcohol, and 10-volume percent lease crude oil. In the current technology case, the surfactant slug contained 20 percent lease crude oil. The concentration of the polymer solution was 600 ppm for reservoir oils with viscosities less than or equal to 10 centipoise. Concentration of polymer was increased with viscosity for oils above 10 centipoise according to the multiplier given in equation 5B.

$$\text{Concentration Multiplier} = (1 + \frac{32 - \text{API}}{10}) \qquad 5B$$

Equation 5B is valid for API gravities greater than 10. A polysaccharide polymer was used.

Table B-4 summarizes surfactant slug and polymer costs as a function of oil price. Costs of surfactant and alcohol based on data from the NPC study are presented in table B-5.

Net Oil, -Projected oil recovery from the surfactant/polymer process was reported as net barrels. The oil used in the surfactant slug and an estimate of the oil equivalent to the surfactant was deducted from the gross oil to determine net production.

Table B-4
Chemical Coats

Oil price $/bbl	Surfactant slug cost - 10-percent lease crude $/bbl	Surfactant slug cost - 20-percent lease crude $/bbl	‘Polymer cost* polysaccharide $/lb
10	7.69	8.69	2.30
15	9.73	11.23	2.40
20	11.74	13.74	2.49
25	13.78	16.28	2.58

● Source: Enhanced Oil *Recovery,* National Petroleum Council, December 1976, p. 100.

Table B-5
Component Costs*

Oil price $/bbl	Surfactant cost 100-percent active $/lb	Alcohol cost $/lb
5	0.29	0.13
10 . . . . ., . .	0.35	0.16
15	0.43	0.20
20	0.51	0.23
25	0.59	0.27

*Includlng tax and transportation.
Source: *Enhanced 011 Recovery,* National Petroleum Council, December 1976, p. 99.

Sensitivity Analyses

Additional computations were made using the low- and high-process performance models to determine sensitivity to changes in chemical costs. Cost sensitivity analysis was accomplished by altering the volumes of surfactant and polymer used in the displacement process. The low-chemical cost case assumes a 40 percent reduction in the volume of the surfactant slug while the high-chemical cost case assumes that 40 percent more surfactant and 50 percent more polymer would be required than used in the base-chemical cost case.

Ultimate recoveries of oil using the surfactant/polymer process with high- and low-chemical cost assumptions are summarized in table B-6 for the advancing technology cases. With high chemical costs, there would be a negligible volume of oil produced at world oil price. The combination of both high-process performance and oil prices approaching the alternate fuels price would be needed to offset high chemical costs if the surfactant/polymer process is to contribute substantial volumes of oil to the Nation's reserves.

Low chemical costs have the largest impact on the low-process performance case where substantial increases in ultimate recovery could occur at both upper tier and world oil price. The effect of lower chemical costs on the high-process performance case is to reduce the oil price required to call forth a fairly constant level of production. For example, if chemical costs are low, the ultimate recovery projected at alternate fuels price is about the same as ultimate recovery at upper tier price. However, low chemical costs have a low probability of occurring unless a major technological breakthrough occurs.

The sensitivity analyses in this study were designed to bracket the extremes which might be expected assuming technology develops as postulated in the advancing technology cases. There are other process and economic variables which would be considered in the analysis of an individual field project which could not be analyzed in a study of this magnitude.

Polymer Flooding

State of the Art—Technological Assessment

The concept of mobility control and its relationship to the sweep efficiency of a waterflood evolved in the early to mid-1950's.[31,32] It was found that the sweep efficiency could be improved if the viscosity of the injected water could be increased. Thickening agents were actively sought. Numerous chemicals were evaluated but none which had economic potential were found until the early 1960's.

During this period, development in the field of polymer chemistry provided new molecules which had unique properties. High-molecular weight polymers were developed which increased the apparent viscosity of water by factors of 10 to 100 when as little as 0.1 percent (by weight) was dissolved in the water. The first polymers investigated were partially hydrolyzed polyacrylamides with average molecular weight ranging from 3 million to 10 million.

The discovery of a potential low-cost method to "slow down" the flow of water and improve sweep efficiency of the waterflood led to many field tests in the 1960's. Nearly all field tests used

Tabie B-6
Surfactant/Polymer Process-Uitimate Recovery
Summary of Computed Results-Process and Economic Variations
(billions of barrels)

Case	Advancing technology cases Oil price $/bbl					
	Low-process performance			High-process performance		
	11.62	13.75	22.00	11.62	13.75	22.00
High chemical costs	0.1	0.1	1.0	0.2	0.2	9,0
Base chemical costs	1.0	2.3	7.1	7.2	10.0	12.2
Low chemical costs	5,8	7.5	8.8	12.0	12.4	14.5

partially hydrolyzed polyacrylamides. By 1970 at least 61 field tests had been initiated[33] and by 1975 the number of polymer field tests exceeded 100. Although most field tests were relatively small, two were substantial. These were the Pembina test in the Pembina Field in Alberta and the Wilmington test in the Ranger V interval of the Wilmington Field in California.

Results of field tests have been mixed. Successful use of polymers has been reported in several projects 3536 where incremental oil above that expected from waterflooding has been produced. At least 2 million barrels of oil have been attributed to polymer flooding from successful projects. [37] Continuation of some projects and expansion of others indicate commercial operation is possible. However, polymer flooding has not been widely adopted. Many field tests yielded marginal volumes of oil. Response to polymer flooding was not significant in either the Pembina Flood or the Wilmington Flood.

Reasons for mixed field performance are not completely understood. polymer floods initiated early in the life of a waterflood are more likely to be successful than those initiated toward the end of a project. Reservoirs which have been waterflooded to their economic limit have not responded to polymer flooding as a tertiary process. Recent research [38] has demonstrated that partially hydrolyzed polyacrylamides degrade when sheared under conditions which may be present in injection well bores. Thus, it is not certain in previous field tests that a reservoir flooded with polymer solution was contacted with the same fluid used in laboratory tests.

Further research and development produced a polysaccharide biopolymer[39] which has improved properties. Polysaccharides are relatively insensitive to mechanical shear and have high tolerance to salt, calcium, and magnesium ions. Solutions containing polysaccharides must be filtered prior to injection to remove bacterial debris which may plug the injection wells. Since the polysaccharide is a product of a biological process, it is susceptible to further biological attack in the reservoir unless adequate biocide is included in the injected solution. Few field tests have been conducted using polysaccharide polymers.

polymer flooding has economic potential because it uses materials which are relatively low cost. Field application is similar to waterflooding with minor changes to permit mixing and proper handling of the polymer solutions. Widespread use by most operators would be possible without extensive technical support. Performance of polymer floods cannot be predicted accurately, and well-documented demonstration projects such as those being conducted in the N. Burbank Stanley Stringer[40] and the Coalinga[41] fields are essential to the widespread use of polymer flooding.

Screening Criteria. --Polymer flooding is not a potential process for all reservoirs which can be waterflooded. Geologic constraints, properties of the reservoir rock and oil, and stage of the waterflood are all critical parameters. Reservoirs which produce primarily through large fracture systems and reservoirs with large gas caps which could not be waterflooded were excluded. In these reservoirs, the polymer slug is likely to bypass much of the reservoir rock. A permeability constraint of 20 millidarcies was selected. While the lower limit of permeability is not known precisely, there is a range of permeabilities where the polymer molecules are filtered out of the injected solution and cannot be propagated through a reservoir. Selection of the correct molecular weight distribution of the polymer reduces the minimum permeability.

Field experience indicates that polymer floods have not been successful when applied after the waterflood has been completed. Reservoirs under waterflood which have volumetric sweep efficiency greater than 80 percent and low residual oil saturations are not good polymer candidates. Consequently, reservoirs with no ongoing waterflood and reservoirs with high volumetric sweep efficiency and low oil saturation were screened from the polymer flooding candidates.

Water quality was not used to screen reservoirs because salinity and divalent ion content do not determine whether a reservoir can be flooded with polymer solutions. These parameters do indicate the type of polymer which may be used. For example, partially hydrolyzed polyacrylamides are frequently preferred in low-salinity systems. Polysaccharides are relatively insensitive to salinity and may be required in order to flood successfully a reservoir which contains high-salinity fluids.

The use of polymers is limited by temperature stability. Proven temperature stability is about 200° F. This limit is expected to be 250° F by 1995. The same temperature limits used in the surfactant/polymer process screen apply to polymer flooding.

Crude oil viscosity was the final screening parameter. Field tests suggest an upper limit of about 200 centipoise. However, there is little published literature which shows that polymer solutions will not displace oil at higher viscosities. Other factors enter in the determination of the upper viscosity limit. Steam displacement and in situ combustion are considered superior processes because both can potentially recover more oil. As crude oil viscosity increases, higher polymer concentrations are required to maintain mobility control. Oil-displacement rates decline for a fixed pattern size. Both of these factors operate in the direction of reducing the rate of return at fixed oil price or requiring a higher oil price to produce a fixed rate of return. Then the crude oil viscosity becomes an economic factor rather than a technical factor.

Most reservoirs which were polymer candidates yielded more oil when developed as CO_2, surfactant/polymer, steam, or in situ combustion candidates. Thus, the OTA method of process selection, i.e., maximum oil if profitable at 10 percent rate of return and world oil price, led to assignment of the poorest reservoirs to polymer flooding.

Oil Recovery Projections

Estimates of oil recovery from the application of polymer-augmented waterflooding to reservoirs which satisfied the technical screen were made using an empirical model. Incremental recovery for the low-process performance case was assumed to be 2.5 percent of the original oil in place. The incremental recovery for the high-process performance case was assumed to be 3 percent of the original oil in place. These estimates closely approximate recent projections for the N. Burbank Stanley Stringer and Coalinga field demonstration tests. They also approximate the average performance of published field tests.[42]

Each reservoir was developed on 40-acre spacing with a ratio of 0.5 injection well per production well. Injection of polymer was continued over the first 4 years of the project at a rate of 0.05 pore volumes per year. Average polymer concentration was 250 ppm. The polymer used was polysaccharide. Costs of polymer at various oil prices were identical to those used for the surfactant/polymer process (table B-4).

The recoverable oil was produced over an 11-year period according to the schedule in table B-7.

Table B-7
Production Schedule for Polymer-Augmented Waterflood

Year	Incremental oil percent of total
1-2	0
3	5
4	10
5	20
6	20
7	15
8	10
9	10
10	5
11	5
Total	100

Sensitivity Analyses

The effects of changes in polymer costs and/or volumes were examined for low- and high-polymer costs for both low- and high-process performance cases. Bases for cost variation were +/- 25 percent change in polymer cost. Results of the economic evaluations are presented in table B-8.

There is essentially no effect of chemical costs on oil production from polymer flooding at the upper tier, world oil, and alternate fuels prices. The sensitivity analyses show that uncertainty in process performance is larger than uncertainties introduced by chemical costs.

Table B-8
Polymer-Augmented Waterflooding
Ultimate Recovery
(billions of barrels)

Case	Advancing technology cases oil price $/bbl — Low-process performance			High-process performance		
	11.62	**13.75**	22.00	11.62	**13.75**	22.00
High polymer cost (+25°/0 over base)	0.2	0.2	0.3	0.4	0.4	0.4
Base polymer cost.	0.2	0.3	0.3	0.4	0.4	0.4
Low chemical cost (-25°/0 from base).	0.3	0.3	0.3	0.4	0.4	0.4

Effect of Polymer Flooding on Subsequent Application of Surfactant/Polymer or Carbon Dioxide Miscible Processes

The OTA analysis assumes a single process would be applied to a reservoir. The possibility of sequential application of two processes was not analyzed. Some reservoirs assigned to the surfactant/polymer process or the $C0_2$ miscible process would also be economic (rate of return greater than 10 percent at world oil price) as polymer floods. However, the decision rules for process assignment placed these reservoirs in the process which yielded the largest ultimate recovery.

One concern caused by this assignment procedure was whether or not the low costs and low financial risk from the polymer projections would cause operators to use polymerflooding as the final recovery process for a reservoir, precluding use of methods which potentially recover more oil.

The principal displacement mechanism in polymer flooding is an increase in the volume of the reservoir which is swept by the injected fluid. No reduction in residual oil saturation over that expected from waterflooding is anticipated because the viscosities of the oils in these reservoirs are low enough to make the residual oil saturations relatively insensitive to the viscosity of the displacing fluid.

A successful polymer flood in the OTA high-process performance would recover 3 percent of the original oil in place. This corresponds roughly to improved volumetric sweep efficiencies of 2 to 7 percent. Both OTA models for surfactant/polymer and CO_2 miscible processes are based on recovery of the residual oil from some percentage of the volume displaced by the preceding waterflood. Polymer flooding increases this contacted volume. Slightly more oil would be recovered from reservoirs which had been polymer flooded prior to surfactant flooding or $C0_2$ flooding if the OTA models of these displacement processes are substantially correct. Therefore, the application of polymer flooding will not prevent subsequent surfactant/polymer or $C0_2$ floods under the conditions postulated in the OTA study.

Finally, polymer flooding prior to surfactant/polymer flooding has been proposed as a method to improve volumetric sweep efficiency by increasing the flow resistance in more permeable paths in the reservoir.[43]

Steam Displacement

State of the Art—Technological Assessment

Steam displacement is a process which has primarily evolved in the last 10 to 15 years.

Development of the process was motivated by poor recovery efficiency of waterfloods in reservoirs containing viscous oil and by low producing rates in fields which were producing by primary energy sources. Most of the development occurred in California and Venezuela, where large volumes of heavy oil are located. Steam displacement has potential application in heavy oil reservoirs in other oil-producing States.

Large-scale field tests of steam injection began in the late 1950's [44,45] with field testing of hot water injection underway at the same time[46,47,48] in an attempt to improve the recovery efficiency of the conventional waterflood. Early steam and hot water injection tests were not successful. injected fluids quickly broke through into the producing wells, resulting in low producing rates and circulation of large volumes of heated fluids.

The process of cyclic steam injection was discovered accidentally in Venezuela in 19s9 and was developed in California.[49] Cyclic injection of small volumes of steam into producing wells resulted in dramatic increases in oil production, particularly in California where incremental oil due to cyclic steam injection was about 130,000 barrels per day in 1968.[50] By *1971* about 53 percent of all wells in California had been steamed at least once.

Cyclic steam injection demonstrated that significant increases in production rate could be obtained by heating the reservoirs in the vicinity of a producing well. However, the process is primarily a stimulation process because natural reservoir energy sources like solution-gas drive or gravity drainage cause the oil to move from the reservoir to the producing well, Depletion of this natural reservoir energy with repeated application of cyclic steam injection will diminish the number of cyclic steam projects. Many of these projects will be converted to steam displacement.

The success of the steam displacement process is due to the high displacement efficiency of steam and the evolution of methods to heat a reservoir using steam. Development of the steam displacement process in the United States can be traced to large-scale projects which began in the Yorba Linda Field in 1960[51] and the Kern River Field in 1964.[52] Estimates of ultimate recoveries (primary, secondary, cyclic steam, and steam displacement) from 30 to 55 percent of the original oil in place have been reported for several fields.

A comparison[53] of trends in incremental oil production from cyclic steam and steam injection for California is shown in figure B-1. Cyclic steam injection is expected to decline in importance as natural reservoir energy is depleted. Production from steam displacement could increase as cyclic projects are converted to continuous steam injection. The rate of conversion will be controlled by environmental constraints imposed on exhaust emissions from steam generators. Incremental oil from steam displacement will be limited to 110,000 barrels per day in California, the level which currently exists, unless technological advances occur to reduce emissions.

Commercial steam-displacement projects are also in operation in Wyoming,[54] Arkansas,[55] and Texas.[56] A large portion of the incremental oil now produced by application of EOR processes is produced by the steam displacement process.

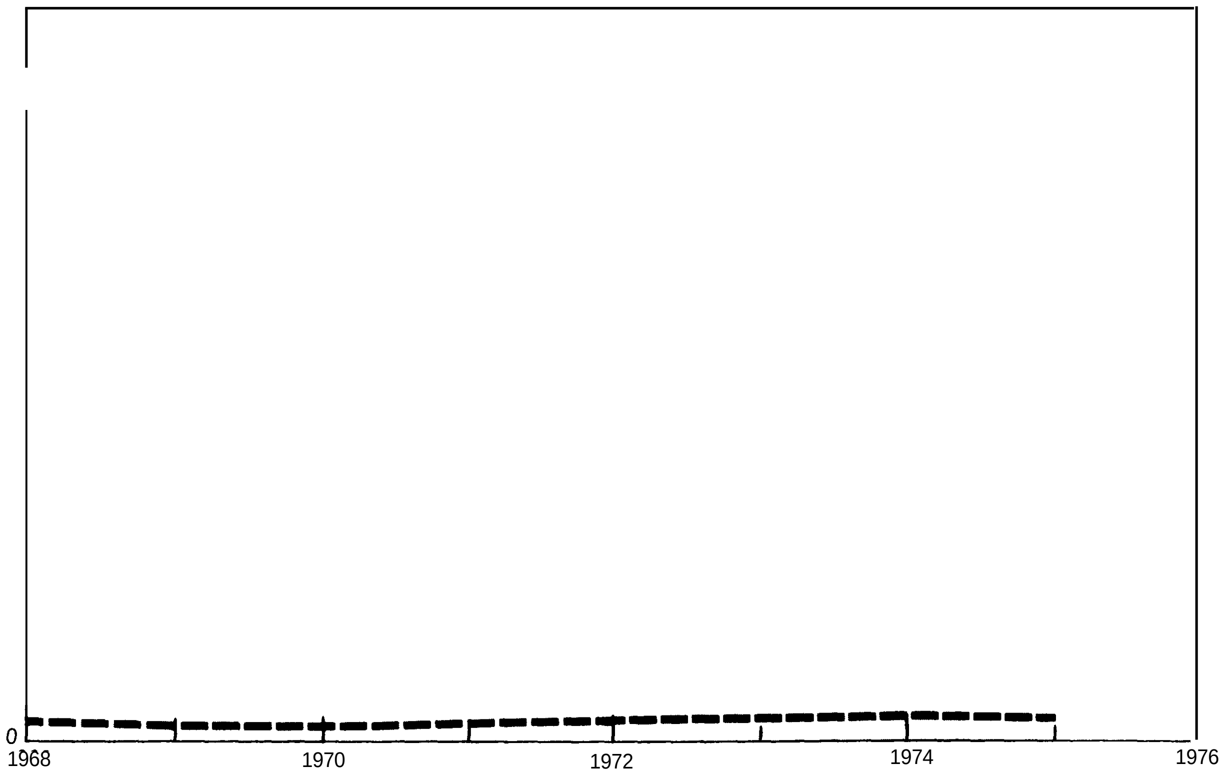
Screen/rig Criteria.—Steam displacement was considered applicable in reservoirs which were located at depths between 500 and 5,000 feet. The upper depth limitation was imposed in order to maintain sufficient steam injection pressure. The lower depth of 5,000 feet is determined by well-bore heat losses in the injection wells. At depths approaching 5,000 feet, heat losses can become excessive even with insulated injection strings. In addition, as depth increases the injection pressure increases, but the fraction of the injected fluid which is condensable decreases. Reduction in displacement efficiencies is expected to occur under these conditions.

The second screening criterion was transmissibility. The transmissibility (permeability x thickness/oil viscosity) is a measure of the rate that the oil moves through a reservoir rock. A transmissibility of about 100 millidarcy feet/centipoise is required for steam and hot-water injection processes in order to keep heat losses from the reservoir to overlying and underlying formations from becoming excessive. ST

Oil Recovery Projections

Recovery Models.—Although steam displacement is the most advanced EOR process, it was

Figure B-1. Historical Incremental Production Thermal Recovery-California



difficult to develop recovery models which applied to an entire reservoir. The OTA data base as well as the Lewin data bases used in the NPC and ERDA reports contained little information on reservoir variability. Review of the technical literature and personal contacts with companies operating in fields with major steam displacement projects revealed considerable variability in thickness and oil saturation. It became apparent that most steam displacement projects were being conducted in the best zones of a reservoir, where oil saturations were higher than the average values in the data base. Thus, OTA concluded that empirical recovery models based on the results of these displacement tests could not be extrapolated to poorer sections of larger reservoirs with the available information. Subdivision of several large reservoirs into smaller segments of different properties as done in the NPC study was considered, but could not be done with the available computer program.

Recovery models were developed by OTA to estimate the recovery based on development of the entire reservoir. In taking this approach, it is Acknowledged that recovery from the better sections of a reservoir will be understated and the recovery from poorer sections will be overstated. However, this approach was preferable to overstatement of recovery caused by applying empirical recovery models from the better zones[58] to other intervals and areas of a reservoir, or application of recovery adjustment factors to extrapolate single-pattern performance to total-project performance.[59]

Each reservoir with multiple zones was developed zone by zone. The technology necessary to complete each zone selectively was assumed to evolve through research and development. The average thickness per zone was determined by dividing the net thickness by the number of zones. Two displacement models were used based on the thickness of the zone. Single zone reservoirs were handled in the same way-according to thickness of the zone.

High-Process Performance Case.—Zone Thickness Less Than or Equal to 75 Feet. -Gross oil recoverable by primary and secondary production followed by steam was considered to be 50 percent of the original oil in place. Thus in each zone,

$$\text{Steam Displacement Oil} = \frac{\text{Original Oil}}{2} - (\text{Primary} + \text{Secondary})$$

Zone Thickness **Greater Than** 75 Feet. –Oil displacement in thick reservoirs is based on the following model of the displacement **process.**

Steam displacement patterns were developed on 2.5-acre spacing with one injection well per producing well.

Region	Areal sweep efficiency	Maximum vertical thickness of swept zone, feet	Residual oil saturation
Steam Zone	0.75	25	0.10
Hot Water Zone	0.90	35	0.25

Low-Process *Performance Case.*—Well spacing was increased to 5 acres. Gross oil displaced by steam was 80 percent of the amount estimated for the high-process performance case.

Timing of Production.—The incremental oil from the steam-displacement process was produced according to the production schedule in table B-9.

Table B-9
Production Schedule for Steam Displacement Process

Year	Annual incremental oil percentage total
1-2 . . . . ~ ~ ~ ~€ .	0
3	12
4	22
5 : : : : : : : :	22
6	20
7	14
8	10
Total	**100**

The same schedule was used for low- and high-process performance models.

Steam Requirements and Costs

Steam requirement was 1 pore volume based on net heated thickness. That is the volume occupied by the combined steam and hot water zones considering the areal sweep efficiency to be 100 percent. Zones with thicknesses less than or equal to 75 feet were assumed to be heated in the entire vertical cross section. Steam was injected over a 5-year period beginning in the third year of field development at the rate of 0.2 pore volume per year.

Lease crude was used as fuel for the steam generators. Twelve barrels of steam were produced per barrel of lease crude consumed. The full cost of the lease crude was charged as an operating cost to the project. Oil consumed as fuel was deducted from the gross production to obtain the net production. Cost of steam generation in addition to the fuel charge was $0.08 per barrel of steam generated to cover incremental operating and maintenance costs for the generator and water treatment.

Other Costs.—The costs of installed steam generation equipment were scaled from a 50 million Btu per hour steam generator costing $300,000.[60] A 1 million Btu per hour unit was assumed to generate 20,000 barrels of steam (water equivalent) per year. The number (possibly fractional) of generators required per pattern was determined from the pore volume of the pattern. Since the steam generator life was longer than pattern life, it was possible to use the same generator on two patterns in the field. The cost of moving a generator was assumed to be 30 percent of the initial cost. Thus the effective cost for the steam generator per pattern was 65 percent of the initial generator cost.

Reservoirs with multiple zones required workovers in production and, injection wells to close the zone just steamed and open the next zone. These costs are discussed in the section on Economic Data—General on page 178 of this appendix.

Table B-10
Recovery Uncertainties Effecting Steam Displacement Results

Case	Production well spacing, acres	Recovery Model[a]: Zone thickness <75 ft.: Gross recovery (primary, secondary and steam displacement) as fraction of original oil in place	Zone thickness > 75 ft.: Maximum steam zone thickness	Zone thickness > 75 ft.: Maximum hot water zone thickness
Low recovery	2.5	0.45	25	30
High-process performance ...	2.5	0.50	25	35
High recovery.	2.5	0.55	30	35

[a]All other model parameters were the same as in the high-process Performance case.

Sensitivity Analyses

Projections of oil recovery by steam displacement contain uncertainties which are primarily related to the recovery efficiency of the process. Additional analyses were made to determine the range of variation in oil recovery due to uncertainties in process performance (table B-10).

One set of projections was based on variations of recovery for a well spacing of 2.5 acres per production well. Projections for low recovery (45 percent) and high recovery (55 percent) are compared with the high-process performance case (50 percent recovery) in table B-11. Results from the low recovery case are essentially the same as the low-process performance case. The projections from the high recovery case are appreciably higher than the high-process performance case.

Table B-n
Effect of Uncertainties in Overall Recovery on Ultimate Production

Steam Displacement Process
(billions of barrels)

Case	Upper tier price ($1 1.62/ bbl)	World oil price ($1 3.75/ bbl)	Alternate fuels price ($22.00/ bbl)
Low recovery	2.1	2.5	3.4
High-process performance	2.8	3.3	6.0
High recovery.	3.9	5.9	8.8

These extremes in recovery performance are also measures of energy efficiency. Crude oil is burned to produce steam. The amount of crude consumed is proportional to the volume of steam required to heat the reservoir. Nearly the same volume of steam and consequently the same amount of lease crude is consumed for each of the three cases. Slight variations occur for zones with thicknesses greater than 75 feet, Most of the additional oil projected in the high recovery case is produced with little additional lease crude required for steam generation. In contrast, a larger fraction of the produced oil is consumed in the low recovery case because about the same amount of crude is consumed to produce steam while a smaller amount of oil is produced by the displacement process.

Pattern size is the second variable which was investigated in sensitivity calculations. Oil recovery was estimated for two additional well spacings using the high-process performance model. Results are summarized in table B-12. If recovery is unaffected by well spacing, there is an economic incentive to increase well spacing over the 2.5-acre spacing used in the OTA study. Results are sensitive to spacing primarily because the costs to work over both injection and production wells in order to move from zone to zone are significant.

Increasing well spacing reduces these costs in producing wells by a margin which permits several large reservoirs to meet the 10-percent

Table B-12
Effect of Well Spacing on Ultimate Recovery of Oil Using the Steam Displacement Process

Case	Production well spacing acres	Incremental 011 (billions of barrels) Upper tier price ($11.62/bbl)	World oil price **($1 3.75/bbl)**	Alternate fuels price **($22.00/bbl)**
High-process performance	**2.5**	**2.8**	**3.3**	**6.0**
High-process performance ., ...,	**3.3**	**3.5**	**5.3**	**6.8**
High-process performance	**5.0**	**5.6**	**6.4**	**7.0**

rate-of-return criteria at lower prices. This is a potential area for technological advances beyond those which were assumed in this study.

In Situ Combustion

State of the Art—Technological Assessment

In situ combustion has been investigated in the united States since 1948.[61] By the mid-1950's, two pilot tests had been conducted. One test was done in a reservoir containing a light oil (35° API) with a low viscosity (6 cp).[62] The second reservoir tested contained 18.4° API oil which had a viscosity of 5,000 cp.[63] These initial pilot tests demonstrated that a combustion front could be initiated and propagated in oil reservoirs over a wide range of crude oil properties.

The initial demonstrations of the technical feasibility of in situ combustion stimulated research and development of the process both in the laboratory and in the field. Over 100 field tests of in situ combustion have been conducted in the United States.[64]

Field testing developed considerable technology. Methods were developed to initiate combustion, control production from hot wells, and treat the emulsions produced in the process. Improved process efficiency evolved with research and field testing of methods to inject air and water simultaneously.[65,66] The wet combustion process was found to have the potential of reducing the air requirements by as much as 30 to so percent over dry combustion.

Many field tests have been conducted but few have resulted in projects which are commercially successful. Economic information was not available on current in situ combustion projects. Continued operation over a several-year period with fieldwide expansion implies satisfactory economics. California fields include the Moco Unit in the Midway Sunset.[67] West Newport,[68] San Ardo, South Belridge, Lost Hills, and Brea-Olinda.[69] Successful operations have also been reported in the Glen Hummel, Gloriana, and Trix Liz Fields in Texas,[70] and the Bellevue Field in Louisiana.[71] The number of commercial operations in the United States is estimated to be 10.[72]

In situ combustion has not been applied widely because of marginal economics at existing oil prices, poor volumetric sweep efficiency in some reservoirs, and competition with steam displacement processes. Some field tests showed a net operating gain but could not generate enough income to return the large investment required for an air compressor. The phrase "a technical success but an economic failure" best describes many projects.

The movement of the in situ combustion zone through a reservoir is controlled in part by variations in reservoir properties. Directional movement has been observed in most in situ combustion projects. There has been limited success in controlling the volume of the reservoir which is swept by the process. This is a major area for research and development.

Reservoirs which are candidates for steam displacement are also candidates for in situ combustion. Experience indicates that steam displacement is generally a superior process from the viewpoint of oil recovery, simplicity of operation, and economics. Thus, applications of in situ combustion have been limited by the development of the steam displacement process.

In situ combustion has one unique characteristic. It is the only process which may be applicable over a wide range of crude gravities and viscosities.

Screening Criteria.--In situ combustion is applicable to a wide range of oil gravities and viscosities. No constraints were placed on oil viscosity. The maximum permissible API gravity is determined by the capability of a particular reservoir rock/crude oil combination to deposit enough coke to sustain combustion. Low-gravity oils which are composed of relatively large fractions of asphaltic-type components meet this requirement. It is also known that some minerals catalyze in situ combustion, allowing high gravity oils to become candidates for in situ combustion.[73] The maximum oil gravity which might be a candidate with catalytic effects was estimated to be 45° API.

Minimum reservoir depth was set at 500 feet.[74] Adequate reservoir transmissibility, i.e.,

$$\frac{\text{Permeabilitv x thickness}}{\text{oil viscosity}}$$

is necessary to prevent excessive heat losses to overlying and underlying formations. The minimum acceptable transmissibility for in situ combustion is about 20 millidarcy feet/centipoise.[75] Carbonate reservoirs were not considered to be candidates for in situ combustion.

Oil Recovery Projections

The wet combustion process was used for the OTA study. All projects were developed as 20-acre patterns. In the wet combustion process, three distinct displacement zones are formed: a burned zone, a steam zone, and a hot water zone. Gross oil recovered from each pattern was computed from the sum of the volumes displaced from each zone. Areal sweep efficiency, maximum zone thickness, and residual oil saturation for each zone are included in table B-13 for the advancing technology cases.

Fuel consumption was 200 barrels per acre foot.[76] The equivalent oil saturation consumed in the burned zone is S_{ob}, where S_{ob} = 200/7,758 X 0); @ is the porosity of the rock, and 7,758 is barrels per acre foot.

The initial oil saturation was S,,,, the material balance average oil saturation computed from equation 1. The volume of oil displaced was determined in the following manner. The actual thickness of each zone was determined by allocating the net pay between the three zones in the order shown in table B-13. A reservoir 20 feet thick would have a burned zone and a steam zone while a reservoir 100 feet thick would experience the effects of three zones in a 50-foot interval. The volume of oil displaced from each zone was computed from the product of the pattern area, areal sweep efficiency, zone thickness, porosity, and displaceable oil in the swept interval. All oil displaced from the swept zones was considered captured by the producing well.

Timing of *Production.—The* life of each pattern was 8 years. Drilling, completion, and other development was completed in the first 2 years. Air and water injection began in year 3 and continued through year 8 for a total productive life of 6 years. The displaced oil was produced according to the schedule in table B-14.

Table B-13
Advancing Technology Cases
Oil Displacement Model
Wet Combustion

Region	Areal sweep efficiency	Max. vertical thickness, ft.	Residual oil saturation: Low-process performance	Residual oil saturation: High-process performance
Burned zone	0.55	10	0	0
Steam zone. .,	0.60	10	(),20	0.15
Hot water zone	080	30	0.30	0.25

Table B-14
Production Schedule
Wet Combustion

Year	Annual production of incremental oil Percentage of total
1 - 2,	0
3	10
4	16
5	22
6	20
7	18
8	14
Total	100

Operating Costs

Air required was computed on the basis of 110-acre feet burned per 20-acre pattern (if the reservoir is at least 10 feet thick) and a fuel consumption of 200 barrels per acre foot. If the air/oil ratio was less than 7,500 standard cubic feet (Scf) per stock-tank barrel (STB), air requirements were increased to yield 7,500. Air requirements were then used to size compressors and to determine the equivalent amount of oil which would be consumed as compressor fuel.

The amount of oil used to fuel the compressors was computed as a Btu equivalent based on 10,000 Btu per horsepower hour. Energy content of the oil was 6,3 million Btu per barrel. This oil was deducted from the gross production.

The corresponding equations for the price of air as the price per thousand standard cubic feet ($/MScf) were derived from data used in the NPC study.[77]

Depth feet	Cost Equation $/MScf
O - 2,500	0.08 + 0.01108 P
2,500- 5,000	0.08 + 0.01299 P
5,000-10,000	0.08 + 0.01863 P
10,000-15,000	0.08 + 0.02051 P

where

P = oil price in $/bbl and the multiplier of P is the barrels of oil consumed to compress 1 MScf of air to the pressure needed to inject into a reservoir at the specified depth.

Compressed air was supplied by a six-stage bank of compressors with 1 horsepower providing 2.0 MScf per day.[78] Compressor costs were computed on the basis of $40()/installed horsepower.

Sensitivity Analyses

The effect of uncertainties in operating costs was examined using the high-process performance model. A low-cost case was analyzed by reducing the compressor maintenance cost from $0.08/MScf to $0.07/MScf. A high-cost case increased the compressor maintenance to $0.10/MScf. Results of these cases are compared in table B-1 5. Cost reduction had little effect on the projected results while the 25-percent increase in maintenance cost reduced the ultimate recovery by 19 percent at upper tier price and 8 percent at world oil price for the high-process performance case,

A case was also simulated in which the displacement efficiency in the steam and hot water zones was increased by changing the residual oil saturation in the steam zone to 0.10 and in the hot water zone to 0.20, Results of this case are indicated as high-displacement efficiency in table B-1 s. The effect of assumed improvement in displacement efficiency resulted in a 17- to 20-percent increase in ultimate recovery but little change in price elasticity.

Table B-15
Effect of Changes in Compressor Operating Costs and Displacement Efficiency in Ultimate Oil Recovery Using the In Situ Combustion Process

Case	Incremental oil (billions of barrels)		
	Upper tier price ($1 1.62/ bbl)	World oil price ($1 3.75/ bbl)	Alternate fuels price ($22.00/ bbl)
High cost	1.4	1.7	1.9
High-process performance	1.7	1.9	1.9
Low cost	1.7	1.9	1.9
High-displacement efficiency	2.1	2.2	2.3

Carbon Dioxide Miscible

State of the Art—Technological Assessment

It has been known for many years that oil can be displaced from a reservoir by injection of a solvent that is miscible with the oil. Because such solvents are generally expensive, it is necessary to use a "slug" of the solvent to displace the oil and then to drive the slug through the reservoir with a cheaper fluid, This process was shown to be feasible at least 20 years ago.[79] An overview of the various kinds of miscible displacements is given by Clark, et al.[80]

Hydrocarbon miscible processes have been developed and studied fairly extensively. A number of field tests have been conducted.[81] While it has been established that hydrocarbon miscible processes are technically feasible, the high cost of hydrocarbons used in a slug often makes the economics unattractive. Recently, attention has focused on carbon dioxide ($C0_2$) as the miscibility agent.[82]

In the OTA study it was assumed that, in general, economics and solvent availability would favor the use of $C0_2$. The $C0_2$ process was therefore used exclusively as the miscible displacement process in the study.

Carbon dioxide has several properties which can be used to promote the recovery of crude oil when it is brought into contact with the oil. These properties include: 1) volubility in oil with resultant swelling of oil volume; 2) reduction of oil viscosity; 3) acidic effect on rock; and 4) ability to vaporize and extract portions of the crude oil under certain conditions of composition, pressure, and temperature.

Because of these properties, $C0_2$ can be used in different ways to increase oil recovery, i.e., different displacement mechanisms can be exploited. The three primary mechanisms are solution gas drive, immiscible displacement, and dynamic miscible displacement.

Solution-gas-drive recovery results from the fact that Co_2 is highly soluble in oil. When $C0_2$ is brought into contact with oil under pressure, the Co_2 goes into solution. When the pressure is lowered, part of the $C0_2$ will evolve and serve as an energy source to drive oil to producing wells. The mechanism is similar to the solution-gas-drive primary recovery mechanism and can be operative in either immiscible or miscible displacement processes.

Helm and Josendalal[83] have shown that $C0_2$ can be used to displace oil immiscible. In experiments conducted with liquid $C0_2$ below the critical temperature, residual oil saturations were significantly lower after flooding with $C0_2$ than after a waterflood. The improved recovery was attributed primarily to viscosity reduction and oil swelling with resultant improvement in the relative permeability. It was noted that the $C0_2$ displacement was not as efficient when a waterflood preceded the $C0_2$.

Carbon dioxide, at reservoir conditions, is not directly miscible with crude oil. However, because $C0_2$ dissolves in the oil phase and also extracts hydrocarbons from the crude, it is possible to create a displacing phase composition in the reservoir that is miscible with the crude oil.

Menzie and Nielson, in an early paper,[84] presented data indicating that when $C0_2$ is brought into contact with crude oil, part of the oil vaporizes into the gaseous phase. Under certain conditions of pressure and temperature, the extraction of the hydrocarbons is significant, especially extraction of the intermediate molecular weight hydrocarbons (C_5 to C_{30}). Helm and Josendahl[85] also showed that $C0_2$ injected into an oil-saturated core extracts intermediate hydrocarbons from the oil phase and establishes a slug mixture which is miscible with the original crude oil. Thus, while direct contact miscibility between crude oil and $C0_2$ does not occur, a miscible displacement can be created in situ. The displacement process, termed dynamic miscibility, results in recoveries from linear laboratory cores which are comparable to direct contact miscible displacement.

Holm[86] has pointed out that the $C0_2$ miscible displacement process is similar to a dynamic miscible displacement using high-pressure dry gas. However, important differences are that $C0_2$ extracts heavier hydrocarbons from the crude oil and does not depend upon the existence of light hydrocarbons, such as propane and butanes, in the oil. Miscible displacements can thus be achieved with CO_2 at much lower pressures than with a dry gas. Methods of estimating miscibility pressure have been presented.[87,88]

The CO_2 miscible process is being examined in a number of field pilot tests.[89,90] The largest of these is the SACROC unit in the Kelly-Snyder Field.[91] Different variations of the process are being tested. In one, a slug of CO_2 is injected followed by water injection. In another, CO_2 and water are injected alternatively in an attempt to improve mobility control.[92]

The preliminary indication from laboratory experiments and these field tests is that the CO_2 process has significant potential. However, the field experience is quite limited to date and some difficulties have arisen. Early CO_2 breakthrough has occurred in some cases and the amount of CO, required to be circulated through the reservoir has been greater than previously thought .93 Operating problems such as corrosion and scaling can be more severe than with normal waterflooding. Greater attention must be given to reservoir flow problems such as the effects of reservoir heterogeneities and the potential for gravity override.

in general, the operating efficiency of the process or the economics have not been firmly established. In the OTA study, the reported laboratory investigations and preliminary field results were used as the basis for the recovery models and the economic calculations.

Screening Criteria.—Technical screening criteria were set in accordance with the following:

Oil viscosity
<12 Cp

Attainable pressure assumed to be = .6 **x** depth -300 psi

Miscibility pressure

< 27° API	4,000 psi
27° - 30" API	3,000 psi
$\geq$ 30° API	1,200 psi

Temperature correction to miscibility pressure

O psi if T < 120° F.
200 psi if T = 120- 150° F.
350 psi if T = 150- 200° F.
500 psi if T > 200° F.

This leads to depth criteria as follows (not temperature corrected):

< 27° API	7,200 ft
27° - 30° API	5,500 ft
$\geq$ 30° API	2,500 ft

This was the same correlation as used in the NPC study.[94] It is noted that the general validity of this correlation has not been established. Crude oils in particular reservoirs may or may not establish miscibility with CO_2 at the pressures and temperatures indicated. Other correlations have been presented in the literature, but they are based on a knowledge of the crude oil composition. Data on composition were not available in the data base used in the OTA study, and a generalized correlation of the type indicated above was therefore required.

Oil Recovery Projections

Onshore Reservoirs.—The recovery model used was as follows:

$$R = \frac{NB_c}{S_{oi}B_o}(S_{orw} - S_{orm})E_{vm}\left(\frac{E_m}{(E_{vm})}\right) \qquad \textbf{6B}$$

where

R = recovery by CO_2 process, stock-tank barrels

S_{orm} = residual oil saturation in zone swept by CO_2. Set at 0.08, No distinction was made between sandstone and carbonate reservoirs.

E_m = sweep efficiency of CO_2 miscible displacement. (E_m/E_{vm}) was set at 0.70.

E_{vm} = volumetric sweep efficiency of the waterflood computed from procedure described in appendix A.

The sweep efficiency for CO_2 miscible (E_m was determined by making example calculations on CO_2 field tests. Field tests used were the following:

Slaughter
Wasson
Level land
Kelly-Snyder (SACROC)

Cowden-North
Crosset

All projects except the Wasson test were reported in the SPE Field Reports.[95] Data on Wasson were obtained from a private communication from Lewin and Associates, Inc. Based upon reported data and reported estimates of the tertiary recovery for each field test, sweep efficiency values were calculated. The ratio E_m/E_{vm} averaged 0.87. Discarding the high and low, the average was 0.80. It was judged that the national average recovery would be less, therefore a value of E_mE_{vm} of 0.70 was used for all reservoirs in the OTA calculations.

The high-process performance model assumes the waterflood residual (S_{Orw} for each reservoir is determined from table A-1 according to geographic region. This value was used unless the volumetric sweep efficiency for the waterflood (E_vJ fell outside the limits described in appendix A. The low-process performance was simulated by reducing the S_{Orw} values in table A-1 by 5 saturation percent. The same limits on the calculated values of E_{vm} were used in the low-process performance model. The recovery model (equation 6B) was unchanged except for E_{vm} and $S_{o:w}$.

The low-process performance model reduced the EOR for those reservoirs in which the calculated E_{vm} fell within the prescribed limits. Where E_{vm} was outside the limits, $S_{o,w}$ was recalculated using the limiting E_{vm} value. Therefore, for these latter reservoirs the recovery results were the same in both the high- and low-process performance models. For $C0_2$ miscible, this was the case for about one-third of the total reservoirs. The average recovery for all reservoirs was 20 percent less in the low-process performance case than in the high-process performance case.

Volurnes of Injected Materials.—The CO_2 requirement was established as follows:

Sandstone Reservoirs—26 percent of pore volume
Carbonate Reservoirs—22 percent of pore volume

Conversion of CO_2 from surface conditions to reservoir conditions was assumed to be:

2 **Mcf $C0_2$ (std. cond.) per 1.0 reservoir bbl**
(A constant value was used.)

Twenty-five percent of the total CO_2 requirement was assumed to be from recovered, compressed, and reinfected gas. Seventy-five percent was purchased.

The $C0_2$ injection schedule was as shown in table B-1 6. The water alternating gas process was used. The ratios were:

Sandstones I:2 **CO_2:H_2O**
Carbonates 1:1 CO_2:H_2O

Table B-16
Carbon Dioxide Injection Schedule

Year	Purchased CO_2 percent of total*	Recycled $C0_2$ percent of total*
1-2	0	0
3	20	0
4	20	0
5	16	4
6 : : : : : : : : : : : :	13	7
7	6	14

● **Total refers** to **total volume** of CO_2 injected over life of **pattern,**

Fluid injection occurred over a 5-year period; reinfected $C0_2$ was used beginning in the third year of the period, along with purchased CO_2.

Timing of Production. —The production profile was set at a fixed percentage of the total recovery (as computed by the recovery model above). The schedule is shown in table B-17. All reservoirs were developed on 40-acre spacing.

Offshore Reservoirs.--Offshore CO_2 miscible displacement was calculated using a different model than the onshore model. The reservoirs of the gulf offshore are steeply dipping because they are nearly universally associated with salt dome formations. This has limited effect on the other processes but great impact on CO_2 miscible. Due to the dip, the CO), with small quantities of CH_4 can be injected at the top of the dip and gravity stabilized. No production is noted until the oil bank ahead of the miscible slug reaches the first producers down dip. The bank is produced until the slug breaks through, at which time the producer is shut in and the slug proceeds further down dip, creating a new bank which is produced in like manner at the next producer further down. The process continues until

Table B-17
Production Rate Schedule for Carbon Dioxide Miscible

Year	Percent of EOR
Carbonates	
1-3	0
4	5
5	9
6	13
7	17
8	19
9	14
lo	10
11	6
12	4
13	2
14	1
Total	100
Sandstones	
1-3	0
4	6
5	19
6	26
7	21
8	13
9	9
10	6
Total	100

Table B-18
Gas Injection Schedule
Offshore Carbon Dioxide Miscible

Year	CO_2-CH_4	Air
1	0	0
2	0.25PV	o
3	0.25PV	o
4	0	0.15PV
5	0	0.15PV

Table B-19
Oil Production Schedule
Offshore Carbon Dioxide Miscible

Year	Production percent of total
1	0
2	o
3	o
4	50
5	50
Total	100

the final bank has been produced at the bottom of the formation. Because the integrity of the miscible slug must be maintained, no water injection is contemplated. However, air is compressed and used to push the CO_2-CH_4 mixture after a relatively large volume of the mixture has been injected. Residual oil saturation after miscible displacement, S_{Orm}, was set at 0.08. Sweep efficiency, Em, was set at O.80 (i.e (Em/Evm) x E_{vm} = 0.80). This is a significantly higher sweep efficiency than used, on the average, for onshore reservoirs.

The fluid injection schedule for offshore reservoirs is shown in table B-18 and the oil production schedule is given in table B-19.

Carbon Dioxide Costs

Well Drilling and Completion Costs.-Because of special requirements created by CO_2 flooding, the base drilling and completion cost was increased by a factor of 1.25 for injection wells.

Compression Costs.—Twenty-five percent of the CO_2 requirement was met from recycled CO_2. Compression equipment was purchased and fuel costs were charged to this recompression.

Carbon Dioxide Pricing Method.—The cost of CO_2 is a variable of major importance. Costs of CO_2 can vary widely depending on whether the source is natural or manufactured gas and depending on the transportation method and distance. In fact, this EOR technique probably has the greatest potential for economies of scale because of the variability of these costs.

The cost algorithm used in the OTA study was developed by Lewin and Associates, Inc., and a summary of this analysis follows. Reservoirs were placed into one of four categories. These categories are:

- Concentrations of large reservoirs adequate to support the construction of a major CO_2 pipeline.
- Concentrations of smaller reservoirs where the bulk of CO_2 transportation would be by

major pipeline but where lateral lines would be required to deliver CO_2 to the numerous smaller fields,

- Smaller concentrations of large (and small) reservoirs where a smaller pipeline or alternative means for transporting CO_2 could be used.
- Individual, small reservoirs to be served by lateral pipeline or tanker trucks, where the amounts of required CO_2 would not justify the building of a new pipeline.

Results of the analysis of each of these categories is provided in the section below. The following subsection contains the details of the calculations.

Results of Carbon Dioxide Cost Calculations

Concentrations of *Large* Reservoirs. Given the indicated locations of natural CO_2 and the concentration of large candidate reservoirs such as in western Texas, eastern New Mexico, and southern Louisiana, it appears that the reservoirs in these areas could be served by major CO_2 pipelines.

The CO_2 cost model uses the following algorithms for assigning CO_2 costs to reservoirs:

- $0.22 **per Mcf for producing CO_2,**
- $0.24 per Mcf for compression and operation costs, and
- $0.08 per 100 miles of pipeline distance, including small amounts of lateral lines, assuming a 200 MMcf per day of pipeline capacity.

Under these assumptions, the base cost for CO_2 delivered to concentrations of large reservoir areas would be according to the following chart. All reservoirs, large and small, in these geographic areas would be able to take advantage of the economies of scale offered by the basic concentration of large reservoirs.

Geographic area	Approximate truckline distance (miles)	**Laterals (miles)**	**Carbon dioxide cost per Mcf (dollars)**
Louisiana—South	200	100	0.70
offshore	400	200	0.94
Texas-District 76	300	100	0.78
District 7C,8,8A,9	300	100	0.78
District 10	300	100	0.78
Offshore	500	100	0.94
New Mexico East and West	200	100	0.70
Wyoming	300	—	0.70

Adequate Concentration of Large and Small Reservoirs Served by Lateral Lines.—The second class of reservoirs would be the large and small reservoirs in close proximity to the major trunklines. These reservoirs could be serviced by using short distance lateral lines. Carbon dioxide costs were assigned as follows:

- $0.46 **per** Mcf for producing and compressing the CO_2, and
- $0.20 per Mcf **per 100** miles for transportation.

The CO_2 model assumes that reservoirs in the following geographic areas could be served by short distance trunklines or linking lateral lines to the main trunklines, using pipelines of 50 MMcf per day capacity.

Geographic area	**Approximate distance trunklines or laterals (miles)**	**Carbon dioxide cost per Mcf (dollars)**
Colorado	100	0.70
Mississippi	100	0.70
Oklahoma	150	0.78
Utah	100	0.70

Low Concentration, Large and Small Reservoirs, Close to Natural Sources of Carbon Dioxide.—The third class of reservoirs are those close to natural CO_2 sources where only minimum transportation charges would be required to deliver the CO_2 to the field.

The first question is what size of pipeline can be justified. This was examined for the two smaller potential States of Alabama and Florida. It was assumed that both of these States would justify a 100 MMcf pipeline under a 10-year development plan and a 50 MMcf pipeline under a 20-year development plan. For a 50 MMcf pipeline the costs were assumed to be as follows:

- $0.46 per Mcf for producing and compressing the CO_2, and
- $0.20 per Mcf per 100 miles for transportation, including laterals.

The CO_2 model assumes that the following geographic areas are close to natural CO_2 sources and could be served by small pipelines, having 50 MMcf/day capacity.

Geographic area	Approximate pipeline distance (miles)	Carbon dioxide cost per Mcf (dollars)
Alabama	200	0.86
Arkansas	200	0.86
Florida	300	1.02
Kansas	200	0.86
Montana	200	0.86
West Virginia	100	0.70

An alternative to this third class of reservoirs are those similar reservoirs that are not close to natural CO_2 sources. The reservoirs in these geographic locations would need to be served by CO_2 extracted from industrial waste products (e.g., from chemical complexes, ammonia plants, gasoline plants, combined powerplants, etc.).

An analysis of minimum required pipeline size indicated that each of these areas could support a 200+ MMcf per day pipeline under a 10-year development plan and a 100 MMcf per day pipeline under a 20-year development plan. The following costs were used for these reservoirs:

- $0.90 per Mcf for extracting the manufactured CO_2,
- $0.25 per Mcf for compression and operation,
- $0.08 per Mcf for 100 miles of trunk pipeline (200 MMcf per day capacity), plus
- $0.30 per Mcf for three 50-mile lateral lines (50 MMcf per day capacity) connecting the CO_2 source to the trunkline.

Under these assumptions, the base cost for CO_2 for the geographic areas in this category would be as follows:

Geographic area	Approximate pipeline distance (miles)	Purchasing, operating, and gathering costs per Mcf (dollars)	CO_2 cost per Mcf (dollars)
California-Central Coastal, L.A. Basin, and offshore	200	1.45	1.61
Louisiana—North	200	1.45	1,61
Texas--District 1	200	1.45	1.61
Districts 2,3,4	200	1.45	1.61
Districts 5,6.	200	1.45	1.61

Low Concentration, Small Reservoirs.—The final category of reservoirs considered in the analysis are the small reservoirs located in the moderate- and low-concentration geographic areas. The alternatives here are to construct a small pipeline to the trunkline or to deliver the CO_2 via truck. Large trunkline construction for low concentration reservoirs is infeasible.

For those geographic regions where the large reservoirs are already served by a pipeline, it appears likely that additional small lateral lines could be added to extend the CO_2 delivery to small fields. These fields would only need to pay the marginal costs of delivery. Because of this, rather small CO_2 lateral lines could be constructed (as small as 5 MMcf per day), which would serve an area with as little as 5 million barrels of recoverable oil. it was thus assumed that the average CO_2 costs for the small fields in a region already served by a pipeline would be the same as base costs for that region.

For concentrations lacking such existing trunklines, i.e., the remaining States, tanker-trucks would deliver CO_2. These would include:

Illinois	North Dakota
Indiana	Ohio
Kentucky	Pennsylvania
Michigan	South Dakota
New York	Tennessee
	Virginia

The cost in these States was set at $2.75 per Mcf.

Calculation Method and Details—Carbon Dioxide Costs

The method used to derive the CO_2 costs is briefly outlined in this section. The analysis followed a seven-step sequence:

- calculate the relationship of pipeline capacity to unit costs,
- translate pipeline capacity–cost relationship to pipeline investment costs per Mcf, for various pipeline capacities,
- calculate the pipeline delivery costs per Mcf that vary by distance,
- calculate the CO_2 purchase and delivery costs per Mcf that do not vary by distance,
- calculate full costs per Mcf for natural and manufactured CO_2,
- translate pipeline capacity to minimum required field size, and
- complete the breakeven analysis of using pipeline versus truck for delivering CO_2 to the field.

Relationship of Capacity to Costs.—The following were assumed for calculating pipeline investment costs:

- $330,000 per mile for 200 MMcf per day capacity,
- investment is scaled for capacity by a 0.6 factor, and
- pipeline will last 20 years.

Fixed and variable costs were set as follows:

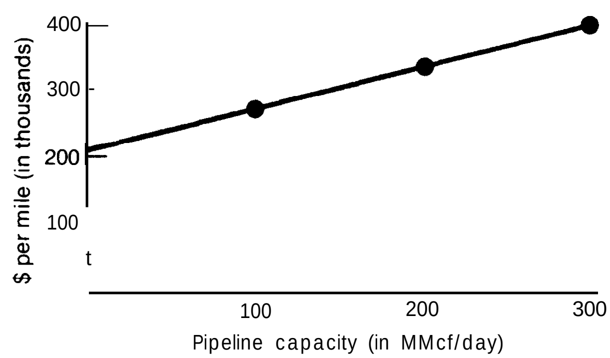
- fixed costs plus variable cost exponent (capacity) = total

Using the above data:

- fixed costs + 0.6 (200,000 Mcf/day) = $330,000 per mile,
- fixed costs = $210,000 per mile, and
- variable costs = $600 per MMcf/day per mile.

This relationship of costs to capacity has the general form shown in figure B-2.

Figure B-2. Pipeline Cost Versus Capacity



Pipeline Investment Costs per Mcf.—The cost–capacity graph was translated into a cost per Mcf (per 100 miles) graph by dividing costs by capacity, as follows:

For the 200 MMcf/day capacity at $330,000 per mile, the cost per Mcf per 100 miles with no discounting of capital is:

($330,000 X 100)/(200,000 X 365 X 20) = $0,023 per Mcl

If an 8-percent rate-of-return requirement is imposed, and it is assumed that no return results until the fourth year, the costs would be raised to:

$$C = \frac{330{,}000 \times 100}{200{,}000 \times 365}\left[\frac{(1.08)^{4}}{\frac{(1.08)^{16}-1}{.08(1.08)^{16}}}\right] \qquad 7B$$

C = $0.07 per Mcf per 100 miles

Similarly, the pipeline investment cost per Mcf **can be** generated as shown in table B-20.

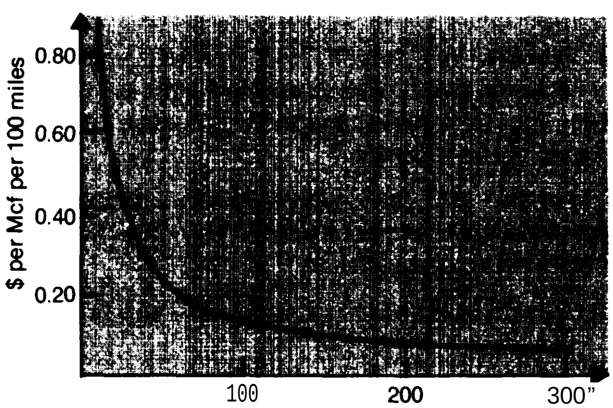
labia 6-20
Pipeiine Capacity Versus investment
(8-percent rate of return)

Pipeline capacity (MMcf/day)	Pipeline investment cost per Mcf ($ per 100 miles)
300	0.05
200	0.07
100	0.11
50	0.20
25	0.37
lo	0.89
5	1.79

Pipeline Delivery Costs Variable by Distance.— The pipeline investment cost was added to pipeline operating costs to develop pipeline costs per Mcf that are variable by distance. The following was assumed:

- pipeline operating costs are $O.01 per Mcf per 100 miles, and
- the pipeline capital costs from table 6-20 are applicable,
- with these assumptions, the variable cost per Mcf per lOO miles can redeveloped as shown in figure B-3.

Figure B-3. Variable CO_2 Transportation Costs Versus Pipeline Capacity



Carbon Dioxide Costs Not Variable by Distance.—The following was assumed:

- repressurizing operating costs are $0.16 per Mcf
- repressurizing capital costs are $0.08 per Mcfbased on the following:
  - $700 per hp
  - 280 hp required to pressurize 1,000 Mcf per day
  - Compressors will last 20 years
  - 8-percent discount rate,
- the purchase cost of naturally occurring CO_2 is $0.22 per Mcf,
- extraction costs for manufactured CO_2 are $0.90 per Mcf, and
- additional lateral lines will be required to gather and transport manufactured CO_2.

Based on the preceding, the fixed costs for manufactured CO_2 will be $1.14 per Mcf with lateral lines as shown in table B-21.

Table B-21
Lateral Lines Associated With Pipeline Capacity

Pipeline capacity (MMcf/day)	Amount and size of lateral lines
300	3 to 50 mile @ 50 MMcf/day
200	3 to 50 mile @ 50 MMcf/day
100	3 to 50 mile @ 25 MMcf/day
50	2 to 50 mile @ 10 MMcf/day
25	1 to 50 mile @ 10 MMcf/day
10	1 to 50 mile @ 5 MMcf/day
5	None

Total Costs per Mcf.—The investment and operating costs were then added to the purchase price for natural CO_2 and extraction and gathering costs for manufactured CO_2 to obtain the total cost per Mcf. These are shown for various conditions in table B-22.

Relationship of Pipeline Capacity to Field Size.—The pipeline capacity was related to field size using the following assumptions:

- 5 Mcf are required per barrel of recovered oil,
- CO_2 is injected over 10 years, and
- CO_2 recovers 30 percent of the oil left after primary/secondary recovery.

Then the conversions of pipeline capacity to field size shown in table B-23 were used.

Break-Even Analysis.-Using $2.75 per Mcf as the trucked-in cost for CO_2, two curves were

Table B-22
Total Costs per Mcf of CO_2
(dollars)

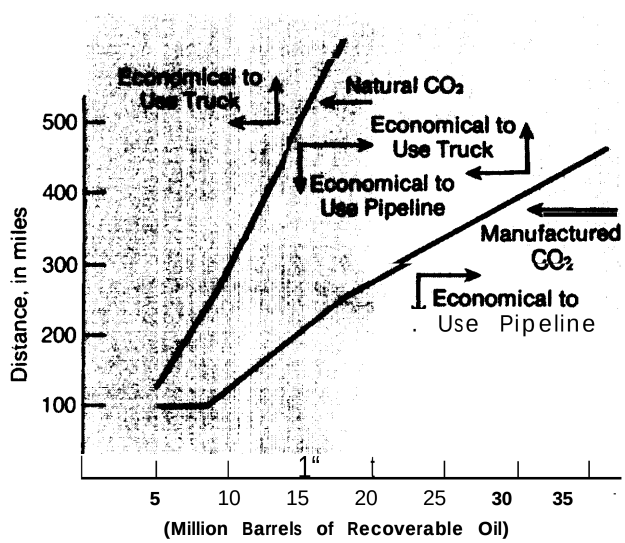
Pipeline capacity (MMcf/day)	Distance (miles)	Transp. costs	Fixed operating	Purchase (natural)	Extract from manuf.	Gather from manuf.	Full cost for natural	Full cost for manufactured
300 . . .	100	0.06	0.24	0.22	0.90	0.30	0.52	1.50
	200	0.12	0.24	0.22	0.90	0.30	0.58	1.56
	300	0.18	0.24	0.22	0.90	0.30	0.64	1.62
	400	0.24	0.24	0.22	0.90	0.30	0.70	1.68
200 . . .	100	0.08	0.24	0.22	0.90	0.30	0.54	1.52
	200	0.16	0.24	0.22	0.90	0.30	0.62	1.60
	300	0.24	0.24	0.22	0.90	0.30	0.70	1.68
	400	0.32	0.24	0.22	0.90	0.30	0.78	1.76
100 . . .	100	0.12	0.24	0.22	0.90	0.57	0.58	1,83
	200	0.24	0.24	0.22	0.90	0.57	0.70	1.95
	300	0.36	0.24	0.22	0.90	0.57	0.82	2.07
	400	0,48	0.24	0.22	0.90	0.57	0.94	2.19
50 . . .	50	0.10	0.24	0.22	0.90	0.90	0.56	2.14
	100	0,21	0.24	0.22	0.90	0.90	0.67	2.25
	200	0.42	024	0.22	0.90	0.90	1.88	2,46
	300	0.63	0.24	0.22	0.90	0.90	1.09	2.67
	400	0.84	0.24	0.22	0.90	0,90	1.30	2.88
2 5	50	0.19	024	0.22	0.90	0.90	0.65	2.23
	100	0.38	0.24	0.22	0.90	0.90	0.84	2.42
	200	0.76	0.24	0.22	0.90	0.90	1.22	2.80
	300	1.14	0.24	0.22	0.90	0.90	1.60	3.18
1 0	50	0.45	0.24	0.22	0.90	0.88	0.91	2.49
	100	0.90	0.24	0.22	0.90	0.88	1.36	2.94
	200	1.80	0.24	0.22	0.90	0.88	2.20	3.84
5 . . .	50	0.88	0.24	0.22	0.90	—	1.34	2.02
	100	1.76	0.24	0.22	0.90	—	2.22	2.90
	200	3.52	0.24	0.22	0.90	—	3.98	4.66

Table B-23
Pipeline Capacity as a Function of Field Size

Pipeline capacity (MMcf/day)	Minimum required concentration (or field size): Incremental oil recovered by C02 (million barrels)	Minimum required concentration (or field size): Residual oil in place (million barrels)
300	219	730
200	146	490
100	73	240
50	36	120
25	18	60
10	9	30
5	5	17

determined: one for natural and one for manufactured CO_2. These curves, shown in figure B-4, indicate the field size (oil concentration) and distance combinations where either pipeline or trucked CO_2 would be more economic.

Figure B-4. Transportation of CO_2— Break-Even Analysis



Sensitivity Analyses

Calculations were made with different sets of parameters than those presented in the main body of the report. In general, these additional calculations were done to determine the sensitivity of the results to certain of the important variables. For CO_2 miscible, two important considerations were the minimum acceptable rate of return and the price of the injected CO_2. Results of calculations in which these parameters were varied are given in this section.

High-Process Performance—High-Risk Case.— A calculation was made in which the minimum acceptable rate of return was set at 20 percent. The rate of implementation of projects was governed by the rate of return earned in a manner analogous to that given by table 8 in chapter Ill. The schedule of starting dates based on rate of return is given in the section on the economic model (p. 35).

Results of this calculation, considering the case in which the process is viewed as a high risk technology, are given in table B-24 for the world oil price. Ultimate recovery is dramatically reduced from the conventional risk case (lo-percent rate of return) presented in the body of the report. At lo-percent rate of return, the ultimate recovery is 13.8 billion barrels compared to 4.7 billion barrels with a 20-percent minimum rate of return. Production rates are correspondingly reduced.

This result strongly suggests that a great deal of research and development work must be done to establish the processes, and that economic incentives must be provided if the projections presented in the body of the report are to be reached,

Sensitivity *to Carbon Dioxide* Costs. -Calculitions were made in which the purchase cost of CO_2 was increased by factors of 1.5 and 2.5. A significant uncertainty exists relative to CO_2 costs and variations of these magnitudes are considered feasible.

Results for the high- and low-process performance cases are shown in table B-25 and B-26,

Table B-24
Estimated Recoveries for Advancing Technology—
High-Process Performance

High Risk (20-percent rate of return)
Carbon Dioxide Miscible

	World oil price ($13.75/bbl)		
	Onshore	**Offshore**	**Total**
Ultimate recovery:			
(billion barrels)	4.1	0.6	4.7
Production rate in:			
(million barrels/day)**			
1980	0.1	*	0.1
1985	0.1	*	0.1
1990	0.1	•	0.1
1995	0.6	0.1	0.7
2000	0.9	0.1	1.1
Cumulative production by:			
(million barrels)**			
1980	100	•	100
1985,	300	*	300
1990	400	100	600
1995	900	200	1,100
2000	2,700	500	3,200

● Less than O. I million barrels of daily **production, or less than 100 million barrels** of **cumulative production.**

● "Daily production figures rounded to 0.1 million barrels, cumulative production figures rounded to 100 million barrels; row totals may not add due to rounding.

Tabie B-25
Sensitivity of Ultimate Recovery to Carbon Dioxide Cost

Advancing Technology-High-Process Performance Case
(billions of barrels)

Cost factor	Upper tier price ($11.62/bbl)			World 011 price [$1 3.75/bbl)			Alternate fuels price ($22 .00/bbl)		
	Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
1.0”	85	0,6	9.1	129	0.9	13.8	18.5	2.6	21 1
1.5 :	3.9	01	4.0	6.7	0.3	7.0	15.9	19	178
2.5 .	0.4	0.0	0.4	18	0.0	1.8	11.5	0 6	12 .1

“Case reported In body of report

Table B-26
Sensitivity of Ultimate Recovery to Carbon Dioxide Cost

Advancing Technology—Low-Process Performance Case
(billions of barrels)

cost factor	Upper tier price ($11.62/bbl)	World oil price ($1 3.75/bbl)	Alternate fuels price ($22.00/bbl)
1.0”	3.5	4.6	12.3
1.5	0.8	1.8	8.9
2.5	0.3	0.3	4.2

“Case reported in body of report

respectively. As seen in table B-25, increasing the cost of CO_2 by a factor of 1.5 reduces ultimate recovery by a factor of about 2 at upper tier and world oil prices. The effect is not so pronounced at the alternate fuels price. Increase of the cost by a factor of 2.5 essentially eliminates production at the upper tier price and reduces recovery to less than 2 billion barrels at world oil price.

For the low-process performance case, an increase of CO_2 cost by a factor of 2.5 reduces ultimate recovery to about 0.3 billion barrels at world oil price, and to about 4 billion barrels at the alternate fuels price.

Economic Model

The economic model was developed by Lewin and Associates, Inc.[96] In this section the structure of the basic model will be described, followed by tabulations of the economic parameters.

Structure of the Model

The model uses a standard discounted cash-flow analysis. The unit of analysis is the reservoir with economic calculations being made for a single “average” five-spot pattern within the reservoir. Results of the single-pattern calculation are then aggregated according to a reservoir development plan (described below) to determine total reservoir economic and production performance.

Cash inflows are determined using the specific oil recovery models previously described for each process. Recovery models are applied using the reservoir parameters from the data base. An assumption was made that 95 percent of the oil remaining in a reservoir was contained within 80 percent of the area. This “best” 80 percent was then developed in the model. An adjustment of reservoir thickness was made to distribute the 95 percent of the remaining oil over an acreage equal to 80 percent of the total acreage. Timing and amounts of oil production are dependent on the particular EOR process applied as previously described.

Cash outflows are based on several different kinds of costs and investments. These are: 1) field development costs, 2) equipment investments, 3) operating and maintenance (O & M) costs, 4) injection chemical costs, and 5) miscellaneous costs, such as overhead. Listings and descriptions of the costs follow.

Using the cash inflows and outflows, an annual overall cash-flow calculation is made considering Federal and State taxes. Appropriate State tax rules are incorporated for each reservoir. Cash flows are then discounted at selected interest rates to determine present worth as a function of interest rate. Rate of return is also calculated.

The discounted cash-flow analysis was made at three different oil prices. These included upper tier price ($1 1.62 per barrel), world oil price ($1 3.75 per barrel), and an estimated price at which alternate fuels would become competitive ($22.00 per barrel). All costs were in 1976 real dollars with no adjustment for inflation.

Reservoirs were developed if they earned a rate of return of at least 10 percent by one of the EOR processes. In situations where more than one EOR process was applicable to a reservoir, the EOR process yielding the greatest ultimate recovery was selected as long as a rate of return of at least 10 percent was earned.

Specific Economic Assumptions

Date of Calculations.—Ail calculations were made as of a date of July 1, 1976. Cost data were projected to that date. No attempt was made to build inflation factors into the calculations of future behavior.

Sharing of Operating and Maintenance Costs.—Well operating and maintenance costs were shared between primary and secondary production and enhanced oil production. A decline curve for primary and secondary production was generated for each reservoir. This was based on specific reservoir data, if available, or on regional decline curve data if reservoir data did not exist. Well operating costs were assigned annually to enhanced oil operations in direct proportion to the fraction of the oil production that was due to the EOR process.

General and Administrative (Overhead) Costs.—These costs were set at 20 percent of the operating and maintenance costs plus 4 percent of investments (excluding any capitalized chemical costs). Where O & M costs were shared between primary and secondary and enhanced recovery, only that fraction assigned to EOR was used as a basis for the overhead charge.

Intangible and Tangible Drilling and Completion Costs.—Intangible costs were expensed in the year incurred in all cases (no carryback or carry forward was used in the tax treatment). These costs were set at 70 percent of drilling and completion costs for new wells and 100 percent of workover costs.

Tangible costs were "recovered" by depreciation. Thirty percent of drilling and completion costs were capitalized plus any other lease or well investments. A unit of production depreciation method was applied.

Royalty Rate.—A rate of 12.5 percent of gross production was used in all cases.*

Income Taxes.—The Federal income tax rate was set at 48 percent. The income tax rate for each State was applied to reservoirs within the State. An investment tax credit of 10 percent of tangible investments was used to reduce the tax liability. If a negative tax were computed in any year, this was applied against other income in the company to reduce tax liabilities.

Chemical Costs—Tax Treatment.—For tax purposes, chemicals, such as CO_2, surfactant, polymer, and so on, were expensed in the year of injection. Tax treatment of the chemical cost is an important consideration. The effect of having

"In most current leases, a royalty is charged on net production. However, there is a trend to charge a royalty on gross production in some Federal leases and because this trend could extend into the private sector in the future, OTA calculations assessed royalty charges against gross production.

to capitalize chemicals (and recover the investment via depreciation) was treated as a part of the policy considerations. This is discussed in the main body of the report.

Size of Production Units--For purposes of the economic calculations, a production unit was assumed to consist of the acreage associated with one production well. This varied from process to process. The spacing used is shown in table B-27.

Table B-27
Production Unit Size

Process	Acres	Production wells	Injection wells
CO_2 miscible	40	1.0	1.0
Steam drive	2.5-5.0	1.0	1.0
In situ combustion .	20	1.0	1.0
Surfactant/polymer	Variable (Max= 40)	1.0	1.0
Polymer.	40	1.0	0.5

Information on number and age of production and injection wells was input as part of the data base. Existing wells were used and worked over as required according to their age and condition,

As previously indicated, an assumption was made that 95 percent of the remaining oil in place was located under 80 percent of the reservoir acreage. The oil in this "best" acreage was assumed to be uniformly distributed.

Timing of *Reservoir* Development.-Reservoirs were developed according to a plan designed to simulate industry implementation of EOR processes in a reservoir. The first part of the timing plan consists of a schedule of starting dates based on rate-of-return criteria. This was discussed in the main body of the report, and the schedule is given in table 8 in chapter III. This schedule is for the conventional risk situation with a 10-percent rate of return taken as the minimum acceptable rate,

A "high-risk" case was also considered in which the minimum acceptable rate of return was set at 20 percent. The schedule of starting dates was altered for this high-risk case as shown in table B-28.

The second part of the timing plan consists of the elements of the specific reservoir development scheme, once a starting date is assigned. The seven elements of the reservoir development plan are as follows:

Table B-28
Schedule of Starting Dates
High-Risk Case

Date	Continuations of ongoing projects rate of return	New starts rate of return
1977	>20%	%60%
1978	>20%	>45%
1979	>20%	>40%
1980	>20%	>35%
1981	>20%	>30%
1982	>20%	>28%
1983	>20%	>26%
1984	>20%	>24%
1985	>20%	>22%
1986	>20%	>20%
1987 -2000	≥20%	≥20%

Reservoir study. Preliminary engineering studies and laboratory tests are conducted. A decision is made whether or not to undertake a technical pilot.

Technical *pilot.* Pilot consists of one or two five-spot patterns on close spacing. Technical parameters are evaluated.

Evaluate pilot, planning. Pilot results are evaluated and plans are made for economic pilot. Budgeting occurs.

Economic pi/et. Pilot consists of four to eight five-spot patterns on normal spacing. Purpose is to evaluate economic and technical potential.

Evaluation and planning, Results of pilots are evaluated. Plans are made for full-scale development.

Pipeline construction (CO, miscible only). Pipeline necessary to carry CO_2 from source to reservoir is constructed.

Development of complete reservoir. The remaining part of the reservoir is developed according to a set time schedule.

The time devoted to each of the seven steps for each process is shown in table B-29.

Extrapolation to Nation.—To obtain the national potential for EOR, calculated reservoir

Table B-29
Timing of Reservoir Development

Step	Years of Elapsed Time by EOR Technique				
	Steam	In situ	CO_2	Surfactant/ polymer	Polymer
Reservoir study	1	1	1	1	1
Technical pilot	2	2	2	2	0
Evaluate pilot, planning . . .	1	1	1	1	0
Economic pilot	3	2	4	4	5
Evaluation and planning. . .	1	2	1	1	1
Pipeline construction	—	—	2	—	—
Development of reservoir.	10	10*	5	10	2
. Total	18	18	16	19	9

*In situ proceeds in four separate segments introduced 3 years apart.

recoveries were first extrapolated to the State or district level and then summed to yield the national total. The State or district extrapolation factor was the ratio of remaining oil in place (ROIP) (after secondary recovery) in the State or district divided by the ROIP in the data base reservoirs in the State or district.

An example calculation for the State of Wyoming follows (for world oil price).

Calculated EOR Recovery. . . . . 0.56 billion bbls
(from reservoirs in data base)
Percent of ROIP in data base. 43.0
ROIP in data base . . . . 10,628 million bbls
ROIP in State. . . . . 24,700 million bbls

$$\text{State EOR} = 0.56 \times 10^9 \times \frac{24.7 \times 10^9}{10.6 \times 10^9} \ldots 1.3 \text{ billion bbls}$$

The State and district subdivisions used for extrapolation are shown in the tables of economic parameters (Table B-30 for example).

Economic Data— General

This subsection is taken directly from the report of Lewin and Associates, Inc., to the Energy Research and Development Administration.[97] Much of the material is quoted directly. Economic parameters are given which are used in the model previously described. In the analysis, specific values of the parameters are calculated based on geographic location, reservoir depth, condition of the wells, and the existence of waterflooding or other secondary recovery. A large number of geographic areas have been established. In many cases these correspond to a State, but in other cases (such as Texas) several districts are defined within a State. Four depth categories have been defined. Condition of the wells in a reservoir is judged by the year of most recent development. Existence of secondary recovery in a reservoir is noted from State reports.

The general economic parameters are presented through a series of tables as follows:

Table B-30 Drilling and Completion Costs for Production and Injection Wells
Table B-31 Well, Lease, and Field Production Equipment Costs—Production Wells
Table B-32 Costs of New Injection Equipment
Table B-33 Well Workover and Conversion Costs for Production and Injection Wells
Table B-34 Basic Operating and Maintenance Costs for Production and Injection Wells
Table B-35 Incremental Injection Operating and Maintenance Costs
Table B-36 State and Local Production Taxes
Table B-37 State Income Taxes.

Each exhibit presents the parameters actually used in the models. The first six tables are accompanied by attachments that explain or illustrate the derivation of the parameters. All the tables are stated in 1976 prices.

Parameters in the above tables are for onshore reservoirs. Additional economic parameters for offshore reservoirs follow.

Table B-30
Drilling and Completion Costs for Production and Injection Wells

(dollars per foot of drilling and completion)

State/district	Geographic unit	Depth category 0-2,500’	2500-5,000’	5,000-10,000’	10,000-15,000’
California					
East central	1	31.60	28.03	50.02	93.62
Central coast	2	42.61	42.70	45.35	74.71
South	3	39.71	49.74	46.81	70.10
Offshore	4	75.88	59.99	56.38	64.59
</ 200’wD		N.A.	N.A.	N.A.	N.A.
201 -400’WD		N.A.	N.A.	N.A.	N.A.
401 -800’WD		N.A.	N.A.	N.A,	N.A,
>800’WD		N.A.	N.A.	N.A.	N.A.
Louisiana					
North	5	21.84	21.62	37.98	33.93
South	6	60.99	53.00	46.95	57.62
Offshore	7	112.32	110.32	109.42	103.20
<=200’wD		N.A.	N.A.	N.A.	N.A.
201-400’WD		N.A.	N.A.	N.A.	N.A.
401-800’WD		N.A.	N.A.	N.A.	N.A.
>=800’WD		N.A.	N.A.	N.A.	N.A.
Texas					
I...	8	17.94	23.91	31.34	35.00
2	9	18.00	27.15	28.36	33.40
3::::	10	32.28	37.09	34.12	63.75
4	11	28.23	24.17	23.46	77.67
5	12	16,71	26.23	32.51	55.96
6	13	32.66	19.19	31.51	60.96
70	14	13.30	19.94	20.99	N.A.
7C	15	30.91	20.60	26.50	43.42
8	16	30.86	23.15	31.66	43.85
8A	17	17.49	18.00	24.87	41.58
9	18	14.72	23.38	28.32	33.00
lo	19	24.77	18.68	27.27	48.41
Offshore	20	112.32	110.32	109.42	103.20
<=200’wD		N.A.	N.A.	N.A.	N.A.
201-400’WD		N.A.	N.A.	N.A.	N.A.
401-800’WD		N.A.	N.A.	N.A.	N.A.
>=800’WD		N.A.	N.A.	N.A.	N.A.
New Mexico					
East	23	35.15	31.25	34.00	50.01
West	24	45.38	22.57	25.27	34.00
Oklahoma	25	20.37	25.10	30.59	49.61
Kansas					
West	30	15.72	20.07	23.03	34.00
East	31	15.72	20.07	23.03	34.00
Arkansas					
North	32	17.74	20.04	26.48	33.50
South	33	17.74	20.04	26.48	33,50
Missouri	34	20.57	‘25.10	30.59	49.61
Nebraska					
Central	35	20.37	25.10	30.59	49.61
West	36	45.38	22.57	25.27	34.00
Mississippi					
Hi Sulphur	40	23.32	23.32	23.69	56.25
Lo Sulphur	41	23.32	23.32	23.69	56.25

N.A. = not applicable.

Table B-3 Cont.

State/district	Geographic unit	Depth category 0-2,500’	2,500-5,000’	5,000-10,000’	10,000-15,000’
Alabama					
Hi sulphur.	42	28.26	27.94	40.00	55.69
Lo sulphur.	43	28.26	27.94	40.00	55.69
Florida					
Hi sulphur.	44	28.26	27.94	40.00	55.69
Lo sulphur.	45	28.26	27.94	40.00	55.69
Colorado	50	45.38	22,57	25.27	34.00
Utah	53	39.18	42.00	45.13	93.48
Wyoming	55	42.24	47.07	34.81	104.69
Montana	57	15.98	30.05	36.80	48.98
North Dakota	58	26.00	31.05	37.87	45,10
South Dakota	59	26.00	31.05	37.87	45.10
Illinois	60	24.46	26.43	32.74	50.00
Indiana. ...., ...	61	24.46	26.43	32.74	50.00
Ohio					
West	62	24.46	26.43	32.74	50.00
East	63	15.38	19.09	18.14	30.00
Kentucky					
West	64	24.46	26.43	32.74	50.00
East	65	15.38	19.09	18.14	30.00
Tennessee					
West	66	24.46	26.43	32.74	50.00
East	67	15.38	19.09	18.14	30.00
Pennsylvania.	70	15.38	19.09	18.14	30.00
New York	71	15.38	19.09	18.14	30.00
West Virginia	72	15,38	19.09	18.14	30.00
Virginia	73	15.38	19.09	18.14	30.00
Alaska					
North Slope	80	N.A.	N.A.	370.00	340.00
Cook Inlet	31	N.A.	N.A.	190.00	180.00

N.A. = not applicable.

Tabie B-31
Weii,Lease,and Fieid Production Equipment Costs-Production Wells

(dollars per production well)

State/district	Geographic unit	Depth category 0-2,500’	2,500-5,000’	5,000-10,000’	10,000-15,000’
California					
East Central	1	33,300	51,900	47,200	51,200
Central Coast...	2	33,300	51,900	47,200	51,200
South	3	33,300	51,900	47,200	51,200
Offshore	4	300,000	300,000	300,000	300,000
<=200’wD.	90	300,000	300,000	300,000	300,000
201-400’WD.	91	300,000	300,000	300,000	300,000
401-800’WD	92	N.A.	N.A.	N.A.	N.A.
>800’WD	93	N.A.	N.A.	N.A.	N.A.
Louisiana					
North	5	23,500	45,600	50,500	44,400
South.	6	24,700	47,300	52,900	48,800

N.A. = nonapplicable.

Table B-31—Cent.

State/district	Geographic unit	Depth category 0-2,500’	2,500-5,000’	5,000-10,000’	10,000-15,000’
Offshore	7	300,000	300,000	300,000	300,000
<=200’WD”	95	300,000	300,000	300,000	300,000
201 -400’WD	96	300,000	300,000	300,000	300,000
401-800’WD	97	N.A.	N.A.	N.A.	N.A.
>=800WD	98	N.A.	N.A.	N.A.	N.A.
Texas					
I	8	23,500	45,600	50,500	44,400
2	9	23,500	45,600	50,500	44,400
3 :::::::::::::::::::... . . .	10	23,500	45,600	50,500	44,400
4	11	23,500	45,600	50,500	44,400
5::.	12	23,500	45,600	50,500	44,400
6	13	23,500	45,600	50,500	44,400
7B” :	14	23,100	32,900	52,400	45,200
7C	15	23,100	32,900	52,400	45,200
8	16	23,100	32,900	52,400	45,200
8 A :::::::::::::::::: ::::::	17	23,100	32,900	52,400	45,200
9...	18	23,100	32,900	52,400	45,200
lo	19	24,900	37,100	49,100	58,200
Offshore	20	300,000	300,000	300,000	300,000
<=200’wD	95	300,000	300,000	300,000	300,000
201-400’WD	96	300,000	300,000	300,000	300,000
401-800’WD	97	N.A.	N.A.	N.A.	N.A.
>=800’WD.	98	N.A.	N.A.	N.A.	N.A.
New Mexico					
East	23	23,100	32,900	52,400	45,200
West	24	35,600	45,400	76,900	68,200
Oklahoma	25	24,900	37,100	49,100	58,200
Kansas					
West	30	24,900	37,100	49,100	58,200
East	31	24,900	37,100	49,100	58,200’
Arkansas					
North.	32	24,900	37,100	49,100	58,200
South	33	23,500	45,600	50,500	44,400
Missouri.	34	24,900	37,700	49,100	58,200
Nebraska					
Central	35	24,900	37,100	49,100	58,200
West	36	35,600	45,400	75,900	68,200
Mississippi					
Hi Sulphur.	40	23,500	45,600	50,500	44,400
Lo Sulphur	41	23,500	45,600	50,500	44,400
Alabama					
Hi Sulphur.	42	N.A.	N.A.	N.A.	N.A.
Lo Sulphur	43	23,500	45,600	50,500	44,400
Florida					
Hi Sulphur.	44	N.A.	N.A.	N.A.	N.A.
Lo Sulphur	45	23,500	45,600	50,500	44,400
Colorado	50	35,600	45,400	76,900	68,200
Utah.	53	35,600	45,400	76,900	68,200
Wyoming.	55	35,600	45,400	76,900	68,200
Montana	57	35,600	45,400	76,900	68,200
North Dakota	58	35,600	45,400	76,900	68,200
South Dakota	59	35,600	45,400	76,900	68,200
Illinois	60	24,900	37,100	49,100	58,200
Indiana. . . . , ...	61	24,900	37,100	49,100	58,200

N.A. = not applicable.

Table B-31-Cent.

State/district	Geographic unit	Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	10,000-15,000'
Ohio					
West	62	24,900	37,100	49,100	58,200
East	63	8,400	17,000	N.A.	N.A.
Kentucky					
West	64	24,900	37,100	N.A.	N.A.
East	65	8,400	17,000	N.A.	N.A.
Tennessee					
West	66	24,900	37,100	N.A.	N.A.
East	67	8,400	17,000	N.A.	N.A.
Pennsylvania	70	8,400	17,000	N.A.	N.A.
New York	71	8,400	17,000	N.A.	N.A.
West Virginia	72	8,400	17,000	N.A.	N.A.
Virginia	73	8,400	17,000	N.A.	N.A.
Alaska					
North Slope	80	N.A.	N.A.	N.A.	N.A.
Cook Inlet	81	N.A.	N.A.	N.A.	N.A.

N.A. = not applicable.

NOTE:
Well, lease, **and field production equipment designed** for secondary but excluding Injection equipment Includes all items except tubing and wellheads (which are Included In JAS drilling costs) required to lift the fluid to the surface at the producing wellhead by artiflcial lift, Including rod pump, gas lift, or hydraulic lift, depending on geographic area and depth. These costs also Include all equipment to process the produced fluids prior to custody transfer. The major items included are: heater-treater, separator, well testing system, tanks, flow levers from producing wells, water disposal systems, and, when applicable, crude desulphurizatlon facilities. These are average costs per *production well.*

Table B-32
Costs of New Injection Equipment

(dollars per injection well)

State/district	Geographic unit	Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	10,000-15,000'
California					
East Central	1	30,500	30,500	48,500	48,500
Central Coast	2	30,500	30,500	48,500	48,500
South	3	30,500	30,500	48,500	48,500
Offshore	4	100,000	100,000	150,000	150,000
<= 200'wD	90	N.A.	N.A.	N.A.	N.A.
201 -400'WD	91	N.A.	N.A.	N.A.	N.A.
401 -800'WD	92	N.A.	N.A.	N.A.	N.A.
>=800'WD	93	N.A.	N.A.	N.A.	N.A.
Louisiana					
North	5	28,500	28,500	45,300	45,300
South	6	31,100	31,100	52,300	52,300
Offshore	7	100,000	100,000	150,000	150,000
<= 200'wD	95	100,000	100,000	150,000	150,000
201-400'WD	96	100,000	100,000	150,000	150,000
401 -800'WD	97	N.A.	N.A.	N.A.	N.A.
>=800W D	98	N.A.	N.A.	N.A.	N.A.

N.A. = not applicable.

Table B-32-Cent.

State/district	Geographic unit	"Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	10,000-15,000'
Texas					
1	8	28,500	28,500	45,300	45,300
2	9	28,500	28,500	45,300	45,300
3	10	28,500	28,500	45,300	45,300
4	11	28,500	28,500	45,300	45,300
5	12	28,500	28,500	45,300	45,300
6	13	28,500	28,500	45,300	45,300
70	14	27,700	27,700	44,100	44,100
7C	15	27,700	27,700	44,100	44,100
8	16	27,70P	27,700	44,100	44,100
8A	17	27,700	27,700	44,100	44,100
9	18	27,700	27,700	44,100	44,100
10	19	30,000	30,000	64,100	64,100
Offshore	20	100,000	100,000	150,000	150,000
<=200'WID	95	100,000	100,000	150,000	150,000
201-400'WD	96	100,000	100,000	150,000	150,000
401-800'WD	97	N.A.	N.A.	N.A.	N.A.
>=800WD	98	N.A.	N.A.	N.A.	N.A.
New Mexico					
East	23	27,700	27,700	44,100	44,100
West	24	42,800	42,800	74,700	74,700
Oklahoma	25	30,000	30,000	64,100	64,100
Kansas					
West	30	30,000	30,000	64,100	64,100
East	31	30,000	30,000	64,100	64,100
Arkansas					
North	32	30,000	30,000	64,100	64,100
South,	33	28,500	28,500	45,300	45,300
Missouri	34	30,000	30,000	64,100	64,100
Nebraska					
Central	35	30,000	30,000	64,100	64,100
west	36	42,800	42,800	74,700	74,700
Mississippi					
Hi Sulphur	40	28,500	28,500	45,300	45,300
Lo Sulphur	41	28,500	28,500	45,300	45,300
Alabama					
HiSulphur	42	28,500	28,500	45,300	45,300
Lo Sulphur	43	28,500	28,500	45,300	45,300
Florida					
HiSulphur	44	28,500	28,500	45,300	45,300
Lo Sulphur	45	28,500	28,500	45,300	45,300
Colorado	50	42,800	42,800	74,700	74,700
Utah	53	42,800	42,800	74,700	74,700
Wyoming	55	42,800	42,800	74,700	74,700
Montana	57	42,800	42,800	74,700	74,700
North Dakota	58	42,800	42,800	74,700	74,700
South Dakota	59	42,800	42,800	74,700	74,700
Illinois	60	30,000	30,000	64,100	64,100
Indiana	61	30,000	30,000	64,100	64,100
Ohio					
West	62	30,000	30,000	64,100	64,100
East	63	12,200	12,200	N.A.	N.A.

N,A. = not applicable

Tabie B-32--Cent.

State/district	Geographic unit	"Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	1o,ooo-15,000'
Kentucky					
West	64	30,000	30,000	N.A.	N.A.
East	65	12,200	12,200	N.A.	N.A.
Tennessee					
West	**66**	30,000	30,000	N.A.	N.A.
East	**67**	12,200	12,200	N.A.	N.A.
Pennsylvania.	70	12,200	12,000	N.A.	N.A.
New York	71	12,200	12,000	N.A.	N.A.
West Virginia	72	12,2(-)0	12,200	N.A.	N.A.
Virginia	73	12,200	12,000	**N.A.**	N.A.
Alaska					
North Slope	80	N.A.	N.A.	**N.A.**	**N.A.**
Cook Inlet	81	N.A.	N.A.	**N.A.**	N.A,

N.A **= not applicable.**

Note:

Cost of **water injection equipment** for waterflood projects in-eludes the **equipment necessary to** install a waterflood in a **depleted primary producing** field. The malor items included are: water supply wells, water tankage, injection plant and accessories, injection heads, water injection lines, and electrification.

Table B-33: Part A
Well Workover and Conversion Costs for Production and injection Wells

Workover and/or Conversion Costs for Enhanced Recovery

Years field has been operated underexisting recovery **process**	Percent of wells worked **over**	Percent of wells over 25-years old— **(conversion costs)**	Composition conversion cost **percent**
More than 25	**100**	100	100
16 **to 25.**	50	80	40
6 **to 15. ....,**	**25**	**64**	16
1 to 5.	0	0	0

Table B-33: Part B
Well Workover and Conversion Costs for Production and injection Wells

(dollars per well)

State/district	**Geographic unit**	**Depth category** **0-2,500'**	**2,500-** 5,000'	5,000-1 0,000'	10,000-1 5,000'
California					
East Central	1	**20,400**	**50,200**	103,400	220,000
Central Coast.	**2**	**20,400**	**50,200**	103,400	220,000
South.	**3**	**20,400**	**50,200**	103,400	220,000
Offshore.	**4**	**150,000**	150,000	170,000	225,000
<=200'WD	90	**N.A.**	N.A.	**N.A.**	N.A.
201 -400'WD	91	**N.A.**	N.A.	**N.A.**	N.A.
401 -800'WD	92	**N.A.**	N.A.	N.A.	**N.A.**
>800'WD	93	**N.A.**	N.A.	N.A.	**N.A.**

N.A. = not applicable.

Table B-33: Part B-Cent.

State/district	Geographic unit	Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	10,000-15,000'
Louisiana					
North. ... , ...	5	21,700	38,200	64,100	135,000
South	6	35,400	69,000	94,000	139,700
Offshore	7	150,000	150,000	170,000	225,000
<=200'WD.	95	150,000	150,000	170,000	225,000
201-400'WD	96	150,000	150,000	170,000	225,000
401-800'WD.	97	N.A.	N.A.	N.A.	N.A.
>800'WD	98	N.A.	N.A.	N.A.	N.A.
Texas					
l	8	21,700	38,200	64,100	135,000
2	9	21,700	38,200	64,100	135,000
3	10	21,700	38,200	64,100	135,000
4	11	21,700	38,200	64,100	135,000
5	12	21,700	38,200	64,100	135,000
6	13	21,700	38,200	64,100	135,000
70" :	14	16,900	27,400	57,500	133,400
7C	15	16,900	27,400	57,500	133,400
8	16	16,900	27,400	57,500	133,400
8 A :	17	16,900	27,400	57,500	133,400
9	18	16,900	27,400	57,500	133,400
lo	19	17,400	29,700	59,800	132,500
Offshore	20	150,000	150,000	170,000	225,000
<=2()()'wD. . . . . , .	95	150,000	150,000	170,000	225,000
201-400'WD	96	150,000	150,000	170,000	225,000
401-800'WD. ..,, ...	97	N.A.	N.A.	N.A.	N.A.
>=800'WD.	98	N.A.	N.A.	N.A.	N.A.
New Mexico					
East	23	16,900	27,400	57,500	133,400
West	24	34,700	50,900	76,900	147,500
Oklahoma	25	17,400	29,700	59,800	132,500
Kansas					
West	30	17,400	29,700	59,800	132,500
East	31	17,400	29,700	59,800	132,500
Arkansas					
North	32	17,400	29,700	59,800	132,500
South	33	21,700	38,200	64,100	135,000
Missouri.	34	17,400	29,700	59,800	132,500
Nebraska					
Central	35	17,400	29,700	59,800	132,500
West	36	34,700	50,900	76,900	147,500
Mississippi					
Hi Sulphur.	40	30,000	50,000	100,000	200,000
Lo Sulphur	41	21,700	38,200	64,100	135,000
Alabama					
Hi Sulphur.	42	30,000	50,000	100,000	200,000
Lo Sulphur	43	21,700	38,200	64,100	135,000
Florida					
Hi Sulphur.	44	30,000	50,000	100,000	200,000
Lo Sulphur	45	21,700	38,200	64,100	135,000
Colorado	50	34,700	50,900	76,900	147,500
Utah.	53	34,700	50,900	76,900	147,500
Wyoming	55	34,700	50,900	76,900	147,500
Montana	57	34,700	50,900	76,900	147,500
North Dakota	58	34,700	50,900	76,900	147,500

N.A. = not applicable.

Table B-33: Part B-Cent.

State/district	Geographic unit	Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	10,000-15,000'
South Dakota	59	34,700	50,900	76,900	147,500
Illinois	60	17,400	29,700	59,800	132,500
Indiana	61	17,400	29,700	59,800	132,500
Ohio					
West	62	17,400	29,700	59,800	132,500
East	63	8,900	29,500	N.A.	N.A.
Kentucky					
West	64	17,400	29,700	N.A.	N.A.
East	65	8,900	29,500	N.A.	N.A.
Tennessee					
West	66	17,400	29,700	N.A.	N.A.
East	67	8,900	29,500	N.A.	N.A.
Pennsylvania	70	8,900	29,500	N.A.	N.A.
New York	71	8,900	29,500	N.A.	N.A.
West Virginia	72	8,900	29,500	N.A.	N.A.
Virginia	73	8,900	29,500	N.A.	N.A.
Alaska					
North Slope	80	N.A.	N.A.	N.A.	N.A.
Cook Inlet	81	N.A.	N.A.	N.A.	N.A.

N.A. = not applicable.

Note:

Costs of conversion of existing producing or injection well to "new" producing or injection well include those to workover old wells and equipment for production or injection service for EOR. Costs are averaEes ofcosts for woduction wells and infection wells and are calculated based on percentages of applicable items of new well drilling costs and equipment costs required for workover or conversion.

Table B-34
Bask Operating and Maintenance Coats for Production and Injection Wells

(dollars per well per year)

State/district	Geographic unit	Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	10,000-15,000'
California					
East Central	1	11,600	15,700	17,500	19,800
Central Coast	2	11,600	15,700	17,500	19,800
South	3	11,600	15,700	17,500	19,800
Offshore	4	60,000	60,000	75,000	75,000
<=200'WD	90	60,000	60,000	75,000	75,000
201-400'WD	91	60,000	69,000	84,000	84,000
401-800'WD	92	60,000	72,000	90,000	90,000
>=800'WD	93	60,000	84,000	105,000	105,000
Louisiana					
North	5	9,900	13,900	16,500	16,900
South	6	8,800	12,200	15,200	15,800
Offshore	7	60,000	60,000	75,000	75,000
<= 200'wD	95	60,000	60,000	75,000	75,000
201 -400'WD	96	60,000	69,000	84,000	84,000
401 -800'WD	97	60,000	72,000	90,000	90,000
>=800'WD	98	60,000	84,000	105,000	105,000
Texas					
1	8	9,900	13,900	16,500	16,900
2	9	9,900	13,900	16,500	16,900

N.A. = not applicable.

Table B-34-Cent.

State/district	Geographic unit	Depth category 0-2,500’	2,500-5,000’	5,000-10,000’	10,000-15,000’
3	10	9,900	13,900	16,500	16,900
4	11	9,900	13,900	16,500	16,900
5	12	9,900	13,900	16,500	16,900
6	13	9,900	13,900	16,500	16,900
70	14	8,000	8,600	11,700	13,000
7C	15	8,000	8,600	11,700	13,000
8	16	8,000	8,600	11,700	13,000
8A	17	8,000	8,600	11,700	13,000
9	18	8,000	8,600	11,700	13,000
lo	19	10,000	11,100	15,500	18,000
Offshore	20	60,000	60,000	75,000	75,000
<=200'WD	95	60,000	60,000	75,000	75,000
201-400’WD	96	70,000	70,000	84,000	84,000
401-800’WD	97	72,000	72,000	90,000	90,000
>=800'WD	98	84,000	84,000	105,000	105,000
New Mexico					
East	23	8,000	8,600	11,700	13,000
West	24	8,700	14,400	25,500	41,800
Oklahoma	25	10,000	11,100	15,500	18,000
Kansas					
West	30	10,000	11,100	15,500	18,000
East	31	10,000	11,100	15,500	18,000
Arkansas					
North	32	10,000	11,100	15,500	18,000
South	33	9,900	13,900	16,500	16,900
Missouri	34	10,000	11,100	15,500	18,000
Nebraska					
Central	35	10,000	11,100	15,500	18,000
West	36	8,700	14,400	25,500	41,800
Mississippi					
Hi Sulphur	40	15,000	21,000	24,600	27,000
Lo Sulphur	41	9,900	13,900	16,500	16,900
Alabama					
Hi Sulphur	42”	15,000	21,000	24,600	27,000
Lo Sulphur	43	9,900	13,900	16,500	16,900
Florida					
Hi Sulphur	44	15,000	21,000	24,600	27,000
Lo Sulphur	45	9,900	13,900	16,500	16,900
Colorado	50	8,700	14,400	25,500	41,800
Utah	53	8,700	14,400	25,500	41,800
Wyoming	55	8,700	14,400	25,500	41,800
Montana	57	8,700	14,400	25,500	41,800
North Dakota	58	8,700	14,400	25,500	41,800
South Dakota	59	8,700	14,400	25,000	41,800
Illinois	60	6,000	.6,700	9,900	10,800
Indiana	61	6,000	6,700	9,900	10,800
Ohio					
West	62	6,000	6,700	9,900	10,800
East	63	2,300	2,600	N.A.	N.A.
Kentucky					
West	64	6,000	6,700	N.A.	N.A.
East	65	2,300	2,600	N.A.	N.A.
Tennessee					
West	66	6,000	6,700	**N.A.**	N.A.
East	67	2,300	2,600	**N.A.**	N.A.

N.A. = nonapplicable.

Table B-*Cont.

State/district	Geographic unit	"Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	1o,ooo-15,000'
Pennsylvania	70	2,300	2,600	N.A.	N.A.
New York	71	2,300	2,600	N.A.	N.A.
West Virginia	72	2,300	2,600	N.A.	N.A.
Virginia	73	2,300	2,600	N.A.	N.A.
Alaska					
North Slope	80	N.A.	N.A.	N.A.	N.A.
Cook Inlet	81	N.A.	N.A.	N.A.	N.A.

N.A. = not applicable.

Note:

Direct annual operating expense, including waterflooding, in- eludes expenditures for operating producing wells and operating a water injection system. These operating expenditures include the normal daily operating expense, surface repair and maintenance ex- pense, and subsurface repair; maintenance and services. These are average expenditures per producttin we//, and include the expend- itures of operating an injection system,

Table B-35
Incremental Injection Operating and Maintenance Cost*

(dollars for injection well per year)

State/district	Geographic unit	Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	1o,ooo-15,000'
California					
East Central	1	7,700	6,900	11,600	13,200
Central Coast	2	7,700	6,900	11,600	13,200
South	3	7,700	6,900	11,600	13,200
Offshore	4	40,000	40,000	50,000	50,000
<=200'wD	90	40,000	40,000	50,000	50,000
201-400'WD	91	40,000	56,000	56,000	56,000
401 -800'WD	92	40,000	48,000	60,000	60,000
>800'WD	93	40,000	56,000	70,000	70,000
Louisiana					
North	5	6,600	9,300	11,000	11,300
South	6	6,000	8,100	10,100	10,600
Offshore	7	40,000	40,000	50,000	50,000
<= 200'WD	95	40,000	40,000	50,000	50,000
201 -400'WD	96	40,000	56,000	56,000	56,000
401 -800'WD	97	40,000	48,000	60,000	60,000
>=800'WD	98	40,000	56,000	70,000	70,000
Texas					
1	8	6,600	9,300	11,000	11,300
2	9	6,600	9,300	11,000	11,300
3	10	6,600	9,300	11,000	11,300
4	11	6,600	9,300	11,000	11,300
5	12	6,600	9,300	11,000	11,300
6	13	6,600	9,300	11,000	11,300
7B"	14	5,400	5,800	7,800	8,600
7C	15	5,400	5,800	7,800	8,600
8	16	5,400	5,800	7,800	8,600
8 A	17	5,400	5,800	7,800	8,600
9	18	5,400	5,800	7,800	8,600
lo	19	6,700	7,400	10,300	12,000
Offshore	20	40,000	40,000	50,000	50,000
<=200'wD	95	40,000	40,000	50,000	50,000
201-400'WD	96	45,000	45,000	56,000	56,000
401-800'WD	97	48,000	48,000	60,000	60,000
>=800'WD	98	56,000	56,000	70,000	70,000

N.A. = not applicable.

Table B-35-Cent.

State/district	Geographic unit	Depth category 0-2,500'	2,500-5,000'	5,000-10,000'	10,000-15,000'
New Mexico					
East	23	5,400	5,800	7,800	8,600
West	24	5,800	9,600	17,000	27,900
Oklahoma	25	6,700	7,400	10,300	12,000
Kansas					
West	30	6,700	7,400	10,300	12,000
East	31	6,700	7,400	10,300	12,000
Arkansas					
North	32	6,700	7,400	10,300	12,000
South	33	6,600	9,300	11,000	11,300
Missouri	34	6,700	7,400	10,300	12,000
Nebraska					
Central	35	6,700	7,400	10,300	12,000
West	36	5,800	9,600	17,000	27,900
Mississippi					
Hi Sulphur	40	10,000	14,000	16,400	18,000
Lo Sulphur	41	6,600	9,300	11,000	11,300
Alabama					
Hi Sulphur	42	10,000	14,000	16,400	18,000
Lo Sulphur	43	6,600	9,300	11,000	11,300
Florida					
Hi Sulphur	44	10,000	14,000	16,400	18,000
Lo Sulphur	45	6,600	9,300	11,000	11,300
Colorado	50	5,800	9,600	17,000	27,900
Utah	53	5,800	9,600	17,000	27,900
Wyoming	55	5,800	9,600	17,000	27,900
Montana	57	5,800	9,600	17,000	27,900
North Dakota	58	5,800	9,600	17,000	27,900
South Dakota	59	5,800	9,600	17,000	27,900
Illinois	60	4,000	4,400	6,200	7,200
Indiana	61	4,000	4,400	6,200	7,200
Ohio					
West	62	4,000	4,400	6,200	7,200
East	63	1,600	1,800	N,A.	N.A.
Kentucky					
West	64	4,000	4,400	N.A.	N.A.
East	65	1,600	1,800	N.A.	N.A.
Tennessee					
West	66	4,000	4,400	N.A.	N.A.
East	67	1,600	1,800	N.A.	N.A.
Pennsylvania	70	1,600	1,800	N.A.	N.A.
New York	71	1,600	1,800	N.A.	N.A.
West Virginia	72	1,600	1,800	N.A.	N.A.
Virginia	73	1,600	1,800	N.A.	N.A.
Alaska					
North Slope	80	N.A.	N,A.	N.A.	N.A.
Cook inlet	81	N.A.	N.A.	N.A.	N.A.

N.A. = not applicable.

Note:
Direct annual operating expense, including waterflooding, ineludes expenditures for operatlng producIng 011 wells and operating a water injection system, These operating expenditures Include the normal daily operating expense, surface repair and malntenanceexpense, and subsurface repair; maintenance and services These are average expenditures *perproduc(iorrwel~* and include the expend-Itures of operating an injection system,

Table B-36
State and Local Production Taxes

Includes Severance, Ad Valorem, and Other Local Taxes.

State/district	Geographic unit	Tax rate
California	1-4	0.080
Louisiana	5-7	0.129
Texas	8-19	0.082
New Mexico	23-24	0.090
Oklahoma	25	0.071
Kansas	30-31	0.050
Arkansas	32-33	0.060
Missouri	34	0.050
Nebraska	35-36	0.046
Mississippi	40-41	0.060
Alabama	42-43	0.061
Florida	44-45	0.050
Colorado	50	0.100
Utah	53	0.050
Wyoming	55	0.100
Montana	57	0.050
North Dakota	58	0.050
South Dakota	59	0.000
Illinois	60	0.020
Indiana	61	0.050
Ohio	62-63	0.050
Kentucky	64-65	0.050
Tennessee	66-67	0.050
Michigan	69	0.050
Pennsylvania	70	0.050
New York	71	0.050
West Virginia	72	0.050
Virginia	73	0.050
Alaska	80-81	0.080

Source: State tax records.

Table B-37
State Income Taxes

State Income Tax Rates for Corporations.

State/District	Geographic unit	Tax Rated
California	1-4	0.09
Louisiana	5-7	0.04
Texas	8-19	—
New Mexico	23-24	0.03
Oklahoma	25	0.04
Kansas	30-31	0.04
Arkansas	32-33	0.05
Missouri	34	0.05
Nebraska	35-36	0.05
Mississippi	40-41	0.03
Alabama	42-43	0.05
Florida	44-45	0.05
Colorado	50	0.05
'Utah	53	0.04
Wyoming	55	0.05
Montana	57	—
North Dakota	58	0.06
South Dakota	59	0.04
Illinois	60	—
Indiana	61	0.05
Ohio	62-63	0.05
Kentucky	64-65	0.05
Tennessee	66-67	0.05
Michigan	69	0.05
Pennsylvania	70	0.05
New York	71	0.10
West Virginia	72	0.05
Virginia	73	0.05
Alaska	80-81	0.05

'Percent of value of gross production, paid in year incurred.

Source: Local and State tax records verified by production company data,

Offshore Costs

Basic offshore development and operating costs were placed in one of two categories, depending on whether the costs varied or not with water depth. They were derived from U.S. Bureau of Mines data and a Lewin and Associates, Inc., study for OTA. All costs were updated to mid-1976 using similar inflation indices as apiied for the onshore cost models.

Costs That Do Not Vary With Water Depth

Three cost items within basic development and operating costs, while varying by reservoir depth, are not materially affected by water depth. These are:

- well, lease, and field equipment costs for producing wells;
- New injection equipment for injection wells;and
- Well workover and conversion costs.

These cost data are presented in table B-38.

Air costs (for injection) were set at the same value as in the in situ combustion cost model.

Table B-38
Offshore Costs That Do Not Vary by Water Depth

(costs in dollars)

Activity	Reservoir depth categories			
	0-2,500'	2,400-5,000'	5,000-1 0,000'	10,000-1 5,000'
Well, lease, and field equipment costs per production well	300,000	300,000	300,000	300,000
New injection equipment per injection well	100,000	100,000	150,000	150,000
Well workover and conversion costs per well.	150,000	150,000	170,000	225,000

Costs That Vary With Water Depth

The remaining three offshore development and operating costs do vary by water depth. These are:

- Drilling and completion costs,
- Basic operating and maintenance costs,
- Incremental injection, operating, and maintenance costs.

These are presented on table B-39. The bases of the drilling and completion costs are shown in table B-40.-This table gives a breakdown of the drilling and completion costs by water depth.

Table B-39
Offshore Costs That Vary by Water Depth

(costs in dollars)

Activity	Reservoir depth categories			
	0-2,500"	2,500-5,000'	5,000-1 00,000'	100,000-1 50,000'
Drilling and completion costs per foot per well, by water depth:				
<200 ft..	112.32	96.87	101.44	97.87
201-400 ft.	112.32	130.64	121.49	111.24
401-800 ft.	112.32	225.82	178.00	148.92
>800 ft..	112.32	522.30	354.04	266.27
Basic operating and maintenance costs per well per year, by water depth:				
<200 ft..	60,000	**60,000**	75,000	75,000
201-400 ft.	60,000	**69,000**	84,000	84,000
401-800 ft.	60,000	**72,000**	90,000	90,000
>800 ft..	60,000	**84,000**	105,000	105,000
Incremental injection operating and maintenance costs per injection well per year, by water depth:				
<200 ft..	40,000	40,000	50,000	50,000
201-400 ft.	40,000	46,000	56,000	56,000
401-800 ft.	40,000	48,000	60,000	60,000
>800 ft..	40,000	56,000	70,000	70,000

"No reservoirs in this depth category-average figure used in water depth categories.

Tabie B-40
Driiiing and Completion Cost Bases

(costs in dollars)

	Depth category		
	2,500-5,000	5.000-10.000	10,000-15,000
A. 0-200' WATER DEPTH (Mean = 100' WD)			
(1) Av. Cost/ft. (Incl. av. platform), JAS, updated	**110.32**	**109.42**	103.20
(2) X wghtd. av. depth (JAS)	**4,760**	**8,000**	12,000
(3) = Av. total cost/well.	**524,020**	**875,360**	1,238,400
(4) Av. platform cost (assume 18-slot, 1/2 at 100', 1/2 at 300' WD)	7,000,000	7,000,000	7,000,000
(5) / Av. No. wells (Assume 18) = Av. platform cost/well.	388,900	388,900	388,900
(6) Line (3) – Line (5) = Av. Drilling and completion (D&C) costs per well ... ,	135,120	486,460	849,500
(7) Line (6) / (2) = Av. Drilling cost/ft. (ex. platform)	28.45	60.81	70.79
(8) Av. platform for depth (1 2-slot) @ $3.9 million / 12 slots = Platform cost/well.	325,000	325,000	325,000
(9) Line (8) / Line (2) = Av. Platform cost/f t..	68.42	40.63	27.08
(lo) Line (9) + Line (7) "= Av. D&C cost incl. platform	96.87	101.44	97.87
B. 201-400' WATER DEPTH (Mean = 300' WD)			
Line (1) – (6) – See Section A			
Line (7) Average drilling cost/ft. (ex. platform)	28.45	60.81	70.79
,Line (8) Av. platform for depth (half 18, half 24, 1/2 @ $8.7 million / 18 dots 1/2@ $11./million / 24 slots	485,400	485,400	485,400
(9) Line (8) / Line (2) (wght. av. depth) = Av. platform cost/ft.	102.19	60.68	40.45
(lo) Line (9) + Line (7) = Av. D&C cost incl. platform	130.64	121.49	111.24
C. 401-800' WATER DEPTH (Mean = 600' WD)			
Lines (1) – (6) – See Section A			
Line (7) Av. drilling cost/ft. (ex. platform).	28.45	60.81	70.79
Line (8) Av. platform. @ $22.5 million / 24 slots	937,500	937,500	937,500
(9) Line (8) / (2) – Av. platform. cost/ft. ,	197.37	117.19	78.13
(lo) Av. D&C costs incl. platform	225.82	178.00	148.92
D. Greater Than 800' WATER DEPTH (Mean = 1,000' WD)			
Lines (1) – (6) – See Section A			
Line (7) Av. drilling cost/ft (ex. platform)	28.45	60.81	70.79
Line (8) Av. platform @ $56.3mm / 24 slots ... ,	2,345,800	2,345,800	2,345,800
(9) Line (8) / Line (2)	493.85	293.23	195.48
(lo) Av. D&C costs incl. platform.	522.30	354.04	266.27

Appendix B
Footnotes

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[16] *Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 98.

[17] *Enhanced Oil Recovery,* National Petroleum Council, December 1976, p. 97.

[18] H.H. Danielson and W.T. Paynter, *Bradford Sand Micellar-Polymer Flood, Bradford, Pa.,* Third ERDA Symposium on Enhanced Oil, Gas Recovery, and Improved Drilling Methods, Aug. 30-Sept. 1, 1977, p. A-5.

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Appendix C

Legal Aspects of Enhanced Oil Recovery

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LIST OF TABLES

Introduction

The purpose of this appendix is to provide details of legal issues associated with enhanced oil recovery (EOR). The term "enhanced oil recovery" refers to any method of oil production in which gases and/or liquids are injected into the reservoir to maintain or increase the energy of the reservoir or react chemically with the oil to improve recovery. Thus, enhanced recovery encompasses the techniques referred to as pressure maintenance, secondary recovery, and tertiary recovery. The reason for the broader use of the term in this section is the fact that the legal problems are much the same for any technique of oil recovery beyond primary methods. There has been relatively little commercial application of tertiary recovery techniques, so no body of case law specifically regarding it has developed; the law in this area must draw upon experience in pressure maintenance and established methods of secondary recovery. Secondly, the regulatory schemes of most States do not distinguish among the different types of recovery beyond primary methods. Distinctions among the various techniques of enhancing recovery will be made only when necessary.

To assess fully how the law encourages, hinders, limits, or prevents employment of EOR techniques, it would be necessary to examine in detail each reservoir in which such techniques are or might be used. Such was beyond the scope of this assessment. The approach used here identifies existing or possible constraints without attempting to suggest how much more or less oil could be produced with or without particular constraints. Statutes, regulations, and rules of law affecting EOR are described in a general way without discussing their applicability to particular fields, not only because the complex interplay among various factors makes specific judgments about individual fields very difficult, but also because the law on some important points is undecided or very uncertain in most jurisdictions. The views of producers and State regulatory personnel are discussed when appropriate, as are the observations and comments of legal authorities on particular subjects.

Unitization: Voluntary and Compulsory

Basic Principles of Oil and Gas Law

The most efficient means of utilizing EOR techniques is generally to treat the entire oil reservoir as though it were a single producing mechanism or entity. There is no problem with this when the operator of the field owns the leasehold or mineral interest throughout the entire reservoir; in this case obtaining the consent of any other owner of an interest in the minerals in order to undertake enhanced recovery operations is unnecessary. However, where there are other owners of interests in the same field, obtaining consent may be necessary before fieldwide operations may be commenced. In order to better understand the problems that may be involved in securing this consent or cooperation, it would be useful to describe briefly the basic legal framework in which oil and gas operations take place.

The right to develop subsurface minerals in the United States belongs originally with the ownership of the surface. The different States which have fugacious minerals within their jurisdiction are divided as to whether such minerals are owned in place or whether the surface owner owns only a right to produce the minerals that may lie beneath his land. For present purposes the distinction has little significance. It is sufficient to point out that the ownership of the surface carries with it, as a normal incident of ownership, the right to develop the minerals beneath the surface.

The owner of the land may, however, sever the ownership of the surface from ownership of the minerals. He may convey away all or a part of his interest in the development of the minerals and in so doing may create a variety of estates, Thus, for example, the owner of a 640-acre tract of land (one section) may convey to another person (or company) all of the mineral under the land absolutely. Or he may convey to that person a one-half interest, or some other percentage of interest, in all of the minerals beneath the section. Or again, he may convey to another all or a part of the minerals beneath a specific 40-acre tract carved out of the section. Each of these interests would be described as a mineral interest. Unless otherwise restricted by the instrument creating it, the ownership of a mineral interest carries with it the right to explore for, develop, and produce the minerals beneath the land.

Another type of interest that may be created by a landowner or mineral interest owner is a leasehold interest. The owner of the minerals is normally unable to undertake the development of the minerals himself because of the great expense and risk of drilling. in order to obtain development without entirely giving up his interest in the minerals he will lease the right to explore for and produce the minerals to another. In return the lessee will pay a sum **of money as a bonus for the granting of the lease and** will promise to pay the lessor a royalty, generally one-eighth, on all oil and gas produced. Typically, the lessee will be granted the lease for a period of 1 to 5 years (the primary term), subject to an obligation to pay delay rentals if a well is not drilled in the first year, and so long thereafter as oil and gas or either of them is produced from the leased land (the secondary term). In addition to a royalty interest of one-eighth, the lessor will retain a possibility of reverter; that is, if the delay rentals are not paid on time or production is not obtained within the primary term, or if production ceases on anything other than a temporary basis in the secondary term, the interest leased reverts automatically back to the lessor.[1] When the interest reverts, the lessor may then enter into a new lease with another party or may undertake or continue development himself.

The power to grant leases is often described as the executive right, and a mineral interest may be created with the executive power being granted to another person. To illustrate, A as father of a family and owner of a tract of land may give by will to child B a one-quarter undivided interest in the minerals in the land, to child C a one-quarter undivided interest in the minerals, and to child D an undivided one-half interest in the minerals together with the executive right to lease all the minerals. This would mean that only D could execute leases for the development of the minerals. D would be under a duty to exercise the right with the utmost good faith and fair dealing. Each child would receive a share of the proceeds from the development of the land (i.e., a share of the bonus, rental, and royalties), but it would be upon the terms established by D in his dealings with the lessee in granting the lease. Under well-established principles of law, D must exercise this right in such a manner that it does not unfairly advantage him nor unfairly disadvantage the owners of the nonexecutive interests, children B and C. The duties owed by lessees to lessors and royalty owners, and the duties owed by executive right owners to nonexecutive right owners, can impact upon the unitization of mineral lands for enhanced recovery purposes. This is because the lessee or executive right owner must consider not only his own interest but the interests of those to whom he owes a duty in entering into agreements for unitized operations.

In addition to duties, the lessee has certain rights arising from a lease that have significance for EOR, These rights may be express or they may be implied. They are express if the parties to the lease or deed have specifically recognized or granted them in the conveyance. For example, the parties may explicitly provide that the lessee shall have the right to conduct certain activities such as laying pipelines on the surface of the land without being liable in damages. The rights are implied if the parties have not expressly provided for them, but the law recognizes that they exist by virtue of the nature of the transaction between or among the parties. Thus, the lessor and lessee may fail to provide expressly that the lessee has the right to come upon the leased land or to build a road for carrying equipment to a drill site. The law will imply that the lessee has the right to do this when it would not be reasonably possible to develop the minerals without undertaking such activity.

NOTE: All references to footnotes in this appendix appear on page 230.

Briefly stated, the law recognizes that even without express grant, the lessee has the right to use such methods and so much of the surface as may be reasonably necessary to effectuate the purposes of the lease, having due regard for the rights of the owner of the surface estate. It is well established that the lessee does have such rights.[2] However, the question may arise whether such rights are limited to those activities, either surface or subsurface, that could be contemplated at the time of the execution of the lease or deed. The same answer should be given for the more exotic methods of enhanced recovery that the courts have given for traditional waterflood operations when these were not provided for in the lease. In allowing a waterflood project to go forward, the Appellate Court of Illinois stated in a 1950 case:[3]

> The mere fact that this method of production is modern is no, reason to prevent its use by a rule of law. It is true the contract of the parties does not specifically provide for this process, but neither does it specify any other process. The contract being silent as to methods of production, it must be presumed to permit any method reasonably designed to accomplish the purpose of the lease: the recovery of the oil and the payment of royalty. The court would violate fundamental principles of conservation to insert by implication a provision that lessee is limited to production of such oil as can be obtained by old fashioned means, or by so-called "primary operations."

The same rationale would apply to more modern methods of enhanced recovery, even though these methods might involve somewhat greater use of the surface and different types of injection substances.

A closely related question is the extent to which the lessee or mineral grantee may use water located on the property for purposes of enhanced recovery. This has been an area of some controversy and will be taken up in a later section because it involves matters going beyond lease and deed relationships.

Finally, it should be noted that some authorities have contended that there is not only a right for the lessee to unitize or to undertake enhanced recovery activities but also a duty to do so. The implied covenant of reasonable development is well recognized in oil and gas law.[5] It is to the effect that the lessee has the duty, where the existence of oil in paying quantities is made apparent, to continue the development of the property and put down as many wells as may be reasonably necessary to secure the oil for the common advantage of both the lessor and lessee. The lessee is expected to act as a prudent operator would in the same circumstances. With increasing experience with enhanced recovery, it can be argued that a prudent operator would, when it appears profitable, undertake enhanced recovery operations. Thus, where the lessee is reluctant to do so, the lessor might be able to require the lessee to engage in such operations or give up the lease. Probably because of the difficulty or proof of profitability and feasibility for a particular reservoir there has been little litigation on the point. However, one court has noted that there is "respectable authority to the effect that there is an implied covenant in oil and gas leases that a lessee should resort to a secondary recovery method shown to be practical and presumably profitable as a means of getting additional return from the lease."[6] In another case the court similarly declared that "the Lessee not only had a right, but had a duty to waterflood the premises for the recovery of oil for the benefit of the mineral owners should it be determined by a prudent operator to be profitable."[7] Lessors then could encourage enhanced recovery by making demands on their lessees.

The Rule of Capture

One of the most important and fundamental principles of oil and gas law is the rule of capture. It stems from the fact that oil and gas are fugacious minerals; that is, they have the property of being able to move about within the reservoir in which they are found. Followed by every jurisdiction within the United States, the rule of capture is to the effect that a landowner may produce oil or gas from a well located on his land even **if the oil or gas was originally** in place under the surface of another landowner, so long as the producer does not physically trespass on the other's land. The other landowner's recourse against drainage of the petroleum under his property is the rule of capture itself: he may himself drill a well and produce the hydrocarbons and thereby prevent their migration to the property of another.

The problem with the rule of capture has been that it encouraged too rapid development of oil and gas. A landowner or his lessee must drill to recover the oil and gas beneath his property or they will be recovered by a neighbor and lost forever to the landowner. The problem became especially acute when there were many small parcels of land over a single reservoir. Overdrilling resulted from the rush to recover the oil and gas before it is produced by another, and the overdrilling caused the natural pressure of the reservoir to be depleted too rapidly, thereby leaving oil in the ground that could have been recovered with sounder engineering practices.

Conservation Regulation: Well Spacing and Prorationing

Recognizing that the rule of capture was resulting in great loss of resources and excessive production of oil, the producing States began enacting legislation to modify it in the mid-1930's. To prevent excessive drilling the States authorized regulatory commissions to promulgate well spacing rules, limiting the number of wells that can be drilled in a given area.[8] For example, the Texas Railroad Commission in Rule 37 allows, as a general rule, only one well every 40 acres. In general, in each major producing State special spacing rules may be established for each different field and exceptions may be granted upon showing of good cause.[9]

Well spacing alone would not be enough to overcome the problem of excessive production, for a producer might continue to produce at an excessive rate in such a manner as to deplete prematurely the natural drive of the reservoir or in quantities that the market could not absorb. To overcome this, the States established well allowable; that is, they set a limit to the amount of oil or gas that could be produced in any 1 month from a field or well. This is also known as prorationing of production. Well allowable have been set in two different ways. The first is known as MER regulation: allowable are established for production at the maximum (or most) efficient rate of recovery.[10] The maximum efficient rate for a reservoir is established before a regulatory commission by expert testimony as to what would injure the reservoir and produce waste. This rate is not constant, but changes with the age of the field, and is not generally capable of exact computation. The second basic type of regulation of well allowable is known as market demand regulation: MER remains as the maximum rate of production, but the rate actually allowed may be lowered to a level which the commission believes is the maximum amount of production that the market will bear for that month. This is generally established by the commission after it has heard from producers as to the amount that they would like to produce. The commission may wish to give special incentives to certain types of activity and will establish allowable with more being allowed for one type of production than another. To encourage drilling the commission may allow new wells to produce at the reservoir's maximum efficient rate of recovery, while older fields must produce at a lower rate, so that total production from the State does not exceed the anticipated reasonable market demand. With the exception of Texas in recent months, the market-demand type States have set allowable for wells at the maximum efficient rate for every month since 1973.

Pooling and Unitization

Pooling

State regulation of well spacing and production can cause significant problems that must be overcome by the producers themselves or by additional regulations. If there can be only one well within a given area and there are several parcels of land with different owners, some determination must be made as to who will be able to drill a well and who will be entitled to receive proceeds from the production from the well. The integration of the various interests within the area for the purpose of creating a drilling unit for development of a well and sharing of the proceeds is known as pooling.[11] It may be voluntary if the interest owners come together and agree by contract upon the drilling and sharing of the production from the unit well. It may be compulsory if the State forces interest owners to participate on a basis established by the State regulatory commission when there is an applicant who wishes to drill and some of the interest owners are unwilling or unable to reach an agreement upon sharing of development cost and/or production. Pooling then refers to the bringing together of the different interests in a given area so as to integrate the acreage necessary for establishing a drilling unit, and it may be voluntary or compulsory. Virtually all States with production of oil or gas have compulsory pooling statutes which can apply when the parties are unable to reach an agreement for voluntary pooling.

Unitization

Pooling does not result in the reservoir being treated as a single entity; it does reduce the number of competitive properties within a reservoir, but there will still be competitive operations among the enlarged units to the extent permitted by law.

The mo efficient and productive method of producing oil may be achieved only if the entire reservoir can be treated as a single producing mechanism, i.e., when the reservoir may be operated without regard to property lines. This becomes possible when one owner or lessee owns or leases the rights to the entire reservoir or when all the interest holders in the reservoir unite for a cooperative plan of development. When owners of interest do come together for such a purpose for development of most or all of a reservoir this is referred to as unitization.[12] It is much the same in principle as pooling, for it is an integration of interests, and as with pooling it may be voluntary or compulsory; but it is much more complex than pooling in attempting to reach agreement on cost and production sharing, and the statutory schemes for compulsory unitization are more difficult to comply with than for compulsory pooling. Unitization of most or all of a reservoir is usually very desirable or is required in order for there to be application of enhanced recovery techniques to a reservoir.

Voluntary Unitization

Time of Unitization

Ideally, unitization should take place at the first discovery of a reservoir capable of producing hydrocarbons in commercial quantities, or even during the exploration phase. However, this is not feasible for it is only through drilling a number of wells—with production from the first well and subsequent wells going on—that the parameters of the reservoir can be established. Only when the characteristics and the limits of the field are generally known will the parties with an interest in the field be willing to unitize. Prior to that time they would possibly agree to share production of petroleum from under their lands with parties who had no petroleum under theirs. It is only after extensive drilling that it is possible to make an intelligent assessment of the basis upon which participation in the production from the reservoir should be established. Because of this, unitization has generally come about after the primary drive of the reservoir has begun to decline measurably, and it has appeared to interest owners that it may be desirable to unitize in order to undertake operations to enhance recovery beyond the field's life by primary methods of recovery.

Who May Unitize

Once it is clear to some of the parties with interest in the reservoir that unitization is desirable, there is the problem of determining who may undertake the unitization. Without express authorization, either in the lease or by separate agreement, the lessee is not able to unitize the interest of the royalty owners to whom it must pay royalty. The lessee may unitize its own interest—that is, agree to share with another the seven-eighths of production that it normally owns-but without the consent of the royalty owner(s) it may not agree with others to treat the potential production attributable to the royalty interest from the leased acreage on any basis other than the one-eighth (or other fraction) going to the royalty owners. Some leases will contain authority to the lessee to enter into fieldwide unitization agreements on behalf of the lessor, but the noted authority on unitization, Raymond M. Myers, has stated that "[d]ue to the complexity of the modern unitization agreement, a clause authorizing the unitization of the entire field, or a substantial portion thereof, has not generally appeared in oil and gas leases. Lessors have not generally been willing to grant such broad powers to lessees as such authorization would entail."[13] Even with authorization the prudent lessee will gain the express consent of the lessor. Whether the executive right owner may unitize, or authorize the lessee to unitize, the interests of the nonexecutive interests are open to question in most jurisdictions because there has been little litigation on the point.[14] The rule in Texas is that the executive does not have this power; the rule in Louisiana is that he does. In general, it may be stated that it is desirable or necessary to get the express consent of each royalty owner in order to effectuate voluntary unitization.

Reaching agreement on unitization is a complex and drawn out undertaking often involving dozens or hundreds of parties. To understand this and to place in perspective the State's role in unitization of property for purposes of enhanced recovery, it would be useful to examine in some detail the manner in which unitization is agreed upon.

Negotiation of Unit Agreement

The integration of separate and often divergent ownership interests necessarily requires careful negotiation which may extend over several years. The best way to describe effectively the nature of and the problems inherent in the voluntary unitization process is to relate the actual experiences of companies. The discussion of the process which follows draws in part from the case history of the McComb Field Unit in Pike County, Miss.,[15] and from the Seeligson Field Unit in Jim Wells and Kleberg Counties, Tex.[16]

In the evolution of a voluntary unit, each negotiation has its own unique problems and circumstances which affect the ability of principals to achieve fieldwide unitization in a reasonable period of time. Even though no two unit operations are alike in every respect, there appear to be four general stages in the negotiation process:

- Initiation of joint organization,
- planning period,
- Determination of participation formula, and
- Drafting and approval of agreements.

The remainder of this appendix is concerned with the discussion of these four stages and their integration during the formation of a voluntary unit operation.

Initiation of Joint Organization.—The first stage in the unitization process involves the initiation of a joint organization of operating interests who recognize the necessity for a fieldwide unit in order to increase the ultimate recovery of oil and gas. A major operator or leaseowner will usually initiate the process by informing other ownership interests that a unit operation may be desirable for undertaking a particular fieldwide project for enhanced recovery.

For example, shortly after primary production was undertaken in the McComb Field, the coowner of the discovery well and major leaseowner (Sun Oil Co.) began accumulating additional technical information and data with respect to the parameters of the reservoir. The data revealed an alarming condition in the reservoir-a rapid decline in reservoir pressure which could bring premature abandonment with a tremendous loss in recoverable oil reserves. It was apparent that a fieldwide gas- or water-pressure maintenance project was needed to arrest the deterioration of the reservoir and increase ultimate recovery. This pressure maintenance project required fieldwide unitization which, in turn, required full-field participation. A meeting was held in February 1960, at the urging of the Sun Oil Co., and the preliminary evidence was presented to 70 operating interests.

The initial stage of the Seeligson Field Unit negotiation involved a different set of circumstances. Numerous tracts in the field contained gas, oil, or both. A gas-unit operation had existed since 1948, and the current problem was to unitize both oil and gas under one set of agreements. In particular, the proposed new unit operation was primarily concerned with the increased oil production that would result both from the transfer of allowable and from a pressure maintenance program. Thus, operators having had previous negotiation experience could facilitate matters with the negotiation of a new unit agreement. A meeting was called in February 1952, to discuss just such a possibility.

In specific terms, the initiation of a joint organization entails three primary steps. First, after a discussion of the preliminary technical information and data, operators reach a general agreement on the "problem" giving rise to the necessity for a unit operation. Once the problem is identified and clearly defined, then possible solutions for consideration can be enumerated.

During this initial step and the steps that follow, obstacles or delays may be encountered when the joint organization involves a large number of participants. If an inordinate number of operators have had little or no first-hand unitization experience or technical knowledge of the proposed solution projects, or where misunderstandings or suspicions develop, then unnecessary delays may occur in the formation of a joint organization.

The next step encompasses the acceptance of the articles of organization which establish the organizational framework and procedural rules for the initial operating committee (Unitization Committee) and ancillary subcommittees. The Unitization Committee is a temporary body charged with supervising the collection of extensive information and data germane to the formation of the unit as well as presiding over the general negotiations prior to the approval of the unitization agreements. The composition of the Unitization Committee and the various subcommittees requires an acceptable representation of major and independent leaseowners. This will provide a major step in spreading the responsibilities for unit formation among all parties interested in the fieldwide operation and also to minimize the potential misconceptions and mistrust which may develop among operating interests.

The final step in the initiation of the joint organization involves financing of the temporary organizational structure. Rather than the major leaseowner bearing the full costs, financial responsibility is generally shared according to some acceptable method of cost allocation. In the McComb Field, expenses were shared jointly on a well basis.

Generally, the initial stage in the negotiation process does not require more than a few meetings to finalize the temporary procedures for the joint organization. Given sufficient preliminary evidence, most operators recognize the necessity for careful planning and thorough investigation in the development of a fieldwide unitization operation.

Planning Period.—The second stage in the negotiation process centers around the planning period, which culminates in the unitization agreements. This stage involves the activities of various subcommittees who are responsible for collecting extensive data and information and for developing the details for the unit operation. In general, there are four main areas of concern: technical, legal, land, and accounting.

Technical. The gathering of technical data and information is the joint responsibility of a Geologic Subcommittee and an Engineering Subcommittee.

The Geologic Subcommittee prepares the various geological maps and accumulates field data necessary for study by the joint organization. In particular, their duties center around ascertaining the extent of the reservoir in terms of its size, shape, and geological limits. Aside from the extent of the reservoir, this subcommittee is concerned with mapping the thickness, structural position, and extent of the "productive" pay of the reservoir. information gathered by the Geologic Subcommittee is made available to the Engineering Subcommittee for the evaluation of the various projects under consideration and to operators for determining oil recovery factors under various operating conditions. This is an important phase in the negotiation process, due primarily to the fact that the technical feasibility and economic profitability of various projects are evaluated and recommendations submitted to the Unitization Committee for consideration by the joint organization.

The task of this subcommittee is best illustrated by the Engineering Subcommittee of the McComb Field Unit. As the reservoir data were assembled, oil recovery factors were derived under five operating conditions:

1. Primary recovery (18 percent recovery factor);
2. Injection of produced gas (increase ultimate recovery to 23 percent);
3. Gas pressure maintenance (increase ultimate recovery to 30 percent);
4. Water pressure maintenance (increase ultimate recovery to 39 percent); and
5. High-pressure miscible gas injection (increase ultimate recovery to 54 percent).

Based on these oil recovery factors the water pressure maintenance and high--pressure miscible gas injection projects were selected for further feasibility analysis, where the advantages and disadvantages of each project were then evaluated.

While the miscible gas injection project offered the highest oil recovery factor, its disadvantages were extremely critical: the supply of extraneous gas was available but at prohibitive costs; the process was relatively unproven in terms of general industry-wide use; there existed possible corrosion problems as well as contamination of reservoir gas; the project would require a long period of time to implement and would require expensive plant expansion; and, finally, there was a greater risk of failure. Furthermore, the rate of return for the capital investment was calculated to be 31 percent per year.

The advantages of the waterflood project were numerous: ample supply of salt water in the reservoir; relatively lower initial investment expenditure; proven method of recovery with a low risk of failure; minimum time required to implement the project; and undertaking the waterflood project did not preclude the adoption of miscible injection at a later date. In addition, the capital investment **was** calculated to earn a 72-percent annual rate of return. Finally, the primary disadvantage of waterflooding was the relatively lower oil recovery factor.

After careful consideration of the economic feasibility and advantages and disadvantages of each project, the technical subcommittees recommended the selection of the water pressure maintenance project for the McComb Field Unit Operation. Aside from the higher rate of return on capital investment, the major factors which led to the waterflood selection involved the minimum risk of failure and the short implementation time associated with the project. These factors were extremely crucial, given the rapidly declining pressure in the reservoir.

Once the extensive geologic data and engineering information are accumulated and project recommendations set forth, the final task of the technical subcommittees involves a preliminary determination of the participation formula whereby lessors and lessees share in unit production. The relevant aspects of the participation formula will be considered later in this appendix, but it should be noted that the time frame for the work of the technical subcommittees can vary considerably. For the Seeligson Field Unit, the Unitization Committee appointed working interest representatives to the technical subcommittees in February 1952, and the Engineering Subcommittee offered recommendations (with respect to the most feasible project and the tentative participation formula) to a meeting of operators in January 1955. Hence, nearly 3 years had elapsed during which time the major technical groundwork for the unit operation was completed. For the McComb Field Unit, the work of the technical subcommittees was initiated in February 1960 and recommendations and findings were presented approximately 9 months later,

Therefore, the time required for collecting and evaluating detailed technical information and the subsequent recommendations which follow can consume from several months to a few years during the unitization process, In general, a number of factors such as the geological complexity of the reservoir, the number of development wells necessary for assessing the characteristics of the reservoir, the nature of the unitization projects under consideration, and whether the field is in the development phase or production phase may all contribute to the length of time required for the planning period.

Legal. During the planning of a fieldwide unit, the Legal Subcommittee handles the legal aspects associated with the unitization process and the subsequent negotiation and drafting of agreements. This charge necessarily requires an understanding of the desired goal of the unit operation and the manner in which this goal impacts on land titles, overriding royalties, operating leases, and other factors. In particular, the Legal Subcommittee determines whether there are any legal restrictions or problems related to property rights and the achievement of the desired goal of the unit. It is incumbent upon the Legal Subcommittee to advise lessees that they continue their lease obligations to lessors. The Legal Subcommittee must ensure that the implied as well as expressed obligations of lessees are satisfied during the negotiation and execution of a unitization agreement.

The Legai Subcommittee is also responsible for submitting to the appropriate State regulatory agency all requisite documents and instruments which pertain to the unit operation. Such procedures will be discussed in a subsequent section.

Land. The Land Subcommittee is generally comprised of land agents whose function it is to identify royalty owners and leaseholders for the purpose of communicating information to the various interest owners and facilitating the acceptance of the unitization agreements. While operating interests may be readily identifiable, a widespread distribution of royalty interests can make the task of the Land Subcommittee difficult and time consuming. Frequently, overriding royalties, various types of working-interest arrangements, and royalty interests involving estates or trusts may add both time and expense to the complexity of forming a unit.

Once the majority, if not all, of the interested parties are identified, the land agents are responsible for conveying to the ownership interests, information with regard to the nature of the unit operation (in terms of the project to be instituted as well as each owner's share **in unit production).** The work of the Land Subcommittee begins in the planning stage of the unitization process and ends with the obtaining of signatures for the unit agreements.

Accounting. The initial concern of the Accounting Subcommittee involves the accounting for expenses incurred prior to the unit agreement. The work performed by the technical subcommittees and, to a lesser extent, the other subcommittees operating during the planning period generates expenditures which must be underwritten by the operating interests. Accounts are maintained by the Accounting Subcommittee and subsequent billings to operators on a predetermined share basis are made for purchases of supplies and field equipment as well as the overhead costs of the temporary joint organization.

The primary charge of the Accounting Subcommittee, however, is to prepare the joint operation accounting procedures which establish the method of accounting and the allocational rules to be used in the unit operation. The accounting procedures appear as an exhibit to the proposed unit agreement and specify the items to be charged to the joint account, the disposition of lease equipment and material, the treatment of inventories, and the method of allocating joint costs and revenues among unit participants.

An important role of the Accounting Subcommittee entails the explanation and, in some cases, the determination of specific tax considerations which impact on ownership interests as well as the general fieldwide operation. For example, tax legislation and tax court interpretations with respect to EOR projects are ever-changing, and the application of future tax law to EOR projects is in a state of uncertainty. Therefore, the tax treatment applied to EOR projects might affect the incentive among participants of a proposed unit operation to engage in a particular EOR project or it could affect the incentive of an individual ownership interest to commit its property rights to the unit operation.

An example where a possible disincentive exists for joining a unit operation can be seen in the Income Tax Reduction Act of 1975, which eliminated the percentage oil-depletion allowance for major companies. However, an exemption to this is provided for independent producers and royalty owners where an independent producer is defined as one whose total retail sales is less than 5 percent of its total sales. When this exemption is applied, the independent producer can apply the. 22-percent oil-depletion allowance to the market value of a maximum 1,800 barrels per day (for 1976, and declines to 1,000 barrels per day by 1980).[17] When confronted with a choice of joining a unit operation which would enhance the producer's recovery of oil above the limit of 1,800 barrels per day and thus lose the exemption, the independent producer would necessarily be concerned with its participation factor in the unitization agreement. If the independent's share of unit production did not compensate for the exemption loss or ensure at least a comparable return for joining the unit, then the negotiations of the unit operation could face an obstacle to the attainment of full field participation. This situation might create costly delays in the unitization process.

Another example can be seen in the questions arising with respect to the tax treatment of costs associated with EOR projects, where costs relevant to the discussion include intangible drilling and development costs (IDC), cost of physical facilities required in the EOR project, and the cost of injected material .18 According to the internal Revenue Code enacted in 1954, an IDC refers to costs (i.e., labor, fuel, transportation, supplies, and other items having no salvage value) associated with installing equipment "incident to and necessary for the drilling of wells and the preparation of wells for production of oil and gas."[19] Hence, the cost of installing injection wells, production wells, water source wells (in the case of waterflooding), and converting production wells to input wells are treated as IDC and subject to the tax option of either expensing these cost items or capitalizing them. The generally accepted accounting practice is to expense IDC, which allows them to be written off in the year that they occur.

The cost of physical facilities (i.e., storage tanks, pipelines and valves, waste-water treatment equipment, etc.) must, by law, be capitalized and depreciated over the expected useful life of the equipment. However, the method of depreciation may impact on the incentive to undertake a particular EOR project. A straight-line method of depreciation (20 percent per year for 5 years) would provide a "quick" writeoff and enable the full cost of the investment expenditure to be recovered in the first 5 years of the equipment's useful life. With the sum-of-year's digits method (over an 11-year period), only 68 percent of the full cost of the equipment would be recovered during the first 5 years. The allowable depreciation is greater for the straight-line method, and use of this method could improve the economic incentive of the EOR program. 20 Furthermore, the tax treatment advice of the Accounting Subcommittee would be extremely valuable at this point in evaluating the feasibility of projects under consideration by the joint organization.

The cost of the injected material may also be a relevant tax consideration. When high-cost materials are injected into a reservoir and a portion of the injected material cannot be recovered from the reservoir, then the total cost of the unrecoverable material can be expensed during the year in which it was injected, or it can be capitalized and depreciated (using the straight-line method) over the life of the reservoir. In addition, "if it can be demonstrated, in any year, that a particular injection project is a failure (i.e., the injection of this material did not benefit production), a loss may be claimed for the undepreciated cost of the injected material."[21] At the margin, these tax options may be an important consideration when choosing among EOR projects which require the use of high-cost injected material.

Determination of Participation Forrnula.-The "participation formula" (share of unit production accruing to the separate ownership interests) is the heart of the unitization agreement. As such, it represents the principal point of contention among the parties negotiating the voluntary formation of a unit operation. According to the noted authority Raymond Myers, "The ideal is that each operator's share of production from the unit shall be in exact proportion to the contribution which he makes to the unit."[22] However, the determination of the "exact proportion" contributed by each operator to unit production is difficult to determine and has led to long and labored negotiations.

In the early days of unitization, participation was based solely on surface area. The criteria was found to be wanting since, as Myers observes, it assumed "uniform qua!ity and thickness throughout the [reservoir] with each tract having beneath it the same amount of reserves per acre. This rarely, if ever, happened."[23] More recently, shares are often determined in direct proportion to the amount of productive acre-feet of pay zone which lies beneath the surface of each tract. However, this determination may be derived only after a series of development wells have ascertained the parameters of the reservoir. The effective procedure which is frequently utilized is to initially establish participation factors on the basis of surface area and preliminary acre-feet of pay zone criteria, then after the commencement of unit production (usually 6 months), the participation factors are adjusted in accordance with more reliable or updated pay zone values.

Based on geologic studies of the McComb Field, it was determined that the average pay zone thickness was approximately 15 feet per acre for each 40-acre tract. This value provided the basis for allocating unit production among the various ownership interests during the initial production phase in which approximately 18 percent oil recovery would occur. In the second phase of the formula, secondary oil reserves were allocated among the unitized interests on the basis of 75-percent credit for net acre-feet of oil zone plus 25-percent credit for the participation factor used in the first phase. This second phase adjustment of participation factors was designed to take into consideration more technical aspects **(actual pay zone) and thereby give some tracts additional credit for their relatively larger contribution to unit production.**

There are a number of obstacles, delays, or disincentives which tend to affect the acceptance of the participation formula as well as the subsequent negotiations in drafting and approving the unitization agreements. A few of these have been previously discussed and others are worth a brief mention.

Some of the ownership interests may be of the opinion that they should have a "fair advantage" with respect to their participation factor. In particular, some parties may contribute more surface acreage to the fieldwide operation or a portion of the unit's plant and equipment (such as injection wells, storage facilities, and the like) may be located on their property. Hence, by virtue of the large surface acreage contribution or operations taking place on their property, these ownership interests may argue for preferential treatment and the adjustment of their proposed participation factor to reflect this "fair advantage." The debate over this issue may create delays in the determination of an acceptable participation formula and, if left unresolved, could have a detrimental effect on the ability of all parties to form a voluntary unit operation.

Pride of property ownership and/or control over individual operations may affect the willingness of an individual ownership interest (royalty as well as operating) to join a unit and commit their property and operational control to joint decisions. When such strong feelings are held (and they may surface with participation factor dissatisfaction), acceptance of the participation formula or general approval of the unitization agreements may be difficult to achieve.

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A final consideration, which might well impact on the incentive for accepting the participation formula and entering a unit operation, involves the effect of FEA regulations. The domestic price of crude oil is controlled at specific levels by FEA. However, the anticipation of future price deregulation might prompt some producers to leave oil in place until the price of oil increases. This could be particularly critical when the producer feels that its return (based on the participation factor) from the joint operation is marginal, at best.

In **general, the acceptance** of the participation formula by operators and royalty owners reflects their satisfaction with the unit operation and its ability to ultimately increase profits while safeguarding property rights. Fieldwide unitization is initiated in order to increase the ultimate recovery of oil and gas while reducing the riskiness and costs associated with individual operations. Through a joint effort, higher rates of return can thus be realized with the retention of ownership interests in the recovery of oil and gas.

Drafting and Approval of Agreements.—The fourth stage in the voluntary unitization process involves the drafting and approval of agreements by participants engaged in a fieldwide operation. This stage represents the culmination of the efforts and responsibilities undertaken by the various subcommittees with the supervision of the Unitization Committee.

The Legal Subcommittee assumes the task of drafting the unitization agreements for the approval of the ownership interests. The unitization agreements are the legal instruments for the unit operation, and there are generally two types of documents: the Operating Agreement for the operators or working-interest owners, and the Royalty Owners Agreement for the royalty interests. It is customary to distinguish between the two ownership interests in order to facilitate the approval of the unit operation. While operating interests share in the proceeds and costs of the unit operation, royalty owners share only in the proceeds from unit production and do not share in the obligations incurred by the operators. Therefore, separate documents are desirable since the Royalty Owners Agreement contains material only of interest to the royalty owner.

The Operating Agreement contains a legal statement of matters containing the participation formula and adjustments thereof, provisions for enlarging the unit operation, cost allocation, operational procedures, and matters pertaining to titles, easements, and term. Furthermore, the selection of the Unit Operation is specified in this document where the Unit Operator is usually the largest leaseholder in the unit and is responsible for the general supervision of the unit operation. The execution of the Operating Agreement occurs when the signature of the operators have been obtained. This generally requires approximately 6 to 8 months, as in the cases of both the McComb and Seeligson Field Units.

As previously stated, the Royalty Owners Agreement consists of material germane only to royalty interests; as such, this instrument is considerably shorter and less difficult than the Operating Agreement. The Royalty Owners Agreement must be presented to all the owners of mineral interests in the unit area including unleased lands, royalties, overriding royalties, gas payments, and oil payments. The agreement must be acceptable to the various royalty owners before the unit operation becomes effective. Naturally, the primary concern among royalty owners involves their share of the proceeds from unit production and, to a lesser extent, their participation in plant products (gas, condensates, and others) and questions dealing with easements. Therefore, in order to allay any apprehensions or misconceptions, great care has to be exercised by operators in drafting the Royalty Owners Agreement and conveying to royalty interests the nature of the unit operation and how royalty owners would benefit from unitization while retaining their ownership rights. Myers observes that "the interests of the lessee and lessor are for the most part identical, and this fact is of course considered by the royalty owner in accepting the decisions of his lessee."[24]

In order to achieve the maximum objectives of voluntary unitization, it is necessary that all parties having an interest in the unit area become subject to the unit agreements. However, in the absence of compulsory unitization, this may be impossible to obtain when some lessors or lessees refuse to participate in the unit. Even when non joining parties cannot complain about financial losses incident to the unit operation, the land of a non joining lessor or lessee may not be used to achieve the maximum effectiveness of the unitization program.

As a final note, the first four stages in the negotiation and execution of a voluntary unit operation demand much effort and planning on the part of interested parties. The time that is necessary to effect the fieldwide operation varies in accordance with the complexity and frequency of the problems involved. Smaller units which involve fewer ownership interests will generally establish unitization in a relatively shorter time than larger units with numerous and diverse ownership interests. The larger the number of interested parties, the more difficult it is to coordinate and reconcile individual interests with the objectives of the joint organization.

Based on the case histories of the McComb and Seeligson Field Units, the time necessary for voluntary unitization can be quite variable. When the McComb Field agreement was submitted for regulatory approval, signatures of ownership interests had been secured for approximately 68 percent of the royalty owners and nearly 84 percent of the operators. The time required for the completion of the first four stages involved less than 1 l/z years-a relatively short period for a unit operation encompassing over 300 tracts and thousands of ownership interests. On the other hand, the Seeligson Field Unit initiated negotiations in February 1952; by November 1955, signatures of working-interest owners were obtained for the Operating Agreement. In the spring of 1956, the Royalty Owners Agreement became effective and, after nearly 4 years of negotiation, the unit operation for the Seeligson Field became a reality.

Compulsory Unitization

Compulsory unitization begins with voluntary unitization of a majority of the interests within the field. It differs from voluntary unitization in that all States with petroleum allow unitization when most or all of the interested parties agree to it, but not all States will force unwilling parties to have their interests included in the unit operations. Most States, however, do authorize the State commission to enter an order compelling all interests in a field to participate in the unit once there has been voluntary agreement among a specified percentage of interests in the field.[25] This required percentage varies from 60 percent in New York and 63 percent in Oklahoma to a high of 85 percent in Mississippi. Texas is the most significant State without a compulsory unitization statute, but it should also be pointed out that the effect of the statutes in California is so limited in application that they are rather ineffective: the California Subsidence statute provides for compulsory unitization only in areas in which subsidence is injuring or imperiling commerce or safety, while the California Townsite statute applies only to fields over 75 percent of which lie within incorporated areas and which have been producing for more than 20 years.

Without unitization of all interests, unit operators may be liable to nonunitized interests for non-negligent operations, and will have to account to nonunitized interests as though there were no unit. If a lessee in a unit has a royalty interest to which it must account for production, and that royalty interest is not joined in the unit, the lessee will have to account to the royalty owner on the basis of the production from the leased land, not on the basis of the production attributable to the leased land under the unit operations plan. The lessee may have to engage in additional drilling in order to maintain the validity of the lease against non joining reversionary interest owners; such drilling may be completely unnecessary for maximum recovery from the reservoir and, indeed, may be harmful to that maximum recovery. Lack of compulsory unitization or the requirement of a high percentage of voluntary participation could be a significant restraint on unit operations, which in turn could have a significant impact on enhanced recovery.

In response to questionnaires sent to regulators and producers, several State commissions and a significant number of producers identified the inability of getting joinder of the necessary parties in a field for unitization as inhibiting or preventing the initiation of enhanced recovery projects. It was indicated that there probably are several hundred projects in the State of Texas that cannot be undertaken because of the inability to join the necessary interests in the unit.

Four small producers and four larger ones stated that lack of joinder of parties was inhibiting projects in Texas. Producers in 10 States indicated that enhanced recovery projects would be encouraged by compulsory unitization or a lowered voluntary percentage required to invoke compulsory unitization. For example, a Louisiana independent declared "1 think 75-percent royalty owner approval in Louisiana too high. A good project that benefits operator must necessarily benefit royalty owner."

There appears to be little or no difficulty in requiring unitization and enhanced recovery activities on Federal lands. The major pieces of Federal legislation for mineral development on Federal land provide ample authority to the Secretary of the Interior to make such requirements. The Outer Continental Shelf Lands Act, for example, provides that for Federal leases the "Secretary may at any time prescribe and amend such rules and regulations as he determines to be necessary and proper in order to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf (OCS). . . .Without limiting the generality of the foregoing provisions of this section, the rules and regulations prescribed by the **Secretary thereunder may provide** for. . .unitization. . . ."[26] Pursuant to this authority, the U.S. Geological Survey in establishing operating orders for the OCS, Gulf of Mexico area, has provided that "Development and production operations in a competitive reservoir [having more than one lessee] may be required to be conducted under either pooling and drilling agreements or unitization agreements when the Conservation Manager determines. . that such agreements are practicable and necessary or advisable and in the interest of conservation. "[27] The same OCS order requires that operators "timely initiate enhanced oil and gas recovery operations for all competitive and noncompetitive reservoirs where such operations would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles." [28] While Interior's authority does not appear to be quite so 'extensive under the Mineral Leasing Act of 1920, the difficulties for unitization and enhanced recovery on Federal land onshore nevertheless appear minimal when compared with development on private lands.

Procedure for Fieldwide Unitization

The procedure for obtaining commission approval for unitization or for compelling joinder of parties in the unit is similar in most States, although by no means identical. Common elements found in almost all States include the need for application or petition by an interested party (normally the prospective operator), notice to other parties, a hearing, proof of matters required by the pertinent State statute, and entry of an order by the commission defining the unit, and the terms of the unitization. The entire procedure usually takes only a matter of weeks, although there may be a delay or denial of the permit because of inequities in the participation formula. The description of the general procedure involved is intended to be suggestive only, with detailed explanation of the procedure in several of the more important States with enhanced recovery activities. For other treatments, and specific requirements for each State, reference should be made to the work cited[29] and to table c-1 .

Application

The application form and the information required to be contained in it vary from State to State, but five common requirements are present in whole or in part in most statutes. These are that the following should appear:

1) description of the area to be included,

2) description of the operations contemplated,

3) a statement of the unit control and composition,

4) the expense and production allocation formula, and

5) the duration of the unit.

Some States require prior notice to be given to the affected parties and several require that the applicant furnish the regulatory commission with a list of the names and addresses of affected parties.

Who may initiate the regulatory process also varies from State to State. In many States any interested party may submit a petition for unitization, while in others only a working interest owner may start the process. In a number of States the commission may initiate the procedure on its own motion, but this generally is not used except with application by a party. Usually, it is the unit operator who has been selected by the participants in the unit who initiates the process.

As described earlier, the expense and production allocation formula is tediously and carefully negotiated by the parties to the unitization agreement. Agreement with this information will normally be submitted to the commission with the petition or application. When compulsory joinder of other parties is sought, there will be a statement that such parties have been offered the opportunity to join the unit on the same basis as all others. The application will generally also cover the matters which are required by the statute to be found before the commission may enter an order, as discussed under "Proof of Findings Required. "

Notice

Both voluntary and compulsory unitization statutes generally require that notice and an opportunity for a hearing be given prior to the entry of an order establishing or approving the unit. Louisiana, for example, provides that whenever any application shall be made to the commissioner of conservation for the creation, revision, or modification of any unit: the applicant shall be required to file two copies of a map of the unit with the application; the applicant shall be required to give at least 30 days notice of the hearing to be held on the unit in the manner prescribed by the commissioner; and a copy of the plat shall remain on file in the office of the commissioner in Baton Rouge and in the office of the district manager of the conservation district in which the property is located, and be open for public inspection at least 30 days prior to such hearing. JO Other States typically require a shorter time period for notice, but also require that it be given by personal notice and/or by publication in the State register or in a newspaper. Failure to comply with a statutory notice provision may result in the order being declared invalid as to parties who were not given notice.[31]

Hearing

Opportunity for hearing is required in all States prior to the entry of an order for unitization, but in some States, such as Alaska, no formal hearing need be held if no party objects to the unitization proposal after the notice is given.[32] Hearings are generally conducted without rigid formality and are usually governed by the rules of civil procedure of the State and/or such rules as may be promulgated by the State commission pursuant to its delegated authority. Decisions are based on the record evidence and a general right to rehearing and/or appeal is accorded.[33]

Proof of Findings Required

Prior to approval of any unit plan or entry of an order requiring unitization in most States, the State commission must make certain findings. These generally are that unit operations are necessary to increase ultimate recovery from the reservoir or prevent waste, that correlative rights of interest owners are protected, and that the additional cost involved does not exceed the additional recovery anticipated. The Texas statute, for example, provides that unit agreements shall not become lawful or effective until the Texas Railroad Commission finds that:[34]

1) such agreement is necessary to accomplish [secondary recovery operations] or [conservation and utilization of gas] or both; that it is in the interest of the public welfare as being reasonably necessary to prevent waste, and to promote the conservation of oil or gas or both; and that the rights of the owners of all the interests in the field, whether signers of the unit agreement or not, would be protected under its operation;

2) the estimated additional cost, if any, of conducting such operations will not exceed the value of additional oil and gas so recovered by or on behalf of the several persons affected, including royalty owners, owners of overriding royalties, oil and gas payments, carried interests, lien claimants, and others as well as lessees;

3) other available or existing methods or facilities for secondary recovery operations and/or for the conservation and utilization of gas in the particular area or field concerned are inadequate for such purposes; and

4) the area covered by the unit agreement contains only such part of the field as has reasonably been defined by development, and that the owners of interests in the oil and gas under each tract of land within the area reasonably defined by development are given an opportunity to enter into such unit upon the same yardstick basis as the owner of interests in the oil and gas under the other tracts in the unit.

The Louisiana statute, to cite a compulsory unitization statute, provides that an order for unit operation shall be issued only after notice and hearing and shall be based on findings that:[35]

1) the order is reasonably necessary for the prevention of waste and the drilling of unnecessary wells, and will appreciably increase the ultimate recovery of oil or gas from the affected pool or combination of two pools;

2) the proposed unit operation is economically feasible;

3) the order will provide for the allocation to each separate tract within the unit of a proportionate share of the unit production which shall insure the recovery by the owners of that tract of their just and equitable share of the recoverable oil or gas in the unitized pool or combination of two pools; and

4) at least three-fourths of the owners and three-fourths of the royalty owners,. . shall have approved the plan and terms of unit operation, such approval to be evidenced by a written contract or contracts covering the terms and operation of said unitization signed and executed by said three-fourths in interest of said owners and three-fourths in interest of the said royalty owners and filed with the commissioner on or before the day set for said hearing.

As indicated previously, different States with compulsory unitization provisions have varying requirements as to the percentage of parties voluntarily entering into the unitization prior to invoking the compulsory features.

Entry of the Order for Unitization

After application, notice, hearing, and presentation of evidence and findings by the commission, the commission, if approving the unitization, will enter a formal order for the unitization which will become a matter of public record. In Oklahoma, for instance, the order of unitization issued by the Oklahoma Corporation Commission will provide for:[36] 1) the management or control of the unit area by an operator who is designated by vote of the lessees; 2) the allocation of production; 3) the apportionment of operational costs; 4) the manner of taking over the wells and equipment of the several lessees within the unit area and the method of compensation therefore; 5) creation of an operating committee; 6) time of the plan's effectiveness; and *7)* time and conditions of unit dissolution. Other States are similar. Unit members dissatisfied by the unitization order may appeal directly to the Oklahoma Supreme Court.[37]

Interests joined in the unit through compulsion may be allowed to choose prior to commencement of unit operations whether to participate as cotenants sharing in expenses and profits or to take a fair and reasonable bonus and royalty which is expense free. Several States including, among others, Alaska, Colorado, New Mexico, Utah, and Wyoming provide for or require financing programs for nonconsenting parties with limited cash outlay capabilities to defer unit expenses until production is obtained with reasonable risk assessments added.

The problem of determining a fair and equitable basis for allocation of production among the unit members can be an extremely difficult one, as was brought out in the discussion of the problems of negotiating voluntary agreements for unitization. Claims may be made that production should be allocated on the basis of surface acreage, productive acre feet, productive pore space, prior production history, and other grounds. The State commission may use a combination of these. For example, the Oklahoma Corporation Commission for the West Cache Creek Unit in Cotton County, Okla., used a split formula based first upon the estimated remaining net economically recoverable primary production of the unit, and secondly on the floodable acre feet of the unit. The Oklahoma Supreme Court upheld this approach against a challenge by a dissatisfied party who claimed that the formula should, in its second phase, take into account the current production from the claimant's well; the commission's order was, the court ruled, supported by substantial evidence and so the court would not overrule the commission.[38]

State commissions have set formulae on a variety of base: and have generally been upheld by the courts regardless of the formula used.[39] Statues do occasionally provide some standards, but as one authority has stated, "Viewing present statutory standards, shed of all frills, the parties must look for real protection to the integrity of the regulatory agency and of the parties presenting evidence, as well as to careful scrutiny of the information by those who expressly consent to the allocation."[40] Both the sparsity of litigation *on* the subject and statements concerning the regulatory commissions in response to OTA's questionnaires indicate that the State commissions are effectively protecting the interests of the parties to unitization proceedings.

Amendment and Enlargement

Under most statutes for unitization, it is possible to enlarge the unit and/or amend the unit agreement(s) following the same procedures that were used in creating the unit in the first instance. This may occur if additional parties wish to participate in the agreement or if it is learned that the reservoir has different parameters than originally believed.

Effect of Unitization

Each State authorizes the establishment of voluntary fieldwide units, although formal State approval may not be required for the creation of such a unit. There are distinct advantages to getting such approval even when it is not a requirement. First, the State will generally, by statute, immunize the participants from application of the State antitrust laws to the unit operation.[41] Second, it may serve to protect the participants from application of the Federal antitrust laws to the unit operations. The argument can be made that unitization reduces competition and can serve as a means of limiting production and controlling price. However, the general weight of authority is that, so long as there is no collusion in refining and marketing, the mere joint production of oil does not create antitrust problems.[42] Where unitization is necessary to increase total production it would appear that unitization would actually promote competition by increasing the amount of oil available to all the parties. The role of State approval in Federal antitrust considerations (if they should be raised) is that it can be argued that the approval and order of the State commission gives rise to the well-recognized *Parker v. Brown*[43] exemption from the operation of the Federal antitrust laws. That is, in the case of *Parker v. Brown,* the U.S. Supreme Court held that State approval of a raisin marketing program provided the cooperative activities of the raisin growers with immunity from the Federal antitrust laws. The same rationale would apply to unit operations approved by a State commission.[44] Only one Federal case[45] has attempted to apply the Federal antitrust statutes to unit operations, and was terminated through a carefully negotiated consent degree.

Another reason for getting State approval for a voluntary unit even if not required is that it may provide protection from liability for nonnegligent operations to other parties in the reservoir who have not joined in the unit. This is an important subject in itself, and is taken up in a later section. Suffice it to say at this point the element of State approval of the enhanced recovery program has been enough for some courts to establish immunity from such liability for operators. And, of course, where the requisite percentage approval is achieved in a State with a compulsory unitization statute, the entry of a commission order for a unit will result in unitizing the field and all interests in the field may be treated as members of the unit; no separate accounting or operations on a nonunit basis will be necessary.

One more point should be brought out, and that is that under the terms of an oil and gas lease in some instances and by statute in others the establishment of the unit will sever the unitized portion of the leasehold from the rest of the lease.[46] Depending on the wording of the lease clause (known generally as a "Pugh clause" because of the person purportedly creating it originally) or of the applicable statute, such as in Mississippi, Louisiana, and Wyoming, additional activity on the severed part of the leasehold may be necessary to keep the lease in force as to the portion of the lease not included in the unit. Such lease and statutory provisions can serve as a disincentive to lessees to participation in unit operations.

Allowable and Well Spacing

In order for an enhanced recovery project to be successful, it is necessary to be able to produce the oil. The fixing of allowable in market-demand type States could discourage enhanced recovery if the production rates were set at a level below the optimum rate for the reservoir. The regulations of the State commissions generally do make provision for the setting of allowable for enhanced recovery operations. For example, Oklahoma provides that "An" approved and qualified waterflood project shall be entitled to produce an allowable of forty-five (45) barrels of oil per well per day including producing and injection wells on a project basis upon the acreage developed for waterflooding. The commission may increase the allowable for a waterflood project for good cause shown after notice and hearing. "[47] In other States, similar provision is made and/or allowable may be transferred among interest owners for the encouragement of enhanced recovery.[48] Because of special treatment and encouragement of enhanced recovery projects, it does not appear that the setting of allowable would impede enhanced recovery operations. No producer responding to OTA's questionnaires indicated that there was a problem of establishing adequate allowable for enhanced recovery. The same is true of well spacing.

Administrative and Judicial Encouragement to Unitization

A number of State commissions and courts have recognized the benefits that result from undertaking unit operations to enhance recovery and accordingly have attempted to encourage unitization. They have done this in several ways.

One has been to deny to non joining parties the benefits they might have expected to obtain by their refusal to join. Production allowable have been set at a higher rate on occasion for unit members than for those who decline to enter the unit.[49] To cite another example, an agency has limited the royalty payable to a non joining royalty owner to the royalty that would have been paid had the allowable not been increased for the enhanced recovery operations.[50] Such actions have been upheld by the courts. [51]

Another method of encouraging unitization has been for agencies to use their authority over well spacing or the prevention of waste to make unitization more attractive to interest owners. Thus in one well known case,[52] the Colorado Oil and Gas Conservation Commission prohibited the production of gas from a large reservoir unless the gas was returned to the reservoir, used in lease or plant operations, or used for domestic or municipal needs in or near the field. The oil could not be produced without production of the gas, and the gas could not be reinfected without unitization of the field. Although sympathizing with the commission's goal, the Colorado Supreme Court struck down the order on the ground that it was beyond the authority of the commission. Subsequently, Colorado enacted a compulsory unitization statute. A recent effort by the Oklahoma Corporation Commission to require separate owners of interests to develop their land as a unit was struck down as being beyond the statutory authority of the commission.[53]

Finally, the courts have encouraged unitization by denying damages to a non joining interest owner who has asserted that his production has suffered by virtue of the unit operation of the party against whom the claim is brought. Such cases are taken up in a later section.

It should be observed that while agencies and courts have expressed support for enhanced recovery, they are limited to the statutory authority they possess. There is only limited opportunity for them to use their discretion for encouragement of enhanced recovery.

Approval of Enhanced Recovery Projects

Permit Requirements

prior to commencement of any underground injection for EOR purposes, (all enhanced recovery projects require underground injections), the party responsible must obtain approval from the proper State commission. Often this may be done at the same time that approval of unitization is sought; much the same information is required and a similar procedure is employed. The two should be treated separately, however, because they are separate legal requirements involving different considerations and because an operator must get a permit for enhanced recovery operations even when a unitization procedure is not necessary, as when the operator owns the entire area covered by the reservoir.

As with the unitization statutes, the requirements for enhanced recovery operations permits vary from State to State.[54] What is attempted here is to highlight the general features of the regulatory procedures that are similar in most States with detailed references to the regulations of the larger producing States. The procedure typically requires the filing of an application or petition by the party responsible for the project which describes the activity proposed. Depending on the jurisdiction, notice of the proposed action may have to be given to interested parties before application or it may be given subsequent to the application, either by the regulatory commission or by the operator. A hearing upon the application will be held if timely objection is made by an interested party or on the commission's own initiative.

Application

Applications for enhanced recovery permits typically require four elements of information to be included, and these may be specified either by statute or by rule of the **regulatory agency: 1) geographic description of the area** covered by the operation; 2) identification of parties affected or who may be affected by implementation of the proposed project; 3) data concerning the formations underlying the area of operation; and 4) explanation of the recovery program.

Geographic descriptions required generally include a plat of all leases in the affected area with locations given for all present, abandoned, and proposed wells. New Mexico, for example, requires a plat showing the locations of all wells within a 2-mile radius of existing and proposed injection wells and the formation from which the wells are producing or have produced.[55]

To facilitate the giving of notice to affected parties, and to enable the States to prepare conservation plans, the States generally require the application to include one or more of the following: the names and addresses of operators within the area, the names of all operators within the unit, the names of all owners of property interests within one-half mile of injection wells, and the names of all lessees within 2 miles of injection wells.

Data concerning subsurface formations that are generally required under the statutes or regulations include full descriptions of the formations in the area and specific delineation of the reservoir to be flooded. Other such information may be required. Kansas, for example, requires not only the name, description, and depth of the formations to be flooded, but also the open-hole depths of each such formation, the elevations of the top of the oil- or gas-bearing formation in the injection well, the wells producing from the same formation within one-half mile radius of the injection well, and the log of the injection well (if a complete log does not exist, such information regarding the well as is available).[56]

The data concerning development plans that are generally required include specific description of injection methods, identification of the substance(s) to be injected, the source of the substance, and the daily amounts of the injection. information pertaining to casing and casing tests must similarly be submitted along with such log information as is available to the operator. Some States require additional data on oil to gas ratios

and oil to water ratios on production obtained to the date of the application. Separate application requirements exist in some states for waterflood methods, repressurization, disposal wells and the use of hydrogen sulfides'

Because it is typical of the requirements of State commissions for enhanced recovery applications, section 3-30l (b) of the General Rules and Regulations of the Oil and Gas Conservation Division of the Oklahoma Corporation Commission is set forth:

> The application for an order authorizing a pressure maintenance or secondary recovery project shall contain the following:
>
> (1) The names and addresses of the operator or operators of the project.
>
> (2) A plat showing the lease, groups of leases or unit included within the proposed project; the location of the proposed injection well or wells and the location of all oil and gas wells, including abandoned and drilling wells and dry holes; and the names of all operators offsetting the area encompassed within the project.
>
> (3) The common source of supply in which all wells are currently completed;
>
> *(4)* The name, description, and depth of each common source of supply to be affected;
>
> (5) A log of a representative well completed in the common source of supply;
>
> *(6)* A description of the existing or proposed casing program for injection wells, and the proposed method of testing casing;
>
> (7) A description of the injection medium to be used, its source and the estimated amounts to be injected daily;
>
> (8) For a project within an allocated pool, a tabulation showing recent gas-oil ratio and oil and water production tests for each of the producing oil and gas wells; and
>
> (9) The proposed plan of development of the area included within the project.

Notice

Because enhanced recovery operations may affect in one way or another virtually all parties in the vicinity of the operation, the notice requirement and opportunity given for a hearing reflect a liberal attitude toward notification of nearby tract owners and operators. Service of notice must be personal, by mail, or by publication in a readily available or official publication. Generally, notice must be given by the applicant himself to the other parties, and it will have to be given some 10 to 15 days before the application or just after filing of the application. Notice commonly must be extended to owners and operators of the reservoir and all those with interests in property within one-half mile of the injection well(s). Protest against the application must be lodged within 15 days of service of notice or of the application, depending on the jurisdiction, In many jurisdictions no hearing need be held if no party objects to the application or if the commission does not order one on its own motion.

An example of the notice requirements can be given by reference to Alaska's rules[58] which require a copy of the application to be mailed or delivered by the applicant to each affected operator on or before the date the application is filed with the Oil and Gas Division of the Department of Natural Resources. Statements must be attached to the application showing the parties to whom copies have been mailed or delivered. In the absence of any objection within 15 days from the date of mailing, the division's committee may approve the application. If objection is made, the committee shall set the matter for hearing after giving additional notice to the affected parties. Other States **are** similar in their provisions.

Hearing

Once a protest is made to an application or the commission on its own initiative requires one, a hearing will be held on the application. The function of the hearing will be to determine whether the injection program is reasonably necessary for the prevention of waste and to obtain greater recovery from the common source, whether the recovery costs will be less than the proceeds from recoverable oil and gas, and whether the rights of other interested parties are adequately protected. Hearings are governed by the State's rules of civil procedure and/or rules promulgated by the commission pursuant to authority delegated to it. Evidence introduced at the hearings will normally be scientific information and data brought out through the testimony of geologists and engineers under questioning by the operator's attorney or the opponent's attorney. A right to rehearing and/or a court review of a commission decision is generally provided upon timely application.

Order

In general, an application for any type of injection program may be denied by the State commission for good cause; the commission will have considerable discretion allowed by State statute. If the application is approved, an order will be issued by the commission giving the operator authority to proceed. The order will be a matter of public record and can be rescinded for any good cause. The injection program will be subject to additional requirements while it is being implemerited.[59] The operator will normally be required to complete reports before or at the time of commencement of injection, to issue periodic reports regarding the program, and will be subject to inspection of operations by the State regulatory agency. Additional notice to other State agencies may be required after issuance of the order. The appropriate State agency will also have to be notified of the termination of the injection program.

Injection Regulations Under the Safe Drinking Water Act

Acting under the authority of the Safe Drinking Water Act,[60] the Environmental Protection Agency (EPA) has issued proposed regulations[61] that would be applicable to underground injections for EOR purposes. While these regulations were not final at the preparation of this report, it is useful to examine them in the context of the Safe Drinking Water Act and current State control programs. Some type of regulation will be forthcoming from EPA, even if not in the precise form of the present proposals.

The Safe Drinking Water Act was passed into law as an amendment to the Public Health Service Act in 1974. Its purpose is to establish national drinking water standards and ensure minimum protection against contamination of drinking water supplies by well-injection practices. It attempts to accomplish this by having EPA issue regulations specifying minimum requirements for State programs to control underground injection of fluids that may threaten the quality of water in aquifers that are or may be used for public supply. Section 1421 (b) (1)[62] of the Act itself sets out the minimum requirements for State programs to control underground injection. They are, 1) only State-authorized injections may be continued after 3 years from the date of enactment; 2) the injector must satisfy the State that his operation does not endanger the drinking water; 3) the State program must have procedures for inspection, monitoring, recordkeeping, and reporting for injection operations; and 4) the regulations must apply to all persons including Federal agencies.

With specific respect to oil and natural gas production, the Safe Drinking Water Act provides further in section 1421 (b)(2)[63] that:

> Regulations of the [EPA] Administrator under this section for State underground injection control programs may not prescribe requirements which interfere with or impede—
>
> (A) the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production, or
>
> (B) any underground injection for the secondary or tertiary recovery of oil or natural gas, unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection.

In promulgating regulations setting requirements for State programs, it is the interpretation of the Act by EPA that the "Administrator need not demonstrate that a particular requirement is essential unless it can be first shown that the requirement interferes with or impedes oil or gas production."[64] Thus, the burden is upon the State or the enhanced recovery operator to prove that the requirement in question does interfere with or impede production, and EPA further places the burden on the operator to show that the requirement is not essential, That is, EPA has stated that an alternative method of protection of drinking water may be approved by the State commission "if the operator clearly demonstrates that (i) the requirement would stop or substantially delay oil or natural gas production at his site; and (ii) the requirement is not necessary to assure the protection of an existing or potential source of underground drinking water."[65]

it should be observed that EPA does take note of the fact that **oil-producing States** have regulated injections for years, and does set the requirements applicable to injection wells related to oil and gas production in a subpart separate from requirements for other types of injections.

While EPA-required procedures are similar to existing State procedures for injection permit regulation, the proposed regulations would impose much more detailed requirements than do current State procedures. For example, the application requirements for new underground injection under the proposed regulations[66] set forth immediately below should be compared with the Oklahoma regulations concerning application quoted on page 218 of this appendix.

> (a) The application form for any new underground injection shall include the following:
>
> (1) Ownership and Location Data. The application shall identify the owner and operator of the proposed underground injection facility, and the location of the facility.
>
> (2) Engineering Data.
>
> (i) A detailed casing and cementing program, or a schematic showing: diameter of hole, total depth of well and ground surface elevation; surface, conductor, and long string casing size and weight, setting depth, top of cement, method used to determine top; tubing size, and setting depth, and method of completion (open hole or perforated);
>
> (ii) A map showing name and location of all producing wells, injection wells, abandoned wells, dry holes, and water wells of record within a one-half-mile radius of the proposed injection well; and
>
> (iii) A tabulation of all wells requested under (ii) penetrating the proposed injection zone, showing: operator; lease; well number; surface casing size and weight, depth and cementing data; intermediate casing size and weight, depth and cementing data; long string size and weight, depth and cementing data; and plugging data.
>
> *(3)* Operating Data.
>
> (i) Depth to top and bottom of injection zone;
>
> (ii) Anticipated daily injection volume, minimum and maximum, in barrels;
>
> (iii) Approximate injection pressure; and
>
> (iv) Type, source, and characteristics of injected fluids.
>
> *(4)* Geologic Data—Injection Zone. Appropriate geologic data on the injection zone and confining beds including such data as geologic names, thickness, and areal extent of the zone.
>
> *(5)* Underground Sources of Drinking Water Which May be Affected by the Injection. Geologic name and depth (below land surface) of aquifers above and below the injection zone containing water of **3,000** mg/l **total dissolved solids or less and aquifers containing water of 10,000** mg/l total dissolved solids or less.
>
> (6) An electric log on all new wells and on existing wells where available.

The regulations could broaden the number of persons or agencies who could challenge the application and insist upon a public hearing. New requirements would be made for record keeping at several different levels (by governmental agencies and operators); there would be a 5-year limitation on permits; new standards could be required to be met after an injection program has commenced under a properly issued permit; and the specific well requirements go beyond those of many States.

A number of parties have objected strenuously to these proposed regulations or similar prior proposals, and to the general approach taken by EPA under the Safe Drinking Water Act on the grounds that this will significantly hinder EOR operations without corresponding benefits in the protection of drinking water. A resolution of the Interstate Oil Compact Commission of June 30, 1976, for example, declared: "The State regulatory agencies estimate that if the recent draft regulations went into effect it would cause a loss of production of over 500,000 barrels of oil per day and in excess of 2.5 billion cubic feet of gas per day. All of this is from existing wells that have been producing for a number of years with virtually no adverse impact on the environment.[67] While this resolution referred specifically to the immediate predecessor of the currently proposed regulation, personnel with the Interstate Oil Compact Commission indicated in personal contact that the current regulations could still substantially interfere with or impede enhanced recovery of oil.

The Council on Wage and Price Stability recently criticized EPA's proposed regulations on the grounds that EPA may have both underestimated the costs of conducting the State regulatory programs and misjudged the health benefits to be gained by the regulations.[68] Specifically, the Council stated that "EPA's data regarding benefits and costs offered in support of the regulations are too fragmentary, subjective, and inconclusive to enable an informed decision to be made on this issue, " and urged that further evaluations be made before putting regulations into effect.[69]

Finally, both producers and State commissions identified the contemplated EPA regulations as being likely to hinder or discourage enhanced recovery operations. Of the responses from producers, four independent and six large producers stated specifically that the proposed EPA regulations would have an adverse effect on operations. An example of such responses was the following comment of one independent producer from the State of New York: "EPA-proposed rules and regulations regarding existing underground injection wells--could have a very negative effect on enhanced recovery. " One of the large companies responding similarly stated: "The recently proposed EPA rules concerning secondary recovery operations could essentially prohibit new enhanced projects. " One State agency which has authority over several hundred enhanced recovery projects with many more potential projects in the State said that no permit had been denied for such projects but that "Many may be denied next year if the Federal UIC [underground injection control] Regulation is administered as written. " The American Petroleum Institute has also conducted a survey of major and independent producers and has concluded that "Without doubt the proposed regulations will interfere with and impede underground injections and substantially decrease the ultimate production and recovery of hydrocarbons."[70]

In light of the number of such comments, it is clear that EPA-proposed regulations are perceived as having, or as likely to have, an adverse impact on enhanced recovery operations.

Operational Aspects of Enhanced Oil Recovery

Potential Liability to Nonjoining Interests

Relatively few reported cases have arisen in which non joining interests have made claims for damages against unit operators for enhanced recovery activities, and fewer still in which damages have been awarded. However, the issue is an important one as is suggested by the number of articles that have been written on the subject.[71] As one writer has commented, the small number of cases is "like the top of an iceberg, it does not reveal the trouble underneath—the number of secondary [i.e., enhanced] recovery projects delayed or hamstrung by threats of litigation, and the heavy price sometimes exacted by the owners of minority interests in exchange for cooperation.[72] For this reason, it is important to examine briefly the legal theories upon which claims or liability might be based, the treatment of these by the courts in the past, and possible approaches to the problem in the future.

The legal theory upon which a claim for damages may be based will depend in part upon the relationship between the claimant who has not joined the unit and the operator responsible for the enhanced recovery project. If the claimant is a lessor or cotenant of the operator, the claim in most circumstances will be that the operator has breached a duty owed to the claimant or that the operator has caused waste of property jointly owned by both the operator and the cotenant. If the claimant is a neighbor owning an interest in the reservoir, the claim may be based on a theory of trespass, strict liability (ultrahazardous activity), nuisance, or fault. In general, the courts have shown a disinclination to award damages on any of these grounds except the very last—fault.

As discussed in an earlier section, the lease itself governs most relations between lessor and lessee. Most leases are silent with respect to enhanced recovery, however, and it is necessary to examine implied rights and obligations that arise out of the basic relationship. These can be put under many headings, but the general principle that is most important is that the lessee must act in good faith and do nothing to injure the value of the leasehold. While the same relationship is not present in a cotenancy situation, it is nevertheless well recognized that one cotenant should do nothing to reduce the value of the joint property without the consent of the other. In either circumstance, the most likely claim to be raised by a non joining lessor or cotenant is that the lessee/operator is causing or permitting *oil* and/or gas to be drained away from the property. Cases have been adjudicated in several jurisdictions on this basis and will be described briefly.

In the case of Tide Water Associated Oil Co. v. Stott,[73] a pressure maintenance program was undertaken with the approval of the Texas Railroad Commission by the lessee of the claimants. The lessors (claimants) refused to join in the unit. The lessee was also the lessee on other nearby tracts and maintained its lease on the lessors' lands by continuing to conduct primary operations there. The lessors sued the lessee on the theory that it was causing drainage of "wet" gas from under their tracts to the other tracts operated by the lessees. The Fifth Circuit Court of Appeals held in favor of the lessee, saying that there was no liability to the nonconsenting lessors because they had been given an opportunity to join in the unit operations on a fair basis.

In the case of *Carter Oil Co. v. Dees,*[74] a lessee sought a declaratory judgment allowing it to convert an oil production well to a gas injection well for enhanced recovery operations. The lessor opposed this, claiming it would cause drainage of oil from underneath his property. Despite a contrary ruling on an identical case the previous year by the Seventh Circuit Court of Appeals,[75] the Appellate Court of Illinois held for the lessee on the ground that the additional oil gained by the project through drainage from other land would more than compensate for the loss from the lessor's land.

After the Dees case, the Illinois legislature passed an act that expressly stated that enhanced recovery was in the public interest. When a group of nonconsenting lessors and cotenants attempted to block a waterflood operation in the case of Reed v. Texas Company, [76] the Illinois Supreme Court relied upon the legislation to hold for the operator. The court held that the claimants had been offered **an** opportunity to participate in the program on a fair basis, that the State mining board had approved the project, and the project was in the public interest; it stated:

> If a **minority of one or more persons affected by the operation** could prevent it by refusing to join in the agreement, they could then force the others to choose between leaving a large part of the oil underground, or consent to granting the dissidents an unreasonably large percentage of the oil. in other words, the power to block a repressure program by refusing to sign the unitization agreement, would be the power to insist upon unjust enrichment. Surely a court of equity would not support such a rule.

In somewhat similar cases, the North Dakota[77] and Mississippi[78] Supreme Courts followed the same line of reasoning in holding for the operators of other enhanced recovery projects.

It should be observed that despite the denial of damages to lessors, the lessee-operators in cases such as the Stott case must still satisfy other requirements of their leases to keep them valid. Thus in Stott the operator had to maintain separate production activities on the leases and had to account to the claimants separately from the unit operation. However, the courts have shown a willingness to support enhanced recovery despite competing claims of property rights in minerals. An express statement by the legislature in favor of enhanced recovery can be of considerable support for this predisposition in litigation of this nature.

When it is a neighboring interest owner who is claiming damages the theories asserted in support of liability are different. By and large, however, the courts have tended to support enhanced recovery and, with certain exceptions which will be noted, have denied liability.

In injection programs, the fluid injected sweeps from the injection well towards the production well (s). The migration of the fluid can cross property lines, and this fact has led to claims of trespass by neighboring interest owners who have not joined in the unit or enhanced recovery program when they have felt the production from their land was reduced by the fluid sweep. The most important case dealing with this claim of trespass is a Texas case, *Railroad Commission v. Manziel.*[79] In rejecting the neighbor's claim of trespass, the Texas Supreme Court adopted the theory advanced by Professor Howard Williams and Dean Charles Meyers of a negative rule of capture. [80] Just as one may produce oil or gas even though it migrates from the property of another, so too may one inject a substance into the ground for production purposes even though it migrates and causes loss of production for a neighbor. The court also supported its denial of liability by noting that enhanced recovery is in the public interest. No case involving enhanced recovery has been found which has granted damages on a theory of subsurface trespass by injection of fluids.

For some types of ultrahazardous activities there is strict liability (liability without a showing of negligent operations) for damages flowing from the activity. This legal theory overlaps with the principle of nuisance, and the two may be treated together even though one does not usually think of enhanced recovery as being ultrahazardous.[81] In an important recent case arising in Oklahoma, the Tenth Circuit Court of Appeals upheld a decision in favor of a claimant for damages for a non-negligent waterflood project. The court, in *Greyhound Leasing and Financial Corporation v. Joiner City Unit,*[82] relied upon a nuisance provision in the Oklahoma Constitution which states that no private property shall be taken or damaged for private use unless by consent of the owner. Although the unit operator had had the project approved by the Corporation Commission and had offered the claimant an opportunity to participate in the unit, the court found liability. It is possible that the court in another jurisdiction might hold in this manner even without such a State constitutional provision. Because the more exotic methods of enhanced recovery are relatively new and untried, there is a greater possibility that a court might find them ultrahazardous than with normal waterflood operations. The possibility of liability on this ground could be a disincentive to operations even though a number of authorities have expressed disfavor with such a result. Producers in five States indicated that they have enhanced recovery projects being inhibited by fear of such liability.

The final basis for liability for enhanced recovery operations is fault, which includes negligent actions, wanton disregard of the rights of others, and intentional harm. Liability arising from such actions is well recognized whether primary or enhanced recovery operations are involved. In virtually all instances the actions of the operator will be beyond those included in the order of the State commission. Few would contend that operators should have their negligent or intentionally harmful acts excused simply because they are engaged in enhanced recovery operations, although questions might be raised about the standard of care that should be applied to operators in such projects.

In general, the courts have looked with disfavor upon claimants who have been offered an opportunity to join in an enhanced recovery operation on a fair and equitable basis and have refused to join. The commission approval of the projects and public interest in enhanced recovery of oil tend to negate the possibility of liability for non-negligent operations and lend support to the other legal theories—such as the negative rule of capture—upon which a court might decide a claim for damages from a nonconsenting interest owner. A State statute expressing encouragement for enhanced recovery will also tend to negate liability. However, the uncertainty of the law in many jurisdictions makes the undertaking of enhanced recovery without joinder of all the interests in the unit either voluntarily or through compulsory unitization a risky business. Not only may operations result in liability, but the mere possibility that a court might so hold could discourage unitization by recalcitrant minority interests and could provide them strong leverage in bargaining over the participation formula.

Environmental Requirements

Both State and Federal environmental requirements might affect enhanced recovery in several ways. First, they may cause delay in the approval and initiation of projects. Second, they may make enhanced recovery projects a greater economic risk because they could increase costs, could cause liability for violations of the requirements, or could force the shutting down of projects. Such possibilities could discourage efforts to undertake EOR projects. It should be noted that present environmental requirements seem to be restricting only with respect to enhanced recovery in California, and EPA's proposed underground injection regulations discussed in a previous section. The areas of environmental regulations that may be of significance for present or future operations relate to requirements for environmental impact statements, air quality standards, and limitations on water pollution.

Environmental Impact Statements

Environmental impact statements are now required for certain State activities in several States

and for all Federal actions and, proposals significantly affecting the quality of the human environment. In 1970, the California Legislature enacted the Environmental Quality Act,[83] which requires various State and local governmental entities to submit environmental impact reports before undertaking certain activities. The affected State and local agencies are compelled to consider the possible adverse environmental consequences of the proposed activity and to record such impacts in writing. At least one producer has reported that this California requirement has caused "delay in waterflood projects due to delay in permits because of environmental assessment studies." These and other requirements had, said the producer, resulted in "presently over 1-year delay in obtaining permits. "

The National Environmental Policy Act of 1969 in section 102 (2) (c)[84] requires an environmental impact statement to be completed for every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. Since the Federal Government is now involved with enhanced recovery only in limited areas on Federal lands, this Act does not have much effect on enhanced recovery. However, should the Federal Government become involved in regulation of enhanced recovery, an environmental impact statement would probably have to be filed to meet the requirements of section 102(2) (c).

Air Pollution

Air quality requirements are primarily of significance for thermal recovery projects. The legislation of greatest importance in this area is the Federal Clean Air Act of 1970,[85] and the State implementation plans enacted pursuant to it,

Under the Clean Air Act, EPA has established primary and secondary ambient air quality standards. The primary standards are designed to protect the public health and the secondary standards are to protect the public welfare. It is the responsibility of the States to promulgate plans to attain these standards for each of the pollutants for which the EPA has set standards. Limitations for air pollution from new sources of pollution are established by EPA itself. **In addition, the Clean Air Act has been interpreted by the courts as requiring agencies to prevent any significant deterioration in air quality in areas already meeting the standards. Both State and Federal** governments can enforce the Clean Air Act, and stiff penalties may be assessed for violation of regulations.

The precise applicability of the Federal and State requirements under the Clean Air Act depends upon the size and type of equipment used in steam generation, the quality of the fuel used for providing a heat source, and the quality of the air in the State and region where the operations take place. Since most ongoing thermal projects are located in California, it is the State in which there is an indication as to the impact of such air requirements. One producer there indicated that an application for a number of enhanced recovery projects was being delayed while EPA sought additional data on the air quality impact of the equipment to be used. The same producer suggested that some 25 projects were being delayed due to present and pending air-quality and land-use regulations. "Thermal recovery projects," it stated, "have been delayed due to EPA and County Air Pollution Control District regulations and permit requirements. " At least three other large and small producers stated that they had multiple projects being delayed by California air-quality requirements. Hydrogen sulfide regulations in Texas have been made more stringent in recent years, but no producer indicated that this has had an adverse impact on enhanced recovery.

Water Pollution

The most important aspect of water pollution, namely pollution of ground water through seepage from flooding operations, is governed under State and Federal law by the Safe Drinking Water Act as previously discussed. Additionally, the Federal Water Pollution Control Act Amendments of 1972[86] (FWPCA) regulate water quality. Under the FWPCA the discharge of pollutants into navigable waters without a permit is prohibited. The term "navigable waters" is very broadly defined. Severe penalties are provided for violation of the requirements of the Act.

Other Environmental Regulation

There are other local, State, and Federal regulations that can affect enhanced recovery. Land-use planning restrictions and zoning, toxic substance regulation, noise level limits, occupational health and safety requirements, and other measures may impact upon enhanced recovery operations in one way or another. However, the degree of impact is highly speculative at this point.

Water Rights

All types of enhanced recovery, as previously noted, require water either for flooding purposes or for steam generation. Water of low quality has seemed adequate in the past, but for some of the more sophisticated techniques of enhanced recovery, fresh water will be more desirable. Questions of water rights for enhanced recovery have generated problems and litigation in the past, and it can be expected that such issues could become more important in the future. A brief treatment of the principles that have guided the courts with respect to water rights suggests the problems that may be faced in acquiring water for enhanced recovery.

Before discussing the law applicable to water, it is necessary to mention some of the classifications of water that are made, for the rights may turn on the classification. Water, of course, may be found on the surface of the earth or underground. Surface waters may be classified as diffused (having no defined channel or course such as a marsh), water courses, lakes, springs, or waste water. Underground waters may be classified as underground streams or as percolating waters (having no flow or water course) .[87]

The right to own or use water can present questions in three basic areas. First, there may be controversy arising between lessor and lessee, or between surface owner and mineral interest owner, as to water found on or adjacent to the land where the oil is located. Second, questions can arise between those who wish to use water for enhanced recovery and others who assert rights to the water but have no relationship with the enhanced recovery project or land on which it is located. Third, and perhaps overlapping the other two, will be matters of regulation of water use by the States.

Lessor-Lessee Rights

The litigation that has arisen in the past with respect to water rights for enhanced recovery has dealt primarily with the respective rights of lessor and lessee, or surface owners and owners of mineral interests beneath the surface. For simplification, reference will be made simply to lessor and lessee. In such litigation, it has been presumed that the original owner of the surface owned the right to the water and could dispose of it for enhanced recovery purposes; the question litigated has been whether there was such a disposition, either expressed or implied.

The first type of issue that has arisen is whether a grant of "oil, gas, and other minerals" (or a similar phrase) has included water as a mineral. Courts have held that freshwater is not a mineral within the meaning of this clause in an oil **and gas lease or deed.[88] instead, the courts treat fresh water as belonging to the surface estate whether the water occurs at the surface or must be brought from the underground. Therefore, the lease or deed from the surface** owner must expressly grant rights to use of this water, or the rights to the water must arise as part of an implied right to use of the surface for the development of the mineral estate. One Texas court made a distinction between fresh water and salt water, holding that salt water is part of the mineral estate,[89] but the Texas Supreme Court has since said that salt water and fresh water alike should be treated as belonging to the surface estate.[90]

Many oil and gas leases do contain an express grant of right to the lessee to use water from the lease premises. They often contain a provision such **as** the following:[91]

> The lessee shall have the right to use, free of cost, water, gas and oil found or located on said land for its operations thereon, except water from the wells of the lessor.

Does this provision, which does not mention enhanced recovery, authorize the use of water from the land for enhanced recovery purposes when such techniques were not known in the

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area or to the industry when the lease was granted? It is generally treated as authorizing the use of water on the leased premises for enhanced recovery, but a notable Texas case, *Sun Oil Co. v. Whitaker,*[92] to be discussed shortly, declined to rule on this question when given the opportunity. A problem with a clause such as the one quoted is that the water for enhanced recovery may have to be used on other lands and this is not permitted by the provision. However, the royalty owners agreement will include a provision for this when there is unitization. if a nonroyalty interest owner is the owner of the surface, other agreement will have to be made to authorize the use of the water off the leased property.

Finally, even if there is no express provision for use of water for enhanced recovery, there will generally be an implied right to use of the water. As stated in a previous section, the lessee has the right to use so much of the surface as may be reasonably necessary to effectuate the purposes of the lease having due regard for the rights of the owner of the surface. This will include water, and several courts have expressly applied this implied right doctrine to water (both fresh and salt) for use in enhanced recovery operations. [93]

The most recent and important of these decisions is *Sun 0il Co. v. Whitaker.*[94] In this Texas case, one Gann gave a lease to Sun Oil in 1946 and then conveyed away the surface rights to Whitaker in 1948. The lease had an express provision for the use of water substantially like the one quoted above. After years of production by primary methods, Sun decided to waterflood the formation. It received authority from the Texas Railroad Commission to use fresh water for this purpose, and began producing water from a nonreplenishable water formation for the program. The owner of the surface, Whitaker, was using fresh water from the same formation for irrigation of farmland. Sun sought to prevent Whitaker from interfering with its production, and Whitaker in the same suit sought to prevent Sun from using the water for enhanced recovery. The court held, without ruling on the extent of the express provision, that the oil and gas lessee's estate was the dominant estate, that the lessee had an implied grant of free use of such part and so much of the premises as was reasonably necessary to effectuate the purpose of the lease, that the implied grant extended to and included the right to use water in such amounts as would be reasonably necessary to carry out its operations under the lease, and that the waterflood operation was reasonably necessary to carry out the purposes of the lease. It should be noted that the court found that no other source of usable water on the leased tract was available, and that the decision was by a narrow majority of five to four. With only a slight change of facts this court and any other could easily hold to the contrary, so that an enhanced recovery project operator is certain of his rights to water only if they have been expressly granted for enhanced recovery purposes.[95]

Riparian and Appropriation Rights

When the rights to water of parties other than the lessor and lessee are considered, several rules of ownership of rights must be taken up. These are the doctrines of riparian rights and rights of prior appropriation, and some States follow a combination of these two.[96] Which rule applies to a particular State has largely been determined by the climate and geographical region in which the State is located. Generally speaking, these doctrines apply to watercourses with underground waters being governed by a theory of absolute ownership or a reasonable use limitation only. However, in some States, the rights doctrines will apply to underground water as well as surface water.

Riparian Rights.—The doctrine of riparian rights is found to apply in some 31 States (table C-2) located primarily in the eastern half of the United States, where there is more water. Under this principle, the owner of land adjacent to a watercourse (the riparian owner) is entitled to reasonable use of such amount of water as he can put to a beneficial purpose. A reasonable use is such that it will not unduly disturb a lower riparian's right to some minimum flow of water and which is suitable to the character and size of the particular watercourse. A limitation on the right is that the water must be used on the riparian owner's premises, or at least within the watershed. In States following this principle, percolating waters are generally treated as being subject to absolute ownership by the surface owner or a principle like the rule of capture is applied, so that the underground waters may be sold and transported away from the watershed.

The significance for enhanced recovery under the riparian rights approach is that production of oil is a beneficial use as is required under the doctrine, and water generally will be available from one source or another. However, whether the water is from a watercourse or from underground it may be necessary for the operator to contract for the water. Use of the water for waterflooding can be enjoined by lower riparian owners only if they can show that there has been an excessive or unreasonable taking of the water, leaving them with less than their fair share.

Rights of Prior Appropriation.—The doctrine of prior appropriation developed in the more arid regions of the United States and presently applies in nine States, commonly designated as the Rocky Mountain States. Prior appropriation is the taking of a portion of a natural supply of water, in accordance with law, with the intent to apply it to some beneficial use within a reasonable time. As before, enhanced recovery operations do constitute a beneficial use of the water.[97] The right to the water is fixed by time, not by location on the watercourse. Thus, an upstream appropriator who is later in time (junior appropriator) in his appropriate ion is subordinate in right to a downstream prior (senior) appropriator's right to the water. Appropriation is a vested right then to take or divert and consume the same quantity of water forever.

Ownership of land is generally a prerequisite to appropriation. However, as has been stated by one authority that "[i] n the absence of statute, it has always been the rule in States following the appropriation doctrine that an appropriator may change the use and place of use so long as the change does not injure other appropriators. [98] This means that, subject to State regulation, a party may acquire or dispose of his appropriation rights. The importance of this is that operators are faced with the problem that with prior appropriation the right is perpetual with no provisions for short term appropriation of water. The ability to buy and sell rights is significant, for the use of water for enhanced recovery is of limited amount and duration; the operator must buy on a short-term basis, if possible, or appropriate the water and sell the rights after completion of operations. Where the operator is a junior appropriator, he is subject to having his water diminish or cease entirely in times of shortage.

Dual System.—Some 10 States apply a combination of the two principles described above known as the California doctrine. That is, they follow a rule that a riparian owner may take water from a source but only as much **as he** can put to a reasonable beneficial use. Surplus water is subject to appropriation by nonriparian owners or to export by riparian owners to nonriparian lands; but this appropriation or export is junior to the prior rights of the riparian appropriators. Beyond this, generalization is very difficult, for the States have gone in different directions through court decisions and legislation.

As stated previously, EOR is regarded as a beneficial use of water. While a nonriparian operator may acquire rights for water in the dual-system States, his rights will be subject to prior appropriation by those senior in rights to him. Ground water is likely to be the subject of special legislation in such States.

State Regulation of Water Use

The trend in the current development of water law has been, as noted by the leading authority on the subject, "toward more public regulations through permit systems, accompanied by new legislative efforts in some States to recognize the interrelationship between many surface and ground water sources and to combine the controls and management under one statute.[99] Regulation is more comprehensive generally in the more arid Western States than in the more humid Eastern States, although the Eastern States do regulate pollution of waters. A number of Western States following the prior appropriation doctrine have agencies which regulate the acquisition, transfer, or change of appropriation rights. Because regulation of ground water is of relatively recent date in most States, its treatment in statutes tends to be more comprehensive than for surface waters, and the permit systems are more extensive.

Whether surface waters or ground waters are to be used in enhanced recovery, it is likely, particularly in the western half of the United States, that an operator will have to be issued a permit acknowledging his right to the water prior to using the water he has acquired for the EOR project. This will probably be done through the office of a State engineer, a commission, or a water resources board in a proceeding separate from the one for a permit to inject the water. The procedure is similar to that for getting approval for the EOR project. There have been few cases arising from administrative problems involving enhanced recovery projects, and little or no indication from the literature or the questionnaires that State regulation of water rights has caused any problems for enhanced recovery. The potential for problems exists, however, because the agencies might likely become focal points for competing claims over the uses to which fresh water should be put.

Table C-1
Unitization Statues: Voluntary and Compulsory
[Adapted from Eckman, 6 Nat. Res. Lawyer 382 (1973)]

Statute	Citation
Alabama	Code of Ala., Tit. 26, ~fj 179 (70) to 179(79)
Alaska	Alas. Stat. $31.05.110
Arizona	Ariz. Rev. Stat. $$27-531 to 27-539
Arkansas	Ark, Stat. Ann. 1947, $53-115, C-1 to C-8
California Subsidence	Calif. Pub. Res. Code $$3321 to 3342
California Townsite	Calif. Pub. Res. Code Q$ 3630 to 3690
Colorado	Colo. Rev. Stat. 1963, 100-6-16
Florida	Fla. Stat. Ann. ~ 377.28 (1) and (2)
Georgia	Ga. Code Ann. $43-717 (b) and (c)
Idaho	Idaho Code ~ 47-323
Illinois,	Smith-Hurd, Ill. Rev. Stat. Ch. 104$84 b, c
Indiana	Burns Ind. Stat. ~ 46-1714 (b) and (c)
Kansas	Kans. Stat. Ann. $$55-1301 to 15-1315
Louisiana Subsection B	La. Rev. Stat. 1950, Tit. 30, # 5B
Louisiana Subsection C	La. Rev. Stat. 1950, Tit. 30, $ 5C
Maine	Me, Rev. Stat. ~ 2159
Michigan	Mich. Comp. Laws Ann. 3$319.351 et seq.
Mississippi	Miss. Code 1972 ~$ 53-3-101 to 53-3-110
Missouri	Rev. Stat. Mo. 1969, $259,120
Montana	Rev. Code of Mont. 1947, $$ 60.131.1 to 60.131.9
Nebraska	Re. Rev. Stat. Neb. 1943, $57-910
Nevada. ... ,	Nev. Rev. Stat. 522.070
New Mexico	N.M. Stat. Ann $$ 65-14-1 to 65-14-21
New York. ... ,	N.Y, Environ. Conserv. Law $23-090, subdivs. 1, 3-12
North Dakota	No. Dak. Cent. Code $$ 38-08-09.1 to 38-08-09.17
Ohio	Ohio Rev. Code $1509.28
Oklahoma	52 Okla. Stat. Ann. $~ 287.1 to 287.15
Oregon	Ore. Rev. Stat. 520.270 to 520.330
South Dakota	So. Dak. Comp. Laws 45-9-37 to 45-9-51
Tennessee	Term. Code Ann. 60-104 (d) (13)
Texas	Vernon's Civ. Stat. Tex. Ann., Article 6008b
Utah	Utah Code Ann. 40-6-17
Washington	Rev. Code Wash. ~~ 78.52.340 to 78.52.460
West Virginia	W. Va. Code 1931 $4 22-4 A-8 to 22-4 A-9
Wyoming	Wyo. Stat, ~ 30-222

Table C-2
Comparative Chart of Aspects of Unitization Statutes

State	Percent working or royalty int. req'd vol. = voluntary only:	Proof or findings required				Unit area Part or All of Single or Multip. pools	Water rights doctrine R-riparian PA-prior appropriation D-dual system
		Inc. ult. recovery	Prevent waste	Protect corr. rights	Add.cost not over add. recov		
Alabama	75	Yes	Yes	Yes	Yes	PAM	R
Alaska	62.5	Yes	Yes	Yes	Yes	PAS	PA
Arizona	63	Yes	Yes	Yes	Yes	PAS	PA
Arkansas	75	Yes	Yes	Yes	Yes	PAS	R
California Subsidence*	65	No	No	Yes	Yes	PAM	D
California Townsite*	75	Yes	—	Yes	Yes	AS	D
Colorado	80	Yes	—	Yes	Yes	PAM	PA
Florida	75	Yes	Yes	Yes	Yes	PAM	R
Georgia	None	—	—	—	—	PAS	R
Idaho	vol.	—	Yes	orYes	—	PAM	PA
Illinois	75	Yes	Yes	Yes	Yes	PAM	R
Indiana	None	Yes	Yes		Yes	PAS	R
Kansas	75	Yes	Yes	Yes	Yes	PAS	D
Kentucky	75	Yes	Yes	Yes	Yes	PAM	R
Louisiana Subsection B.	None		Yes			PAS	R
Louisiana Subsection C	75	Yes	Yes	Yes	Yes	AM	R
Maine	85-W -65-R	Yes	—	—	Yes	PAM	R
Michigan	75	Yes	Yes	Yes	Yes	PAM	R
Mississippi	85	Yes	Yes	Yes	Yes	PAM	D
Missouri	75	Yes	Yes	Yes	Yes	PAS	R
Montana	80	Yes	—	Yes	Yes	PAM	PA
Nebraska	75	Yes	Yes	Yes	Yes	PAM	D
Nevada	62.5	Yes	Yes	Yes	Yes	PAS	PA
New Mexico	75	Yes	Yes	Yes	Yes	PAS	PA
New York	60	Yes	—	Yes	Yes	PAS	R
North Dakota	80	Yes	Yes	Yes	Yes	PAM	D
Ohio	65	Yes	—	Yes	Yes	PAS	R
Oklahoma	63	Yes	Yes	Yes	Yes	PAS	D
Oregon	75	Yes	Yes	Yes	Yes	PAM	D
South Dakota	75	Yes	Yes	Yes	Yes	PAM	D
Tennessee	50						R
Texas	vol.	—	Yes	Yes	Yes	PAM	D
Utah	80	—	Yes	Yes	Yes	PAS	PA
Washington	None	Yes	Yes	Yes	Yes	AM	D
West Virginia	75	Yes	Yes	Yes	Yes	AS	R
Wyoming	80	Yes	Yes	Yes	Yes	PAM	PA

● See text, page 211.

Adapted in part from Eckman,6Nat Res. Lawyer 384(1973).

APPENDIX C
FOOTNOTES

1 The description here is of what is known as the "unless" type lease, the type in use in most States. A slightly different type lease, an "or" lease, is in use in California. The difference between the two relates primarily to the automatic termination of the lease in the primary term for the "unless" lease. H. Williams and C. Meyers, *Oil and Gas Law*, $601.5 (1975).

2 Gray, "A New Appraisal of the Rights of Lessees Under 011 and Gas Leases to Use and Occupy the Surf ace," 20 *Rocky Mt. Min. L. Inst.* 227 (1 975).

3 *Carter* 011 v. *Dees*, 92 N. E.2d, 519 (1 950).

4 Merrill, "Implied Covenants and Secondary Recovery, 4 *Okla.* 1. *Rev* 177 (1 951); Walker, "Problems Incident to the Acquisition, Use and Disposal of Repressuring Substances Used in Secondary Recovery Opera tions, " 6 Rocky *Mt. Min L Inst* 273 (1 961); see also, H. Williams and C. Meyers, *Oil and Gas Law* § 935 (1 975), and cases and authorities cited therein.

5 Martin, "A Modern Look at Implied Covenants to Explore, Develop, and Market Under Mineral Leases, " 27th *Oil & Gas Inst* 177 (Matthew Bender 1976).

6 In re Shailer's Estate, 266 P.2d 613, 616-617 (Okla. 1 954).

7 *Tidewater Oil Co. v. Penix, 223* F. Supp. 215, 217 (E.D. Okla. 1963).

8 See generally, Interstate Oil Compact Comm ission, *A Study of Conservation of 011 and Gas in the United States*, 13-14 (1964).

9 The rules and regulations (No. 105) of the Arizona Oil and Gas Conservation Commission, to cite another example, provide that an 80-acre spacing will apply for oil wells in the absence of an order by the Commission providing for the spacing of wells and establishing drainage or drilling units for a reservoir.

10 A recent treatment of the subject is Bruce, "Maximum Efficient Rate—Its Use and Misuse in Production Regulation," 9 *Nat. Res. Lawyer* 441 (1 976).

11 H. Williams and C. Meyers, *Oil and Gas Law* § 901 (1975).

12 Ibid,

13 R. Myers, *The Law of Pooling and Unitization* § *3.02(2)* (2d ed. 1967).

14 H. Williams and C. Meyers, *Oil and Gas Law* § *339.3, 1975.*

15 For discussion of th is unit, OTA has drawn upon Prutzman et al , "Chronicle of Creating a Fieldwide Unit, " .5th *National Inst. for Petroleum Landmen* 77 (1 964).

16 Description of the establishment of this unit is contained in R. Myers, *The Law of Pooling and* Unitization Ch. IV (2d ed. 1967) and the discussion of unit formation which follows is largely drawn from this work.

17 Ibid. § 10.08 (1 976 Supp.).

18 Ibid. § 10.07.

19 *Enhanced Oil* Recovery, National Petroleum Council, (December 1976), 87.

20 Ibid. 88,

21 Ibid. 89,

22 R. Myers, *The Law of Pooling and Unitization* § 4.02(2d ed. 1967).

23 Ibid.

24 Ibid. § 4.06,

25 Appendix C gives the citation to each State's compulsory unitization statute and the basic requirements of each State's act(s) (tables C-1 and C-2).

26 43 U.S.C. § 1 334(a) (l).

27 OCS Order 11 (16) (Cult of Mexico Area).

28 OCS Order 11 (15) (Gulf of Mexico Area).

29 Eckman, "Statutory Fieldwide Oil and Gas Units: A Review for Future Agreements, " 6 *Nat. Res. Lawyer 339* (1 973); Lawson, "Recent Developments in Pooling and Unitization, " 23rd *Oil & Gas Inst.* 145 (1 972); R. Myers, *The Law of Pooling and Unitization*, Ch. IX (2d ed. 1967); W. Summers, *The Law of Oil and Gas*, Chs. 29, 31 (1 966); H. Williams and C. Meyers, *Oil arrd Gas Laws* § 913 (1 975).

30 Louisiana Revised Statutes, Title 30, Ch. 1, § 6(B).

31 E.g., Moore *Oil, Inc. v. Snakard,* 150 F. Supp. 250 (W.D. Okla. 1957), remanded on joint motion of parties, 249 F.2d. 318 (10th Cir. 1957).

32 11 Alaska Administrative Code § 22.540.

33 Colorado, for example, provides that any party to the commission's rehearing who is dissatisfied with the disposition of the application for rehearing, "may appeal therefrom the district court of the county wherein is located any property of such party affected by the decision, by filing a petition for the review of the action of the commission within twenty (20) days after the entry of the order following rehearing or after the refusal for rehearing as the case may be, " Colorado Revised Statutes, Title 65, Article 3$ 22(b).

34 Vernon's Tex. Ann. Civ. Stat., Article 6008b § 1

35 Louisiana Revised Statutes, Title 30, Ch. 1, § 5C.

36 Oklahoma Statutes, Title 52, $287.4.

37 Ibid. §287.6.

[38] *Producers Development Co.* v. *Magna Oil Corp*, 371 P.2d 702 (Okla. 1962).

[39] H. Williams and C, Meyers, *Oil and Gas Law* § 970 (1 975), and cases discussed therein.

[40] Eckman "Statutory Fieldwide Oil and Gas Units: A Review for Future Agreement" 6 *Nat. Res Lawyer* 339, 360 (1 973).

[41] E.g., Wyoming Statutes Annotated, $30-222.

[42] H. Williams and C. **Meyers,** *Oil and Gas Law* § **911** (1 **977); R** Myers, The *Law of* Pooling *and Unitization,* Ch. XII, **(2d** ed. 1967)

[43] 317 US. 341 **(1** 943).

[44] R **Myers,** *The Law of Pooling and Unitization* § 12.03 **(1**), (2d ed 19671.

[45] *United States* v. *Cotton Valley Operators Committee,* 75 F. Supp. **1,** 77 **F. Supp** 409 (W **D.** La. 1948), *aff'd* **339** U.S. 940 (1 950).

[46] H. Williams and C. Meyers, *01/ and Gas Law* § 953 *(*1**975).**

[47] Oklahoma Corporation Commission, General Rules and Regulations of Oil and Gas Conservation Division, **vision,** § **2-261** (d)

[48] E.g**,** Texas **Railroad** Commission, **011** and Gas Division; Rule 48, New Mexico Oil Conservation Commission, Rule **701** E.3

[49] *Tide Water Associated Oil Co. v Stott, 159* F. 2d 174 [5th Cir. 1946), cert. denied 331 U.S. **817** (1 **947).**

[50] *Dobson* v. *Arkansas Oil and Gas Commission,* 235 S W.2d 33 (Ark 1950).

[51] Other examples include *Republic Natural Gas co* v. *Baker, 197* F 2d 647 (1 Oth Cir. 1952); *Corley* v. *Mississippi State Oil and Gas Board,* 105 S 2d 633 (Miss. 1958); *Barnwell, Inc* v. *Sun Oil Co*, 162 S 2d 635 (Miss. 1964) See generally, H Williams and C. Meyers, *Oil and Gas Law* § 933 (1 975)

[52] *Union R,] ilroad Co* v. *011 and Gas Conservation Comrn/$$/err,* 284 P.2d 242 (Colo. **1955),**

[53] *Helmeric b & Payne, Inc.* v. *Corporation Commission,* 532 P.2d 419 (Okla. 1975).

[54] A State by State brief treatment is Interstate 011 Compact Commission, *Summary of Secondary Recovery and Pressure Maintenance Rules and Regulations in* tire *United States* (September 1969).

[55] New Mexico Oil Conservation Commission, Rule 701 B 1,

[56] **Kansas** Corporation Commission, General Rule\ and Regulations, § 82-2-502, A well log is the **written record** describing **the strata, water,** oil or gas encountered in drilling **a well** with **such additional information as to gas volumes, pressures rate of fill-up, water depths, caving strata, and casing record as is usually recorded in the normal procedure of drilling.** *Ibid., $82-2-101,*

[57] E.g. **Texas Railroad Commission,** Oil **and Gas Division, Rule 36(c) (1 O) pertaining to hydrogen sulfide Injections,**

[58] 1 **1 Alaska Administrative Code § 22.400(c).**

[59] Michigan, **for** example, **gives the supervisor** of wells the **authority, as part of his power to prevent waste,** "To **require** the **locating, drilling, deepening, redrilling or** reopening, casing, **sealing, operating and plugging of wells** drilled **for 01 l and gas or for secondary recovery projects, or wells for the disposal of salt water, brine or other oil field wastes to be done in such manner or by such means as to prevent** the **escape of oil** or **gas out of one stratum into another, or** of **water or** brines **into oil or gas strata; to prevent** pollution **damage to or destruction of fresh water** supplies including **inland lakes and streams and the Great Lakes and connecting waters, and valuable brines by oil, gas or other waters, to prevent the escape of oil, gas or water into workable** coal **or other mineral deposits; to require the** disposal **of** salt water **and brines and oily wastes produced** incidental **to** oil **and gas operations, in such manner and by** such **methods and means that no unnecessary damage or danger to or destruction** of **surface or underground** resources**, to neighboring properties or rights, or to life,** shall **result.** " Mich. Comp Law **Ann § 319.6(c).**

[60] 42 U.S.C. §§ **300** f-300j-9.

[61] **140** CFR Part 146, **41** Fed. Reg. 36730 (August 31, 1976)

[62] 42 **U,** S.C. § **300h (b)(1).**

[63] Ibid. §§ 300h **(b) (2).**

[64] 41 **Fed, Reg. 36731.**

[65] Ibid.

[66] Ibid. 36744. 40 **CFR § 146.47.**

[67] 35 *01/ & Gas Compact Bulletin,* June **1** 976 **p 13,**

[68] Council **on Wage and** Price Stabi**lit y** Release **CM'** PS-204 (Oct. **27, 1976).**

[69] **Ibid. at 23-24.**

[70] Letter of Roy **F. Ca l** son, Production Director, American Petroleum Institute, Dallas, Tex., to Office of Water Supply, Environmental Protection Agency, Washington, D C,, under date of Jan, 12, 1977.

[71] A l ist of these is contained in H. Williams and C Meyers, *Oil and Gas* Law, § *204.5* (1975).

[72] Lynch, "Liability for Secondary Recovery Operations," 22nd *Oil & Gas Inst.* 37, 79(l 97 l),

[73] 1 59 F. 2d 174 (5th C ir. 1946), cert. denied, 331 U S **817** (1 **947),**

[74] 92 NE **2d** 519 (Ill app. **1950).**

[75] Ramsey v. Carter Oil Co., 74 F. Supp. 481 (E. D. Ill. 1947), affm'd 172 F.2d 622 (7th Cir.), cert. denied 337 U.S. 958 (1949), reh. denied, 338 U.S. 842 (1949).

[76] 159 N. E. 2d 641 (Ill 1959).

[77] Syverson v. North Dakota State Industrial Commission, 111 N.W.2d 128 (N.D. 1961).

[78] California Co. v. Britt, 154 So.2d 144 (Miss. 1963).

[79] 361 S.W.2d 560 (Tex. 1962).

[80] H. Williams and C. Meyers, *Oil and Gas Law*, § 204.5 (1975).

[81] Lynch, "Liability for Secondary Recovery Operations," 22nd *Oil & Gas Inst* 39, 65 (1971).

[82] 444 F.2d 439 (10th Cir. 1971).

[83] California Public Resources Code §§ 21000-21151.

[84] 42 U.S.C. § 4332

[85] 42 U.S.C §§ 1857 *et seq*

[86] 43 U.S.C §§ 1151 *et seq*

[87] These classifications by Hutchins have been criticized but they remain useful and have been important in the development of water law. See R. Clark, *Waters and Water Rights* § 3.1 (1967).

[88] Vogel v. Cobb, 141 P.2d 276 (Okla. 1943); Mack Oil Co. v. Laurence, 389 P.2d 955 (Olka. 1964); H. Williams and C. Meyers, *Oil and Gas Law* §219.6 (1975).

[89] *Ambassador Oil co*, v. *Robertson*, 384 S.W 2d 752 (Tex. Civ. App. 1964).

[90] *Robinson* v. *Robbins Petroleum Corp*, 501 S. W. 2d 865 (Tex. 1973).

[91] Walker, "Problems Incident to the Acquisition, Use and Disposal of Repressuring Substances Used in Secondary Recovery Operations," 6th *Rocky Mt. Min. L. Inst* 273 (1961).

[92] 483 S.W.2d 808 (Tex. 1972).

[93] E.g., *Holt* v. *Southwest Antioch Sand Unit*, Fifth Enlarged, 292 P.2d 998 (Okla. 1955).

[94] 483 S.W.2d 808 (Tex. 1972).

[95] A subsequent Texas case held the implied right to use water from the surface of the leasehold did not extend to use of the water for operations off the leased premises *Robinson v. Robbins Petroleum Corp.*, 501 S.W.2d 865 (Tex. 1973).

[96] The discussion which follows is drawn primarily from the following sources: R. Clark *Water and Water Rights passim* (1967); Losee, "Legal Problems of a Water Supply for the Oil and Gas Industry," 20th *Oil & Gas Inst.* 55 (1969); Trelease, "The Use of Fresh Water for Secondary Recovery of Oil in the Rocky Mountain States," 16th *Rocky Mt. Min. L. Inst.* 605 (1971); Walker, "Problems Incident to the Acquisition, Use and Disposal of Repressuring Substances Used in Secondary Recovery operations." 6th *Rocky Mt. Min. L. Inst.* 273 (1961).

[97] *Mathers* v. *Texaco*, 421 P.2d. 771 (N. M. 1966)

[98] Losee, "Legal Problems of a Water Supply for the Oil and Gas Industry,: 20th *Oil & Gas Inst.* 55, 81 (1969).

[99] R. Clark, *Water and Water Rights* § 441 (1967).

Glossary

Glossary[1]

Accelerated depreciation—Any of a number of forms of depreciation which allow the write-off of capital investments more rapidly than straight line depreciation. Straight line depreciation consists of depreciating an equal fraction each year over the useful life of the asset. With accelerated depreciation, larger fractions are depreciated in earlier years and smaller fractions in later years.

API gravity—The standard American Petroleum Institute (API) method for specifying the density of oil:

$$\text{degrees API} = \frac{141.5}{\text{specific gravity}} - 131.5$$

Barrel—A liquid volume measure equal to 42 U.S. gallons.

Brine—Water saturated with or containing a high concentration of sodium chloride and other salts.

Btu—British thermal unit; the amount of heat needed to raise the temperature of 1 pound of water 10 F at or near 39.2° F; a measure of energy.

Capitalized cost—A cost which is capitalized is not deducted from taxable income in the year it is incurred; rather it is depreciated over the useful life of the investment.

Cash bonus leasing—The leasing system currently being used for most offshore lease sales by the U.S. Government. A fixed royalty, usually .1667, is used, and the winning bidder on each tract is the one with the highest offer of an advance cash payment (bonus) for rights to explore and develop the tract.

[1]Sources: Energy Research and Development Administration and the National Petroleum Council, with additions.

Centipoise— A unit of viscosity equal to 0.01 poise. A poise equals 1 dynesecond per square centimeter. The viscosity of water at 20° C is 1.005 centipoise.

Connate water—Water that was laid down and entrapped with sedimentary deposits, as distinguished from migratory waters that have flowed into deposits after they were laid down.

Constant 1976 dollars—Dollars with the purchasing power of the U.S. dollar in the year 1976. This term is used to provide a measure of comparability to project costs, revenues, rates of return, and capital requirements which might otherwise be distorted by varying estimates of the unpredictable factor of inflation or deflation in future years.

Core—A sample of material taken from a well by means of a hollow drilling bit. Cores are analyzed to determine their water and oil content, porosity, permeability, etc.

Darcy—A unit of permeability. A porous medium has a permeability of **1** darcy when a pressure of 1 atm on a sample 1 cm long and 1 sq cm in cross section will force a liquid of 1-cp viscosity through the sample at the rate of 1 cu cm/sec.

Depreciation—A deduction from the taxable income base each year to account for wear and tear and obsolescence of capital equipment.

Depreciation-double declining balance—A form of accelerated depreciation in which twice the normal straight line depreciation rate is applied each year to the remaining depreciation base.

Depreciation-unit of production—Depreciation based upon the fraction of total estimated reserves that are produced each year.

Discounted cash flow rate of return—A particular measurement of investment profitability that accounts for costs, revenues and the time value of money.

Emulsion—A suspension of one finely divided liquid phase in another.

Enhanced oil recovery (EOR)—That recovery of oil from a petroleum reservoir resulting from application of an enhanced recovery process.

Enhanced recovery process—A known technique for recovering additional oil from a petroleum reservoir beyond that economically recoverable by conventional primary and secondary recovery methods. Three such proc esses are discussed in this assessment:

Thermal recovery process: Injection of steam into a petroleum reservoir or propagation of a combustion zone through a reservoir by air injection into the reservoir.

Miscible flooding *process:* Injection of a material into a petroleum reservoir that is miscible, or nearly so, with the oil in the reservoir. In this assessment, carbon dioxide (CO_2) is the only such material considered.

Chernical flooding process: Injection of water with added chemicals into a petroleum reservoir. In this assessment, two chemical types are considered:

a. surfactants
b. polymers

EOR---Enhanced oil recovery.

Evolution of technology-Presumed future improvements in EOR techniques as a result of research and experience.

Expensed cost—A cost item which is expensed is written-off (deducted from the taxable income base) in the year the cost is incurred.

Fireflooding—A synonym for in situ combustion.

Forward combustion—Air is injected and ignition is obtained at the well bore in an injection well. Continued injection of air drives the combustion front toward producing wells.

Fracture—A general term to include any kind of discontinuity in a body of rock if produced by mechanical failure, whether by shear stress or tensile stress. Fractures include faults, shears, joints, and planes of fracture cleavage.

Injection well—A well in an oil field used for putting fluids into a reservoir.

In situ—in the reservoir, or, in place.

In situ combustion—Heatin~ oil to increase its mobility by decreasing its viscosity. Heat is applied by igniting the oil sand or tar sand and keeping the combustion zone active by the injection of air.

Interracial tension—The contractile force of an interface between two phases.

Investment tax credit—A credit on taxes payable for capital investment. The credit is a fraction of the cost of the capital investment (currently .1) and is received for the year the investment is placed in service.

Known oil fields-Oil fields in the United States that have produced petroleum before 1976.

Lease—A part of a field belonging to one owner or owner group; an owner commonly "leases" the (mineral) rights to an operator who produces oil, and normally gas, and pays for the "lease" with part of the production (royalty). On occasion, the owner (leasor) and the operator (lessee) is the same person.

Micelle (and micellar fluid)—A molecular aggregate, generally of molecules that have an oil-seeking end and a water-seeking end. An oriented layer of such molecules on the surface of a colloidal droplet stabilizes oil-in-water or water-in-oil emulsions, making oil and water quasi-miscible.

Miscible—Refers to liquids and their ability to mix. Liquids that are not miscible separate into layers according to their specific gravity.

Miscible agents—A third substance that promotes miscibility between water and oil, such as natural gas, hydrocarbon gas enriched with LPG, or compounds that are miscible with oil and with water.

Miscible displacement—When oil is contacted with a fluid with which it is miscible, they dissolve each into the other and form a single phase. There is no interface between the fluids and hence there are no capillary forces active.

Miscible displacement recovery—The use of various solvents to increase the flow of crude oil through reservoir rock.

Mobility—A measure of the ease with which a fluid moves through reservoir rock; the ratio of rock permeability to fluid viscosity.

Monte Carlo simulation-A method for estimating the extent to which uncertainty about the input variables in a complex mathematical model produces uncertainty in the outputs of the model. The model is operated using values selected at random from estimated distributions of the likely values of each input variable. This process is repeated many times (several hundred or more), giving a large sample of output values based on a wide range of combinations of values of input variables. These calculated results are then combined to give an estimate of the mean value and range of uncertainty for each output variable.

Oil recovery—A procedure whereby petroleum is removed from a petroleum reservoir through wells. Three kinds of oil recovery are referred to in this assessment:

Primary recovery: Oil recovery utilizing only naturally occurring forces or mechanical or physical pumping methods.

Secondary recovery: Oil recovery resulting from injection of water or natural gas into a petroleum reservoir.

Enhanced *recovery: See* separate entry.

Oil **saturation—The** extent to which the voids in rock contain oil, usually expressed in percent related to total void.

Original oil-in-place (OOIP)-Petroleum existing in a reservoir before oil recovery.

Permeability—The permeability (or perviousness) of rock is its capacity for transmitting a fluid. Degree of permeability depends upon the size and shape of the pores, the size and shape of the interconnections, and the extent of the latter. The unit of permeability is the darcy.

Petroleum —A naturally occurring material (gaseous, liquid, or solid) composed mainly of chemical compounds of carbon and hydrogen.

Pilot test—An experimental test of an EOR process in a small part of a field.

Polyacrylamide-—A type of polymer.

Polymer—A type of organic chemical, characterized by large molecules, that is added to water for polymer flooding.

Polysaccharide—A type of polymer.

Porosity—The fraction of the total volume of a material that is made up of empty space, or pore space. It is expressed in terms of the volume of pore space per unit volume of the material. Porosity is a measure of the material ability to absorb liquids, since it measures the empty space available to hold liquids.

Present value—The current worth of a flow of income. Income in future periods is discounted by the interest between the current period and each future period. Present value is the sum of the discounted values **for all future periods as** shown below:

$$PV = \sum_{t=1}^{T} \frac{V_t}{(1+r)^t}$$

where V_t is the income (or loss) in year t and r is the rate of interest.

Price elasticity of supply—The responsiveness of quantity supplied to changes in price. Specifically, elasticity is the percentage change in quantity divided by the percentage change in price.

Primary recovery—See oil recovery.

Rate of return—The rate of interest yielded by **investments in a project. Specifically, the rate of return is the rate of interest which equates the stream of revenues and costs to zero as shown below:**

$$o = \sum_{t=1}^{T} \frac{V_t}{(1+i)^t}$$

where V_t is after tax value in year t and i is the rate of interest which equates the time stream of values to zero. V_t may be positive or negative-usually it will be negative in early years during investment and positive during later years.

Reserves—The amount of a mineral expected to be recovered by present day methods and under present economic conditions.

Reservoir—A discrete section of porous rock containing an accumulation or oil or gas, either separately or as a mixture.

Reservoir fluids—Fluids contained within the reservoir under conditions of reservoir pressure and temperatures; because of this fact their characteristics are different from the characteristics of the same fluids existing under normal atmospheric conditions.

Residual oil—The amount of liquid petroleum remaining in the formation at the end of a specified production process.

Resource base—Total petroleum in place which may be subjected to attempted oil recovery,

Resources—The estimated total quantity of a mineral in the ground.

Reverse combustion—in this process, the formation is ignited at the producing well and the combustion zone moves countercurrent to the injected air and reservoir fluid stream. Because the oil flows into a zone already heated, there is no tendency for it to congeal and decrease permeability.

Royalty—A share of production from a lease reserved for the mineral rights owner.

Saturation—Ratio of volume of pore fluid to pore volume, expressed as percent and usually applied to water, oil or gas separately. Sum of the saturations of each fluid in a pore volume is 100 percent.

Screen—A list of conditions that need to be met if a process is to qualify for oil recovery.

Screening process—The steps of determining if a process passes or qualifies under a **screen.**

Secondary recovery—see oil recovery.

Steamflooding—Steam displacement (or steam drive) follows, the same basic principle as the waterflood. Steam under pressure is fed into special injection wells, both to heat the oil in place and to drive it to producing wells.

Steam soaking—Steam is used as a stimulation medium to heat the area of the reservoir around the well bore (also called steam stimulation, huff-and-puff, or cyclic steam injection). Steam under pressure is injected down the casing or tubing of a producing well. A typical steam injection lasts for 5 to 8 days. Following the injection period, the well is returned to production.

Sulfonates—Surfactants formed by the reaction of sulfuric acid (or sulfur trioxide) with organic molecules. The sulfonate group in its acid form is SO_3H, and the sulfur atom is linked directly to a carbon. **In use, sulfonates are neutralized with bases and** used **in the ionic form.**

Surface tension—The tension forces existing in the extreme surface film of an exposed liquid surface due to unbalanced cohesive forces within the body of the liquid.

Surfactant—A material which tends to concentrate at an interface, used to control the degree of emulsification, aggregation, dispersion, interracial tension, wetting, etc.

Sweep efficiency—The ratio of the volume of rock contacted by the displacing fluid to the total volume of rock subject to invasion by the displacing fluid.

Tertiary-Refers to a recovery process that is implemented following secondary recovery; a third recovery phase following primary recovery and secondary recovery. All tertiary recovery is enhanced recovery, but the reverse does not always hold.

Thermal recovery —See enhanced recovery process.

Ultimate recovery—The quantity of oil or gas that a well, pool, field, or property will produce. It is the total obtained or to be obtained from the beginning to final abandonment.

Viscosity—The internal resistance offered by a fluid to flow.

Waterflooding—A secondary-recovery operation in which water is injected into a petroleum reservoir to create a water drive to increase production.

Well logging—The detailed record of the rocks passed through in drilling.

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