1. Executive Summary

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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 os 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 01 l 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-process performance	Upper tier:	$11.62	21.2	0.4	1.1	2.9
	World Oil:	$13.75[a]	29.4	1.0	1.7	5.2
	Alternate fuels:	$22.00[b]	41.6	1.3	2.8	8.2
		$30.00	49.2	[d]		
	More than	$30.00	51.1			
Low-process performance	Upper tier:	$11.62	8.0	0.4	0.5	1.1
	World oil:	$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 foreign oil delivered to the east coast, deflated to July 1, 1976.

[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]Production rates were not calculated for oil at prices of $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.